Solar electricity generation across large geographic areas, part II: A Pan-American energy system based on solar

Working Paper of the Wegener Center for Climate and Global Change and the Center for Climate and Energy Decision Making at Carnegie Mellon

Submitted to *Renewable and Sustainable Energy Reviews*

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Abstract

Combining solar electricity generation sites across large geographic areas, as recently proposed by research and large industrial consortia, can significantly reduce the intermittency of solar energy. With the "Solar Grand Plan", Zweibel, Fthenakis and Mason proposed a predominantly renewable energy supply system for the US using high insolation areas in the US Southwest. Large-scale solar energy generation to meet the growing US energy demand could solve some very pressing issues. However, due to limited timezone coverage and low insolation in winter, the Grand Plan still needs expensive overcapacity, long-term storage, and fossil-fuel based electricity during periods of low insolation. Here we apply a new method to the challenge of renewable energy generation for the US. We first convert 20 years of daily NASA Solar Sizer insolation data to hourly resolution. Using these hourly data we optimize site selection, electricity generation and storage based on the daily rhythm of insolation at each site. We show that linking North and South American electricity generation and demand allows eliminating fossil fuels and drastically decreasing expensive long-term storage while increasing the available load. We then outline major transmission lines for such a Pan-American network and their costs. This is combined with projected solar electricity costs and utilization rates into an estimate of total electricity costs for a Pan-American network. Resulting revenue flows and good availability of energy in its most valuable form, electricity, could enhance economic development in South America. Arising mutual benefits for North and South America make a sustainable solar energy supply much more practical.

Keywords: large-scale solar energy network; renewable energy; US super grid; solar intermittency; hourly insolation data

1 Introduction

The cost of photovoltaics (PV) for electricity generation has fallen rapidly during recent years. Average manufacturing costs of the PV price leader First Solar have fallen to half during the last five years, from $1.40/watt in 2006 to $0.69 in its most efficient factory in mid 2011 [1]. Parts of Italy are believed to have reached grid parity in 2010 [2], followed closely by parts of California, and by Hawaii and Spain [3-5]. In parallel, but somewhat slower, the cost of solar thermal (ST) energy has decreased considerably. Construction of large-scale solar installations has begun worldwide [6-10], e.g. two PV plants in California of 230MW and 550 MW [11]. These developments offer new options in dealing with pressing problems in the energy sector, namely global climate change and ocean acidification attributed to greenhouse gas release from the use of fossil fuels [12,13], economic problems due to highly volatile oil prices and limited fossil fuel reserves [14], and geopolitical problems due to the dependence of most industrialized countries on a small number of supplying countries marred by political tensions [15].

Given the recent development of the costs of solar energy and the resulting growth of generation capacity, large-scale solar energy plans have been proposed. The Desertec Foundation developed a plan to supply 80% of the electricity for 30 European countries from renewable energy by 2050, generated in Europe, the Middle East and North Africa (the so-called EUMENA countries) [16,7] using mainly concentrating solar power (CSP) and wind energy. Zweibel et al. [17, hereafter Z08] proposed a US Solar Grand Plan which would supply 69% of the US electricity needs and 35% of the total US energy needs (including transportation) from solar by 2050. Z08 project costs of PV panels of $1.2-1.3/ Watt peak (Wp) in 2020 (in real 2007$, i.e. not accounting for future inflation), corresponding to levelized solar electricity generation costs of 5.3-5.7¢/kWh according to a follow-up study [18]. Projections for the Desertec plan foresee levelized electricity costs of €0.05 plus transmission costs of €0.015 in 2020, and of €0.04, plus €0.01, in 2050 [16].

Principally, linking solar electricity generation sites across large geographic areas can significantly reduce intermittency [19,20]. However, this requires optimal selection of generation sites from different time zones based on hourly solar insolation data, as well as optimization of the generation and storage capacity at each site [21]. Both the Solar Grand Plan and the Desertec EUMENA plan rely on few adjacent time zones and require a considerable amount of oversupply, storage and a proportion of non-renewable electricity to address day to day intermittency, low insolation in winter and possible worst-case conditions. The Grand Plan assumes fuel combustion on the order of 11.7% of the total energy consumed and storage of at least 25,000 TWh or 8% of the energy generated. The required fuel could be renewable; however, overcapacity, storage and fuel are expensive.

Here we apply a new solar energy optimization method, as presented in a companion paper [21], to these problems. Our approach first converts daily insolation data (available on a 1°x1° grid from NASA Solar Sizer, [22]) to hourly scale and subsequently optimizes generation and storage capacity. Use of hourly data allows calculating the combined solar irradiation of multiple sites given their respective times of sunrise, sunset and intensity of solar irradiance. With this approach we investigate how the costs of intermittency in the US Grand Plan could be reduced by coupling energy generation from suitable locations in the Northern and Southern Hemispheres. We show that linking North and South American electricity demand and generation allows eliminating fossil fuels and drastically decreasing expensive long-term storage while increasing the feasible load. The same method could be applied for investigating the Desertec EUMENA network [16,7]; the procedure for overcoming those problems would be analog. From a geopolitical perspective the Americas seem to be in a more advanced position for the approach elaborated here.

In section 2 we briefly review the Solar Grand Plan and discuss the electricity price implications of the required storage and overcapacity. In section 3 we provide a brief overview of the method used [21] and explain how it is applied to a Pan-American extension. We discuss insolation at the sites considered, projected demand, required generation capacity and storage. We then outline possible major transmission lines for a Pan-American network and discuss the associated costs given current technologies and expected future developments. In section 4, we discuss the results of our optimization and combine the projected costs for solar electricity and transmission into an estimate of total electricity costs for the Pan-American network. Resulting revenue flows and good availability of energy in the most valuable form of electricity could enhance economic development in South America and allow mutual benefits for North and South America. In combination with technical and economic advantages this would make a sustainable solar energy supply much more practical.

2 The Solar Grand Plan revisited

Z08 assume a total generation capacity of 15.95 terawatt (TW; the dimensions in this paragraph are as in Z08) for a projected energy demand of 3.1 TW. The present US energy demand is 29,300 terawatt hour (TWh) annually or 3.34 TW. Z08 assume an annual increase of 1% in the net energy demand and considerably higher future efficiency in meeting energy needs, resulting in an annual demand of 27,255 TWh or 3.1 TW in 2050, down from 29,307 TWh in 2020. The total generation capacity is composed of 2.9 TW PV going directly to the grid, 7.5 TW PV filling compressed air energy storage (CAES), 1.3 TW distributed PV, 2.3 TW CSP plants with thermal storage, 1 TW wind energy with CAES, 0.2 TW geothermal power, 0.25 TW biomass-based fuel production, and 0.5 TW geothermal heat pumps for heating and cooling buildings. In 2100, the renewable portfolio would meet the entire US electricity demand and more than 90% of the projected energy demand of 4.7 TW (41,030 TWh annually). By displacing 300 large coal-fired power plants and at least 300 natural gas plants, the plan would reduce CO_2 emissions by 62% relative to 2005 levels. The plan requires a cumulative subsidy of $420 billion required until 2050. This is about twice as much as the global investments of $212 billion into renewable energy technologies in 2010 [23].

Like the Desertec EUMENA plan, the Solar Grand Plan assumes the construction of new ultra high voltage direct current (HVDC) power transmission networks with 800 kilovolt (kV). In the past, solar energy plans requiring long distance power transmission have been hindered by the prohibitive costs of both solar energy and long distance transmission. This is changing with the recent availability of very-long-distance HVDC lines [24]. With the completion of the first two lines in 2010 [25,26], further rapid cost decreases are expected from the combined effects of learning and economy of scale for the construction of transmission lines, stations and for transmission itself.

2.1 Storage and overcapacity costs

By 2050, Z08 project levelized electricity costs of 5.3-5.7¢/kWh for energy from PV and, additionally, 3-5 ¢/kWh costs of CAES. A follow-up study calculates that costs of 5.7¢/kWh by 2020 imply that systems are installed at $1.30/Wp at locations with annual insolation of 2,300kWh/m^2 (Table A-1 in [18]). The price at which electricity is sold depends on panel manufacturing costs, the balance of system (BOS) costs and the profit margin. BOS comprises non-panel expenses such as inverters, installation and connection to the grid. Panel costs and BOS together comprise the total systems costs.

The 2010-2014 roadmap by the PV price leader, First Solar, in its 10-K and 10-Q filings, projects total systems costs of 10-12 ¢/kWh or $1.43-$1.61 per Wp in 2014 [27,1]. We assume that by 2014 profit margins may be in the range of 20% -30% – down from about 50% in 2009 [28], implying a total systems price (with profit margin) of $1.72-$2.09/Wp. These projections are credible, as First Solar has in the past consistently performed better than projected in its roadmaps. During 2005-2010 First Solar decreased average panel manufacturing costs by 13.7% annually. Considerable efforts are also made to reduce BOS costs. If costs continue to fall at the same rate as they did over the last 5 years, electricity prices of 5.3-5.7¢/kWh could already be achieved in 2016 or 2017.

The calculation of levelized electricity costs in [18] assumes 20% electricity loss. Kymakis et al. [29] calculate losses of 38.3% in a detailed analysis based on experiences with a PV park in Crete, taking into account losses due to the transformer, inverters and factors such as dust on panels and the PV panel temperature gradient. Many of those losses have been considerably decreased recently, e.g. [29] lists 7.5% inverter losses for 2007 but in 2011 losses at SMA were between 1-2.5% [30]. Also, PV give DC so that no inverter from DC to AC is needed if a DC transmission line is used [7,20,24,25,31] – which we assume as standard in long-distance grids. This further decreases losses. Additionally, [29] includes losses in transmission lines. We treat these losses separately in sections 3 and 4 as some of the lines in a Pan-American network are very long and, accordingly, have higher losses than the grid connecting to the PV park in Crete [29]. Overall, a loss factor of 20% as assumed by Zweibel [18] appears adequate here, but now taking into account all factors listed in [29] save the loss in transmission lines, and updating loss factors to present values. Losses of 20% imply an increase in the cost of electricity by 1¢/kWh if costs of electricity from solar parks decline to 5¢/kWh; 38% losses increase electricity costs by 2¢/kWh. These numbers are likely to decrease. In comparison, transmission costs can vary between 1-5¢/kWh at 100% utilization of the line and no losses, but utilization can be as low as 10%-25%, which would increase transmission costs to between 4¢/kWh and 50¢/kWh. Thus, transmission, the utilization rate and transmission costs are of about equal importance with generation costs and of higher importance than losses.

If PV is to make a major contribution to the US energy supply, global production volumes of PV panels must increase by at least a factor of 25 relative to 2010 [28]. Meeting the total global energy demand of 14 TW (i.e. all energy, not just electricity) requires an increase of current global manufacturing by a factor of 125. If the 120% growth rate of PV during 2010 continued, this scale of production would be achieved in 6 years. If the US solar market grew at a rate near the worldwide 2005-2010 average of 50% [32] during 2011-2020, e.g., at 42% as projected in [33], it would take 15 years to achieve 14 TW; at lower growth rates as used in [34] it would take until 2050. With economies of scale resulting from continued growth and larger production volumes, as well as the current rapid technological developments, total systems costs may fall below and possibly considerably below $1.30/Wp. In February 2011, the US Department of Energy announced the Sunshot Initiative aimed at reducing PV system costs by about 75% before 2020 with a target of $1/Wp. Panel manufacturing costs by the price leader First Solar in the second quarter of 2011 were at $0.69/Wp in its most effective factory and at $0.98/Wp for the BOS. First Solar is currently implementing measures to increase panel efficiency from 11.7% to 15.3%. As these more effective panels use the same BOS, this higher efficiency corresponds to a decrease of BOS costs from $0.98/Wp to $0.75/Wp. Taking into account decreases of manufacturing costs between 2009 and 2011 and near future cost decreases projected by First Solar, we assume a total systems price of $1.07/Wp in 2030 for the networks analyzed here. According to Zweibel [18], this corresponds to an electricity price of 4.7¢/kWh at locations with annual insolation of 2,300 kWh/m^2 and 20% electricity losses due to DC-AC conversion. This loss factor of 20% is used here although inverters have become more efficient; but now the 20% are all-encompassing as described above.

A follow-up study to Z08 (Fthenakis et al., hereafter F08) [35] describes that all CSP plants have auxiliary boiler units using natural gas or renewable fuels during winter. In 2050, these boilers are projected to consume 11.7% of the total energy consumption. If no boilers are used, the capacity must suffice to meet the load and charge the storage also during winter when sunlight is limited to 10 hours at one third of the summer intensity, yet 14 hours of night have to be supplied for. F08 [35] assume that all capacity except distributed PV and geothermal has storage for the night, for seasonal differences and for worst-case insolation. For PV peak load, CAES with 100h of storage is employed with an overcapacity of 45% or 5.1TW. For PV base load, 300h of CAES storage and an overcapacity of 412% are assumed. The conversion of solar energy into electricity, electricity into potential energy in the form of compressed air, and compressed air back into electricity has losses in each stage. Hence, F08 also employ CSP, which – though likely more expensive than PV – is well suited to thermal storage. Thermal storage is cheaper than CAES because heat is stored directly without prior transformation into electricity. Thermal storage at Spain's Andasol CSP plants is very good for about 7.5 hours and acceptable for up to 16 hours [36]. CAES allows much longer storage times at low losses but with considerable conversion losses.

In 2100, the Grand Plan would meet a demand of 4.7 TW. The ratio between this demand and the capacity needed to generate this amount of electricity (16.73 TW) gives the factor of overcapacity of about 3.5. This yields costs of $(3.5-1)\cdot 5.7$¢/kWh plus 3-5¢/kWh for storage as assumed by F08, for a total cost between 17.25-19.45¢/kWh for electricity that comes from storage.

To calculate the costs of fuel for the auxiliary gas fired plants, we assume 50% efficiency, which is high for gas plants that are configured to meet peak load. Actual efficiency may be lower, implying higher costs for the fuel but lower costs for the gas plant. Following Z08 we assume that the gas plants comprise 11.7% of the total energy consumption, or 5.8% of electricity production with the assumed efficiency, at costs of 6 ¢/kWh. Then, electricity costs for the 5.8% of electricity generated by the gas plants increase by $0.058\cdot 6$¢$=0.35$ ¢/kWh. If the costs of PV and CSP drop to 2 ¢/kWh, which would be extreme, total costs will be $3.5\cdot 2$¢/kWh plus 1-2 ¢/kWh given by Z08 for transmission, i.e., 8 to 9¢/kWh, or between 11 to 14¢/kWh with storage.

3 The Pan-American extension

Intermittency in solar energy generation arises from the variation of insolation with the cycle of day and night, the weaker insolation and shorter days during winter, and general variability. In our evaluation of twenty years of insolation data on hourly scale, we find that linking North and South American sites for electricity generation can significantly reduce intermittency due to all three causes. In particular, low winter insolation is a major problem if solar electricity is generated in North America alone. This problem can be overcome through a Pan-American extension with South American desert sites. A further reduction in intermittency is achieved by also including tropical sites in South America.

We consider eighteen desert, arid or above average sunny locations in North and South America (Table 1): the three large deserts in North America (the Mojave, Chihuahuan and Sonoran), a site each in Florida and Texas, sites in or adjacent to the northern and southern Atacama desert, and three tropical sites in South America. We also consider sites at more poleward latitudes as these have high and long summer insolation. Table 1 lists the location of each site and the average annual insolation values on the horizontal plane (from [22]).

Insolation exceeds 2,000kWh/m^2 for all sites equatorward of ±40° latitude with the exception of the site in Florida. Consequently these sites are well suited for both PV and CSP. The Atacama is the desert with the lowest amount of rainfall worldwide and up to 20% higher insolation than the Mojave. The Sechura and Caatinga are tropical areas at respectively 6°S and 6.4°S; the Sechura is a desert while the Caatinga is semi-arid. The Sechura experiences very little variation in insolation and length of day throughout the year, with typically 12:25 hours of sunlight in December and 11:35 hours in June. The Sechura is not affected by snowfall, in contrast to subtropical locations like the Mojave. Including the Caatinga enables more even availability of insolation, as it is located considerably further east than the other areas at –2h coordinated universal time (UTC). Electricity generation in the Caatinga could begin 2 hours earlier than in the Atacama, 4 hours earlier than in Texas and 5 hours earlier than in the Mojave.

Longer availability of sunshine can markedly decrease the required storage, if a sufficiently large capacity is installed in that area. To illustrate the contributions of the different sites we consider seven different configurations (Table 2), including three North American configurations and four Pan American configurations with and without tropical sites as well as with and without higher latitude sites.

Figure 1 shows the change in insolation over the course of 2 days during each season for the Mojave, Atacama and Caatinga locations. Due to its tropical location, insolation at the Caatinga site is rather even throughout the year. Figure 2 shows the insolation over one year in the Mojave from the Northern Hemisphere and the Atacama from the Southern Hemisphere, as well as their average. A smooth average over the seasons as in Figure 2 is only possible if the selected generation sites on the two hemispheres are similar in climate, capacity and distance from the equator. Such a setup allows decreasing intermittency considerably. When the two sites are combined, the ratio between the 20 year minimum and maximum of insolation is reduced to 0.51, compared to 0.11 for the Mojave alone and 0.2 for the Atacama alone. Our evaluation of insolation data over twenty years shows that without tropical and low-lying hot deserts, problematic outages occur from different forms of attenuation such as snow events in the Mojave, or, on very rare occasions even in the Atacama. Decreasing occurrences of extreme peak-demand markedly decreases costs. Including tropical sites can also reduce the required long-term storage, which is important for economic optimization.

3.1 Calculation of hourly insolation and optimization of generation and storage

We use NASA Solar Sizer data of daily insolation [22] over the 20 years from 1986-2005. Data are for rectangular 1° x 1° boxes on a horizontal surface and are recalculated for the actual irradiance of PV panels that are tilted according to the latitude. We then determine the maximum hourly power that a particular configuration can give continuously over these 20 years for a given amount of storage. We use a constant consumption to allow a fast comparison of combinations of generation sites within different configurations, but as shown in [21], this method also allows optimizing configurations to meet quite different load patterns. In the first step, a simple optimization process is used that considers day-to-day changes of insolation but does not consider time zones or insolation changes during the day [21]. The required consumption for each day is subtracted from the electricity generation of that day in that configuration. If generation does not suffice, the storage fills the deficit. Thus, on each day, the insolation plus the available storage must be larger than or equal to the daily consumption. If the storage does not suffice, the storage is increased until the consumption can be met from ongoing electricity generation plus electricity in storage. Naturally, the consumption must be lower than or at most equal to the electricity that can be generated with the average insolation in that configuration. Any remaining new electricity is added to the storage while it still has capacity. Surplus electricity, beyond demand and filling of storage, is counted as "excess electricity" because in some networks the price for excess electricity can be negative. Charging of the storage begins when electricity generation is higher than demand, and discharging begins when generation drops below consumption.

This procedure is performed for 20 years with 365 days including 5 leap years, i.e. 7305 days. This first optimization takes into account seasons and attenuation from weather, but neglects the rhythms of day and night. The generation of electricity is seen as evenly distributed over a day. This could be interpreted as having all configurations supply electricity uninterruptedly without use of storage during the night. In the second phase of the optimization, the results from the first phase serve as initial values for an iteration using insolation data recalculated for an hourly scale. The calculation of hourly irradiance from the daily data uses established astronomical or meteorological formulas [37] together with the solar angle above the horizon (as an indicator for the intensity of irradiation given time-zone differences) to calculate sunrise, sunset and irradiance at each site. The variables in this calculation depend on the true solar time of each location and on the fractional year, the number of the day in that year indicating the seasons and the declination of the sun. This is done for the 7305 daily insolation values during 1986-2005 at each location [21]. In total, the optimization evaluates 3.2 million data points for the 18 locations of the 7 configurations.

Based on the hourly insolation values, we run the optimization with three different optimality criteria: minimization of the necessary generation capacity, minimization of the required storage, and an intermediate setup in which the revenue from electricity minus costs for storage minus costs for generation capacity is maximized, giving values that are between the two extreme cases. Computing typically needs between 10-30 hours on fast desktop computers. The second phase of optimization is much more precise than phase 1 and sometimes gives values that are considerably different from the values from the simple, straightforward calculation in phase 1 (optimization 1 can be too high but never too low). The discrepancies between the calculation with hourly and the calculation with daily data show that too simplistic procedures can lead astray [21].

Since we use daily data over 20 years, a wide range of weather conditions are represented, including the major volcanic eruption of Mt. Pinatubo in 1991, which decreased global sunlight temporarily by up to 10%. In addition, the procedure allows the optimal selection and combination of locations and the optimization of their respective capacity to meet a given load pattern.

Figure 3 shows the calculated daily rhythms of insolation, charging and the use of storage over 50 hours for each of the four seasons for the combination of the three North American deserts with three South American deserts (configuration 4 in Table 2). Here, the load is kept at 1 MW and the capacity of the storage is limited to 12MWh, so that charging stops in all panels although electricity for charging would still be available. The longest nighttime in the North American three desert configuration (configuration 1) is 14 hours in the northern winter. Nighttime decreases by 2 hours when all southern locations in North America are linked (configuration 2) due to the addition of the site in Florida. Linking the three North and three South American deserts (configuration 4) shortens the longest nighttime to 9 hours, i.e. by 5 hours compared with the North American three desert configuration. Inclusion of the Caatinga site shortens the longest nighttime to 8 hours. Combining all locations (configuration 7) gives 7 hours of night in the northern winter. In this configuration there is always some solar irradiance during the northern summer with values >0 but below 0.2kW/m^2 for 5 hours and peak values above 12 kW/m^2. This illustrates how calculating the rhythm of day and night in each location within a given configuration allows determining the necessary capacity and type of storage to eliminate intermittency.

The value of linking North and South American sites is further illustrated by the decrease in the ratio between minimum and maximum insolation. In configuration 2 which links all five North American sites, average daily insolation varies between a daily minimum of 2.98 kWh/m^2 in December and a maximum of 7.1 kWh/m^2 in June, corresponding to a ratio of 42%, whereas the extremes through the 20 years have a ratio of 1.1 to 9.1 or 12%. For a network with the six North and South American desert sites, average daily insolation has a minimum of 5.6 kWh/m^2 in January and a maximum of 6.4 kWh/m^2 in April, corresponding to a ratio of 87.5% and a ratio of 3.1 to 7.3 or 42% for the extremes through the 20 years. Thus the average is much more even over the year. Adding the two tropical sites improves the ratio of the long-term averages of maximum and minimum to 90% with an average daily insolation minimum of 5.6 kWh/m^2 in January and a maximum of 6.21 kWh/m^2 in October. Configuration 7 with all 18 locations results in a slight further improvement with a minimum of 5.0 in January, a maximum of 5.52 in October, a ratio of 91%, and a ratio of 3.85 to 6.51 or 59% for the extremes. Long term averages are based on the 23 year average from NASA Solar Sizer [22].

3.2 Demand projection

F08 [35] project a decrease in primary energy demand due to the higher efficiency resulting from the transition to sustainable electricity. Electricity generation with an efficiency of about 33% consumes 40% of the primary energy in the US. Numbers are globally similar, the total global primary energy consumption in 2009 was 16.5 TW, of which 6.5 TW were used to generate 2.1 TW of electricity [38], i.e., with an efficiency of 32.3%. Consequently, generating 1kWh of electricity from solar power plants substitutes 3 kWh of primary energy. If all electricity were from renewable sources, this would deliver the equivalent of $\frac{40\%}{3} = 13.3\%$ of primary energy demand in the form of (renewable) electricity, thereby decreasing primary energy demand by the difference between current primary energy demand for electricity (40%) and the then remaining demand (13.3%), i.e. by roughly 27%. A demand of 4.7 TW in 2100 for the US as assumed by [35] and a similar development in Canada gives an annual energy demand of 5.2 TW, or 41,000 TWh for the USA and 5,000 TWh for Canada.

For a scenario with high energy demand in South America we assume that the average annual economic growth in South America during 2010-2100 will be at most 4%. Growth of 4% yields a ratio of 1.6:1 between the North and South American economies until 2100, i.e. a demand of 28,750 TWh for South America (including Mexico). This gives a total projected demand of 74,750 TWh for North and South America, corresponding to a capacity of 8.5 TW. From an energy unit cost supply perspective, higher growth rates than 4% per year would be better, as a ratio close to 1 between North and South America increases the utilization rate of transmission lines, which in turn decreases costs, as we will discuss below.

3.3 Long-distance transmission in a Pan-American network

High-capacity, long-distance transmission lines have recently become feasible. The first two lines with low electricity loss were completed in 2010 in China by ABB and Siemens, linking the Three-Gorges Dam with major centers at distances up to 2,600 km [25,26]. These have a capacity of 6 GW at 800 kV DC. HVDC lines offer significant cost savings over long distances relative to conventional AC or lower voltage DC [24]. First, since there are no capacitive, inductive or dielectric losses, transmission losses are reduced to a fraction, i.e. 2%-2.5% per 1,000 km for 800 kV DC [7,24,39]. Second, the investment costs for the lines are lower. Their tracks are much narrower compared with AC transmission, so that right of way is considerably decreased.

The number of very long distance transmission lines needed for a Pan-American network depends on the degree of cooperation between countries, their economic growth, the percentage of renewable energy in the network, reliability standards, and the development of transmission technology. Costs of transmission lines depend on factors such as costs of labor, right of way, capital cost, required redundancy of lines, terrain and land cover, and life expectancy of the lines.

The highest demand for electricity transmitted from the Southern Hemisphere would be in the northern winter, when North American electricity generation is at 1/3 of generation during summer. If the 5.2 TW projected North America demand were supplied by renewable energy, 2/3 of the required 5.2TW or 3.5TW would need to come from South America. At the present transmission capacity of 6 GW per HVDC line, 580 lines would be needed to link the two hemispheres. Transmission lines at 1500kV are now discussed [40] which would increase capacity by a factor of $(1500/800)^2$ or 3.5 and decrease transmission costs per kWh by 17% [40]. The network between the two hemispheres would need 165 lines with 1500kV.

Lines would need to connect and cross a number of countries. Some lines might be submarine or underground in spite of higher costs. Underground cables used to be several times as expensive as overhead lines; however, given the growing size of the required cables and considerable progress in underground HVDC technology, the cost difference has decreased to a factor of 2 [41] and will likely continue to decrease [42]. Underground cables would also be less susceptible to resistance from citizens, which has in the past changed planned lines from overhead to underground [42].

The direct distance between the US grid of the "Grand Plan" and the closest Southern Hemisphere desert is 5,900 km, e.g., a link of San Diego (the southernmost large US city close to the Mojave) with Lambayeque in Peru. A direct link would need more expensive submarine cables. Overhead lines would be less expensive though somewhat longer, for example linking Lambayeque to Medellin in Columbia (1,500 km) and San Diego (5,500 km) for a total of 7,000 km. Other overhead lines could connect Arica to Columbia (2,800 km) and San Diego (5,500 km) for a total of 8,300 km. In section 4 we list (land) distances between several major centers and deserts that would need to be connected.

Our calculation of transmission costs uses two different cost estimates together with different learning curves. Manufacturers rarely provide data on transmission costs since costs depend on many local issues including negotiations between the customer and company. Significant differences in costs are expected for the right of way, which can be expensive. With DC lines, the DC electricity from PV panels does not need conversion, so that a station with an inverter at the beginning of the line is not needed [43]; while conversion to high voltage (without a station) is still necessary ("array converter", a comparatively simple, cheap electronic device). Thus, the main costs of DC transmission are due to the line itself and the station at the end of the line that converts from DC to the AC used by the grid. To err on the cautious side, we assume that the array converter for the conversion from the about 100V of the PV panels to the high voltage of the line has the same costs as the station at the end of the line, i.e., around $450-510 million for a line of 6GW [24,44].

Our higher transmission cost estimate is based on Bahrmann [44] who gives explicit costs, however for a transmission line with 3 GW in 2006. The second estimate, which we evaluate according to three different learning curves, is calculated with more recent data after ABB completed a 800kW DC line with 6GW capacity in China in 2010 [24]. The costs given by ABB, $66.7/kWh/1000 km (figure 1 in [24]) are 40% lower than the costs given by Bahrmann [44] in 2006. 25% of this is due to a lower interest rate and the assumed longer lifetime, the rest should be due to learning and technological advances. Delucchi and Jacobson [45] also find that the costs given by Bahrmann are considerably higher than costs given by other sources for more recent HVDC lines, e.g., $0.34 million/km reported by Cavallo for 500 kV long-distance lines in Canada in 2007 [46], and $0.3-0.6 million/km by Weight et al. [47] for planned 500 kV lines in the North Sea region in 2010 (for comparison, Bahrmann's costs of $1.22 million/km for 800 kV lines translate into $0.99 million/km for 500 kV lines).

The cost of electricity loss in lines is the highest factor in transmission costs. At present, lines have a loss between 2-3% per 1000 km. The cables discussed in [41] would decrease losses to 1%, which according to that author cannot be further improved, even if superconducting cables would be employed, as these need energy for cooling with liquid nitrogen. Moreover, decreasing losses further to below 1% is less important than to get from 3% down to 1%. Loss cannot become zero according to thermodynamics. Station losses are around 0.6% [31]. We assume the same loss of 0.6% for the conversion from the low voltage of the PV panels to the high voltage of the line. The costs of station and line losses depend on electricity generation costs. These are up to 20% lower if the electricity is generated in the Atacama compared to the Mojave or other deserts with lower insolation; however, we here assume the same higher price for consistency.

3.4 Learning curves for transmission costs

In 2010, only two very long distance high capacity transmission lines had been completed [25,26]. For several technologies, learning curves are known that give the relative manufacturing costs as a function of the number of doublings in the volume of production. If 200 similar lines are built, this implies an increase in manufacturing and learning by factor 100. A comparison of transmission costs in 2006 [44] and 2010 [24] shows that learning considerably decreases costs. Huang et al. estimate a further 17% cost decrease if lines with 1500 kV are built [40]. The ultimate transmission technology would be superconductivity, which could completely eliminate resistance in lines, could use lower voltages and would thus need fewer transformers and stations while decreasing losses [48,49].

Learning curves can be described by a cost function of the form $C_0\alpha^n$, where C_0 is the initial cost of the line including stations and other electronics, n is the number of doublings of manufacturing capacity, and $0<\alpha<1$ describes the decrease in manufacturing costs per doubling of manufacturing. We estimated earlier that 580 lines may be necessary to link North and South America, in addition to lines that connect in east-west direction. Installation of 200 or 1000 lines, respectively, is close to $2^8=256$ or $2^{10}=1024$ i.e. between seven to nine doublings in manufacturing from currently 2 lines.

The following learning curve gives manufacturing costs as a function of the number of doublings:

(1) $$c_1(t)=c_0a^{(\ln(M(t)/M_0)/\ln(2))}$$

where $c_1(t)$ describes the costs in year t, c_0 is the cost in year 2011 (the first year for which the number of doublings will become available), $0<a<1$ is the learning coefficient, $M(t)$ is the manufactured transmission capacity in year t (in GW) and M_0 is the capacity in year 2011. The smaller a, the faster the learning. For PV with its exceptionally rapid decrease of manufacturing costs, a learning coefficient a=0.8 has been observed [50,51] (without footing). The value here will be lower, because PV is a semiconductor technology and no other industry is known for the type of exponential progress exhibited by this sector.

An index for the manufactured capacity must include both the length of transmission lines with 800kV or higher and their capacity. The first publications in 2006 on 800kV technology still gave numbers for 3GW lines [44]; the first lines that were built, however, already had 6 GW, and the present discussion is for lines up to 30 GW [41]. At 30 GW it might be possible to have 8 or more doublings because many countries pursue an increase in interconnectivity [52]. As an index to describe manufacturing capacity we suggest multiplying the length of HVDC lines in 1000 km with the capacity in GW. The new lines in China would have an index of about $2.6\cdot 6=15.6$; a line of 8000 km with 20 GW capacity would have an index of 160. This index allows lumping together all manufacturing of lines and cables with 800kV and above, regardless of their voltage.

The index also indicates costs of the cable, however not directly given two nonlinearities in cost: A 6GW line is less than two times as expensive as a 3GW line [24,25,44] and a line with two times the length of another line also is less expensive than twice the costs of the shorter line. To be strict we suggest comparing manufacturing costs of "standard lines" which have 20 GW capacity (1.5 MV as discussed in [40]) and a length of 5000 km. Such lines may become more typical for the large-scale grids needed for a Pan-American link than 6 GW lines. For the cost calculations below we nevertheless assume 6 GW lines since this is the current standard.

Costs $c_1(t)$ in Equation (1) decreases to 0 with increasing n. However, zero costs are not possible given material costs and a minimum amount of labor for production and installation. Hence, equation (1) is restated with a footing F that gives the minimum costs of manufacturing a standard transmission line, with the number of doublings in manufacturing capacity given by $n(t) = \ln(M(t)/M_0)/\ln(2)$:

$$(2) \qquad c_1(t) = F + \tilde{c}a^n$$

where the coefficients $\tilde{c}$ and a are such that equations (1) and (2) have the same value in the beginning. We use three learning curves with different speeds of learning, a low speed given by $0.05 + 0.95^n$, a middle speed of $0.12 + 0.88^n$ and a more rapid speed of $0.22 + 0.78^n$. Figure S1 shows the development of these curves during 2010-2050.

Based on the resulting costs E, the levelized transmission costs L_c per kWh are calculated with the standard formula for amortization of cost over time:

$$(3) \qquad L_c = E \cdot A / (8760 \cdot U)$$

with expenditures E, amortization coefficient A for a 40 year equipment lifetime and utilization factor U (division by 8760 converts to kWh). Our equipment lifetime estimate is on the careful side; Delucchi and Jacobson [45] indicate lifetimes between 50 and 70 years. The coefficient A is between 0.058 for a capital interest rate of 5% and a 40 year life expectancy of the equipment, 0.075 for an interest rate of 7% and a 40 year life expectancy, and 0.106 for an interest rate of 10% and a 30 years life expectancy. The example in [44] uses the latter values; we use 7% and 40 years. Other costs that have to be added are for operation and maintenance; these may be around 1% of the line costs.

3.5 Grid utilization

The utilization rate depends on the use of the line and the legal framework. For example, present North American reliability standards would require full redundancy of such high capacities. A transmission line that is used by only one solar plant has the same (usually low) utilization factor as the plant. The capacity factor of a solar installation is defined as the percentage of energy which this installation gives during a year compared to the energy it would give for uninterrupted sunshine during all 8760 hours of the year with 1 kWh/m^2. For example, in southern California, the capacity factor of PV is about 20%-26% so that a 1 TW load needs between 3.8TWp and 5TWp generation capacity. Accordingly, low utilization can increase transmission costs by several times.

At 5% utilization U, transmission costs increase by a factor of 20 according to equation (3). With transmission costs between 1¢/kWh and 10¢/kWh at 100% utilization (Table 4), 5%

utilization would cause transmission costs that are economically prohibitive. If the long-distance transmission lines from South America were used only to send electricity to North America, the utilization rate would be about 25%, which still increases transmission costs by a factor of 4. However, the utilization rate can become as high as 60% if solar plants on both hemispheres are connected and electricity is sent in both directions. In theory, additional use of storage can increase the utilization rate close to its theoretical maximum of 100%.

High utilization may be less important if the costs of a line are partially or fully paid from other sources, for example given its contribution to regional development. In South America, east-west lines that connect the main grid with consumers could play an important role for economic development; consequently, their costs should also be evaluated in that context. The east-west lines from the Caatinga region through Brazil could considerably support the economic development of the entire transect from the Atlantic to the Pacific. Once these lines connect to the grid in the Atacama region, they could bring electricity from the US to the Caatinga region during southern winter. This line would have a total length of 14,000 km. From the perspective of solar energy supply, the electricity imported during winter from the respective other hemisphere is peak electricity that meets peak load. As peak electricity is expensive its costs can justify very long transmission lines; the costs of the imported electricity could still be below common peak electricity prices.

Connecting east-west lines with the north-south backbone (NSB) could significantly increase the utilization factor of the NSB and thus decrease transmission costs of the longest lines. The NSB is used on average at 60% of its maximum utilization to transmit electricity from the south to the north during October-March. During April-September, electricity is transmitted from the north to the south. This gives a utilization rate of up to 60%. In addition, this line would be used to transmit electricity from the Caatinga to the rest of the American continent beginning at about 6:30 hours Caatinga time until the deserts in the west of South America get sunlight. The NSB is also used to transmit electricity from regions with good weather to regions affected by attenuation. In total, we expect that utilization rates could slightly exceed 60%.

The grid should have adequate spare capacity as a network with redundant lines is far less vulnerable than a network with a tight capacity or a small number of lines. If a politically instable country allowed the destruction of long-distance lines in a network with redundancy, it will be disconnected from a major source of its energy, whereas other countries will still get electricity via other lines in the network. Like today with major supra-regional technical infrastructure it can be assumed that countries will be very careful to avoid interruptions in their territories.

4 Results and discussion

Table 3 lists the results of our calculation of hourly insolation for the years 1986-2005 and the subsequent optimization of generation capacity and storage. Results according to the three optimality criteria are presented in the upper three blocks of the table: minimization of the necessary generation capacity, minimization of the required storage, and an intermediate setup in which the revenue from electricity minus costs for storage minus costs for generation capacity is maximized. This corresponds to a simultaneous optimization of both, storage and generation capacity giving values for storage and capacity that are between the two extreme cases. For each optimization, we also list the total electricity generated and excess electricity that will have to be discarded due to the storage being full (unless it is used, for example, to produce hydrogen). We also list the capacity factor and the effective capacity factor, which is the ratio of the necessary generation capacity for 1 MW load divided by the theoretical amount which this capacity could have generated throughout a year with 8760 kWh/m^2 [21]. As in the Grand Plan, two types of storage are needed, long-term expensive CAES storage and short-term much cheaper thermal storage which may last up to 10 hours [36]. In our advanced configurations, most of the night-time gap can be covered by the short-term thermal storage. Table 3 shows the total storage required with a certain generation capacity as well as an upper boundary for the required long-term storage. The table shows that within limits, generation capacity can be substituted for storage and vice versa [21]. To effectively compare the seven configurations, the fourth (bottom) block of the table compares the generation capacity and storage required to meet three different loads: the generic load of 1 MW and the loads of 4.7TW and 8.5 TW corresponding, respectively, to the projected North American demand and the combined North and South American demand for 2100.

In a US-based network with electricity generation at the three US Southwest locations, the required capacity to continuously meet a 1 MW load is between 6.4MWp (with 71.7 MWh of storage) and 26.4MWp (with 14.2 MWh of storage). With 6.4MWp of generation capacity, all of the required 71.7 MWh of storage may have to be long-term (as discussed in section 3.1., phase 1 of the optimization which does not use hourly insolation values can give values that are too high but never too low). With 26.4MWp of capacity, the maximum required long-term storage is 0.5 MWh. The required capacity in optimization 1 increases slightly (for any amount of storage investigated) if sites in Florida and Texas (configuration 2) or the high latitude sites (configuration 3) are added, because these additional sites have lower average insolation than the desert locations. To supply the demand of 4.7 TW projected for North America for 2100 with the three US Southwest sites, a capacity of 41TWp and 126 TWh of storage are necessary, according to the intermediate solution.

Combining North and South American sites into one network permits a dramatic reduction in the required capacity and storage. For a load of 1 MW, a configuration using both North and South American deserts allows reducing the required minimum capacity by 21% to 5.1 MWp with 50 MWh of storage (a 30% reduction), of which at most 8.7 MWh have to be long-term (a 88% reduction). In the minimum storage solution, the required generation capacity in the North and South American deserts configuration is reduced by 15.5% to 22.3 MWP and storage is reduced by 27.5% to 10.3 MWp. In this case, no long-term storage is needed at all. The other Pan-American configurations offer similar reductions in required capacity and storage. Notably for the most practical, intermediate configurations, adding tropical sites dramatically reduces the required long-term storage. The extended Pan-American configuration in particular needs only negligible long-term storage even at low generation capacity. As long-term storage is costly, and as thermal storage needs CSP which is more expensive than PV, decreasing long-term storage through skillful combination of locations becomes an effective method of cost minimization.

A Pan-American network (with or without tropical sites) can meet the combined North-South American demand of 8.5 TW projected for 2100 with a generation capacity of between 48-52 TWp and 127-152 TWh of storage. This is only slightly more capacity than the 41-51 TWp needed by a US network with the three US Southwest sites to meet the load of 4.7 TW projected for North America alone. Thus, a Pan-American network can meet almost twice the demand with a similar generation capacity. This advantage is even more obvious in the need for storage, which is 126 TWh for a 4.7 TW load in the network of the three US Southwest sites, versus 127 TWh for the Pan-American configurations 6 and 7 and a load of 8.5TW.

The reduction in storage, and in particular long-term storage, enabled by a Pan-American extension points to perhaps the biggest problem faced by a US-based solar energy network. Due to the combination of low insolation and shorter days during winter, a North American solar network requires large amounts of expensive long-term storage, overcapacity and fuel. As is evident from the numbers given above, a combination of North and South American sites provides a natural solution to this problem.

Table 4 lists cost estimates for transmission lines with different assumptions on cost reduction due to learning, as outlined in section 3.4. The bottom portion of the table gives typical distances between Southern Hemisphere deserts and North America. The shortest is a link between San Diego and the Sechura, which is an atypical desert region as it is located considerably north of the Atacama in the tropics. Solar plants in the Sechura would still have to be connected to South American cities further south, so that the transmission line lengths given in Table 4 cannot really be decreased.

The higher estimate is for a transmission line with 3 GW with 2006 technology [44]. The lower estimate is based on cost estimates by ABB in 2010 after completion of a 6GW 800kW DC line in China [24]. Both give similar costs for the station, around $450-510 million but the more recent station has twice the capacity. The losses in row 3 are calculated by multiplying the line length with (low) loss rates of 2%. To calculate the costs of losses (row 4) we multiply the assumed electricity costs of 7.5 ¢/kWh with the losses attributed to the two stations (0.6%) and the losses attributed to the line (times the line length). Although only one station is required, we here add a second station to account for the conversion to higher voltage and other loss factors, e.g. filtering. The total costs in row 6 are the sum of the costs of transmission, losses, and two stations. As longer lines do not need more stations than short lines, costs are lower per kilometer for longer lines. We evaluate the costs according to 2010 technologies further with three different learning curves by multiplying with the respective learning factor in rows 8-10; row 7 presents the costs for the higher costs of transmission given by Bahrmann [44] under mid learning conditions. Here, the learning rates are also applied to the decrease of losses. Line costs increase less than proportionately with distance due to the high costs of the station at the end of the line.

With assumed solar electricity costs of 4.7¢/kWh in 2030, we estimate costs of 1.59 ¢/kWh for transmission between the Atacama and San Diego, 1.22 ¢/kWh for transmission between the Sechura and San Diego, and 1.98 ¢/kWh for transmission between the Caatinga and San Diego. This implies total costs of 5.85¢/kWh, 5.58¢/kWh and 6.12 ¢/kWh for electricity brought to San Diego from, respectively, the Atacama, the Sechura, and the Caatinga and vice versa. The time when grid parity is reached will also depend on the development of coal electricity prices and emissions policies. Grossmann et al. [53] calculated 4.7¢/kWh levelized costs of electricity from coal but approximately four times higher costs for peak-load plants [28].

PV may play a central role in such a network [28]; however, reliability and continuity of energy output will be enhanced if a variety of technologies besides PV are used. Due to the current extensive research and rapid development of renewable energy technologies, state-of-the-art solutions may change quickly. Most favorable is a culture of constant assessment of new options and adaptive management.

5 Conclusions

The proposed Pan-American network offers significant improvements with regard to fuel, capacity and storage over a US only network as proposed by Z08 [17] in the Solar Grand Plan. The Grand Plan requires fuel on the order of 11.7% of the energy consumed, and storage of about 47% of the energy generated; projected electricity prices from PV are 5.3-5.7¢/kWh by 2050 and 7.3-7.7 ¢/kWh with transmission costs. The Pan-American network presented here does not require fuel and is able to meet the projected demand of the entire North and South American continent in 2100 with about the same capacity than that required for a North American network in order to meet only the projected North American demand. Total estimated electricity costs without storage will be between 5.85¢/kWh, 5.58¢/kWh and 6.12 ¢/kWh for electricity brought to San Diego from, respectively, the Atacama, the Sechura, and the Caatinga. This is less than the electricity prices estimated by Z08. However, the most important cost savings relative to the Solar Grand Plan result from the dramatic decrease in expensive long-term storage, for which we do not estimate costs here. As long-term storage has comparatively high losses, use of such storage requires a significant portion of the overcapacity calculated in Z08 (with storage costs of 3-5 ¢/kWh according to Z08).

Relative to a North American network delivering the same load, the maximally required long-term storage is reduced by 88% in a Pan-American network (configuration 4) when capacity is minimized and by 93.6% in a Pan-American network that also includes tropical sites. In the intermediate solution (which minimizes the weighted sum of storage and capacity), the maximally required long-term storage is reduced by 44% in a Pan-American network and by 56% in a Pan-American network with tropical sites.

Future work could assess long-term storage needs in more detail based on a sensitivity analysis of the error resulting from the conversion of daily insolation data to hourly scale. It could also determine various different configurations of generation and storage at the different sites, taking into account projections of the costs of different generation technologies, storage, capacity, and transmission, as well as aspects of economic and social development and the minimizing of ecological impacts. We will briefly discuss some of these issues below.

A Pan-American solar energy network offers a number of advantages. Perhaps most importantly, it significantly reduces greenhouse gas emissions and US dependency on oil imports at low electricity costs. In Brazil, where hydropower accounted for approximately 85% of electricity generation in 2009 [54], a solar network could help buffer against droughts, and the hydropower in turn could act as a storage for times of low solar insolation. A solar network could play an important role in a warming world where precipitation in Brazil may decrease, with average annual flow in basins used for hydropower generation projected to decrease by 9-11% in a scenario of approximately doubled CO_2 concentrations [55].

Large-scale availability of electricity could play an important role in supporting the creation of new industries in South America, in particular in Brazil, Argentina, Chile, Columbia and Mexico, countries where energy consumption has been shown to have a strong correlation with economic growth [56]. The present use of arid areas for agriculture provides only low income. Availability of electricity and new uses of (relatively small fractions of) land could permit the development of schemes to improve living conditions through education and the support of local economic development. Consequently, the costs of international transmission lines should not be attributed only to the initial objective of electricity supply but also to goals of regional development.

Including the Caatinga into a Pan-American grid could support economic development through improved availability of electricity in remote areas. However, the area for solar energy generation will need to be selected very carefully as the Caatinga includes valuable ecological habitats. On the other hand, overall land demand per kWh is lowest for CSP and almost as low for PV compared to other types of electricity generation [57, 28]. In contrast to coal, PV and CSP use mostly desert or arid areas. The area needed to generate 8.5 TW (the demand projected for the Americas in 2050 at high economic growth) at an average insolation of 250W/m^2 and 14% module efficiency is $\frac{85,000,000,000,000}{250 \cdot 0.14} = 242,857$ km^2, i.e. less than 0.6% the total American land area of 42,549,000 km^2. With an assumed PV thin-film efficiency of 11.6% (which is projected to be at 14% by 2014), the area required would be 293,103 km^2, i.e. less than 0.7% of the total American land area. Coal based electricity generation not only consumes more land (including for mining and transportation) [57] but also affects the environment through extensive water use and pollutants such as heavy metals, sulphur dioxide, nitrogen oxides, and CO_2.

Geopolitical issues that future research should consider arise from the inclusion of a number of different countries into such a network. A Pan-American grid is a challenge; it would connect very different political regimes and very different mentalities. Not all countries may be deemed politically suitable to host transmission lines. We propose that transmission resembles a web of lines with redundancy for cases of individual line failure. If one line carries at most 25 GW, i.e., four times the present highest capacity, 100 lines will be necessary for the north-south transport of 2.5 TW, and 230 lines for 5.7TW. In a network without redundancy, the effect of failure of one line would be like the failure of 25 big power plants. If a country with political problems hosts four such lines, it could cause a lot of damage. On the other hand, a country that allows such damage will itself be cut off from this electricity source. Additionally, the present system of energy supply is highly vulnerable, in particular with regard to oil production and distribution.

In a Pan-American network, each hemisphere has a natural market – the other hemisphere – for its excess electricity during its summer as this is the winter of the other hemisphere. Thus, the excess electricity – a kind of almost waste- can instead be sold as peak electricity. In the beginning this allows a high line utilization rate, but for higher amounts of electricity generation line utilization falls because the sizes of the North and South American economies are too different. The ratio of the North American GDP to the GDP of the rest of the Americas is currently 3.9:1, whereas the ratio of population numbers is 0.64:1. Given the high potential from its population, the South American economies may grow considerably. Eventually, the 3.9:1 ratio would imply a utilization factor of approximately 40% because lines are used only at 12.5% in the north-south direction. With storage in all locations, electricity can flow 24 hours per day according to the respective load factors. This may raise the utilization rate above 70%. An important consequence is that electricity costs for North America will be progressively lower if South America develops well. Thus, the economic development of South America would imply economic advantages for North America as well.

Starting with a review of the Grand Plan, an improved and extended scheme would also offer support for large scale economic development of the whole American continent, with economic growth in South American implying lower transmission and electricity costs for North America. Thus, a Pan-American network could have positive effects much beyond the immediate purpose of reducing solar intermittency and meeting the growing US energy demand via a renewable network that requires little expensive storage and overcapacity.

6 Acknowledgements

The first and third authors were supported by a research grant of the Austrian National Bank (Project No 14451, DEVELOP). The second author was supported by the Center for Climate and Energy Decision Making created through a cooperative agreement between the National Science Foundation (SES-0949710) and Carnegie Mellon University.

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8 Figures

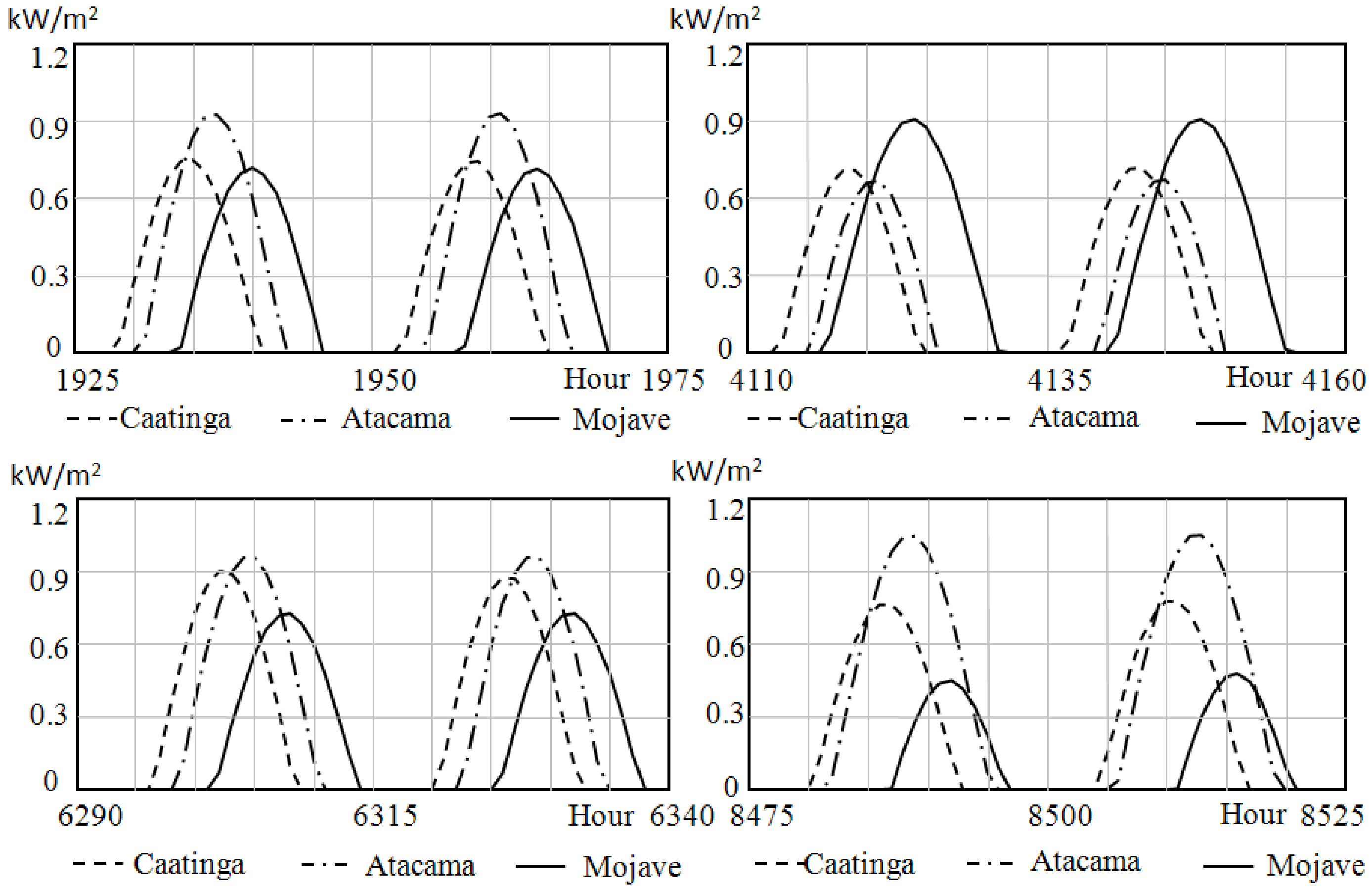

Figure 1. Comparison of insolation in kW/m^2 in three locations for two consecutive days (50 hours) during the four seasons: March 21st (top left), June 21st (top right), September 21st (bottom left), December 21st (bottom right).

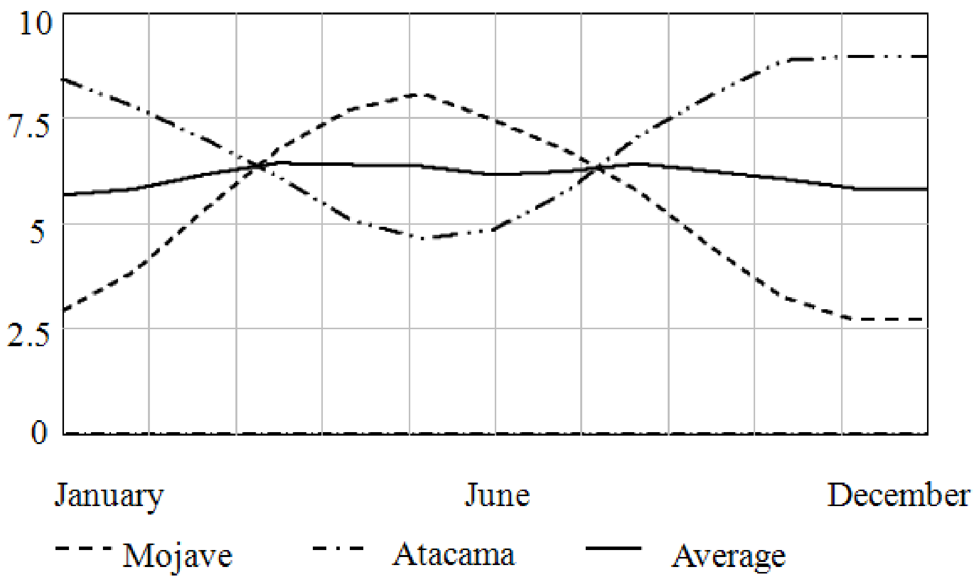

Figure 2. 23-year average of daily insolation in kWh/m^2 in the Atacama and Mojave and the average of the two locations (data from [22]).

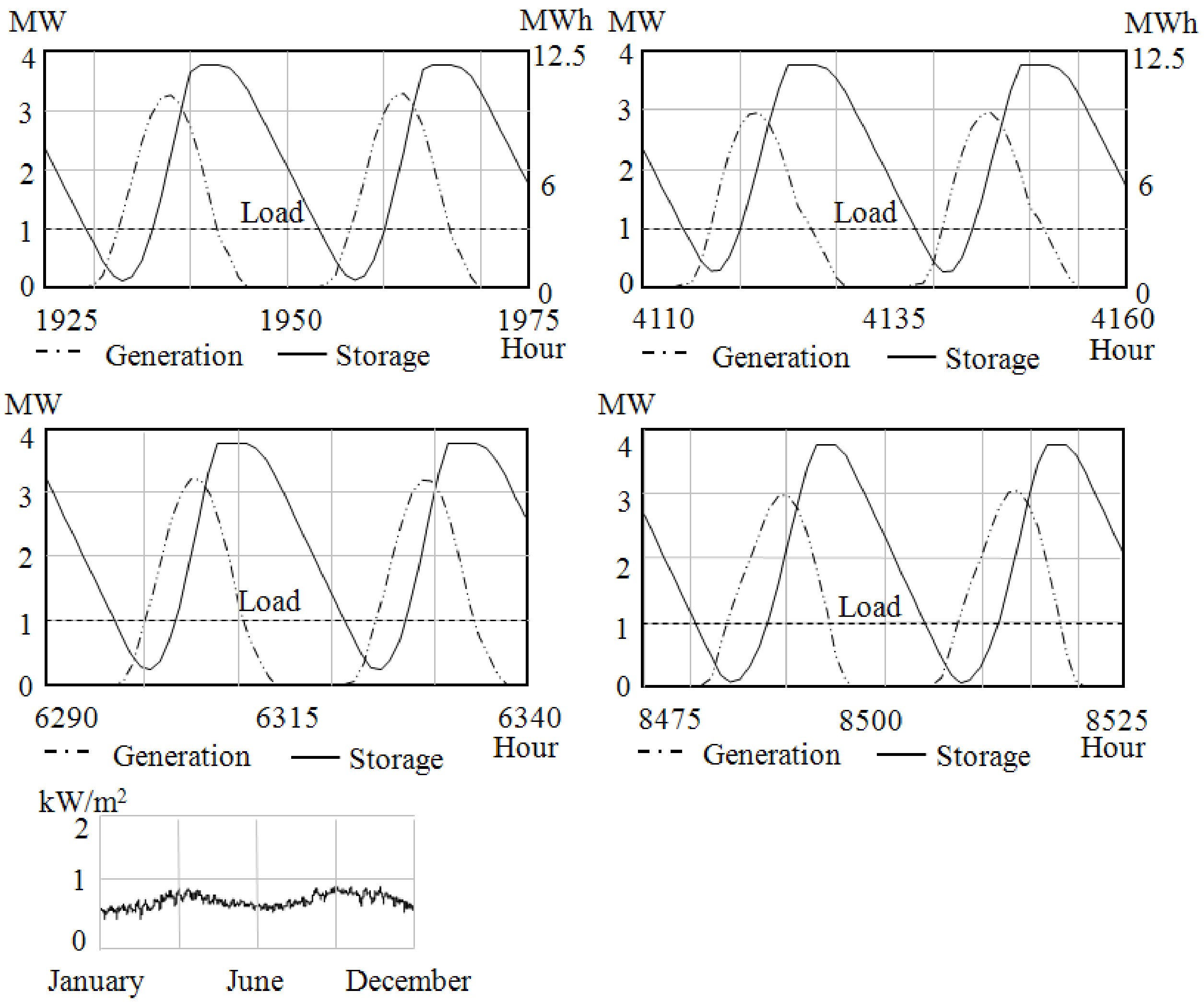

Figure 3. Generation and load (in MW, scale on left) and storage (MWh, scale on right) of the ten sites of the “Pan-American deserts“ network on March 21st (top left), June 21st (top right), September 21st (bottom left) and December 21st (bottom right). Bottom panel: average insolation of the ten sites.

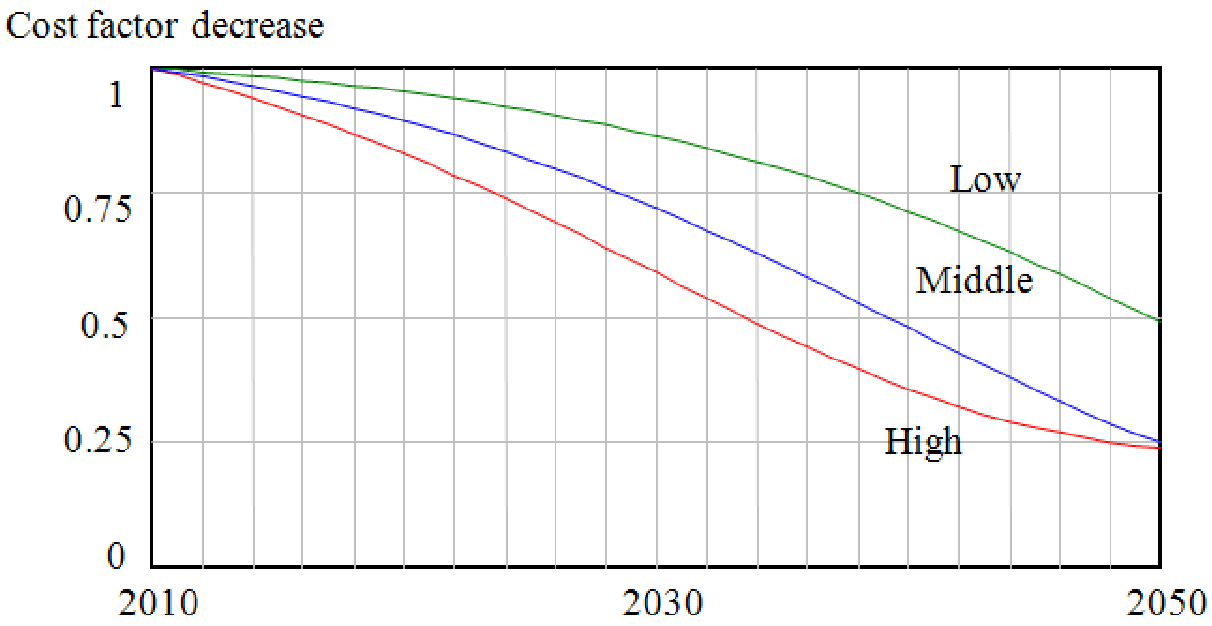

Figure S1. Learning curves pertaining to the costs of transmission line manufacturing with three different speeds of learning during 2010-2050.

Tables

Table 1: The 18 locations in the US, Mexico (MX) and South America with geographical position and annual insolation in kWh/m^2.

Location	**Position**	**Insolation**
North America		
Deserts in North America		
Chihuahuan desert (US; MX)	31°N 108°W	2150
Mojave Desert (US)	36°N 117°W	2300
Sonoran desert (US; MX)	32°N 113°W	2180
North American regions with high insolation		
Florida	29°N 83°W	1840
Texas (US)	32°N 102°W	2020
North American regions at higher latitude		
Alaska Panhandle	58°N 134°W	1650
Koyukuk/Alaska	66°N 153°W	1720
South America		
Deserts in South America		
Atacama north (Chile)	19.5°S 69.5°W	2360
Atacama south (Chile)	24°S 69°W	2650
Bolivia Litoral	19°S 67°W	2290
Atacama further south (Chile)	27°S 69°W	2700
East of Atacama (Argentina)	24°S 67°W	2500
Catamarca (Argentina)	27°S 67°W	2430
North of Atacama (Peru, Interoceanica Sur)	17°S 70.5°W	2300
Tropic areas South America		
Caatinga (Brazil)	6.4°S 38°W	2080
Sechura I (Peru)	6°S 80°W	1980
Sechura II (Peru)	8°S 79°W	2100
South American region at higher latitude		
Santa Cruz (Argentina)	55°S 69°W	1125

Table 2: Sites included in the seven configurations and their basic characteristics

Configuration		**Sites (see Table 1 for details)**	**Sites**	**Longest nighttime (hours)**	**Max. and min. daily insolation**
1	North America deserts	3 North American deserts	3	14	9.05 1.05
2	North America hot areas	Configuration 1 and the two high insolation sites	5	12	8.48 1.27
3	North America extended	Configurations 1, 2 and the North American higher latitude sites	7	12	8.0 0.98
4	Pan America deserts	Configuration 1 and Atacama south, Bolivia Litoral, Catamarca	6	9	7.3 3.1
5	Pan America deserts + tropics	Configuration 4 and two tropical sites: Caatinga, Sechura I	8	8	7.15 3.41
6	Pan America extended South	Configuration 5 and Atacama north, Atacama further south, Sechura II	11	8	7.31 3.94
7	Pan America extended	All sites from Table 1	18	7 (see text)	6.51 3.85

Table 3: Electricity generation and storage for 7 large-scale networks and an assumed annual consumption of 8.76 GWh (1 MW load) according to three optimality criteria: low generation capacity, low storage, and a setup in which both generation capacity and storage are relatively low. The required generation capacity and size of storage to meet the loads of 4.7TW and 8.5TW are given in the last 4 rows, based on optimization 3.

	1 North America deserts	**2 NA hot areas**	**3 NA extended**	**4 Pan-America deserts**	**5 Pan Am deserts + tropics**	**6 Pan Am extended South**	**7 Pan Am extended**
Number of sites	3	5	7	6	8	11	18
Longest nighttime [h]	14	12	12	9	8	8	7
Max/min daily insol. [kWh/m^2/d]	9.1/1.1	8.5/5.2	8/1	7.3/3.1	7.2/3.4	7.2/3.4	6.5/3.9
Average insol.	5.39	5.18	4.43	5.98	5.92	5.93	5.34
Optimization 1: Minimization of generation capacity with higher storage							
Gen. Capacity low [MWp]	6.4	6.5	8.3	5.1	5.0	4.8	5.5
Storage total [MWh]	72	75	80	50	45	40	35
Max long-term storage [MWh]	78	66	65	8.7	4.6	2.1	0.9
Electricity generated [GWh]	14.5	14.1	16.6	12.3	11.6	11.1	11.9
Electr. from storage [GWh]	4.6	4.4	3.9	3.9	3.9	4.1	3.8
Excess electricity [GWh]	5.8	5.3	7.8	3.5	2.8	2.3	3.1
Capacity factor [%]	25.9	24.7	22.8	27.5	26.6	26.4	24.7
Effective capacity factor [%]	15.6	15.4	12.1	19.6	20.1	20.9	18.3
Optimization 2: Minimization of storage with higher generation capacity							
Gen. Capacity high [MWp]	26.4	24.8	35.9	22.3	23.7	27.8	29.7
Storage total [MWh]	14.2	13.7	13.6	10.3	9.9	10.0	9.7
Max long-term storage [MWh]	0.5	0	0	0	0	0	0
Electricity generated [GWh]	59.8	53.6	71.5	53.6	55.0	64.2	64.2
Elect. from storage [MWh]	4.3	3.9	3.1	3.4	2.9	3.0	2.6
Excess electricity [GWh]	51.0	44.8	62.8	44.9	46.3	55.5	55.4
Capacity factor [%]	25.8	24.7	22.7	27.5	26.5	26.4	24.7
Effective capacity factor [%]	3.8	4.0	2.8	4.5	4.2	3.6	3.4
Optimization 3: Intermediate solution minimizes both, generation capacity and storage							

Gen. Capacity medium [MWp]	10.6	9.6	10.9	6.1	5.6	5.7	6.0
Storage total [MWh]	20.0	20.0	24.8	17.9	17.0	14.9	14.9
Max long-term storage [MWh]	3.11	5.4	14.9	1.75	1.36	0.29	0.15
Electricity generated [GWh]	23.9	20.7	21.7	14.8	13.0	13.1	13.1
Electricity from storage [MWh]	4.5	4.2	3.8	3.8	3.8	3.9	3.7
Excess electricity [GWh]	15.1	11.9	12.9	6.0	4.3	4.3	4.3
Capacity factor [%]	25.8	24.7	22.7	27.5	26.5	26.4	24.7
Effective capacity factor [%]	9.5	10.4	9.2	16.3	17.8	17.7	16.5
Generation capacity and storage to meet the loads of 4.7TW and 8.5TW; base intermediate values							
4.7TW: Gen. cap. [TWp]	41	45	51	29	26	27	28
4.7TW: Storage [TWh]	126	94	117	84	80	70	70
8.5TW: Gen. Capacity [TWp]	74	82	93	52	48	49	51
8.5TW: Storage [TWh]	228	170	211	152	145	127	127

Table 4: Costs of transmission with and without learning; learning is the state of year 2030 with the functions shown in Figure S2. Bahrmann [44] gives explicit costs per MWh transmission for a 3GW 800kV line with 2006 technology and a length of 1200 km; [24] gives actual costs for the 800kV line completed in China in 2010 by ABB.

Losses and costs without learning, 100% utilization rate Two different cost estimates - top row: 2010 technology [24], bottom row: 2006 technology [44]							
1	**Distance (km)**	**2,500**	**5,000**	**7,500**	**10,000**	**15,000**	**20,000**
2	**Transmission costs in ¢/kWh**	0.14 0.87	0.29 1.74	0.43 2.61	0.57 3.48	0.86 5.22	1.14 6.96
3	**Line losses in %**	5.0 6.25	10.0 12.5	15.0 18.75	20.0 25.0	30.0 37.5	40.0 50.0
4	**Costs of losses (line and stations), electricity price of 7.5¢/kWh, ¢/kWh**	0.47 0.56	0.87 1.03	1.22 1.50	1.59 1.97	2.34 2.90	3.09 3.84
5	**Costs of 2 stations, ¢/kWh**	0.13 0.29					
6	**Total costs, ¢/kWh**	0.74 1.72	1.25 3.06	1.77 4.40	2.29 5.73	3.33 8.41	4.36 11.09
Losses and costs subject to learning and different utilization rates							
7	**Total costs 2006 technology, mid learning, 60% utilization, ¢/kWh**	1.05	1.99	2.93	3.87	5.75	7.63
8	**Line losses with 2010 technology, mid learning, in %**	3.60	7.20	10.79	14.39	21.59	28.78
9	**Total costs 2010 technology, low learning, 60% utilization, ¢/kWh**	1.06	1.81	2.55	3.30	4.79	6.28
10	**Total costs 2010 technology, mid learning, 60% utilization, ¢/kWh**	0.88	1.50	2.12	2.75	3.99	5.23
11	**Total costs 2010 technology, high learning, 60% utilization, ¢/kWh**	0.72	1.23	1.74	2.25	3.27	4.29
12	**Total costs 2010 technology, mid learning, 80% utilization, ¢/kWh**	0.74	1.23	1.72	2.22	3.20	4.19

Typical distances between Southern hemisphere deserts and North America

	Atacama south – San Diego	**Piura (Sechura) – San Diego**	**Atacama – Caatinga**	**Paraiba (Caatinga) – San Diego (direct)**	**Paraiba (Caatinga) – San Diego (land)**
Length (km)	9,557	7,184	3,850	9,400	12,040