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The UNFCCC Paris Agreement is indicative of the global effort to shift from fossil to renewable energy. Given its abundance and continuous cost decline, photovoltaic electricity is set to play a major role, requiring determination of its economic value in dependence on market share and time horizon. While the literature evaluates short-term perspectives for small market shares and medium-term for significant shares, we develop an approach to determine the costs of "dispatchable" solar electricity, where distributed photovoltaic electricity combined with storage and transmission serves full market coverage. This provides a reference for the long-term economic value of solar electricity.

Keywords: Renewable Energy, Sustainability, Allocative Efficiency

JEL codes: D61, Q01, Q24

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Implementation of the global community´s objective adopted in the United Nations Framework Convention on Climate Change (UNFCCC) Paris Agreement to hold "the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels" (UNFCCC (2015): Article 2 (1.a)), is likely to respect the broad scientific consensus that "the first step in a comprehensive transformation of the energy system is a decarbonization of the electricity system" (e.g. Rogelj et al. (2015): 523).

The intermittent nature of most renewable electricity generation technologies (solar, wind) renders the traditional evaluation metric of Levelized Costs of Electricity (LCOE) inadequate for economic evaluation – at least in its original form, as system integration costs need to be taken into account. While a revised economic evaluation for solar electricity is covered in the literature for low (Joskow, 2011) and medium market penetration (Barker et al., 2013; Hirth et al., 2015), available approaches for the evaluation of very high (or even complete) market penetration are to date still rudimentary at best, based, e.g., on mitigation oriented Integrated Assessment Models (IAMs), with market penetration either limited at 15 to 30% or requiring strict back up capacity or (fixed) integration mark ups for higher penetration. Examples are the IAM GCAM (Global Change Assessment Model) requirement of one full gas-powered unit backup capacity for each new solar unit when market penetration passes 25% (Van de Ven, 2016) or a fixed cost mark up rising with the share of variable renewable energy in the REMIND model (Regionalized Model of Investments and Development, Luderer et al., 2015). The higher the market penetration the more important is a disaggregated consideration by time and space – e.g. how to meet the "Residual Load Duration Curve" beyond renewable supply – in order to determine the adequate dimension of integration costs and the derived social value of solar electricity (Pietzcker et al., forthcoming; Ueckerdt et al., forthcoming). Most recent advances in Mitigation-Process IAMs indicate that a more appropriate representation of integration costs significantly increases the optimal shares of wind and solar across models (Pietzcker et al., 2016). While specialized energy system models are well prepared to achieve this task, they have not yet been employed for the economic evaluation of *photovoltaic (PV)* solar electricity at very high market penetration (see e.g. Scholz et al., forthcoming).

Thus it remains an open question whether the company level observation that "solar (is) fast becoming [the] least-cost option for US utilities" (Beetz, 2015) will translate equally to the social level also at much higher penetration rates. In other words, what will be the integration costs associated with the recent company level PV electricity offers at 2.90 ¢/kWh (Parnell, 2016b) (or even lower ones in the future) for significantly higher penetration levels of solar?

Given the combination of the steady and ongoing cost decline of PV solar electricity generation and storage technologies, the electrification of many sectors of the economy (e-mobility, housing, industry, see Williams et al., 2012; McCollum et al., 2014), as well as de-carbonization requirements (Paris Agreement), market penetration rates of PV solar electricity are rising worldwide, rendering the determination of its economic value increasingly relevant. What integration costs will society face at significantly higher penetration rates? Technological and economic developments as well as political agreements thus indicate that the economic evaluation for high – or even full – market penetration with solar becomes an issue of major interest.

We here present a method to determine the economic value of photovoltaic electricity (including integration costs) at complete market penetration. This requires the consideration of a system integrating photovoltaic generation capacity with adequate storage capacity and/or spatially dispersed generation connected by transmission lines, as both elements of system extension allow to overcome the intermittency characteristic of PV generation at isolated locations, and the system to supply dispatchable electricity. Costs of adequately designed systems thus include integration costs. We quantify the respective social economic value of PV electricity for different system configurations and time horizons.

We find that system integration costs for photovoltaic electricity can be reduced to such levels that PV could likely be the social best choice even up to the last capacity unit added under complete renewable market coverage. We also discuss the configuration characteristics of generation capacity, storage and transmission in a system of dispatchable PV electricity designed to that end.

I. Economic evaluation of solar electricity

The determination of the economic costs and benefits of installing additional renewable electricity generation capacity differs across the time horizon and market penetration levels considered. For the short term, all costs and benefits are evaluated depending on the existing state of technology and the overall power system (i.e., the operating characteristics of incumbent generators and infrastructure of the electric power system are taken as given). The marginal benefit of expanding solar capacity equals the marginal production cost of the marginal production technology that is substituted for by the expansion of solar electricity production. This marginal production cost of substituted generation includes private (including fuel, depreciation) and social costs (such as GHG emissions). The traditional metric for comparing the competitiveness of generation technologies, the LCOE which measures life-cycle costs per MWh supplied, has been identified as inadequate for intermittent renewables including solar, prominently first in this journal by Joskow (2011). In particular, LCOE does not take into account the economic attractiveness subject to the timing of electricity supply (hour of day and year). With electricity prices fluctuating widely across the day and season (in some instances as much as two orders of magnitude) we typically find a positive correlation between electricity supply and demand profiles for low market penetration of solar. An example is the correlation between solar insolation and electricity demand for air conditioning for most regions in the U.S. during summer. As such correlations increase the attractiveness of solar based on the over-proportional supply in typical peak times, they need to be adequately acknowledged. Baker et al. (2013) analytically specify these benefits for the short run, depicting the relevance of the covariance between the hourly time series of solar generation for replaced marginal production costs on one hand and reduced GHG emissions on the other hand.

For the medium term the power system can structurally adjust to accommodate higher penetration rates by renewables, modifying marginal benefit evaluations. On the cost side, increased adoption of solar technologies tends to reduce production and installation costs.

We label the time horizon as "long-term" for which solar economic evaluation is not influenced by any installed component of the current power system infrastructure, as the power system can by then be redesigned according to long-term objectives (such as carbon-free electricity).

The medium to long-term adjustment of the power system can be geared to acknowledge the specific characteristics of variable renewables and to reduce integration costs. Due to their dispatchable nature, traditional generation technologies like coal, gas-combined cycle, nuclear, and hydropower can be controlled by the system operator. Within some limits (including ramp rates and the associated costs, or water availability for hydropower), they can be switched on and off based on their economic attractiveness with respect to continuously floating electricity prices and system requirements. When dealing with variable renewables system operators rather have to respond to "what comes at them by calling on dispatchable generators to balance supply and demand continuously" (Joskow, 2011). Three characteristics of variable renewables that give rise to system integration costs when adding variable renewables have been identified (Milligan et al., 2011; Borenstein, 2012; Hirth et al., 2015):

- Variability: the supply of variable renewables does not ideally follow load profiles. For solar, for example, supply is characterized by daily and seasonal cycles. This causes integration costs to adjust generation and load profiles. In comparison, fossil fuel based power plants require contingency reserves for cases of sudden system failure, the costs of which are shared among all generation (Milligan et al., 2011).
- Uncertainty: the supply of variable renewables is uncertain until realization as it is determined by weather conditions such as cloud cover, wind speed and direction, or haze, all of which are beyond the control of the system operator. Deviations between forecasted generation and actual production need to be balanced at short notice, which is costly.
- Location-specificity: the supply of variable renewable is location-specific, "i.e. the primary energy carrier cannot be transported in the same way as fossil or nuclear fuels. Integration costs occur because electricity transmission is costly and good renewable sites are often located far from demand centers." (Hirth et al., 2015)

Hirth et al. (2015) derive integration costs of variable renewables from their marginal economic value of electricity in terms of €/MWh. Considering that "the marginal economic value (or benefit) is the increase in welfare when increasing [variable renewable] generation by one MWh" and "if demand is perfectly price-inelastic, this equals the incremental cost savings when adding one MWh to a power system", they define integration cost as the spread between the market value of the variable renewable (i.e. the revenue that an investor in renewables will earn on the market) and the load-weighted average electricity price. The characteristics of variability, uncertainty, and location-specificity and the associated demands on the system (profile-related, balancing-related, and grid-related) – at least for medium to high penetration rates – imply that the market value of the variable renewable is below the load-weighted average electricity price. I.e. in the social optimum the electricity price (which indicates the social value of electricity) also has to cover integration costs. Note, that for low market penetration the integration costs of solar electricity are usually negative, i.e. due to the previously indicated positive correlation of solar supply and demand profile, solar is more attractive than the load-weighted average electricity price. In other words, for low market penetration the effect that solar replaces peak load generation dominates. Since peak generation is more expensive than the average electricity price this implies an additional welfare benefit and thus negative integration cost for employing additional solar electricity.

A complementary view on the very same concept and the above definition of integration cost from the economic value perspective can be taken under the cost perspective. While the traditional cost metric of LCOE covers life cycle cost (installation and operation) of the new generation capacity, this excludes further costs elsewhere in the power system for integrating variable renewables. Variability implies profile-related costs, uncertainty balancing-related costs, and location-specificity grid-related costs. These cost components are somewhat mutually interdependent (e.g. the very same storage can answer several of these demands); their total can be labeled “integration cost” (these costs are identical to the integration costs defined above). From a social cost perspective these integration costs can also be seen to add to the traditional LCOE to give the total of “system LCOE”. The respective integration costs are not determined by the (characteristics of the) variable renewable alone, but by the interaction of the variable renewable and the properties of the power system it is added to.

For any market penetration level (and thus also for the socially optimal quantity of variable renewable supply) the level of integration costs from both perspectives is identical (see Figure 1).

[Insert Figure 1 Here]

Quantifications of costs for low and medium penetration rates of variable renewables are available in the literature; these include integration costs within overall economic evaluations. For low penetration, Baker et al. (2013) report short run costs based on a broad review across solar generation technologies. They analytically specify short run benefits, extending Lamont (2008), including the – at low penetration rates negative – integration cost. They apply a short run evaluation empirically for a single grid-connected 5kW (dc) fixed PV array for four US locations (Boston, MA; San Francisco, CA; Trenton, NJ; Tucson, AZ) and derive a break-even cost per Wp installed (assuming a social cost of carbon at US$ 21/tCO2) of US$ 0.85 (San Francisco, west-facing arrays) to US$ 1.45 (Boston, south-facing arrays), while their most optimistic (yet referring to 2011 and this small-scale unit) installation cost amounts to US$ 3/Wp.

For penetration rates up to 40% Hirth et al (2105) quantify integration costs based on a broad survey of published studies and decompose them to profile-related, balancing-related, and grid-related costs. They find that the largest cost component – notably at this low penetration level and in a medium-term context – is usually reduced utilization of capital embodied in thermal plants, a cost component that has not been accounted for in most previous integration studies.

Solar electricity, however, is likely to gain significantly higher penetration than 40% in the long term. Below we develop a quantitative approach to determine integration costs for significantly higher penetration rates.

For 38 years now installed solar PV capacity has roughly doubled every two years, and the trend in module costs development was stable at a 19% cost reduction with each doubling (Breyer and Gerlach, 2013; Martinez-Duan and Hernandez-More, 2013; Fraunhofer ISE, 2016).

In the following we discuss cost decreases for large-scale installations, currently still at low penetration rates. In an invitation for tender in Dubai in 2014, the winning bid was at 5.7 US¢/kWh (Parnell, 2016a). In a 2015 power-purchase agreement (PPA) between First Solar (vendor) and Berkshire Hathaway total costs of electricity from PV generated in Nevada were at 3.87 ¢/kWh (Clover, 2015). In early 2016 the lowest-price bid accepted for electricity from PV was for Dubai at 2.9 ¢/kWh (Parnell, 2016b). Taking into account the respective insolation in different locations it is possible to calculate the electricity costs if a power plant like the new one in Dubai (at about 2200 kWh/m^2/year) were installed in other locations. Costs would be 3.2 ¢/kWh in the Mojave desert in the US (with 1980 kWh/m^2/year), 2.5 ¢/kWh in the Atacama Desert in South America (with 2525 kWh/m^2/year) and 4.2 ¢/kWh in the Chinese Gobi Desert (with 1520 kWh/m^2/year).

While the PPA covers all direct costs, from operation and maintenance, as well as depreciation, up to profit, it does not cover integration costs. Thus, depending on how the latter develops with rising market penetration, i.e. depending on how solar is integrated into the overall system, and even given that PV electricity costs are forecasted to further decline, it is system integration costs of PV that will determine whether PV will be competitive at very high coverage when compared with system LCOE for other generation technologies. Considering the LCOE for alternative electricity generation options, this could be the case if PV system integration costs can be kept reasonably low: E.g. EIA (2016) gives LCOE for new plants operational in year 2020 in the US of 9.5 ¢/kWh for coal power plants, natural gas 7.3, nuclear 9.5, geothermal 4.8, biomass 10, wind power 7.4 and wind offshore of 19.9.

“The cost of crystalline silicon photovoltaic (PV) modules has fallen by 99% since 1978 and by 80% since 2008” (e.g. Wagner et al., 2015). Given the already low cost of PV and the fast further decrease of costs to date "solar (is) fast becoming [the] least-cost option for US utilities" (Beetz 2015), or the "default technology of the future" (Lacey 2015). Thus the potential (or foreseeable) future of solar electricity expansion merits proper economic analysis of its integration costs for high and very high market penetration, which are achievable in the long term.

II. Economic evaluation of solar electricity in the long term

Physical abundance, expected further cost decreases and greenhouse gas emission concerns render PV electricity particularly promising in comparison with other renewable generation technologies (e.g. Grossmann et al., 2010).

With cost development addressed above, we now consider physical abundance more closely. Previous work suggested installing PV preferably in deserts given abundant insolation and little competition with other uses. We find that the current total global energy (i.e., not just electricity) demand, if met with electricity, could be met by a PV area accounting for 1.4% of the total global desert area (in absolute 265, 500 km^2, see Appendix for details). While this is an illustrative comparison, a significant fraction of actual PV capacity is installed by households, farmers and companies on their buildings or in the form of building-integrated PV (Kalogirou, 2015). In those terms the U.S. rooftop area alone could cover 50% of the current U.S. electricity demand. Farmers in hot regions (latitudes below 35°) often use shading cloth for valuable crops (Marrou et al., 2013). If semitransparent PV is used for agricultural shading (Dupraz et al., 2010; Macknick et al. 2013), 5% of the U.S. agricultural area could (physically) meet the global energy demand; the PV panels could be installed sufficiently high so that vehicles can be operated beneath them. Thus, there is no evident scarcity of area and PV installations are often built in the most surprising places to take advantage of the abundant solar influx. In particular building-integrated PV is seen as enabling a highly desired architectural revolution, inducing more comfortable buildings and reducing costs of ownership (Cockram, 2016).

One electricity generation technology – at selected locations – turns out competitive with PV: wind. In some locations in the U.S. wind electricity can come at costs as low as 2-3 ¢/kWh (American Wind Energy Association, 2016). However, this potential is quite limited in quantity. Due to lack of good land-based locations wind plants increasingly have to be built in offshore locations, in spite of the very high costs. In comparison, space for PV is abundant.

For the long term there are thus clear indications to consider a power system with PV electricity as the reference technology, i.e. the default technology that will provide the last unit added for full market coverage. This possibility is indicated e.g. in DOE's SunShot mission "to be a catalyst to enable dispatchability in solar power plants [PV and concentrating solar power] in order to accommodate and interconnect ANY level of high penetration of solar generation in the grid." (DOE 2016, accentuation in original).

A. Dispatchable solar electricity

Consequently we suggest considering PV electricity as a reference technology for the long term perspective. Other sources of renewable energy should be added to the energy system if their performance is superior to PV (which would then further decrease costs).

What would a system in which PV has the dominant market share look like and what would be its costs? The fractions of other renewables that come at system LCOE below that of PV will remain well below full market coverage, and PV is to supply the load profile remaining after subtraction of such exploited and socially cheaper supply options. At least as a thought experiment this perspective can be pursued here to learn from its results.

As photovoltaic electricity is an intermittent renewable, a system containing only generation modules cannot meet demand profiles with their wide variety of shapes typical for the present system. The balancing of supply and demand can, however, be achieved by (a) adding storage capacity to the system and/or (b) integrating generation sites at various locations into the system. In order to isolate and analyze the supply side, we do not address here the third option of balancing, demand side management, but take load profiles as given. A PV-based electricity system that is capable of supplying any particular pre-specified load profile (which we shall label "dispatchable solar electricity" system) thus combines the elements of PV modules for electricity generation, energy storage, and/or transmission lines to connect different generation (and demand) locations. Present technological developments in four areas (PV modules, lithium-ion batteries, high-voltage direct current (HVDC) transmission and semi-conductor based power electronics) have made it possible to design such a solar system as a dispatchable one, capable of meeting any given load profile (Grossmann et al., 2015; on recent enabling supergrid technology developments see MacLeod et al., 2015; National Academy of Sciences, Engineering and Medicine, 2016 and Tahata et al., 2015).

As the long-term consideration does not know any fixed costs, long-term marginal costs equal average costs. Solar electricity system LCOE thus are equal to the average cost of a solar electricity supply system (including generation capacity, storage capacity and transmission lines) capable of supplying the particular load profile demanded (or covering a residual load profile for the case when supply of renewable electricity generated with lower system LCOE has been subtracted).

B. The design of a cost minimal dispatchable PV electricity system

In the design of a dispatchable PV electricity system let us start with a system at a single location. To meet any load profile with demand at times when there is no (or low) solar radiation, electricity storage capacity needs to be integrated. Using (hourly) annual solar insolation data at any specific location the required pairs of electricity generation capacity G and storage S can be derived, such that S is minimal to provide a given dispatchable electricity load profile for a given G. We previously showed that these pairs exhibit a smooth relationship of mutual substitutability between G and S (G-S isolines, Grossmann et al., 2015), see e.g. the G-S isoline for location New York in Figure 2. A G-S isoline is the curve combining minimal G and S along which the given load is met, whether it is of constant or variable profile. The G-S isoline is the lower boundary of the feasible area of all values of G and S that meet a given load. Along an isoline, increasing S decreases the required G by evening out daily and seasonal intermittency, while adding G reduces the required S by meeting the load directly also shortly after sunrise and before sunset (see the Appendix for more detailed information on G-S isoline derivation).

While isolines between production factors are broadly used in microeconomics, it is not self-evident that solar insolation—which is governed by attenuation and the overlap of the daily and seasonal cycles—will yield a smooth tradeoff between G and S. We found empirically that this relationship holds for linear loads and for real hourly loads with considerable variation that fluctuate rapidly over time (Grossmann et al. 2015), and thus can use this relationship below to determine system LCOE of dispatchable solar electricity as the costs arising at the minimal cost combination of G and S that can meet any such given load profile.

[Insert Figure 2 here]

The second direction to match specific load profiles with intermittent solar radiation is the introduction of a geographical spread of generation sites to reduce the effect of the day and night cycle and of seasonal variations. East-west enlargement addresses the former, north-south enlargement the latter in increasing the area (and thus points in time) in which (significant) solar radiation can be used by the system. We integrate the three large deserts in North America (Mojave, Chihuahuan, Sonoran) to a configuration NA3, add further production sites across North and South America to a Pan-American configuration with 18 sites, PA18 (for configuration details see Table A.1 in the Appendix), and finally add further locations across the globe to a global configuration of 77 sites, G77 (see Figure 2; for configuration details see Table A.2 in the Appendix). The G-S-isoline relationship holds for hourly and daily insolation data in a 10 km × 10 km grid, for insolation from an isolated location with irradiation data at 10-min intervals and for arbitrary connections between up to 240 1°×1° locations distributed over the whole globe, including Arctic and Antarctic locations with six months of night. Including Antarctica is done only for analytical and illustrative purposes as the respective international treaties preclude any commercial use of areas in Antarctica. Such a geographically extended network can overlay different rhythms of day and night as well as seasonal cycles such that the network always has a sufficient amount of radiation. A combination of locations without night would be expected to hide or at least distort the hyperbolic shape of the respective isoline as the cosine pattern of daily solar radiation (Milone and Wilson, 2008) is almost hidden under the overlay of manifold daily patterns. It is thus remarkable that G−S isolines for global networks still show the hyperbolic shape (Grossmann et al., 2015). Increasing geographical spread, on the other hand, adds the requirement for transmission lines, with cost minimizing design of such distributed solar networks addressing the three cost components of generation capacity, storage and transmission lines.

Finally, we have to address uncertainty of supply at any specific point in time and location due to phenomena such as cloud cover or haze. We found that expanding the time horizon of observed solar irradiation data that feeds into the G-S isoline construction across a multi-year period shifts the isoline outward, as the likelihood of particularly unfavorable weather conditions to be included increases. However, the more we expand the time horizon, the smaller the further outward shift, which might indicate the existence of an upper bound for the isoline. This is best visible for a trans-hemispheric configuration of fewer generation locations, as given for a Pan-American configuration of 6 locations in Figure 3 (for configuration details see Table A.1 in the Appendix). While the G-S isoline shifts significantly when expanding the time horizon by 5 and 10 years, the 10 year and 20 year time horizon isolines already overlap almost fully. We note that G-S isolines in the earlier Figure 2 have been derived drawing from the extensive 20 year time horizon on solar insolation data.

[Insert Figure 3 here]

We are thus equipped with the G-S isoline concept for analyzing the interaction between generation capacity, storage capacity and geographically dispersed production in PV systems addressing all three dimensions of integration costs. We will apply these in the following to derive minimal costs of dispatchable solar electricity. This will serve as the indicator for system LCOE (i.e. including integration costs) of dispatchable solar systems, the relevant cost reference value for high market penetration levels.

C. The time horizon to establish a dispatchable PV electricity system

If we take into account the higher efficiency of electricity compared to fossil fuels and assume a continuation of the last 38 years in which global installed PV capacity doubled every two years, it would take 20 more years (i.e., up to 2036) with a current installed PV capacity of 0.25 TWp and a current total global energy demand of 10 TW, to reach an installed PV capacity of 250 TWp that could serve the fivefold current global total energy demand (total energy, not just electricity) within a G-S isoline optimized dispatchable PV system. We consider this the time required at least to install a system of full PV market penetration.

III. System LCOE of PV electricity at complete market penetration

In the subsections below we identify installation cost rates that are then used for cost minimization of different PV system configurations. To that end we first discuss the time profile of installation. Installing PV capacity for complete market penetration – when we continue to follow the global doubling of installed capacity every two years which we observed for the last 38 years – would take until around 2036, as we just indicated. Installation at this speed (or slower) implies that at least 99% of the ultimately installed capacity will be installed after 2022. By 2022 a further three capacity doublings beyond the 2016 level (and associated production cost reductions) will have occurred. In our analysis we will thus employ not only current cost levels for installing generation capacity, storage capacity and transmission lines, but also those foreseen for 2022, which will most likely still result in an upper bound for long term system LCOE of dispatchable PV electricity, as growth towards global size would most likely further decrease the costs of these components.

Note, however, that we follow the long-term cost concept here, implying that we assume that all existing generation capacities incompatible with the new system have reached the end of their planned lifetime. If the development of such global PV supply occurs at a speed that completes the production grid faster, rendering this assumption not to hold for some capacity, additional costs of reduced utilization of capital embodied in current (thermal) plants would need to be added. We will return to this qualification.

A. Cost of PV generation and storage capacity

The 2016 Dubai electricity bid can be used to infer the underlying investment cost, requiring a lifetime assumption. The actual lifetime of PV has improved during the last decade and now might be 50 or 60 years (e.g. according to the European Institute for Photovoltaics). Financing institutions prefer to use a lower life expectancy to be on the safe side. With a 40 year lifetime and 5% capital costs the 2.9 ¢/kWh electricity costs in Dubai correspond to costs of fully installed PV, including profit and operation and maintenance, of $1094/kWp; with a 30 year lifetime, the costs would be $980/kWp. The installation costs in 2022 will benefit from triple cost reductions by 19% each. We thus in the following employ PV capacity installation costs of $1000/kWp in 2016 and $500/kWp in 2022.

For storage we use lithium-ion battery storage costs at two levels, $150/kWh and $100/kWh. In 2016 General Motors will pay $145/kWh for the batteries of its new electric vehicle, the Chevrolet Bolt and has announced costs of $100/kWh in 2020 (Cole 2015). Tesla has announced costs of $100/kWh for its batteries for electric vehicles after 2020 (Bullis 2014). According to Jefferies analyst Dan Dolev (Ayre 2015), Tesla will drive down battery-pack-level costs to around $38/kWh once Tesla's Gigafactory hits peak production via economies of scale, improved chemistry, supply chain optimization, and other factors. Thus our high value is above the cost level announced by two leading companies and our low cost level is considerably higher than the extreme projection by Dolev.

B. Cost of transmission lines

With HVDC transmission cables only recently installed for a distance of 580 km, and a contract awarded for the survey for a 1470 km cable between Iceland and the UK (MMT 2015), uncertainties persist on how to cross deep-sea topography with several faults and sea bed mountain ranges (Karlsdottir, 2013), a challenge that exists for all trans-Atlantic and trans-Pacific routes. Hence, costs of transmission lines and their future development is significantly more uncertain than costs of PV electricity generation modules or Li-ion batteries. In the following we thus only use the latter two cost rates to optimize for minimum cost electricity, and we only add the bandwidth of possible transmission costs development on top of resulting minimal costs of (G,S) combinations. We recalculate transmission costs from Chatzivasileiadis et al. (2013) as given in the Appendix and employ resulting cost rates as given in Table 1 for each of the configurations analyzed here. With extensive experiments on the origin of electricity in a Pan-American network and a European-American configuration we found that on average about 1/3 of the electricity comes from the longest distance, 1/3 from regional distance and 1/3 is local, which thus are the shares we use for the fractions of electricity generation that transmission costs (for respective distances) need to be allocated to for each configuration. Table 1 gives lower and upper bounds for transmission costs for year 2012 (for two different types of cables, Britned and newer NorNed, both using costs from Chatzivasileiadis et al., 2013) and forecasts costs for year 2022 at both 5% learning rate and 10% learning rate (for derivation see the Appendix).

[Insert Table 1 here]

C. Cost of dispatchable PV electricity at complete market penetration

Applying the above installation cost rates per kWp generation capacity and per kwh storage capacity we employ the G-S isolines for the four configurations to identify cost minimal generation and storage combinations to continuously meet a 1,000 kW load. For each configuration and for the costs connected to two installation years (2016 and 2022) Table 2 reports the optimal G-S combinations, annualized costs, as well as system LCOE, including integration costs and transmission costs in the respective bandwidth. For the configurations NA3 and PA18 PV generation capacity is equally distributed across respective sites, for the global configuration G77 we found that optimized distribution of generation capacity across sites could further decrease costs by 5% and thus do report the results for this configuration (specified in Table A.2 in the Appendix in detail).

[Insert Table 2 Here]

Integration cost I_{PV} of PV systems with complete market penetration (reported in column (6) of Table 2) is given by the difference between $\text{LCOE}_{\text{system}}$ (i.e. the costs of dispatchable electricity, reported in column (8) in Table 2) and $\text{LCOE}_{\text{traditional}}$, and is defined by

$$(1) \qquad I_{PV} = LCOE_{system,PV} - LCOE_{traditional,PV} = \frac{C_G + C_S + C_T}{L} - \frac{C_G}{E},$$

where C_G denotes annuity of costs of PV generation capacity, C_S of storage capacity, and C_T of transmission lines of the overall PV system, L denotes the annual electricity load met by the PV system, i.e. only that fraction of electricity generation actually demanded, with excess supply not considered, while E denotes the annual total electricity generated, i.e. irrespective of whether it meets demand or is excess supply of electricity.

We find integration costs to strongly vary with system design. Dispatchable electricity of PV-only systems can first be enabled by the integration of storage. When implemented at single locations this implies costs at about the level that Table 2 (column 6) indicates for New York, 12.51 ¢/kWh, resulting in a system LCOE at 14.76 ¢/kWh (in the long-term perspective; for 2016 installation costs the integration costs are even close to double this value). Following also the complementary strategy of geographical dispersed PV electricity generation, integration costs can be significantly reduced. Each of the following extensions reduces integration costs to less than half: integrating sites across a continent like North America reduces integration costs to 5.54 ¢/kWh (i.e. that part of integration costs that relate to PV capacity and storage, as a fraction of primary electricity costs denoted in Table 2, column (5); to get full integration costs for dispersed networks now transmission costs have to be added, here of 0.02 to 0.08 ¢/kWh). Expansion across the hemispheres reduces them to 1.77 ¢/kWh (plus up to 0.65 ¢/kWh for transmission) and for a global network integration costs amount to (including transmission costs) 0.55 – 1.37 ¢/kWh. We note that in principle dispatchability could also be established by a pure strategy of only geographic dispersion (while employing no storage at all). We presented such a system in Grossmann et al. (2015), but note that this is connected to somewhat higher integration costs.

We conclude that system design for an energy system price determined by PV dispatchable electricity does not only significantly matter for the level of integration costs, but can also be used to reduce integration costs to render dispatchable PV electricity competitive.

IV. Discussion

Having employed the tool of G-S isolines to quantify system integration costs for PV electricity as a reference technology at complete market penetration we find that and discuss in the following:

- System integration costs depend on overall system design at least as strongly as on the market penetration rate;
- More specifically, for PV electricity at complete market penetration the trans-hemispheric connection is identified as a precondition for achieving significant competitiveness advantages;
- Foreseeable development paths of transmission technology imply a range of future transmission costs, that even for global networks, as the most transmission intensive, are likely to be sufficiently low that such networks could clearly offer the cheapest dispatchable PV electricity;
- Earlier estimates on the level of PV generation capacity that is required to be installed for complete penetration prove to be too high by an order of magnitude;
- Finally we acknowledge that there are (at least) two aspects where our analysis needs further consideration, and these are working in opposite directions with respect to the attractiveness of such PV-based systems: if the PV system is developed fast, reduced utilization of capital embodied in current (thermal) plants needs to be considered as additional integration cost; on the other hand, new DC grids offer additional benefits for existing AC grids, and installing storage offers benefits for existing systems as well.

Below we discuss each of these issues in turn.

While the literature offers quantifications of the change in integration costs when moving from low to medium market penetration, we here supply one for complete market penetration. Figure 4 depicts the metrics of system LCOE and traditional LCOE for dispatchable electricity for four configurations differing (a) across site configurations and (b) for each site configuration across generation capacity installed (and respective storage and transmission line capacity required to meet the given 1,000 kW load profile; i.e. to meet dispatchability). To be precise, for clarity of exposition system LCOE in Figure 4 are restricted to their main components of generation and storage costs, but neglect transmission costs as the latter are available only for a bandwidth (Table 1). As transmission costs – even when at their upper bound – are well below LCOE traditional for all configurations the following insights on the characteristics of integration costs hold unambiguously.

In Figure 4 the difference between system LCOE and traditional LCOE denotes system integration costs. We see that system LCOE is broadly dominated by system integration costs; that the cost-minimal choice of the generation capacity installed can significantly reduce system integration costs (and thus the total of system LCOE); and – maybe most importantly – that increasing the geographical spread of the solar network can significantly reduce system integration costs. In particular, the trans-hemispheric integration of generation sites reduces system integration costs to the order of magnitude of (or for the global configuration to even below) the traditional LCOE. Taking a look at traditional LCOE in Figure 4, we see that these are obviously constant across generation capacity, somewhat higher for the single, more northern location of New York, but similar for all other geographically more dispersed configurations that include sites with higher solar insolation.

The trans-hemispheric connection is thus identified as a precondition for achieving complete and fully dispatchable solar electricity at highly competitive costs. This is a result of the significant summer-winter difference in solar insulation at medium and higher latitudes. In numbers, costs for dispatchable solar electricity are 15 ¢/kWh for a system with a single, somewhat northern production location such as New York, 7 ¢/kWh for a network that connects the large three north American deserts (Mojave, Chihuahuan, Sonoran), 3.3 ¢/kWh (plus up to 0.65 ¢/kWh for transmission costs, not depicted in Figure 4) for a Pan-American network that connects 18 locations throughout the Americas and 2 ¢/kWh (plus up to 1 ¢/kWh for transmission) for a global network that connects 77 locations distributed over the globe.

[Insert Figure 4 here]

Figure 4 shows the effect of constructing large networks which would give complete coverage and simultaneously significantly decrease costs. Global networks would allow global trade in electricity. So far electricity is the only form of energy that is not yet *globally* traded. Costs of up to 3 ¢/kWh for dispatchable electricity are well below the cheapest fossil-based electricity costs, referring to fossil-based costs that do not include their respective system integration costs for peak load coverage (while the latter is covered in the PV integration costs derived here). Globally the electricity sector is one of the largest economic sectors. A development in this direction would be of highest importance also to mitigate global climate change and ocean acidification.

Also at much lower market penetration the cost of meeting respective specified demand shares with PV electricity significantly decreases with increasing geographical spread. We note, however, that at lower than full market penetration such electricity cost that we now turn to no longer denote system LCOE, as a system not supplying all electricity necessarily does not fully cover integration costs (we thus are no longer concerned with systems of dispatchable electricity in this paragraph). With this difference to our above analysis in mind, the comparison of Figures 5 (cost of meeting demand shares with PV electricity without storage in the system) and 6 (with storage in the system) indicates that

- For systems without geographical spread storage is the most crucial component to enable meeting rising demand shares. E.g. for a single location system (such as New York depicted in Figure 5) without storage, costs of meeting demand shares with PV electricity begin to rise significantly beyond a share (or market penetration) of 20%, and penetration rates beyond 50% are obviously impossible, while the inclusion of storage reduces the slope of this increase and in principle does allow full market coverage (albeit at quite significant costs; see Figure 6).
- For both cases (with and without storage) we see that geographical spread significantly reduces costs of meeting rising demand shares with PV electricity, in particular so at higher market coverage. In the market coverage range approaching 100% it clearly is the geographical spread that dominates the reduction in electricity cost (rather than the inclusion of storage).

[Insert Figure 5 here]

[Insert Figure 6 here]

A crucial element in spatially dispersed generation networks is transmission lines. Foreseeable development of transmission technology can be taken into account to derive a respective range of future transmission costs, as supplied above in Table 1. We find that it is unlikely that transmission costs even for the most extended, and thus most transmission intensive of the networks analyzed, the global G77 configuration, would be higher than 1 ¢/kWh in the long run. Even in the most unfavorable case of high transmission costs (per km), the global configuration supplies dispatchable electricity far cheaper than any other PV configuration. As the demand calculation for PV generation capacity and storage capacity is based on the daily weather patterns across an observation period of 20 years, these costs already include highly unfavorable situations of low insolation (e.g., during the volcanic outbreak of Mount Pinatubo in Indonesia in 1991 with decrease of insolation observed as far away as in Switzerland), i.e., they acknowledge the uncertainty characteristic of variable renewables. We thus find that in addition to the evident advantages of PV for local use, also developments of larger, up to global PV networks have a lot to offer. Accordingly, initiatives to that end are discussed by industry; we point out recent examples in the Appendix.

Our results also shed new light on a range of quantifications of the required generation capacity and resulting costs for full energy supply by PV electricity. E.g. in the public presentation of the new Tesla Powerwall and Powerpack batteries, Elon Musk stated that 160 million Powerpacks would allow complete solar energy supply for the U.S. (Musk, 2016). The Tesla Powerpack has a storage capacity of 100 kWh so that 160 million Powerpacks would provide 16 TWh of storage. Total U.S. electricity demand in 2014 was 3,900 TWh (EIA, 2016) or 440 GW of power. The optimal feasible pair of G and S for 1 MW of load is (G=13.7 MWp, S=27.2 MWh) if all solar electricity comes from the configuration NA3 of the three major deserts in North America. This would be 120 million Powerpacks; the slightly higher number from Tesla takes into account that the PV capacity would mostly be distributed over the U.S. where most areas have lower insolation than in NA3. Our results thus can be seen in line with the order of magnitude given by Musk (while denoting a 25% lower requirement for generation capacity). However, Musk further stated that 2 billion Powerpacks would allow a full global solar energy supply for electricity, vehicles and buildings. Current global power consumption is 12.3 TW (2013). If supplied with the Global Solar 77 configuration, the optimal feasible pair is (G=5.5 MWp, S=1.7MWh) per 1 MW of load, i.e. global energy supply would need (68 TWp, 21 TWh) of resources in G and S, or 210 million Powerpacks which is only 10% of the number given by Musk. This big difference is due to optimization of the combination of locations, enabled by the G-S isoline concept. For a back of the envelope comparison of costs between Musk's numbers and the Global Solar 77 system we can use the amount of G calculated through optimization and combine that value of generation capacity with the two very different amounts of storage. Electricity costs (with \$500/Wp and \$100/kWh) would be 1.99 ¢/kWh for the optimized Global Solar 77 configuration and 3.31 ¢/kWh for a configuration with the storage capacity as specified by Musk. Global energy costs for the current energy demand for the version with 3.31 ¢/kWh would be higher by \$1,430 B per year (equivalent to some 1.5% of current global GDP). This shows the dramatic importance of applying advanced optimization when designing global renewable energy supply systems.

Finally we acknowledge that there are (at least) two aspects where our analysis needs further consideration. On the one hand, integration costs are higher than those given above, if the PV system is developed so fast that reduced utilization of capital embodied in current (thermal) plants still needs to be considered for plants that have not reached the end of their lifetime. In a full cost calculation the opportunity cost of GHG emissions will somewhat lower these additional integration costs.

On the other hand, several aspects of the dispatchable PV system analyzed above can be used to improve the already existing supply system (and thus counterbalance additional costs of fast installation): (a) DC grids as relevant for PV configurations are highly valuable also for improvement of the existing AC grids, e.g. the underlying power electronics allow considerably cheaper "back-to-back" DC connections between two or more AC grids; (b) cheap Li-ion storage can in particular also cope with peak loads in the existing grid, including new and unexpected ones, possibly rendering any thus oriented (more expensive) peaker plants obsolete.

V. Conclusion

Continuous cost declines in photovoltaic generation modules and electricity storage, in combination with de-carbonization requirements arising from the 2 degree objective of the Paris Agreement, the physical abundance of PV, as well as recent technological developments in power electronics and foreseeable developments in high voltage direct current (HVDC) transmission cables render an economic evaluation of a future energy system based on PV electricity – up to even the last capacity unit added – of crucial importance. We here use globally disaggregated hourly insolation data across two decades to derive minimal cost configurations (generation capacity and site distribution with the associated transmission lines and storage capacity) for dispatchable PV electricity at complete market penetration. For the long-term perspective we find that "only-PV" based energy systems can be designed such that electricity is supplied at a low 3 $¢_{2016}$/kWh (covering also all integration costs; and based on the upper bound of uncertainty in transmission line cost development considered) and thus can be considered the reference technology. For rising market penetration we find that storage, and particularly for very high market coverage most of all geographical dispersion of generation sites enable reasonable integration costs and thus to achieve competitive overall electricity cost. This is particularly true for trans-hemispheric distribution of sites.

While we have applied a constant 24h load profile here, sensitivity analysis shows that deviation from a linear load, depending on the specific profile of seasonal peaks, can change costs in either direction. While the system design can be adjusted by stronger reliance on sites with an insolation profile that correlates with the seasonal peak profile (higher generation capacity can be chosen in the same hemisphere for summer peaks or in the complementary one for winter peaks), costs increase when seasonal peaks are either that pronounced that such correlation is best achieved with sites at higher than mid latitudes, as these sites usually show less overall insolation, or when load peaks are in fall or spring for which there are no sites with a corresponding seasonal peak correlation in insolation. In a sensitivity analysis within the global configuration we find strongest upward sensitivity when using the current US electricity load profile of Texas — which is most unfavorable (relative to the time profile of solar insulation with two peaks, in both summer and fall). This increases costs by 22% (2016 installation) and 19% (2022 installation). Applying the current European load profile (characterized by about 30% higher demand in winter than in summer) increases costs by 5% for both installation dates. While both are extreme assumptions, a mixed load profile of a third each, the Texas, European and linear load – which might be seen to resemble global actual load – results in costs of less than 1% higher (2016 installation) and less than 1% lower (2022 installation) than those of the linear load.

Complementary to the evident attractiveness for local use, PV also offers the option of highly competitive dispatchable electricity supply in global configurations so that the local advantage can be a convenient driver for the development of a global system.

While the main open questions for a such directed development of the long-term global electricity supply from solar are in long-distance transmission technology and cost, as well as its political attractiveness, the economic evaluation set forth in applying the G-S isoline concept enables analysis in many fields of system design also for the short term (such as relating system cost only to electricity below excess supply) and smaller-scale management (such as storage management under uncertain weather conditions).

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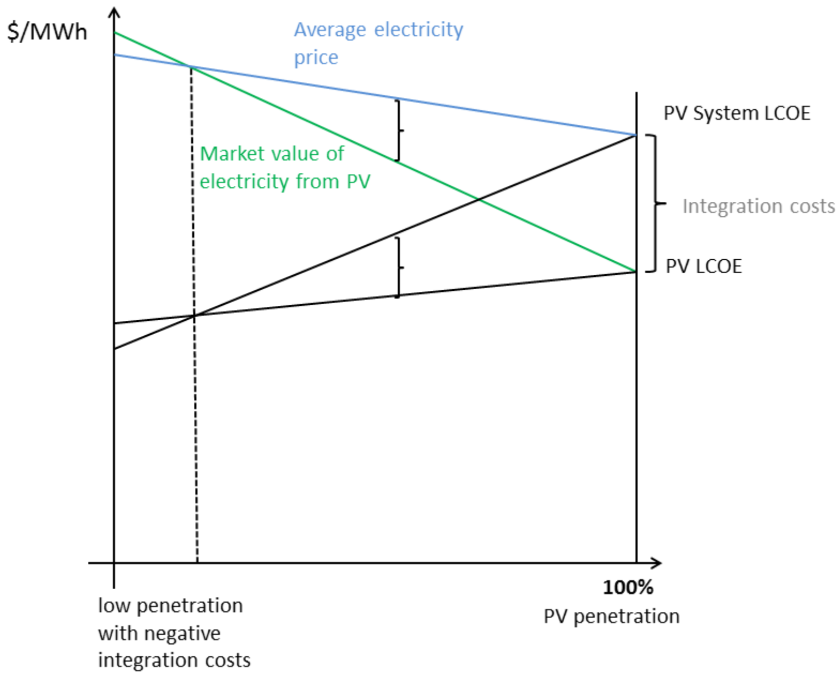

FIGURE 1. PV INTEGRATION COSTS FOR DIFFERENT MARKET PENETRATION RATES

Notes: The long-term equilibrium depicted here has PV as the marginal (most competitive) supply capacity at full market penetration.

Source: Adapted based on Hirth et al. (2015).

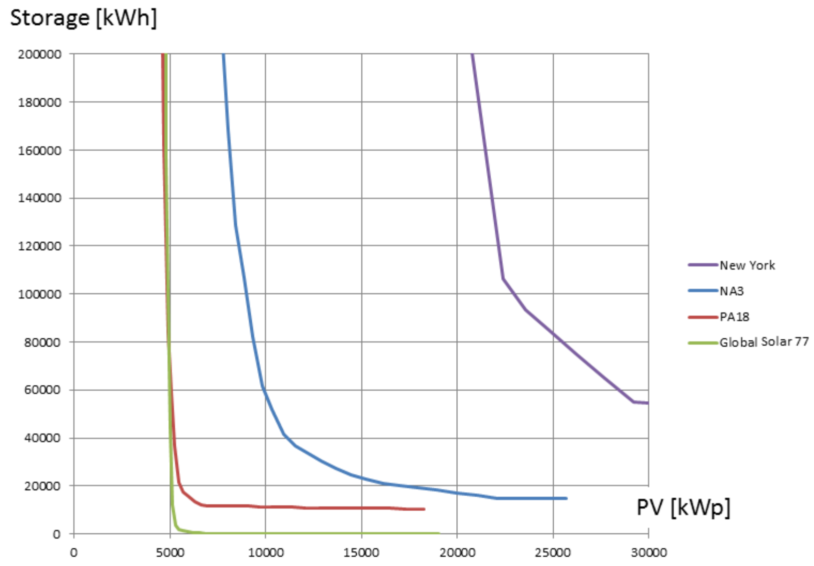

FIGURE 2. G-S ISOLINES FOR FOUR PV PRODUCTION CONFIGURATIONS (MINIMUM REQUIREMENT FOR GENERATION CAPACITY (G) AND STORAGE CAPACITY (S) TO MEET 1,000 KW CONSTANT LOAD)

Notes: The four configurations are: (a) the single location of New York; (b) North American NA3 with the major three North American deserts (Mojave, Chihuahuan and Sonoran); (c) Pan-American PA 18 with 18 locations distributed throughout the Americas and (d) "Global Solar 77" a configuration with optimized distribution of the generation capacity across 77 locations over the globe for provision of dispatchable electricity at minimal costs.

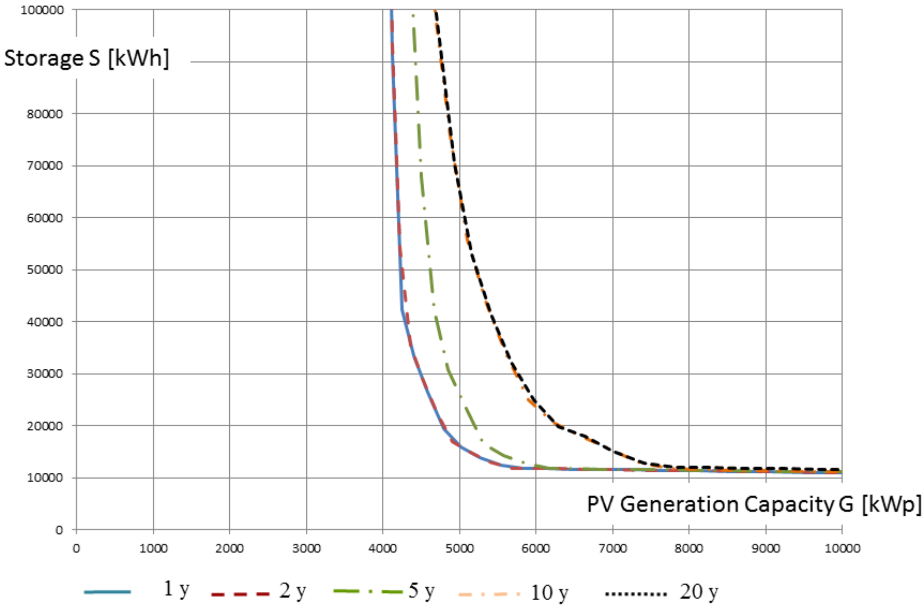

FIGURE 3. G-S ISOLINES FOR SYSTEMS OF DISPATCHABLE PV PRODUCTION BASED ON OBSERVED SOLAR INSOLATION ACROSS TIME HORIZONS OF 1YR, 2YRS, 5YRS, 10YRS AND 20YRS (MINIMUM REQUIREMENT FOR GENERATION CAPACITY (G) AND STORAGE CAPACITY (S) TO MEET 1,000 KW CONSTANT LOAD)

Notes: The production site configuration combines six locations across North and South America: the major three North American deserts (Mojave, Chihuahuan and Sonoran) and three in South America (Atacama, Litoral in Bolivia, Catamarca) and are designed for provision of dispatchable electricity at minimal costs.

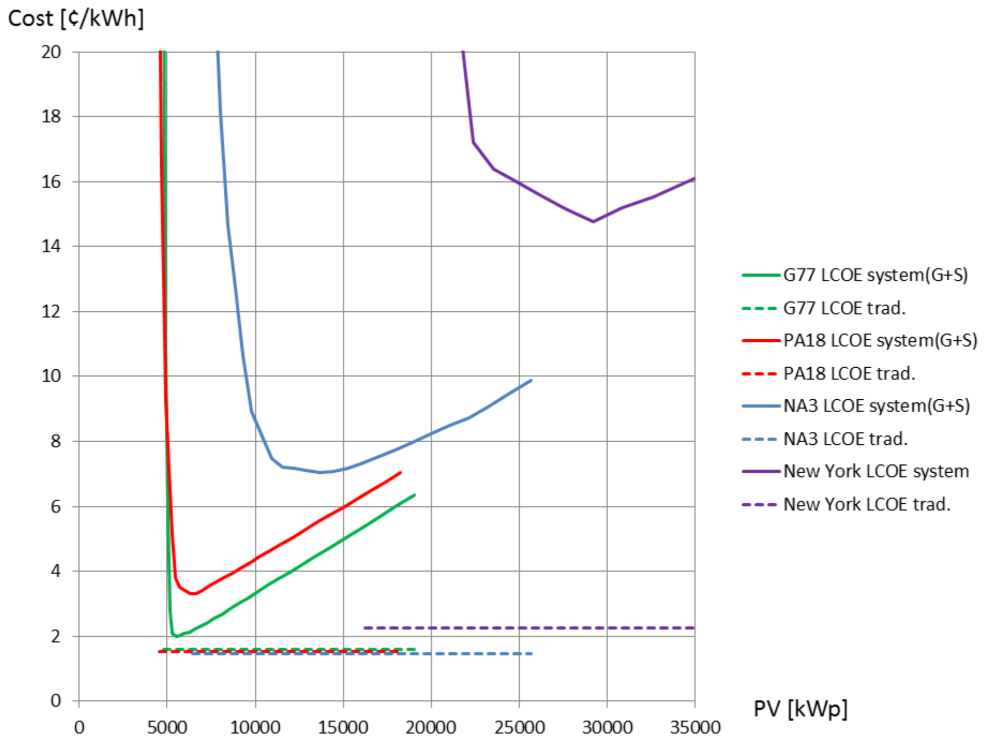

FIGURE 4. GENERATION AND STORAGE COSTS OF PV ELECTRICITY PRODUCED IN SYSTEMS OF DISPATCHABLE ELECTRICITY AT FULL MARKET PENETRATION (SYSTEM LCOE WITHOUT TRANSMISSION COST), AND ITS COMPONENT LCOE TRADITIONAL, FOR FOUR DISPATCHABLE PV PRODUCTION CONFIGURATIONS (ACROSS INSTALLED PV GENERATION CAPACITY) TO MEET 1,000 KW CONTINUOUSLY

Notes: The four configurations are: (a) the single location of New York (for which full system LCOE are given as no transmission costs apply); (b) North American NA3 with the major three North American deserts (Mojave, Chihuahuan and Sonoran); (c) Pan-American PA 18 with 18 locations distributed throughout the Americas and (d) "Global Solar 77" a configuration with optimized distribution of the generation capacity across 77 locations over the globe for provision of dispatchable electricity at minimal costs. Installation costs of 2022 are applied. Transmission costs are well below LCOE traditional for all configurations.

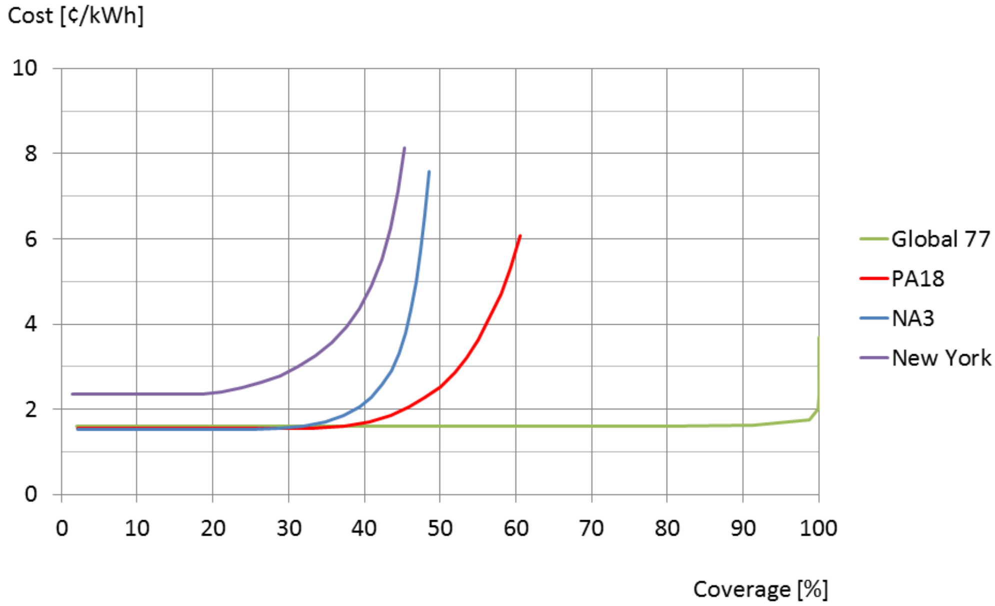

FIGURE 5. COSTS OF MEETING DEMAND SHARES (MARKET COVERAGE) WITH PV ELECTRICITY SYSTEMS, SYSTEMS WITHOUT STORAGE, ACROSS DIFFERENT LEVELS OF MARKET COVERAGE, FOR FOUR PV PRODUCTION CONFIGURATIONS TO MEET 1,000 KW CONTINUOUSLY

Notes: The four configurations are: (a) the single location of New York; (b) North American NA3 with the major three North American deserts (Mojave, Chihuahuan and Sonoran); (c) Pan-American PA 18 with 18 locations distributed throughout the Americas and (d) "Global Solar 77" a configuration with optimized distribution of the generation capacity across 77 locations over the globe for provision of dispatchable electricity at minimal costs.

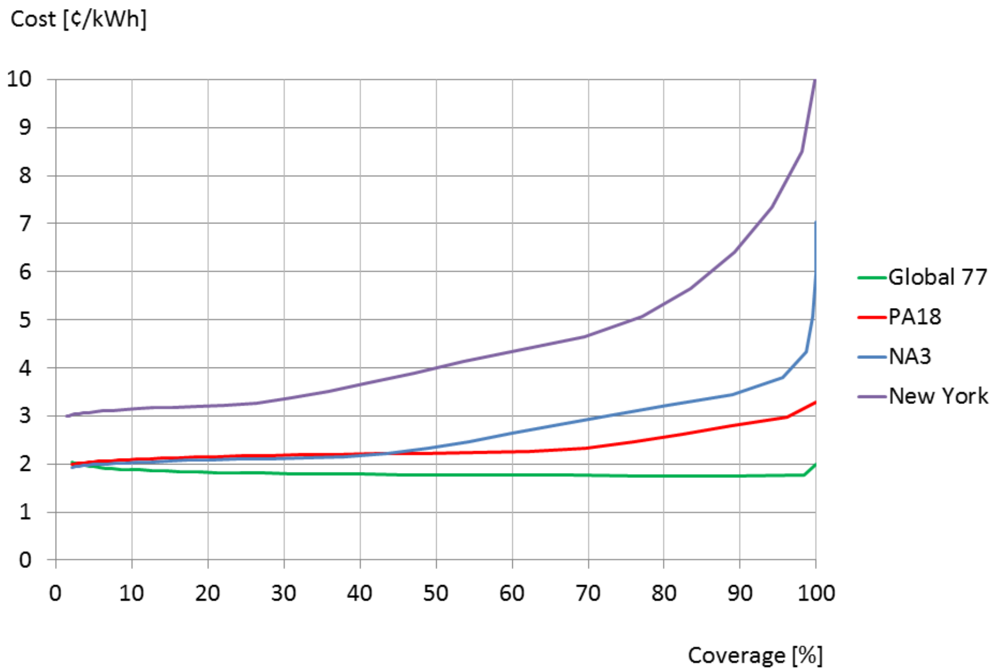

FIGURE 6. COSTS OF MEETING DEMAND SHARES (MARKET COVERAGE) WITH PV ELECTRICITY SYSTEMS, SYSTEMS WITH STORAGE, ACROSS DIFFERENT LEVELS OF MARKET COVERAGE, FOR FOUR PV PRODUCTION CONFIGURATIONS TO MEET 1,000 KW CONTINUOUSLY

Notes: The four configurations are: (a) the single location of New York; (b) North American NA3 with the major three North American deserts (Mojave, Chihuahuan and Sonoran); (c) Pan-American PA 18 with 18 locations distributed throughout the Americas and (d) "Global Solar 77" a configuration with optimized distribution of the generation capacity across 77 locations over the globe for provision of dispatchable electricity at minimal costs.

TABLE 1—RANGE OF COSTS OF ELECTRICITY TRANSMISSION FOR FOUR DISTRIBUTED SOLAR ELECTRICITY NETWORKS, LOWER AND UPPER BOUNDS

	Configuration					
	NA3		PA18		G77	
	Britned	NorNed	BritNed	NorNed	BritNed	NorNed
	[¢/kWh]					
Year						
2012	0.10	0.14	0.49	1.08	0.73	1.61
2022 (w learning rate 5%)	0.06	0.08	0.29	0.65	0.44	0.97
2022 (w learning rate 10%)	0.02	0.03	0.10	0.23	0.15	0.34

Notes: For calculation details see main text. The configurations are defined in the Appendix (see Tables A.1 and A.2).

Source: Author calculations.

TABLE 2—DISTRIBUTED SOLAR ELECTRICITY NETWORKS, MINIMAL COST SET UPS, INTEGRATION AND ELECTRICITY COSTS MID CENTURY (UPPER BOUND)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	PV generation [kWp]	Storage[a] [kWh]	Costs[b] PV generation [$/y]	Costs[b] storage [$/y]	Primary costs electr.[c] [c/kWh]	Integration costs thereof [c/kWh]	Costs transmission [c/kWh]	Costs dispatchable electricity [c/kWh]
Configuration								
A. Install. 2016*								
New York	29.2	55.1	1703	663	27.00	22.49	0.00	27.00
North America**	11.6	36.6	676	441	12.75	9.78	0.10 - 0.14	12.85 - 12.89
Pan-America***	6.3	13.2	367	159	6.00	2.97	0.49 - 1.08	6.49 - 7.08
Global****	5.5	1.7	321	20	3.89	0.73	0.73 - 1.61	4.62 - 5.50
B. Install. 2022*								
New York	29.2	55.1	851	442	14.76	12.51	0.00	14.76
North America**	13.6	27.2	396	218	7.02	5.54	0.02 - 0.08	7.04 - 7.10
Pan-America***	6.6	11.9	192	95	3.29	1.77	0.10 - 0.65	3.39 - 3.94
Global****	5.5	1.7	160	14	1.99	0.40	0.15 - 0.97	2.14 - 2.96

Source: Author calculations.

[a] Storage capacity required such that the cost minimal generation-capacity/storage-capacity combination can meet a continuous load of 1,000 kW.

[b] Annuity based on interest rate of 5%, lifetime of PV of 40 years, and lifetime of storage of 20 years.

[c] Primary costs of electricity denote the annualized costs of generation and storage capacity per kWh, but do not contain costs of transmission, as these are significantly more uncertain and thus are added in their uncertainty bandwidth on top to get the costs of dispatchable electricity (column (8)).

* Installation cost 2016: Optimization of generation and storage capacity carried out for 2016 cost levels of installing these capacities. Arising dispatchable costs of electricity based on annualized system costs based on 2016 investment costs. Accordingly for “B. Installation costs 2022”.

** North American Network integrates production locations at the large three North American deserts (Mojave, Chihuahuan, Sonoran; see Appendix for details).

*** Pan-American network consists of 18 production locations across North and South America (see Appendix Table A.1 for details).

**** Global network consists of 77 production locations across the globe (see Appendix Table A.2 for details).

APPENDIX

AREA CALCULATIONS FOR GLOBAL ENERGY SUPPLY BY PV —The current total global energy demand, if met with electricity, and taking into account the respective efficiencies, is 10 TW, i.e. global energy consumption per year is at 8.76e4 TWh. Deserts typically have an annual insolation of 2000 kWh/m^2 or more. With the present global average efficiency of PV at 16.5% the necessary desert area would be 265,454 km^2 whereas the total global desert area (without Antarctica) is ~19.2 million km^2. Thus, just 1.4% of the global desert area would suffice to supply current global overall energy demand.

CONFIGURATIONS FOR DISPATCHABLE PV ELECTRICITY — The configurations of PV electricity generation sites discussed above combine production locations as specified in Table A.1 (for New York, NA3, PA18 and PA6) and in Table A.2 (for G77).

[Insert Table A.1 here]

[Insert Table A.2 here]

DERIVATION OF G-S ISOLINES — As developed in Grossmann et al. (2015), a G−S isoline is the curve combining minimal G and S along which a constant or variable load is consistently met over a year or longer. To calculate the isolines, electricity from solar insolation at each location is added to the storage as long as capacity permits and the load is subtracted hourly, or at finer time scales if data exist, as long as storage permits. The isolines have been calculated with a dynamic model and alternatively with a spreadsheet in which the storage is stepwise decreased such that the minimal charge in storage becomes 0. An initial minimal value G1 is calculated for a high amount of storage S1 (e.g., for 20 y and a 1-MW load, S1 = 500 MWh). The other points of the isoline are calculated by incrementally increasing G to up to 4 times its initial value, giving values G2, G3, ... and corresponding values of decreasing S2, S3, ...

Twenty years of daily NASA Solar Sizer insolation data on a horizontal surface for up to 77 sites of 1° × 1° each over the 20 years of 1986–2005 are used (NASA, 2010). These data are part of the NASA Surface Meteorology and Solar Energy Release 6.0, which were obtained from the NASA Science Mission Directorate's satellite and reanalysis research programs (NASA, 2013). The surface solar insolation was inferred from satellite observations with the modified method of Pinker and Laszlo (1992) using a radiative transfer model along with water vapor column amounts from the geostationary weather satellite GEOS-4 and ozone column amounts from satellite measurements. Satellite radiances were converted into broadband shortwave top of the atmosphere (TOA) albedos using angular distribution models from the Earth Radiation Budget Experiment (Smith et al. 1986). The radiative transfer model was used to find the absolute value of the surface albedo, which produces a TOA upward flux that matches the TOA flux from the conversion of the clear-sky composite radiance. The years 1986–2005 represent a wide range of weather conditions, including the major volcanic eruption of Mt. Pinatubo in 1991, which decreased sunlight temporarily by up to 10%, even in distant locations. The 77 sites are a selection through optimization from 245 sites that are globally distributed to include all major deserts and dry areas plus selected sites close to densely populated regions, as well as Arctic and Antarctic sites due to their interesting characteristics (and for testing of functions, e.g., because some functions break down for periods of daylight that last longer than 24 h, as is the case poleward of 67°N and 67°S).

Insolation has two components, one due to the rotation of Earth, the other due to the movement of Earth around the Sun. These two movements cause the patterns of day and night and the seasons, respectively, and are precisely predictable (Milone and Wilson, 2008). The solar zenith angle determines the effective radiation at time t of day specified through the fractional year γ and location y (Milone and Wilson, 2008),

(A.1) $c(t, y, \gamma) = C \cdot \cos(\Phi(t, y, \gamma))$

C is the clear-sky value, the maximum irradiation at time t at site y, i.e., the radiation hitting the ground when there is no attenuation. The calculations use the actual daily insolation from Solar Sizer instead of C, so that Eq. (1) approximates the actual distribution of solar radiation over the day specified by t, y, and γ. This method mimics the actual hourly distribution; it gives radiation beginning at sunrise in that location, peaking at noon local time, and ending at sunset.

COST OF TRANSMISSION LINES — With high voltage direct current (HVDC) transmission lines only recently installed for a distance of 580 km, and a contract awarded for the survey for a cable between Iceland and the UK with a length of 1470 km (MMT 2015), uncertainties persist on how to cross deep-sea topography with several faults and sea bed mountain ranges, a challenge that exists for all trans-Atlantic and trans-Pacific routes. An extension of the cable between UK and Iceland from Iceland to Greenland and then to Canada is under consideration. However, the island of Iceland sits on top of the Mid-Atlantic Ridge with its volcanoes. The ridge continues from Iceland to surround South America at its south and extends through most of the Pacific. Hence, costs of transmission lines and their future development are significantly more uncertain than costs of other system elements. Subsea cables would compete with overhead transmission lines as these are possible globally with an addition of only short subsea cables, e.g. between Australia and Indonesia or Alaska and Russia.

We recalculate transmission costs for marine cables from Chatzivasileiadis et al. (2013). These authors discuss the possibility of a trans-Atlantic connection with a length of 5,500 km and give costs of ¢1.3/kWh based on costs of the subsea BritNed cable. The cheapest subsea cable in their table is the NorNed which is based on more recent technology and would give costs for trans-Atlantic transmission of ¢0.7/kWh. These authors calculate transmission costs for wind energy and foresee an additional use of the cables for load sharing between North America and Europe which brings utilization to about 90%. From Grossmann et al. 2014 we take the utilization of transmission within a Pan-American grid of 60%; increase capital costs compared to Chatzivasileiadis et al. from 3% to 5%, but use the lower cable costs from the newer NorNed, not BritNed, and include costs for electricity loss of 2%/1000 km (see last paragraph of this section) with PV electricity costs from 2022 (as estimated above). With these assumptions transmission costs are 0.21 ¢/kWh per 1,000 km. With extensive experiments on the origin of electricity in a Pan-American network and a European-American configuration we found that on average about 1/3 of the electricity came from the longest distance, 1/3 from regional distance and 1/3 was local. In the case of PA18 the long distance is between San Diego and the Atacama at 9,600 km, the regional distance is from NA3 to load centers at a distance of 1,500 km. For the global G77 configuration long distance cables are needed for example between the U.S. Southwest and Australia, e.g. from Brisbane to San Diego at 11,300 km, and between Greece and Lyndon in West Australia at 12,100 km. This gives transmission costs between 0.49 ¢/kWh with NorNed costs and 1.08 ¢/kWh with BritNed costs for PA18; costs for NA3 and G77 are respectively between 0.10 and 0.14 ¢/kWh and between 0.73 and 1.61 ¢/kWh (as given in Table 1 in the main text).

However, these costs data are for the most unlikely case that the transmission lines are only used for transmission from areas with solar insolation to areas without, not for load sharing or transmission of electricity from storage. Transmission costs in these three configurations, if storage is also used to increase utilization and if the cables also do load sharing, could increase utilization to the same 90% as used by Chatzivasileiadis et al.. Additionally, learning in HVDC technology is rapid. Assuming a learning rate of just 5%/year, the respective costs decrease by a factor of 40% by 2022; with a learning rate of 10% per year costs would decrease to about ¼ (see Table 1 in the main text).

Losses have several components, power line losses and losses from converter stations. Line losses in overhead transmission at 800 kV are typically 2.7%/1000 km (calculated from Bahrman 2011, slide 16). These are Joule losses which decrease with the square of the voltage. The 1.5 MV lines that are now under discussion would have Joule loss of 2.7 x (800/1500)^2 ~0.8% /1,000 km. Faulkner and Todd (2010) describe "ElPipes" as an alternative technology for subsea cables with loss of ~1%/1,000 km. Converter stations add losses between 0.6% to 3% per station. A DC cable has up to two stations so that a transmission system with a total length of 6,000 km has total loss of between 7.2% in 2022 with up to 22% now, or 3.6% per 1000 km with typical present technology and 1.2% per 1000 km with further technological development. In the above calculation, as indicated, we use loss of 2% per 1,000 km.

RECENT INITIATIVES TOWARDS TRANSCONTINENTAL ELECTRICITY GRIDS — Global and trans-continental power grids are increasingly discussed in the literature (e.g. Gellings, 2015; Bogdanov and Breyer, 2015; Taggart et al., 2012; Torbaghan et al., 2015; Liu, 2015). Plans are particularly prominent in China.

E.g. the Chairman of the State Grid Corporation of China in early 2016 presented the vision of a world power grid, the Global Energy Interconnection (GEI), that his company wants to have in operation by 2050 (Futurism, 2016; The Energy Times, 2016).

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TABLE A.1—PV ELECTRICITY PRODUCTION LOCATIONS CONSTITUENT OF FOUR CONFIGURATIONS

	Latitude	Longitude	Insolation/year[a]
A. New York			
New York	42.5	-75.5	1292
B. North American (NA3)			
Chihuahuan	31.0	-108.0	1962
Mojave	36.0	-117.0	1977
Sonoran	32.0	-113.0	1959
C. Pan-American (PA18)			
AlaskaPanhndl	58.0	-134.0	950
Arctic_Koyukuk Alaska	66.0	-153.0	956
Chihuahuan*	31.0	-108.0	1962
Florida	29.0	-83.0	1691
Mojave*	36.0	-117.0	1977
Sonoran*	32.0	-113.0	1959
Texas	32.0	-102.0	1859
Argentina	-24.0	-67.0	2420
ArgtCatamarca*	-27.0	-67.0	2261
ArgtSantaCruz	-55.0	-69.0	857
BoliviaLitoral*	-19.0	-67.0	2254
BrazilCaat01	-6.4	-38.0	2178
ChileSouth	-30.5	-70.3	2076
ChileAtacama1*	-24.0	-69.0	2525
ChileAtacama2	-19.5	-69.5	2225
PeruInteroceanica	-17.0	-70.5	2252
PeruSechura1	-6.0	-80.0	1997
PeruSechura2	-8.0	-79.0	2069

Source: Insolation data from NASA (2013).

[a] Insolation data (in kWh/m2/year) are 20 year average for years 1986 to 2005 calculated from NASA Solar Sizer at the coordinates given in columns "Latitude" and "Longitude".

* Denotes locations included in the Pan-American configuration of six production sites (PA6) that Figure 3 refers to.

TABLE A.2—PV ELECTRICITY PRODUCTION LOCATIONS OF THE GLOBAL CONFIGURATION COMBINING 77 SITES

	Latitude	Longitude	Insolation/year[a]	percent of PV[b]
AfNAlgeriaSW	25.5	-2.3	2090	0.9
AfNDRCongo	4.5	26.4	1982	0.7
AfNEthiopia	5.8	42.3	2091	2.9
AfNKenya	2.4	37.4	2213	4.3
AfNMali	16.3	1.0	2099	2.1
AfNNiger	21.0	8.0	2345	3.9
AfNSahaCent	25.0	15.0	2213	1.3
AfNSahaEgypt	25.0	33.0	2150	1.2
AfNSahaMauret	22.0	-7.0	2114	0.5
AfNSahaMauret2	17.2	-7.0	2173	0.1
AfNSahaSudan	18.0	25.0	2449	0.1
AfNSahaWmost	25.0	-12.0	2046	0.1
AfNSaudi45989	27.0	38.0	2097	0.5
AfNSaudiA	23.0	49.7	2198	0.8
AfNSaudiDesert	25.0	48.0	2099	0.3
AfNSomalia	4.3	43.7	2098	0.0
AfNSomaliaNE	9.5	49.0	2325	0.0
AfNUgandaN	2.3	32.8	2077	0.2
AfSAngola	-14.5	15.5	2240	0.5
AfSNamibia	-24.0	16.0	2249	0.2
AfSNamibiacoastal	-22.0	14.5	2095	0.1
Arctic_Koyukuk Alaska	66.0	-153.0	956	3.4
ArcticN_Bering	85.0	-170.0	830	1.7
AsAfghanistan	30.7	64.0	2003	2.7
AsIndia	28.0	72.5	1827	0.8
AsIndiaAndraPrad2	17.0	80.0	1847	0.2
AsIndonesiaJawaTimur	-7.4	111.6	1919	3.0
AsIndonesiaKalimantan	1.3	116.4	1768	4.1
AsIndonesiaPapua	-4.0	137.1	1803	4.4
AsIndonesiaSulawesi	-2.0	120.0	1807	3.3
AsIndonesiaSulawesi2	-3.4	121.9	1965	0.5
AsIndonETimor	-9.8	124.3	2209	0.7
ASIran95	28.5	61.0	1976	0.4
AsIranMakuyehR	29.0	52.5	2009	0.1
AsIranSistan	28.5	60.0	1930	0.1
AsKambodschaKampong	12.3	104.5	1906	0.2
AsKazakhstan	42.5	67.7	1583	1.0
AsMongSukhbaatar	46.0	113.0	1513	1.5
AsPhilipinesMalaybalay	8.1	125.1	1774	0.0
AsSouthKoreaCentral	36.4	127.9	1461	0.5
AustralBrontePark	-40.0	147.0	1682	0.7
AustralE	-27.5	146.0	2062	1.7
AustralForestvale	-26.0	148.0	2074	1.5
AustralPorcupineQLD	-20.0	144.0	2169	1.2
AustralYarraden	-15.0	143.0	2067	0.4
EUFranceNizza	44.5	5.9	1494	0.2
EUGermS	47.5	9.5	1223	0.3
EUGreeceS	37.3	22.0	1629	0.5
EUItalySicily	37.3	14.0	1636	0.1
EURomania	45.0	27.0	1219	0.1
EURussiaSW	46.3	45.2	1319	0.5
EUSpainGuadix	37.0	-3.0	1707	0.1
JapanFukushima	37.5	140.0	1277	0.9
MAGuatemala	15.0	-91.4	1966	0.0
NACaliforniaN	40.3	-122.5	1760	0.4
NAChihuahuan	31.0	-108.0	1962	0.2
NATexasN	34.5	-102.5	1897	1.5

NAUtahC	39.0	-111.0	1725	3.8
NAVirginia	37.0	-78.5	1494	1.9
NAWashingtonState	46.8	-120.5	1379	4.4
NAWyomingSW	42.0	-109.0	1638	4.1
NewZealandRuatahuna	-38.5	177.0	1343	3.8
NewZealandTekapo	-44.0	170.5	1272	3.6
SAArgt	-24.0	-67.0	2420	4.4
SAArgtCatamarca	-27.0	-67.0	2261	4.4
SAArgtChubut	-43.0	-68.0	1616	3.2
SAArgtSantaCruz	-55.0	-69.0	857	1.0
SABraz2	-20.0	-50.0	1931	0.4
SABrazAmazon1	-6.0	-55.0	1784	1.6
SABrazBahia	-10.0	-39.0	1991	1.9
SABrazBahia3	-8.0	-38.0	2155	0.0
SABrazCaat02	-7.0	-36.0	1964	0.2
SABrazCaat09	-11.0	-41.0	2016	0.0
SABrazCaat10	-6.4	-36.0	1964	0.2
SAPeru	-5.0	-80.0	2003	0.9
SAPeruSechura1	-6.0	-80.0	1997	0.2
SAVenezuelaN	8.6	-66.7	1973	0.2

Source: Insolation data from NASA (2013).

[a] Insolation data (in kWh/m2/year) are 20 year average for years 1986 to 2005 calculated from NASA Solar Sizer at the coordinates given in columns “Latitude” and “Longitude”.

[b] Percentage of PV capacity installed at particular location out of total installed PV capacity across the system. Locations with value 0.0 have percentage >0 but < 0.05%.

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