Energy 89 (2015) 739–756

Contents lists available at ScienceDirect

# Energy

journal homepage: www.elsevier.com/locate/energy

# Assessing current and future techno-economic potential of concentrated solar power and photovoltaic electricity generation

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A R T I C L E I N F O

*Article history:*
Received 28 January 2015
Received in revised form
28 May 2015
Accepted 29 May 2015
Available online 26 July 2015

*Keywords:*
Concentrated solar power, CSP
Photovoltaic, PV
Renewable energy
Energy modeling
Land use

A B S T R A C T

CSP and PV technologies represent energy sources with large potentials. We present cost-supply curves for both technologies using a consistent methodology for 26 regions, based on geoexplicit information on solar radiation, land cover type and slope, exploring individual potential and interdependencies. For present day, both CSP and PV supply curves start at $0.18/kWh, in North Africa, South America, and Australia. Applying accepted learning rates to official capacity targets, we project prices to drop to $0.11/kWh for both technologies by 2050. In an alternative "fast-learning" scenario, generation costs drop to $0.06–0.07/kWh for CSP, and $0.09/kWh for PV. Competition between them for best areas is explored along with sensitivities of their techno-economic potentials to land use restrictions and land cover type. CSP was found to be more competitive in desert sites with highest direct solar radiation. PV was a clear winner in humid tropical regions, and temperate northern hemisphere. Elsewhere, no clear winner emerged, highlighting the importance of competition in assessments of potentials. Our results show there is ample potential globally for both technologies even accounting for land use restrictions, but stronger support for RD&D and higher investments are needed to make CSP and PV cost-competitive with established power technologies by 2050.



## 1. Introduction

Model studies indicate that in order to drastically reduce greenhouse gas emissions, a switch to carbon-free energy supply is needed in addition to major energy efficiency improvements [1,2]. Renewable energy is expected to play a major role in this [3], but the role of various renewable resources will clearly differ. Wind power, for instance, is already close to be fully competitive with fossil-fuel based resources, but its potential is constrained to specific regions while intermittency and societal opposition may constrain deployment. In contrast, solar-based resources such as PV (photovoltaics) and CSP (concentrating solar power) have the advantage of a much larger potential, but their costs are currently still relatively high.

There are important differences between PV and CSP. PV can transform both direct and indirect solar radiation into electric power. Although PV costs used to be relatively high (in the order of $3–5/KWe in 2010), they have decreased considerably recently, mostly driven by a sharp increase in demand and an induced increase in the scale of production. The deployment of PV is also constrained by issues of intermittency of supply. In contrast, CSP has emerged in recent years as a potential solution to supply renewable and dispatchable baseload electricity, since it can rely on thermal energy storage, a more competitive solution than electricity storage [4–9]. However, because CSP relies on direct sunlight, its potential is mostly constrained to arid and semi-arid regions [6,10]. Nevertheless, currently even in these areas generation costs are not competitive yet with other generation technologies [6,7]. Like PV, the costs of CSP are expected to decrease significantly as a result of economies of scale and learning by doing [5,8,11].

Several recently published studies estimate the global and regional potential of PV or CSP [7,9,12]. These studies, however, have several limitations. First, they use different methods –

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http://dx.doi.org/10.1016/j.energy.2015.05.145
0360-5442/

limiting their comparability. Second, they pay very little attention to land-use restrictions. In contrast, land-use issues have been taken into account in studies looking at the regional scale [13] or in the global PV study of [14]. Finally, they mostly look at one of these resources: an important issue is that the total potential for CSP and PV is subject to the competition between them for the solar resource, and of both for available land vis-a-vis wind and biomass generation [15]. The degree of this competition also depends on the type of solar radiation used (direct versus diffuse radiation). Some studies have compared CSP and PV potentials but have only done so on a regional or site-specific scale [13,16].

The aim of this paper is to model the global technical and economic potential using comparable assumptions for CSP and. Taking into account land-use characteristics, the long-term development of the economic potentials will then be assessed by directly comparing the costs of electricity at a 0.5 × 0.5° spatial resolution between 2010 and 2050.

## 2. Methodology

### 2.1. Definitions: renewable energy potential

To assess the potential for CSP and PV generation, this study follows the potentials for renewable energy defined by Ref. [15] and the World Energy Council Report [17]:

- The *theoretical potential* is the total primary solar energy flux hitting the Earth's surface suitable for PV and CSP generation. The NASA SSE6 radiation database was used, i.e. the 22-year *Direct Normal Radiation* dataset for CSP and the 22-year *Global Horizontal Radiation* dataset for PV. In addition, NASA also provides a 22-year average monthly no-sun days, used to account for cloudy days (Section 2.3).
- The *geographic potential* is the primary energy flux in suitable and available geographic areas of the globe. Some areas deemed unsuitable are excluded or constrained based on incompatible land use/cover type and other local characteristics (Section 2.4)
- The *technical potential* is the geographic potential after any efficiency losses of the primary to secondary conversion process are accounted for (Section 2.5).
- The *economic potential* is the economically feasible technical potential, ie the portion of the technical potential that is competitive with another relevant form of electricity generation. A cutoff value of $0.35/KWh was implemented as a competitiveness threshold (Section 2.6). It is useful to represent the economic potential as long run supply cost curves (or cost-supply curves) which are based on the cost of electricity or COE. Such curves are included in the output results of this study (Section 3.2).

It is important to note that any potential estimate for renewable energy is sensitive to several assumptions made in the calculations [15]. For example, the geographic potential depends on assumptions made on availability and suitability of areas with different land cover types. The technical potential depends on a wide range of technical assumptions, such as the tilt angle of PV panels, the azimuth alignment of parabolic collectors, or the solar-to-electric conversion efficiencies of each technology. Below, we derive a set of consistent assumptions for both CSP and PV plants based on 1) consistent assumptions of future change (scenario assumptions) and 2) defining a reference plant. For both, first a literature review was conducted to elicit acceptable average values. Below, we first describe the reference plants defined for CSP and PV and after describe the main data sources and assumptions for the theoretical, geographic, technical and economic potential.

### 2.2. Modeling performance of solar electricity generation

#### 2.2.1. CSP performance and reference plant

CSP (Concentrating Solar Power) uses mirrors to concentrate the energy from the sun and, in today's applications, heat a fluid which in turn is used to produce steam. The steam is then used to turn a turbine in the same manner used in conventional power. CSP has the added advantage of being able to store heat (at relatively low costs), which can be used to generate electricity when the sun is not shining. This significantly increases the fraction of time CSP can be operating at its full rated capacity (capacity factor) increasing its competitiveness [6,7,11].

There are several variations of CSP in commercial use today, including Parabolic Trough, Central Tower, Linear Fresnel and Solar Dish. As Parabolic Trough is by far the most mature CSP technology at the moment, we will focus on this technology here [6,9,11,18]. Parabolic Trough CSP mirrors concentrate sunlight onto receivers located at the focal point of the parabola. The receivers consist of stainless steel tubes coated with a material that absorbs heat well. This results in a maximum transfer of heat to the fluid inside the tubes which is next used to drive the turbine or as input into thermal storage tank [6,8,11].

The performance of a CSP plant depends on the irradiance, storage hours and the *SM* (*Solar Multiple*), and all three are interrelated [6,7,9,19]. The solar multiple is related to the size of the solar field: A plant with SM = 1 has a solar field large enough to run the turbine at its nominal capacity.[1] A CSP plant with 6 h of storage is defined as having a Solar Multiple of 2 and requires a larger solar field to store energy and run the plant. The solar multiple is also dependent on the incident DNI since more solar energy per $m^2$ means less collectors to capture the same energy. Finally, the alignment of the parabolic collectors and the plant operational strategy (eg peaking vs baseload) also affect the electricity output of the plant [16]. Solar-to-electric efficiency is subject to technical parameter choices such as the thermal fluid used, or the choice of wet vs dry cooling. Because most areas suitable for CSP deployment are located in arid or semi-arid regions, we choose a dry-cooled reference plant. Dry-cooling reduces water use by about 93% but raises the cost of electricity produced because of the more expensive cooling requirements and because of an efficiency drop in the power block of about 8% [11,20]. For the sake of simplicity, we assume a value of 12% for the dry-cooled solar-to-electricity conversion efficiency, the same as [11] and [9].

Based on the reflections above, we use a reference plant with 100-MW nominal capacity, dry cooling, thermal oil as the heat transfer fluid, 6 h of thermal molten salt storage, and a North-South alignment at zero degrees azimuth angle. Cost and performance data have been taken from Refs. [11,7–9]. The technical lifetime of the reference plant is modeled at 30 years.

#### 2.2.2. PV performance and reference plant

Unlike CSP, PV can convert both diffuse and direct sunlight to electricity and is therefore better suited for areas with a high diffuse component of total radiation. PV (Photovoltaic) cells produce DC (direct-current) electricity directly from sunlight, and the most common application is in flat-plate panels or modules that electrically connect many cells (DOE, 2006). The main formats available commercially are flat-plate crystalline Silicon (c-Si) panels, thin-film and CPV (concentrated photovoltaics). C-Si PV is the dominant technology in the market today and is therefore chosen in this study as the representative PV technology for costing and performance modeling.

[1] To account for parasitic losses, an SM around 1.1 is generally accepted.

The cost of the panels in a PV system represent a large fraction of the total cost [21,22], and recent reductions in panel prices have helped bring down the cost of PV electricity. The DC electricity produced by the panels is converted to AC via an inverter [16,23,24]. Developments in panel as well as BOS (balance-of-system) components are expected to reduce investment costs and improve efficiencies further in the next decades. Storage of PV generated electricity is not widespread due to its high costs, the most common method being battery storage. Therefore, solar PV electricity is represented in this study without storage.

Crystalline PV panels operate optimally when the incident solar radiation is at right angles to the panel surface and an optimal tilt for fixed tilt systems increases efficiencies of the individual panels. However, to minimize shading by neighboring panels, more space is required between the panels [25], which reduces overall system land use efficiency. Ref. [23] reports that "*the reduced power density is much greater than the increased collector yield, so moving from flat rooftop arrays to land-based tilted and tracking arrays can reduce system energy density by more than 50%*".

Because in the assessment of the global PV potential the total area occupied by panels is a significant contributor to the final result, the choice was made to model PV panels as being laid down horizontally to minimize shading.[2] Although no spacing is then required to avoid shading, access is still required between the rows of panels for cleaning and maintenance so that the *packing factor*[3] is not 100%. Ref. [25] reports values of 13–91% packing factor for utility-scale fixed axis PV systems, with a capacity-weighted average value of 47%, the value implemented in this study. The PV reference plant in this study is a 187.5 $MW_{AC}$ (150 $MW_{AC}$ after conversion losses) ground-mounted fixed axis c-Si plant with no storage, following [26]. Cost and performance data were taken from Refs. [22,26], and [25]. A literature review by Ref. [22] yielded average Solar-to-Electric efficiency values for c-Si PV systems with no storage of 11% in 2010, and expected to rise to about 15% by 2020. Here, we choose a baseline solar-to-electric efficiency value of 13% for our long-term assessment for a generic c-Si PV system. Although PV performance is also dependent on ambient temperature, this effect is not modeled explicitly here.

Table 3 presents the assumed characteristics of the two reference plants. The values in this table and the way they are used to calculate the different potentials are discussed in Section 2.3–2.6.

### 2.3. Theoretical potential: the solar resource

The NASA SSE6 global datasets for solar irradiation were used to assess the solar resource available for CSP and PV generation.[4] For CSP, the *Direct Normal Radiation*[5] dataset was used, and for PV the *Global Horizontal Radiation* dataset, both given in units of kWh/m$^2$/day and in 1-degree-resolution. The *no sun days* dataset was used as a measure of the cloudy days in each month and the irradiation datasets for CSP and PV were adjusted to the respective *Minimum Direct Radiation* for CSP and *Minimum Global Horizontal Radiation* for PV on the number of cloudy days in each month.

#### 2.3.1. CSP theoretical potential and direct normal irradiance

The *DNI* values[6] used for CSP were adjusted for cloudy days using the SSE6 *no-sun days* and *Minimum Direct Radiation* datasets, by setting the *DNI* level on the number of cloudy days per month specified by the *no-sun days* dataset to the values in the *Minimum DNI* dataset instead of the *Average DNI*. This resulted in an *Adjusted_DNI* dataset which was used to calculate the CSP potentials for each month of the year, as follows:

$$Monthly\_Avg\_DNI = (DNI\_NASA*(NbrDays - No\_Sun) + (Min\_Avg\_DNI*No\_Sun))/NbrDays \quad (1)$$

where *DNI_NASA* is the daily average DNI for each month, *No_Sun* is the average number of no-sun days in each month, and *Min_Avg_DNI* is the average minimum DNI in each month, all from the NASA SSE6 dataset. Finally, *NbrDays* is the number of days in each month. The resulting datasets were then converted to kWh/m$^2$/year by aggregating across the different months. The resulting dataset was labeled *AdjAnnAvg_DNI* for adjusted annual average *DNI*.

#### 2.3.2. PV theoretical potential and global horizontal radiation

An analogous procedure was followed for PV using the 22-year *Average Global Horizontal Radiation* and the *Minimum Global Radiation* datasets from SSE6. We followed the same steps to calculate cloudy day irradiance for PV using the *no-sun days* and *Minimum Global Horizontal Radiation* datasets, resulting in the *AdjAnnAvg_GHR* datatset.

### 2.4. Geographic potential: land use restrictions

The geographic potential is modeled in the same way for CSP and PV. Obviously, the ability to generate utility-scale solar electricity also depends on the availability of (different types of) land [23,25,27,28]. Here, we account for the role of land by using land maps of the IMAGE 2.4 model for the period 2010–2050 (Fig. 1 shows the 2010 map). A suitability factor was assumed for each land cover class in IMAGE following [15]. The values are shown in Table 1.

Land availability through 2050 was assessed using the resulting land use maps from a IMAGE 2.4 baseline scenario [30]. This scenario is based on median population and economic growth assumptions. In terms of land use, it depicts a world in which agricultural production grows by about 60% up to 2050, mostly driven by population growth and a transition towards more meat-intensive diets in low-income countries. Most of the production increase actually results from increasing yield (more than 80%) with the remaining share resulting from an expansion of agricultural area.

### 2.5. Technical potential

#### 2.5.1. CSP technical potential

To determine the technical potential, we first introduced a minimum feasibility threshold level for average annual *DNI*. Ref. [7]

[2] Another aspect guiding this choice is that the gains from optimal tilting are greater in higher latitude locations (where utility scale PV plant development is less likely to occur), and in locations where diffuse radiation is an important component of the useful solar energy, so that "[t]he economically optimal tilt angle can differ from the irradiance optimised tilt angle, depending on the type of application and the impact of tilt angles on the overall investment cost" [40].

[3] The packing factor is the portion of land covered by panels. We prefer to call it Land Use Factor.

[4] These data were obtained from the NASA Langley Research Center Atmospheric Science Data Center Surface meteorological and Solar Energy (SSE) web portal supported by the NASA LaRC POWER Project. https://eosweb.larc.nasa.gov/sse/. These solar data span 22 years from July 1, 1983 through June 30, 2005, with the direct and diffuse surface solar radiation data derived from measured all sky radiation following a method described in the SSE6 methodology document available from the SSE6 website.

[5] DNR is also referred to as Direct Normal Irradiation or DNI, the abbreviation used throughout this paper.

[6] DNI = Direct Normal Irradiance. DNR and DNI are used interchangeably in the literature.

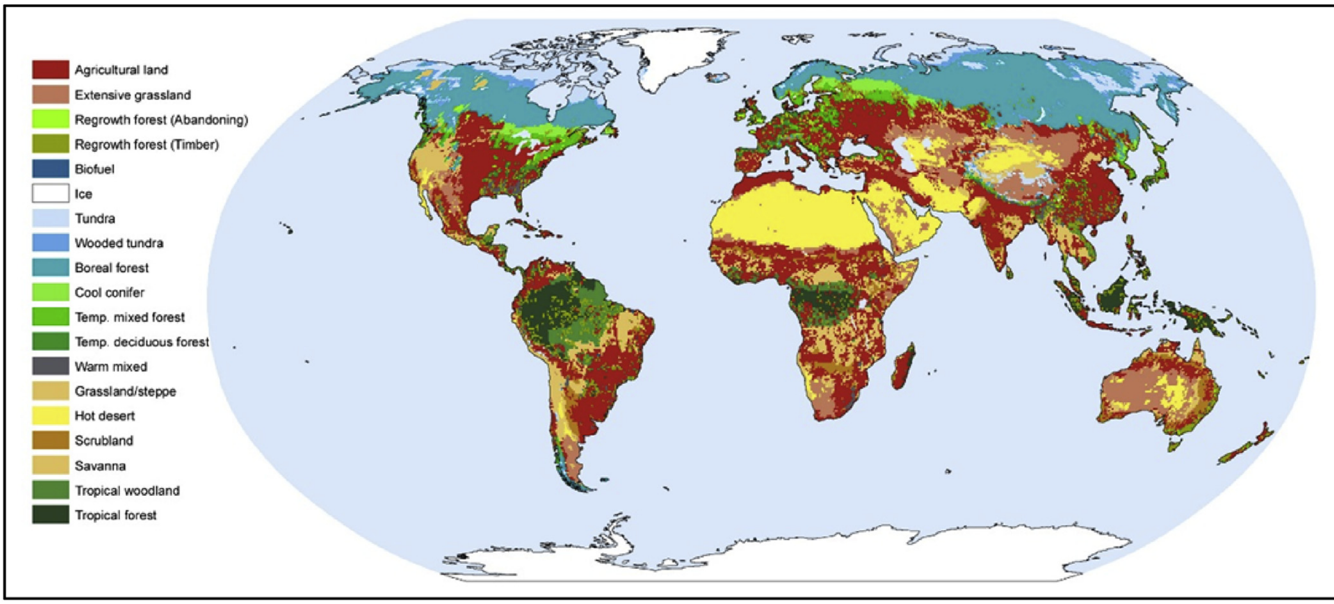


**Fig. 1.** Global Land Cover Type for base year 2010 (Source: [29]).

**Table 1**
Land use restrictions (see text).

| Land cover type | Reference suitability value | Sensitivity analysis |
|---|---|---|
| Agricultural land | 0% | |
| Land currently assigned to biofuel crops | 10% | |
| Land currently assigned to C plantations | 20% | |
| Grasslands, scrubland, steppe and savanna | 10% | 5% and 20% |
| Hot desert | 10% | 5% and 20% |
| Regrowth forests (abandoning) | 5% | |
| Tropical woodland | 1% | |
| All forests are excluded | | |
| Also excluded: urban areas, ice, bioreserve, tundra and wooded tundra | | |

reported a minimum requirement of 300 W/m$^2$ for CSP operation, which translates to a minimum daily irradiance of $DNImin$ = 3.0 kWh/m$^2$/day assuming a 10-h solar day. Higher annual average values have been reported for the economical use of CSP at 5.0 kWh/m$^2$/day [6], and up to 5.5 kWh/m$^2$/day [9]. Here, we choose the threshold of $DNImin = 3.0$ kWh/m$^2$/day to eliminate the technically unsuitable cells (1095 kWh/m$^2$/year).

To estimate plant performance, it is necessary to use high resolution data, both spatially and temporally, which increases computational requirements and complexity. Hence, a simplified model resulting from hourly time series modeling [9] was used to calculate the *FLH* (*Full Load Hours*) of the reference plant based on a given *SM* (*Solar Multiple*) and *DNI*. Table 2 shows the *FLH* from the [9] model for plants with SM2 at various latitudes. Since solar geography is not included explicitly in this first instance of our model, a sample latitude had to be chosen (20° given the average location of the best CSP sites).

**Table 2**
Full Load Hours of a parabolic trough CSP plant with SM2 at various DNI levels and Latitude (Source:[9]).

| SM2 | DNI 1800 | DNI 2000 | DNI 2200 | DNI 2400 | DNI 2600 | DNI 2800 |
|---|---|---|---|---|---|---|
| Lat 0 | 3425 | 3855 | 4221 | 4645 | 4931 | 5285 |
| Lat 10 | 3401 | 3817 | 4187 | 4612 | 4909 | 5222 |
| Lat 20 | 3310 | 3719 | 4098 | 4495 | 4810 | 5096 |
| Lat 30 | 3147 | 3539 | 3943 | 4283 | 4605 | 4887 |
| Lat 40 | 2911 | 3285 | 3719 | 3984 | 4301 | 4604 |

The adjusted annual average *DNI* (Section 2.3.1) was divided into classes according to the cutoff values used to calculate the *FLH* in the Trieb et al. model (Table 2). For cells with average annual *DNI* below the minimum CSP operational threshold of 1095 kWh/m$^2$/year, the full load hours are set to zero. For cells with *DNI* values above 2800 kWh/m$^2$/year, a maximum value of $FLH = 5260$ h per year was implemented. This corresponds to a CF (capacity factor) of 60%. It is assumed that a CSP plant with SM = 2 is not expected to operate at CF > 60%, as it would not be able to store all the energy it receives resulting in discarded solar energy in grid cells with *DNI* above 2800 kWh/m$^2$/year. Thus, the *FLH* for any given cell is zero if $DNI < 1095$ kWh/m$^2$/day, and 0.6 if $DNI > 2800$ kWh/m$^2$/day. For *DNI* values in between, a simple linear regression was used based on the data of Trieb et al. The equation derived in this way is given by

$$FLH = 1.83 * DNI\_AdjAnnAvg + 150 \qquad (2)$$

The technical potential only includes the portion of solar radiation that hits the parabolic collectors or PV panels, so an adjustment to the Geographic Potential is needed. The fraction of land actually covered by collectors is called the *Packing Factor* or *Land Use Factor*, and the average value for parabolic trough plants are around 37% [9]. Therefore, the Technical Potential for a grid cell is given by

$$CSP\_TechPotCell = GeoPotCell*LandUseFactor*SolarElecEff/FLH \quad (3)$$

Where,

$GeoPotCell = CSP\ Geographic\ Potential\ of\ a\ grid\ cell$ (Section 2.4)
$LandUseFactor = 0.37$
$SolarElecEff = 0.12$ (Section 2.2.1).

*2.5.2. PV technical potential*

We use the concept of the *reference yield* to estimate the *FLH* (*Full Load Hours*) of PV systems. The reference yield $Y_r$ is the total in-plane irradiance $H$ divided by the PV's reference irradiance $G$ (the solar flux at which the PV panels are rated). $Y_r$ represents an equivalent number of hours at the reference irradiance, hence the number of hours at the full rated capacity, the definition of *FLH* [24].

$$Y_r = \frac{H}{G} \quad \text{(Hours)} \quad (4)$$

If $G$ equals 1 kW/m$^2$, then $Y_r$ is the number of peak sun-hours or the solar radiation in units of kWh/m$^2$. Since most PV panels are rated at 1 kW/m$^2$ solar flux, the numerical value of the *FLH* is the same as the numerical value of the solar resource expressed in kWh/m$^2$ incident on the panel. The irradiance incident on the panel in turn depends on the tilt angle of the panels. Since the panels are modeled as being horizontal, the total in-plane irradiance $H$ *is* the value of the adjusted annual average global horizontal radiation (Section 2.3.2), the number used to calculate the Theoretical Potential. Hence, numerically speaking,

$$FullLoadHours = AdjAnnAvg\_GHR \quad (5)$$

A quick calculation of the *Capacity Factor* of the modeled PV systems using these *FLH* values[7] yield *CF* around 20% at irradiance values of around 5 kWh/m$^2$/day, in broad agreement with the literature (e.g. Ref. [31]). The PV technical potential in each grid cell is then given by:

$$PV\_TechPot = GeoPot*LandUseFactor*SolarElecEff*CapacityFactor \quad (6)$$

where *GeoPot* is the PV geographic potential for a given grid cell, and from Section 2.2.2, we have

$LandUseFactor = 0.47$
$SolarElecEff = 0.13$ (Section 2.2.2).

*2.6. Economic potential: cost of electricity*

*2.6.1. Specific investment costs*

The *Cost of Energy* or *COE* is for each grid cell given by

$$COE = \frac{\gamma * I + \varepsilon}{E} \quad (7)$$

where $\gamma$ is the annuity factor, $I$ is the specific investment cost for each grid cell per KWe of installed capacity, $\varepsilon$ are the O&M (Operation and Management costs) and $E$ is the annual electricity generation per kWe of installed capacity. Specific investment costs were annualized through the annuity factor $\gamma$, using an interest rate of 10% and a 30-year technical lifetime of the plants.

NREL reports investment costs for 2010 of around US$8000/kWe for a CSP plant meeting the criteria of the reference plant chosen, with O&M costs at $70/kWe-yr [11]. The literature review by Ref. [22] for PV shows a value of about US$3000/kW[8] for utility scale fixed tilt PV systems. Ref. [16] uses 2% of specific investment for O&M costs, which yields $60/kW-yr. Another study estimated the investment cost of fixed axis PV systems in the United States in 2010 to be $4400/kWe [26]. Here, we use a value between these studies of $3500/kWe for our 2010 reference cost scenario. Table 3 summarizes the techno-economic parameters used as inputs for the reference scenario.

*2.6.2. Learning rates and cost reduction potential*

Renewable energy costs are expected to decline in the future as a result of technology development and economies of scale. Two methods are often used to determine future costs to use as model input. On the one hand, direct expert elicitation can be used to derive likely values for the future costs of CSP and PV. On the other hand, estimates can be based on current investment costs and learning rates. We used the latter here, allowing us to account for the impact of different expectations on capacity deployment. Projected capacity deployment was based on national targets for CSP and PV deployment through 2050 (described in detail in Appendix B). For a detailed discussion on learning rates and how they are used in this study see Appendix C.

We follow [18] in using the learning rates suggested by the IEA of 18% for PV and 10% for CSP starting in 2010 [10,32] to calculate solar energy cost evolution through 2050. Specific investment costs for each technology were calculated for the period 2010–2050 for the *Baseline* scenario. In addition, an alternative *Fast Learning* scenario was developed in which rates increased to 25% for PV and 20% for CSP. The learning curves and cumulative global installed capacities used, plus the resulting specific investment costs of CSP and PV for both scenarios are shown in Table 4.

## 3. Results

*3.1. The theoretical, geographic and technical potential*

Table 5 presents the results at the global scale of the theoretical, geographic and technical potentials for PV and CSP in the baseline scenario. The numbers are all very high compared to current electricity consumption levels. Therefore, from here on we concentrate on the economic potential of PV and CSP, and specifically the potential below a cutoff value of $0.35/kWh. For comparison, the total world power consumption in 2010 was 17,863 TWh/year.[9]

*3.2. The techno-economic potential of solar electricity*

The reference land use restrictions outlined in Table 1 were implemented in order to calculate techno-economic potentials for CSP and PV electricity generation in each region of the IMAGE framework. Moreover, we applied the costs calculations as indicated in Section 2.6. This allowed us to calculate the COE at grid level. For the base year 2010, the minimum COE value for both CSP and PV was about $0.18/kWh, indicating that presently, neither technologies is cost-competitive against fossil-based alternatives (with costs in the order of $0.05/kWh). Table 6 compares the resulting COE for CSP and PV with other studies for the years 2010, 2030 and 2050.

Our results for 2010 CSP costs are higher than the estimates by Refs. [6], and in line with those reported by the IEA CSP Roadmap

[7] $CapFactor = FullLoadHours/8760$.

[8] Using euro to dollar conversion of 1.3 dollars per euro (value was given in euros).

[9] IEA Key World Energy Statistics 2012.

**Table 3**
Techno-economic parameters used in the assessment of the economic potential for PV and CSP.

| Parameter | CSP plants | PV plants | Reference |
|---|---|---|---|
| Technology | Parabolic trough | c-Si | |
| Nameplate capacity | 100 MW | 150 $MW_{AC}$ | |
| Storage hours (at rated capacity) | 6 h | 0 h | |
| Solar Multiple | 2 | n/a | |
| Cooling method | Dry | None | |
| Specific investment costs | \$8000/KWe | \$3500/KWe | CSP: Turchi et al. (2010) PV: Peters et al. (2011); Goodrich et al. (2012) |
| O&M costs | \$70/KWe/year | \$60/KWe/year | CSP: Turchi et al. (2010) PV: Peters et al. (2011); |
| Solar-to-electric efficiency | 12% | 13% | CSP: Trieb et al. (2009) PV: Peters et al. (2011); |
| Land-use-factor (packing factor) | 37% | 47% | CSP: Trieb et al. (2009) PV: Ong et al. (2013); |

**Table 4**
Projected Solar installed capacity growth through 2050 and resulting COE (baseline scenario) (Sources: [33,34]; Baseline Learning Rates from Ref. [18]).

| | 2010 | 2030 | 2050 |
|---|---|---|---|
| Baseline scenario | | | |
| Projected installed capacity (GW) | | | |
| CSP | 2.5 | 48 | 108 |
| PV | 100 | 284 | 494 |
| Specific investment cost (2010\$/KWe) | | | |
| CSP (LR = 10%) | 8000 | 5109 | 4512 |
| PV (LR = 18%) | 3500 | 2294 | 1958 |
| Alternative *Fast Learning* cost scenario | | | |
| CSP learning rate = 20% | | | |
| CSP Specific investment cost (2010\$/KWe) | 8000 | 3095 | 2380 |
| PV learning rate = 25% | | | |
| PV Specific investment cost (2010\$/KWe) | 3500 | 1898 | 1508 |

**Table 5**
Global thoretical, geographic and technical potentials for CSP and PV in TWh/year.

| Global potential in 2010 (TWh/year) | CSP | PV |
|---|---|---|
| Theoretical potential | $2.57 \times 10^9$ | $2.51 \times 10^9$ |
| Geographic potential | $8.41 \times 10^6$ | $7.36 \times 10^6$ |
| Technical potential | $1.73 \times 10^5$ | $1.01 \times 10^5$ |

[10]. By 2030, the lowest costs for CSP would be around \$0.12/kWh, and by 2050 around US\$0.11/kWh in the best regions. For 2050, the resulting COE is almost twice the \$0.05/kWh projected by the IEA Roadmap [10], which assumed aggressive deployment of new CSP capacity totaling 183 GW by 2020, a number not reached in this study even by 2050. An elicitation survey involving 16 European experts on solar energy reports \$0.101/kWh as the average expected cost of CSP technologies by 2030, with most estimates ranging between \$0.075/kWh to US\$0.145/kWh [35]. Neither study included the cost of new transmission lines.

**Table 6**
Model results for the cost of electricity generation for the Baseline scenario.

| | 2010 | 2030 | 2050 |
|---|---|---|---|
| CSP COE (US\$/kWh) | | | |
| This study CSP | 0.18 | 0.12 | 0.11 |
| Bosetti et al., 2012 | n/a | 0.101 | n/a |
| IRENA 2012 | 0.11 | | |
| IEA 2010 (CSP roadmap) | 0.20–0.30 | 0.05–0.075 | 0.04–0.06 |
| PV COE (US\$/kWh) | | | |
| This study PV | 0.17 | 0.12 | 0.11 |
| Peters et al., 2011 | 0.20 | | |
| Bosetti et al., 2012 | | 0.12 | |
| IEA 2011 (Solar Energy Perspectives) | 0.18 | | |

For PV, our lowest cost calculated for 2010 is US\$0.17/kWh in Northern Chile. This value drops to US\$0.12/kWh by 2030 and to US\$0.11/kWh in 2050. The 2010 costs in this study are slightly below the US\$0.20/kWh[10] found by Ref. [22]. For 2030, the experts elicitation expected costs to decline to an average of US\$0.12/kWh [35]. This means that our values are close to an average of those mentioned in the literature.

Fig. 2 shows the spatial distribution of the costs of electricity generation. As expected, the best areas are in the arid and semi-arid regions of the world, especially for CSP, with Africa, the Middle East and Australia showing up as very promising areas for both technologies. For CSP in particular Western China and Mongolia also show good economic potential.

Fig. 3 shows the techno-economic potential of CSP and PV in each of the regions of the IMAGE framework and by land cover type. The bars represent the technical potential below the US\$0.35/kWh cutoff.

#### 3.2.1. *CSP techno-economic potential*

The calculations show that after applying the cut-off value, the regions with the highest CSP potentials are near-tropical regions with arid or semi-arid climate areas within them. North and West Africa and Oceania are the regions with the highest potential, approaching some 30,000 TWh/year of electricity generation potential below \$0.35/kWh, while that of China is around 15,000 TWh/year,[11] the USA's is more than 6000 TWh/year, Brazil's is around 4000 TWh/year, and the Rest of South America around 7000 TWh/year.

The sensitivity of each region to the imposed land availability constraints can be seen by looking at the contribution from each land cover type to that region's potential. The result is shown in Fig. 4 (top), with the stacked bars representing the contribution of each land cover type to the regional potential. The CSP technical potential of North Africa is highly sensitive to any constraints assumed on the availability of deserts, as are the potentials in West and East Africa, and the Middle East. Oceania on the other hand is not as sensitive to the availability of deserts, but it shows higher sensitivity to the available grassland.

The top panel in Fig. 4 shows the CSP cost supply curves for selected regions. It can be inferred that some of the best areas for CSP globally are in South America and North Africa, with the most

[10] EUR/kWh converted to US\$/kWh using a 1:1.3 conversion rate.

[11] In IMAGE 2.4 the region named China also includes Mongolia, which has a significant solar electricity potential.

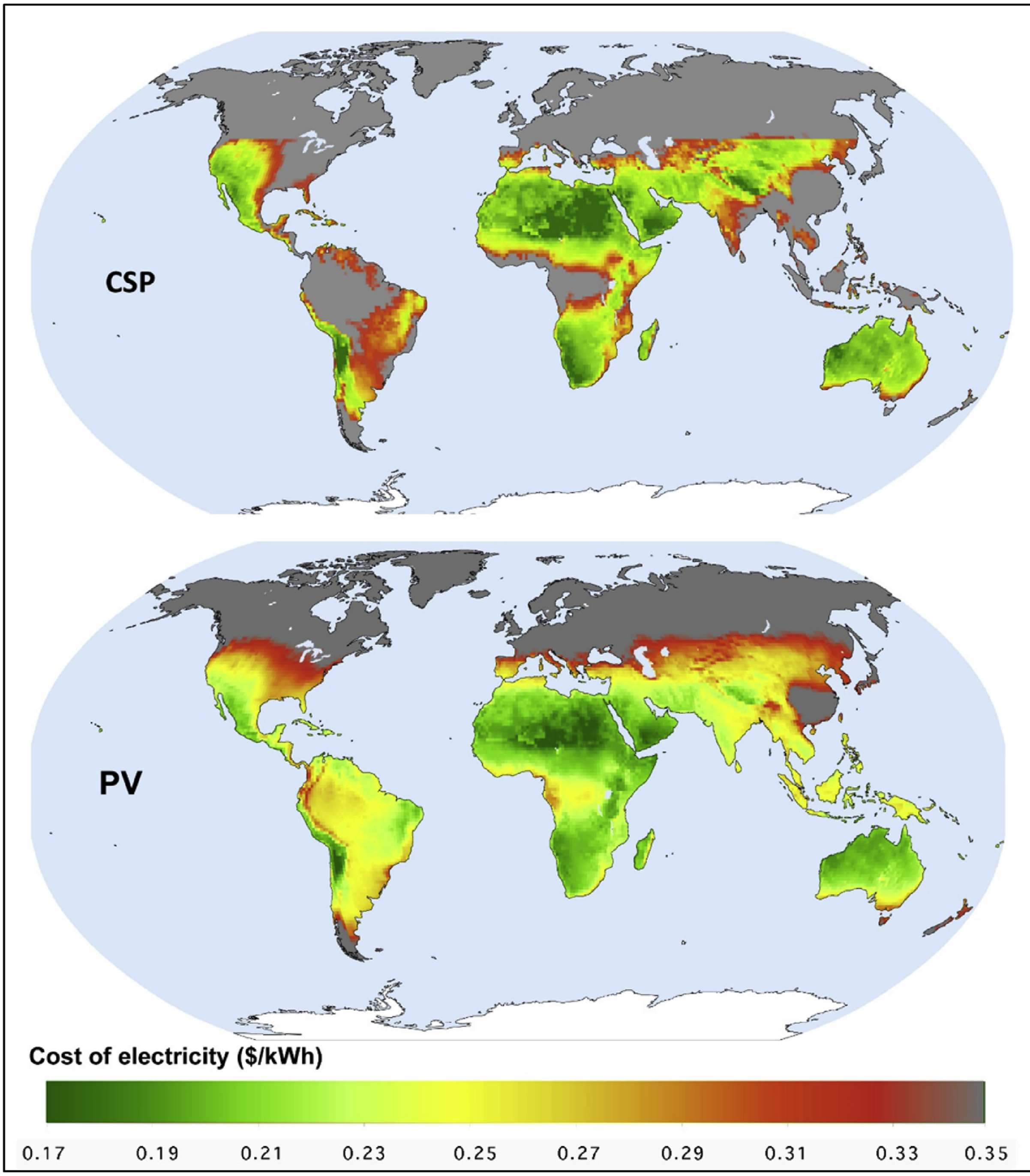


**Fig. 2.** Global Distribution of CSP and PV generation costs for base year 2010 (US$/kWh); costs above US$0.35/kWh excluded.

attractive areas within these regions located in Northern Chile and Argentina and in the Eastern Sahara of Egypt, Sudan, Chad and Libya. China/Mongolia shows a considerable potential, both larger and at lower cost than that of the USA.

### 3.2.2. PV techno-economic potential

The PV technical potential below $0.35/KWh per region for the reference land use restriction case is shown in Fig. 3 (bottom) as function of land-cover type. The resulting technical potential is lower for PV than for CSP, reflecting the value of the 6 h of thermal storage included in the CSP technology. The higher capacity factor allowed by the thermal storage improves the cost of CSP electricity when compared to that of PV, highlighting this important advantage CSP has over utility-scale PV, allowing grid operators to more easily integrate CSP plants into their daily operations [4].

The bottom panel of Fig. 4 shows the PV cost supply curves for selected regions. It does to some degree resemble the curve presented before for CSP. However, it is interesting to note that a reversal occurs in some regions such as USA and Brazil: the economic potential of CSP is better in the USA but the economic potential of PV is better in Brazil, with the Brazilian PV cost supply curve falling below that of the USA throughout the range of its technical potential, which for PV is roughly the same for both regions (Fig. 3).

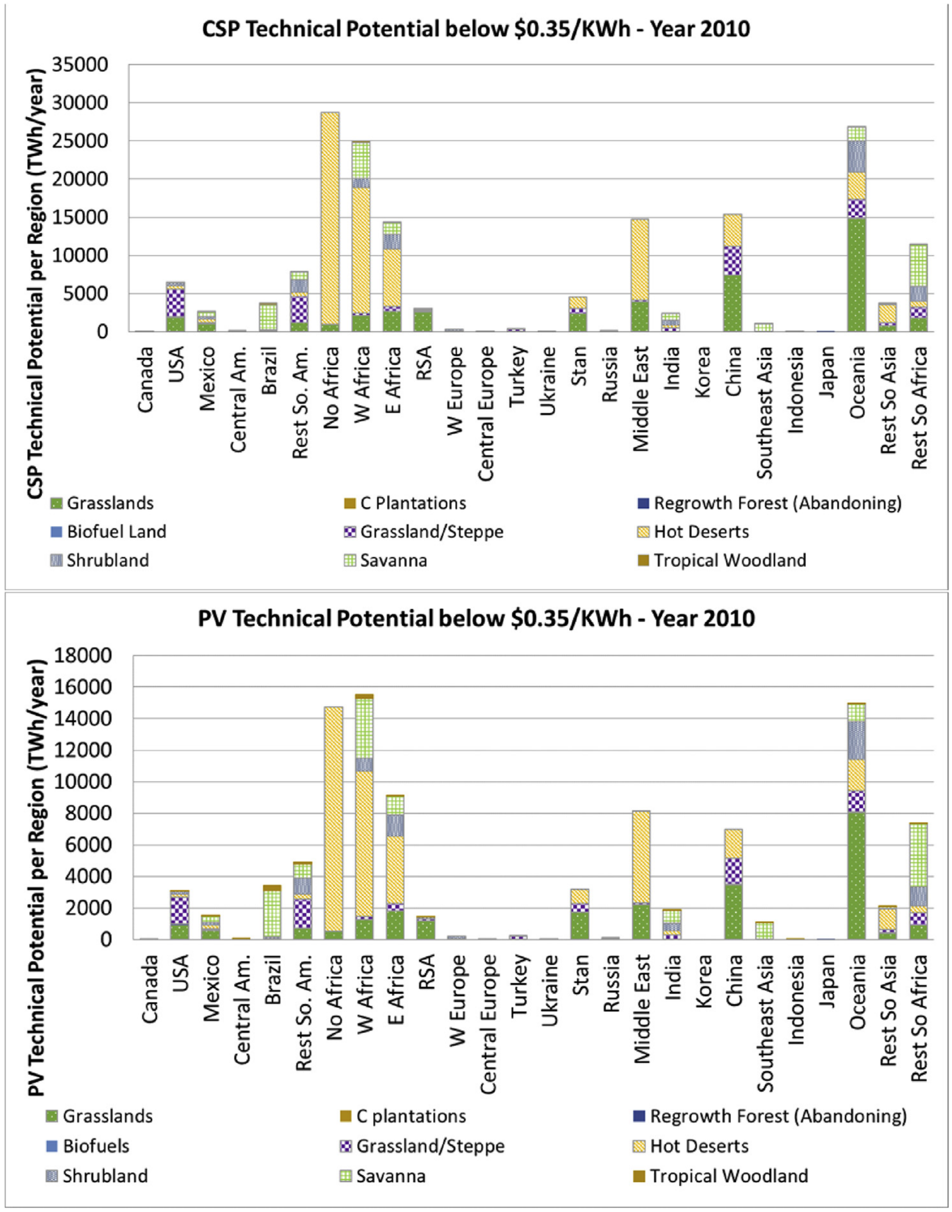


**Fig. 3.** Technical Potential for CSP and utility scale PV below $0.35/KWh by land cover type in each region of the IMAGE framework.

### 3.3. Competition between CSP and PV

As grid cells can only contribute to the CSP or PV potential, we now compare these technologies based on the cost of electricity on a global scale. For each grid cell, we compared the costs of PV and CSP: in case they differed by more than 10%, the lowest cost option was assumed to be the preferred technology for that grid cell. Wherever the COE of PV and CSP differed by less than 10%, the grid cell was assigned as a *Competition* grid cell. This process of comparison based on COE was done for the years 2010–2050 using the reference land use restrictions and investment cost scenarios, and the result is shown in Fig. 6.

Fig. 5 shows the evolution of the COE for CSP and PV under the two modeled scenarios and these curves help explain the maps of Fig. 6. The capacity targets currently announced by several countries (see Appendix B for a list) imply that CSP could enjoy faster reductions in the cost of electricity in the next decade (as discussed earlier), still getting the 'bonus' of the initial stages of the learning curve. This means that around 2030 CSP could become more competitive than PV in substantial areas. In the long run, however, the results project PV costs to decline faster (based on long-term learning potential). This is reflected in the size of the "competition area" in Fig. 6 over time. There are clear areas in which one technology is the preferred technique. For CSP, these include the Western USA, Eastern Sahara, Mongolia, parts of Northern Chile and Argentina, and South Africa. For PV, these include Northern Europe, Equatorial Africa, South-East Asia, Amazonian Brazil, and the tropical Latin American countries.

The areas suitable for both techniques include Australia, large swaths of the MENA region, parts of Southern Africa, Central Asia, and the South-East of the USA.

#### 3.3.1. Effects of competition on techno-economic potential

Under land availability constraints, CSP and PV compete with each other. Figs. 7 and 8, finally, present the technical potential for PV/CSP in 2010 and 2050 accounting for the competition between

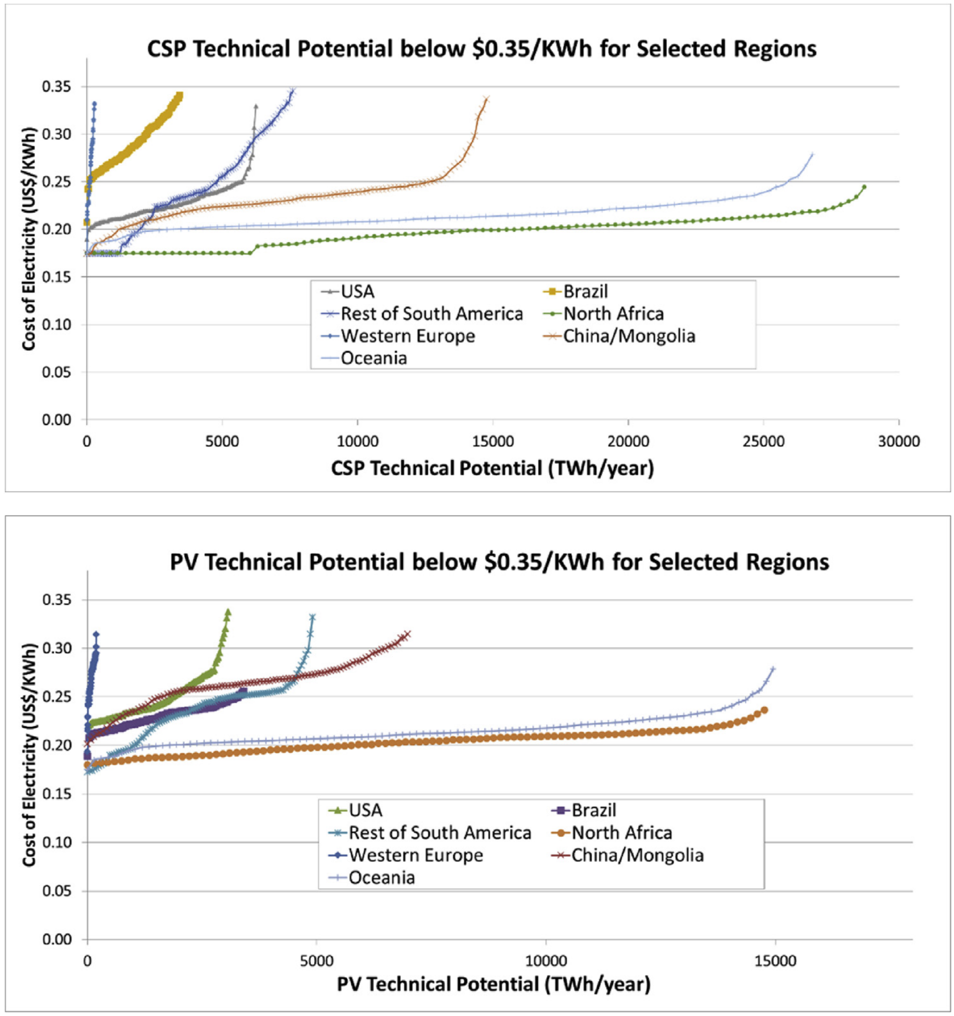


**Fig. 4.** CSP and utility scale PV Cost Supply Curves for USA, Brazil, Rest of So America, North Africa, W Europe, China and Oceania.

them. In the case of the "competition area" we assigned 50% of the potential to each technology, while for the other areas potential was fully allocated to the cheapest technology. Splitting the potentials 50/50 between the two technologies in the competition area is obviously not necessarily realistic, but it serves to illustrate how they are affected when they deplete the same land-based resource. The effect of competition on the technical potential is

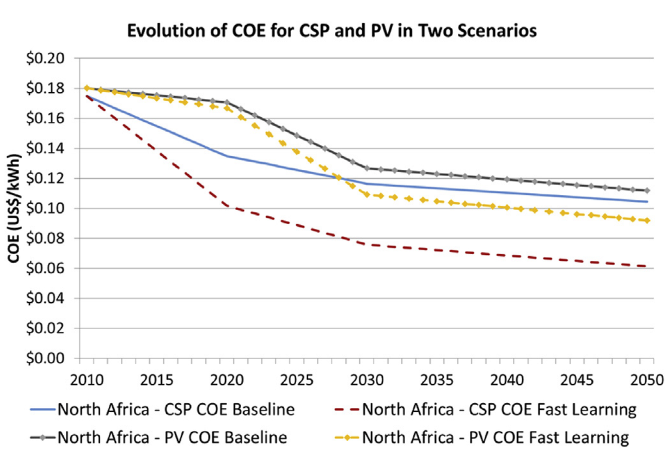


**Fig. 5.** Evolution of CSP and PV cost of electricity under Baseline and Fast Learning scenarios (North Africa region shown).

more important in some regions than others and differs for each technology. Compared to the full potentials in the absence of competition (Fig. 3), PV and CSP potential is cut roughly in half in the regions with a lot of competition cells such as North Africa and Oceania. In other regions, the competition works out differently. For example, since PV is cheaper throughout Brazil both in 2010 and 2050, all the available land is allocated to PV and the CSP potential there goes to zero. Brazil does have sites that are very good for CSP deployment (Malagueta et al., 2013), but on an aggregate level and on a least-cost basis, PV is the more competitive technology there.[12] In the USA, the CSP potential drops by about 50% while the drop for PV is in the order of 67%.

The classes in Figs. 7 and 8 represent costs of electricity from low (blue) to high (red). While in 2010 all of the potential for either CSP or PV is above $0.15/kWh, the situation largely reverts itself by the end of the study period. By 2050, the CSP potential is almost all below that value, with a few regions having significant areas in the $0.15–0.20/kWh range. Because this takes competition into account, wherever the solar resource is not so good, PV tends to be the winner. So the PV potential still includes some areas in the

[12] This is the case in the beginning and end of the study period but competition cells do show up in Brazil during the period as can be seen for years 2020 and 2030 in Fig. 6.

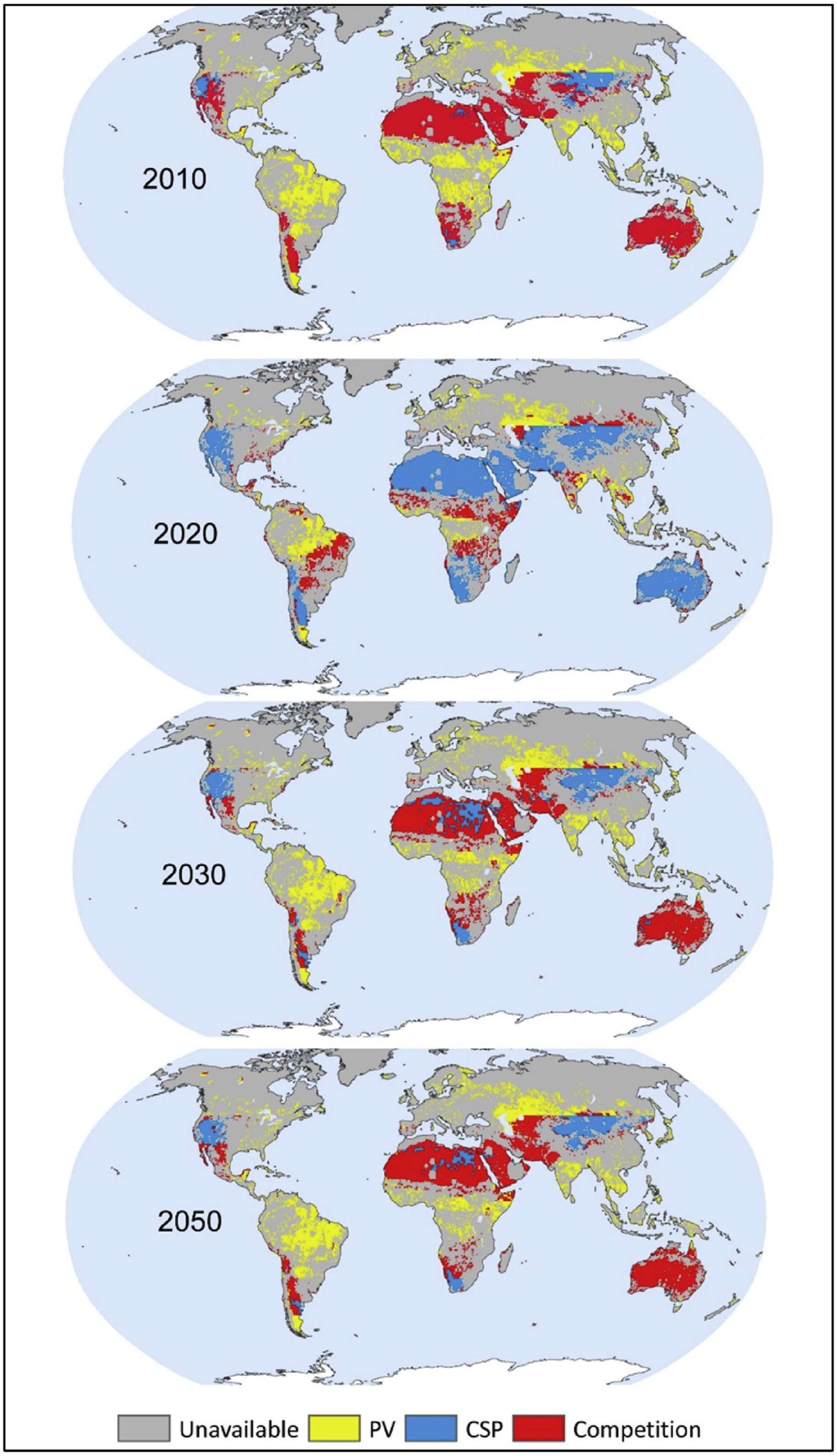


**Fig. 6.** Results of the CSP-PV Competition Model under the reference cost and land use scenarios 2010–2050. Competition (red) areas indicate where PV and CSP costs differ by less than 10%. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

upper range of \$0.30–0.35/kWh, reflecting its better performance in less favorable irradiation sites.

Finally, the regions with the largest technical potential such as north and west Africa, Oceania, USA, rest of South America, already have all their techno-economic potential below US\$0.35/kWh (Fig. 4). This means that the reduction of the generation costs in 2050 do not increase the total potential in these regions. The potential in these regions is already orders of magnitude higher than

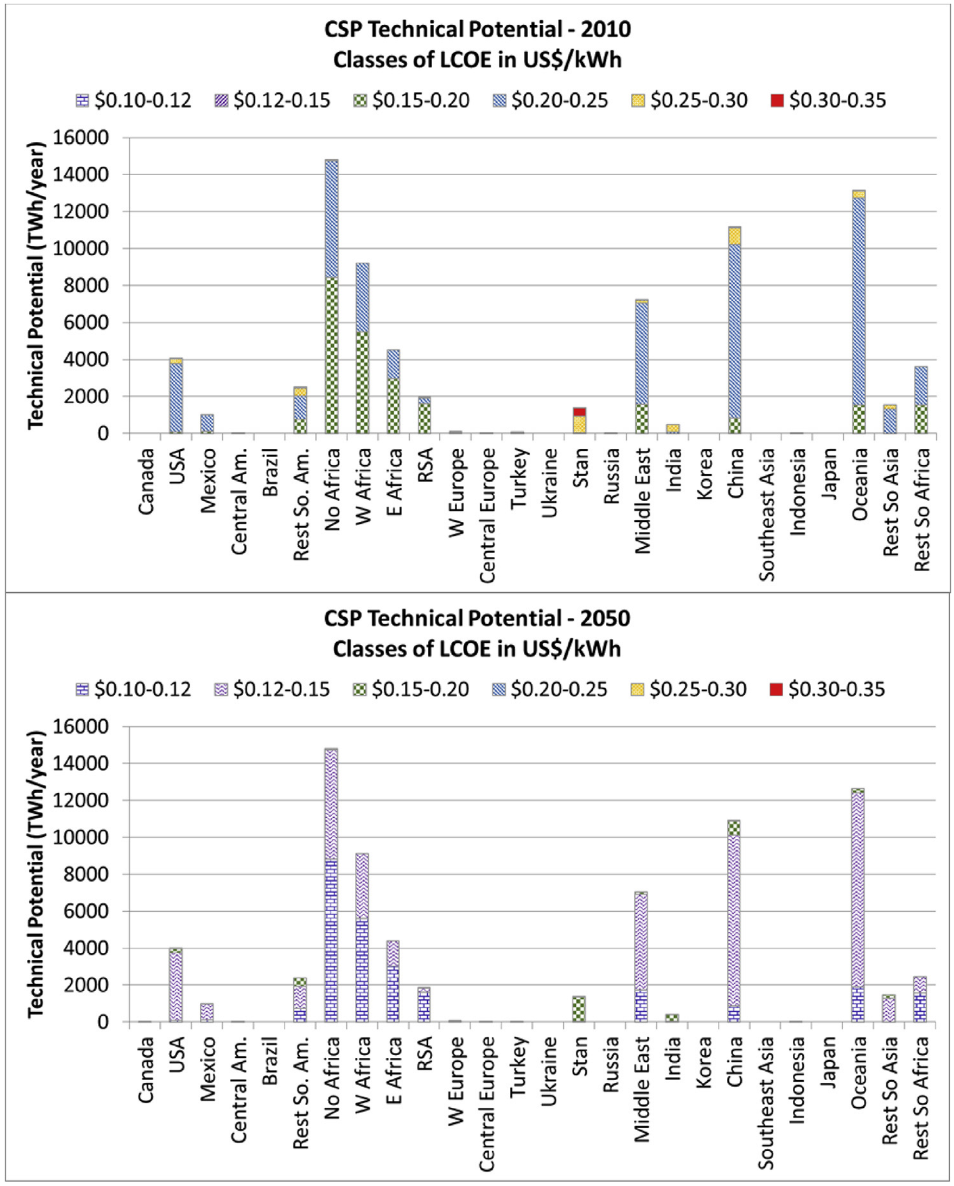


**Fig. 7.** CSP technical potential per region in 2010 and 2050 accounting for competition between CSP and PV.

in other regions with less favorable solar resources. Thus, because of the scale in the graphs, Figs. 7 and 8 do not show the increase in potential in the less favorable regions. However, significant increases do occur in less favorable areas. For CSP, the most striking result is an increase in Indonesia's potential by about 10-fold from about 370 GWh/year to about 3.70 TWh/year mostly from an increase in available land, albeit with a lot of fluctuation during the period. For PV, there is also an increase, especially Canada which sees a 157% increase in its PV techno-economic potential, Russia (38% increase) and the Stans (9.5% increase). Other regions show a decline for both CSP and PV, indicating competition for land with other uses, particularly agricultural expansion, reinforcing the need for more research and the importance of accounting for land-based competition of solar electricity generation and other land uses.

## 4. Discussion

Important uncertainties in the assessment presented here include the specific investment costs, future deployed capacity, the learning rates, the conversion efficiencies and the available land for both technologies.

### 4.1. Land use considerations

It can be inferred from the graphs in Fig. 3 that the CSP and PV technical potentials for each region are sensitive to variations in land use restrictions. Fig. 9 shows the sensitivity of CSP technical potential to variations in restrictions of different land cover types in selected regions. For example, the USA shows high sensitivity to restrictions placed on the availability of the steppes of the western United States. Brazil shows strong sensitivity to variations in the availability of savannas and North Africa to that of hot deserts. These are the areas with the highest *DNI* levels within each region and correspond to expected results.

Oceania is an interesting case because it shows a high degree of sensitivity to restrictions imposed on availability of grasslands, but not on hot deserts. This surprising result is due to most of the high *DNI* locations being in Western Australia, an area dominated by extensive grasslands and not in the hot deserts of the Central

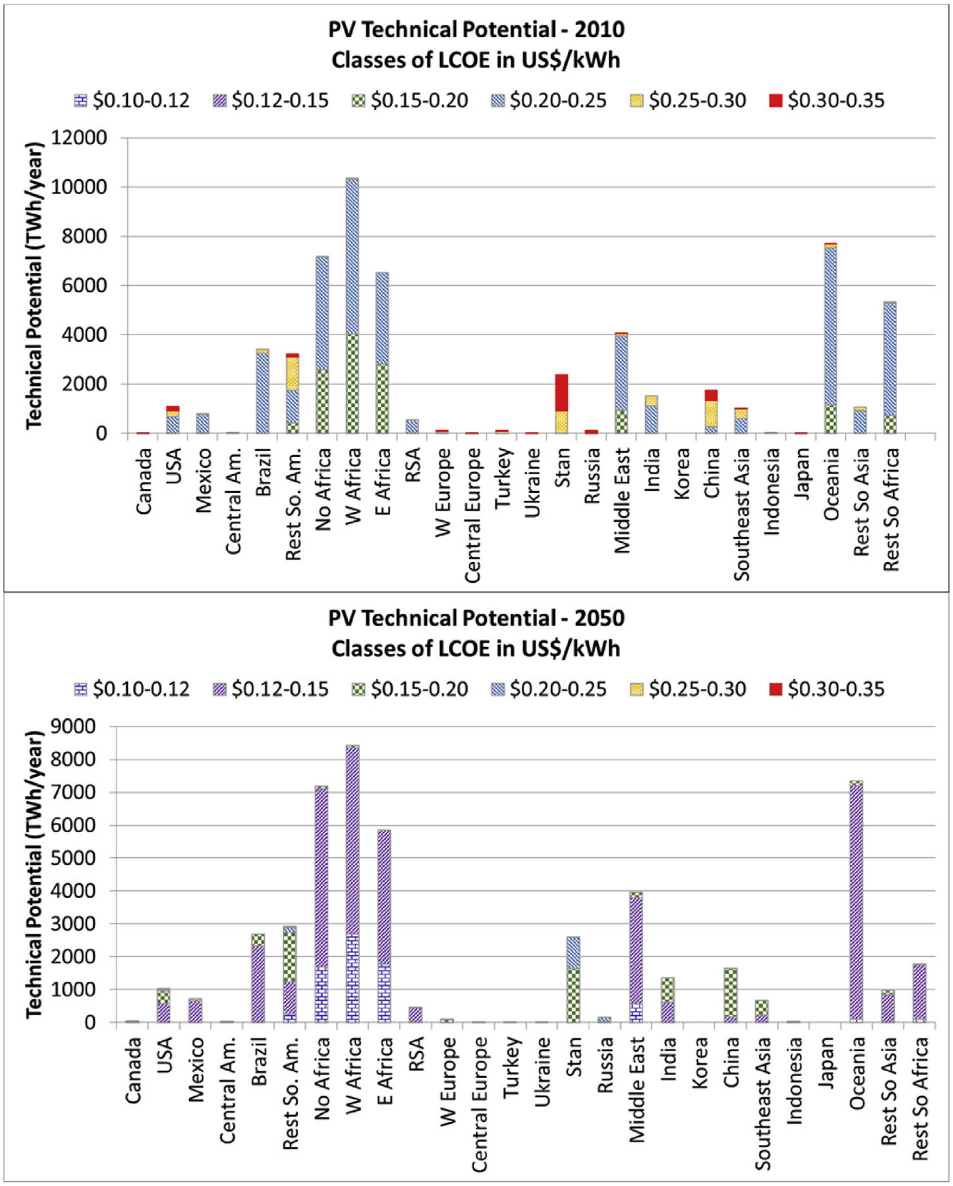


**Fig. 8.** PV technical potential per region in 2010 and 2050 accounting for competition between CSP and PV.

regions as might be expected (See Fig. D2 in supplemental materials). This points to a complex interplay between land use restrictions and the quality of the solar resource when modeling the technical potential of solar electricity and renewable energy in general. We focus here on CSP but the results for PV are similar.

Another dynamic aspect is the relationship between the need for agricultural land and the potential for both CSP and PV (see Fig. 6) especially in sub-Saharan Africa.

The packing factor or land use efficiency represents the portion of the available land actually covered by collectors. A higher packing factor would increase the power density of both technologies and therefore their technical potential by increasing land use efficiency.

### *4.2. Sensitivity to economic parameters*

The results show that solar electricity is currently not yet economically competitive with other more established generation options (with costs typically below $0.10/kWh). By 2050, in our calculations the world's best locations would provide electricity at slightly above $0.10/kWh for both with CSP and PV. Depending on societal preferences and policies (including climate policy) this could mean that solar power would remain uncompetitive with other electricity generation technologies well into the 21st century. Clearly, currently announced capacity deployment alone will not succeed in making solar electricity economically viable. Instead, to arrive at a COE of $0.06/KWh as is the stated goal of the Sunshot Initiative, either a much higher deployment is needed (to profit from learning-by-doing), or innovation would need to occur at a faster rate.

Specific investment costs are an important determinant of the economic potential of solar power. These costs have fallen recently for both CSP and PV. As a new technology, CSP costs have dropped as a result of the recent rise in global capacity deployment since 2007, especially in Spain and the USA. However, in order for this cost reduction to be sustained it would be needed to continue capacity deployment to provide a market for the manufacturers and to bring the technology to scale. While the recent economic crisis

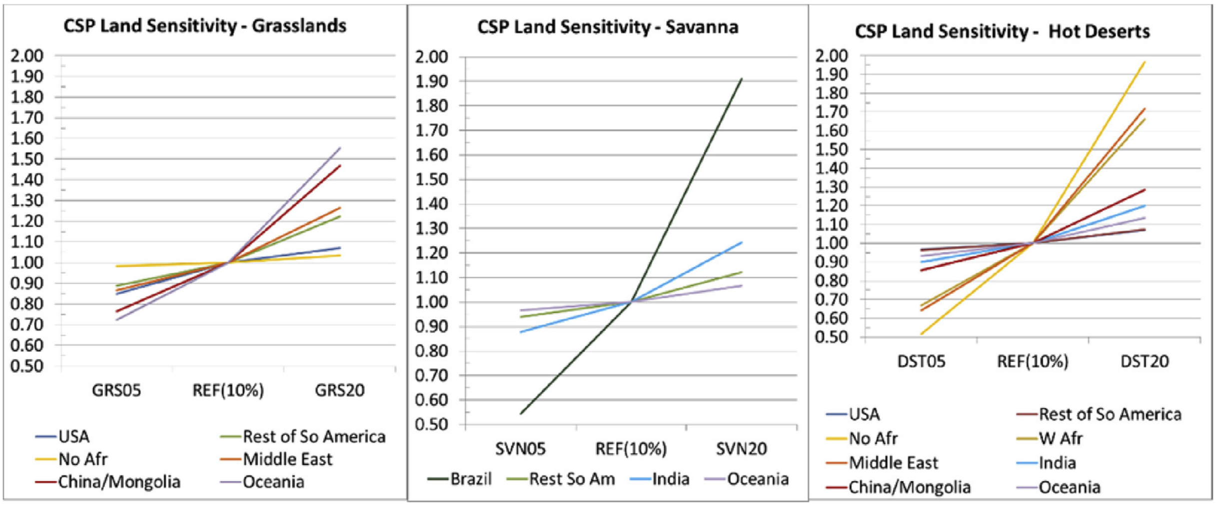


**Fig. 9.** Sensitivity of CSP technical potential to land use restrictions in selected regions.

has slowed down further investments in Spain, other countries have started to invest more. For instance, the largest parabolic trough plant in the world opened in the United Arab Emirates in March 2013, and the Ivanpah solar tower CSP plant in California has recently come online with 377 MW capacity, making it the largest solar electricity generation plant in the world. Opportunities for learning include the HTF (heat transfer fluid) and the thermal energy storage, both leading to a higher efficiency and a better capacity factor for CSP plants.

The photovoltaic industry has also seen sharp reductions in the costs of both panels and BOS (balance of system) components, brought about in large part by the economies of scale introduced with the opening of large manufacturing facilities in China. The drop in panel prices, the impact on PV industries outside China, and the trends in demand in Europe, have caused prices to drop to levels below those implemented in this study. It is uncertain whether the current prices are going to last for the long term, but they are considered too low for at least some industry analysts.[13] In any case, the possibility exists that technological breakthroughs may cause prices to drop faster than modeled in the baseline scenario. Some possibilities are higher efficiency panels and BOS components, as well as switches to other PV configurations such as CPV (concentrated photovoltaics).

To explore future costs of CSP and PV electricity, we assumed full implementation of national targets through 2050 as described in Appendix B. This would bring installed capacity to 108 GW for CSP and 494 GW for PV by 2050 as summarized in Table 4. Specific investment costs in 2050 come down to \$4512 for CSP and \$1958 for PV in the baseline scenario, and \$2380 and \$1508 respectively in the Fast Learning scenario.

To explore the impact of cost uncertainties in both technologies, the Fast Learning scenario increased the learning rate for CSP to 20% and for PV to 25% (potentially mimicking a situation of stronger policy support in RD&D for both technologies). For CSP, the projected costs in this scenario fall dramatically to below \$0.07/kWh throughout most of the regions with a good quality DNI solar resource like the USA, North Africa, Oceania and South America. In the very best sites, the COE of CSP reaches \$0.061/kWh by 2050, indicating that a learning rate of around 20% for CSP is needed to meet the Sunshot Initiative target of \$0.06/KWh. For PV, a 25% learning rate only bring resulting 2050 costs to just below \$0.09/kWh for the best locations. This result indicates that in order to achieve this target, sustained public policy investment in RD&D and regulatory support are needed for both PV and CSP technologies to realize their potential to supply the world's future electricity demand. Since price-competitive thermal energy storage allows CSP to be modeled here with 6 h of storage, this result suggests that storage technologies that increase the capacity factor of PV plants could be crucial in bringing down the cost of PV electricity.

For CSP a higher learning rate may indeed be a realistic scenario. This study modeled parabolic trough because it is the most widely deployed form of CSP, but central tower CSP has the potential to be even more competitive through higher conversion efficiencies caused by higher steam operating temperatures. A transition to central tower as the configuration of choice would be equivalent to a disruptive innovation that would justify a higher learning rate. Several central tower plants are already in operation today and others are in the planning stages.[14] Central tower CSP is also expected to allow higher levels of thermal energy storage (up to 18 h), meaning these plants could function as baseload in the most suitable sites, potentially producing electricity for up to 8000 h per year.

### 4.3. Effect of the cost of new transmission lines

Because the areas with the highest potentials tend to be located far from load centers, the cost of new transmission lines can be a significant barrier to the development of renewable energy [27,36–38]. Solar electricity is particularly affected since the best sites are in inhospitable desert or semi-arid areas with very low population densities. Given the fact that our analysis involves an assessment of global potential in the future we can only roughly estimate transport costs. Neverthless, the impacts of having to build new transmission lines to bring renewable electricity to market are clear. Here, we use an estimate of transmission costs based on the distance between potential and load centre (but not to existing grid).

Gernaat et al. (forthcoming) developed an algorithm to estimate the costs of bringing renewable electricity from remote locations to load centers within the IMAGE 2.4 framework. The algorithm is based on a distance-to-load factor, and on a terrain multiplier to account for the higher cost of building transmission lines on certain

[13] See for example Mints (2013).

[14] NREL/SolarPACES website: http://www.nrel.gov/csp/.

terrains, such as forests and mountains. The result is a weighted (by terrain suitability) indication of the distance to a net-demand-cell. This suitability-weighted distance is multiplied by the cost per km of building a new transmission line. We used financial data and terrain multipliers supplied by Ref. [39] to estimate transmission costs based on construction costs of US$2,390,000 per km (Appendix A).

Fig. 10 shows the effect of the cost of new transmission lines on the cost of PV electricity for each grid cell. The effects of the distance to load on the cost of CSP and PV electricity generation follows a predictable pattern around densely populated areas of the globe. The vast unpopulated areas of Australia and Africa eliminate a significant portion of the economic potential of solar electricity in these regions. On the other hand, the densely populated coastal areas are close to areas of good solar resource that do not require large investments in new transmission infrasctrucutre.

After accounting for distance to load, especially the MENA region stands out for the size of its potential, but other large swaths of good economic potential for CSP and PV can be found in South Africa, Western USA and Northern Chile. Other regions that are not

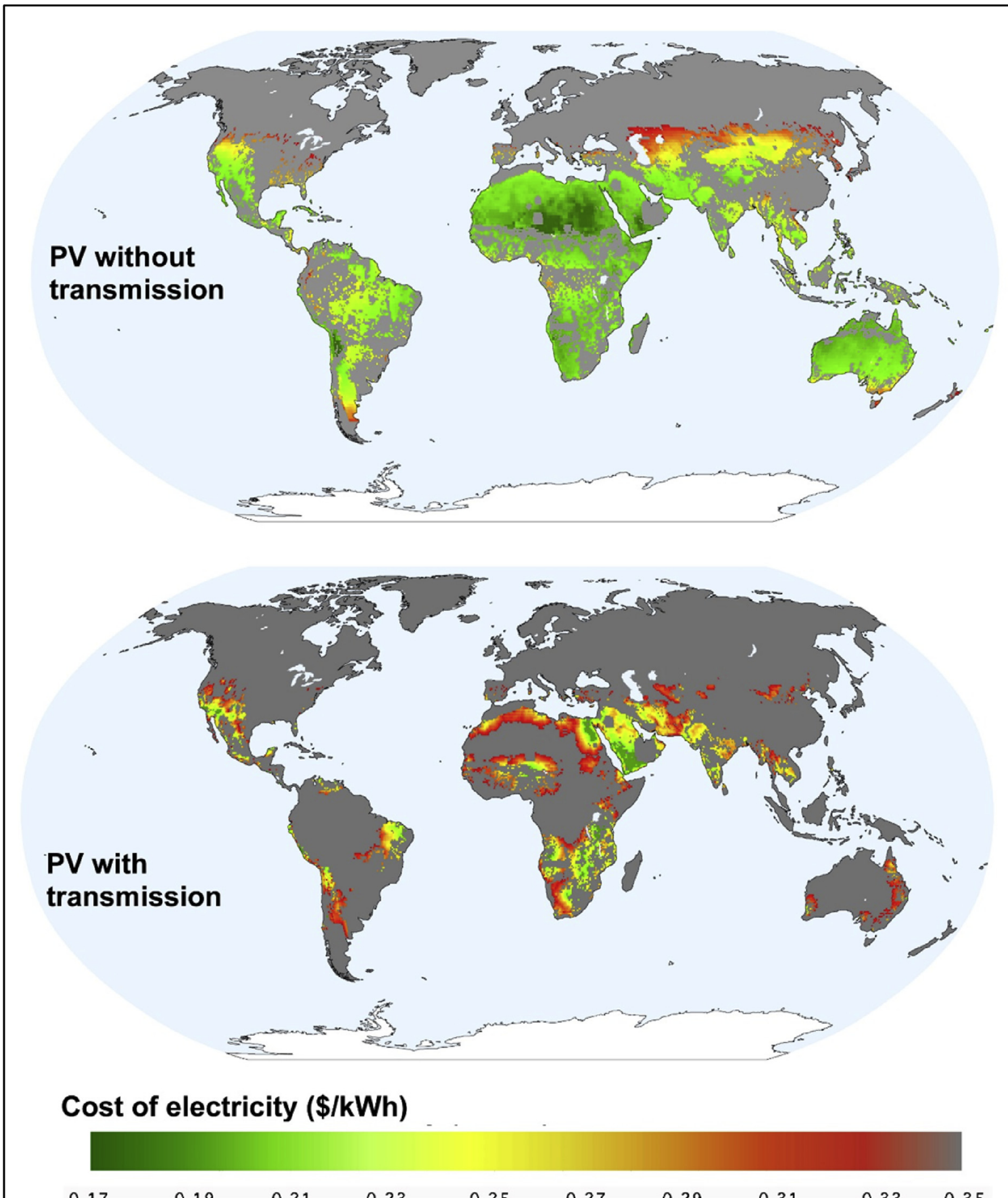


**Fig. 10.** Effect of the cost of building new transmission lines to the nearest load center on the cost of PV electricity (US$/kWh).

as strongly affected by transmission availability include western USA, northern Chile and Argentina, southern Africa, northeastern Brazil, northern China and Mongolia, as well as parts of the Arabian peninsula, India and Pakistan. For a full analysis of the effects of transmission costs on solar and other renewable electricity in the IMAGE framework see Gernaat et al. (forthcoming).

### *4.4. CSP vs PV competition*

This study also modeled the competition between CSP and PV for the same solar resource based on the costs of the electricity produced. An interesting finding is that CSP costs might in the medium term decline faster than PV, making CSP more competitive in specific (high DNI) areas. This is what would be predicted by technology transition theory, since CSP as a less mature technology would enjoy quicker cost reductions caused by a more rapid doubling of installed capacity. This process begins to slow down after 2030. With the reduction in new installed capacity of CSP and the higher learning rate of PV, the further costs improvement could be similar in size (Figs. 5 and 6).

In our calculation, we have assumed that 50% of the potential goes to each technology in cells where the cost of electricity is similar. Although obviously not a very realistic method to divide the potentials, this simple 50-50 split served to indicate the effect of competition for the same land-based resource, causing a reduction of both potentials in all regions. The significant difference in the technical potential of both CSP and PV when they compete for the same solar resource is evidence that cost-supply curves used in integrated assessment models need to account for this competition. This is particularly the case in regions with limited but high-quality solar resources such as South America, South Africa and the USA. More refined methods than a simple 50-50 split need to be developed that take into account the distinct advantages that each technology offers vis-à-vis the available solar resource. Cost supply curves that take this competition into account will be developed and used in the IMAGE framework to study the future contributions of CSP and PV to the global electricity generation matrix.

## 5. Conclusions

This study aimed to explicitly model CSP and PV land use and competition explicitly through 2050 in order to create cost-supply curves in a consistent manner. The most important conclusions are:

- **There is a substantial potential for both CSP and PV**. Important areas include the Southeastern Sahara, Northern Argentina and Chile, the Southwestern USA, Oceania and China/Mongolia. For the best sites, costs are projected to be around $0.11/kWh for CSP and PV in 2050 under current deployment policies. The solar resource is abundant on a global scale but is concentrated in different land cover types in different regions. Although some follow predictable patterns (hot deserts in North Africa), other regions are not as expected (high sensitivity to grassland availability in Oceania). In that context, even accounting for land use restrictions, the combined global CSP and PV techno-economic potential below US$0.35/kWh is estimated at 135,128 TWh/year, accounting for competition between them for the same land-based resource. For comparison, the total world power consumption in 2010 was 17,863 TWh/year.
- **CSP and PV compete for the same solar resource**. On the basis of costs, it is possible to indicate attractive areas for each technology. For CSP, the best sites are in southeastern Sahara and in northern Chile/Argentina, northwestern Australia, South Africa and China/Mongolia. Good potential also exists in southwestern USA, other regions of northern Africa and the Arabian Peninsula. CSP shows a clear competitive advantage in these regions over PV, although utility-scale PV plants would also do well there. Areas where PV has the clear advantage are in Equatorial Africa, the Amazon region, eastern USA, most of Europe, and monsoon India.
- **The remoteness of many sites with some of the best potential raises the question of transmission costs to demand centers**. Including estimates of the cost to build new transmission lines raised the cost of electricity generation in many of the very best sites worldwide. This significant "transmission penalty" pushed large regions out of the economic potential range. However, those regions where the 2010 COE remained below US$0.25/kWh are prime candidates for development of high-capacity transmission infrastructure.
- **CSP electricity generation costs might in the medium term decline faster than PV, but the higher learning rate of PV levels the costs in the medium to long term as CSP capacity deployment slows**. The current projections do not result in generation costs below $0.10/kWh in 2050, but it seems possible to speed-up technology development. An alternative scenario explored assumptions consistent with considerable support in all phases of RD&D, including public policy support for capacity deployment. By increasing learning rates to 20% for CSP and 25% for PV, electricity prices of CSP and PV could reach $0.06/kWh and $0.08/kWh respectively, not including the cost to build new transmission lines from remote areas.
- **When accounting for competition between the two technologies for the same land-based solar resource, their respective techno-economic potentials are reduced roughly in half in regions where the costs of the electricity produced are similar**. In regions where there is a clear winner technology, the effect of competition on the potential depends on the relative electricity prices between the two technologies, and can be significant. The clear impact on the technical potential of both technologies is evidence that cost-supply curves used in integrated assessment models need to account for this competition.

## Acknowledgments

The contribution of David Gernaat and Detlef van Vuuren to this research has been partly funded by the European Union Seventh Framework Programme FP7/2007-2013 under grant agreement n° 308329 (ADVANCE). The authors also gratefully acknowledge the help of PBL colleagues Rineke Oostenrijk with coding, and Johan Meyer with GIS.

## Appendix

### *Appendix A. Cost of new transmission algorithm*

In order to account for the cost of building new transmission lines from remote sites with good solar resource to the load centers, we developed a cost of new transmission model based on a distance-to-load algorithm (Gernaat et al. forthcoming). This algorithm starts at the current grid cell being analyzed and goes outwards in eight directions (N–NE, NE–E, E–SE, etc) searching neighboring cells for the closest load. The search stops when supply meets a net-demand-cell. A net-demand-cell is calculated by subtracting the electricity demand by the solar energy potential at that cell. Next, the distances of all eight direction wedges are multiplied by terrain suitability factors. These terrain suitability factors are multipliers that account for the higher costs of building transmission lines in areas such as forests, steep slopes, water ways etc, and were taken from Ref. [39]. The wedge with the shortest suitability-weighted distance wins and is used as the final indicator.

For this study, the choice was made to use a 230 kV double circuit transmission line as the cost standard since it is robust to carry loads over medium to long distances. It may be an overestimate in some cases and an underestimate in others but, since an average value is needed, this seems like a reasonable first choice to include transmission costs in our calculations. The cost to build a new double circuit 230 kV transmission line according to [39] is US$2,390,000 per km and that is the cost we implemented.

The distance to load factor is multiplied by the terrain multiplier and this weighted distance is then multiplied by an estimate of cost per km obtained from the literature for building new 230 kV double circuit transmission lines. The choice for this transmission line configuration was made because it is robust enough to carry electricity for long distances while still remaining a relatively low cost alternative. For very long distances (>1000 km) HVDC (high voltage direct current lines) are preferred since they minimize losses. However, this would penalize the cells within a shorter distance from the load centers. Therefore, the choice for a medium voltage AC line was made since the idea is to connect the best sites starting with those closest to demand centers. Existing transmission lines were not considered so the estimates reflect the costs to bring the electricity generated to the actual load centers.

## *Appendix B. National official capacity deployment targets for CSP and PV worldwide*

In order to calculate future costs of CSP and PV electricity using the learning curve approach (Appendix C), we used official public policy targets for capacity deployment announced by several countries around the world. Using the base year 2010 specific investment costs (taken from the literature as described in the text) capacity deployment targets were used to calculate what the cost will be given the assumed learning rate for the technology. Table B1 shows the projected capacity targets for CSP and PV in the years 2020, 2030, and 2050 which were used as model inputs. National targets were taken from Refs. [33,34].

**Table B1**
Global installed capacity in 2010 and national projected deployment for CSP and PV.

| | 2010 | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| CSP | | | | |
| Algeria | | 1500 | 7200 | 7200 |
| Bangladesh | | | | 500 |
| China | | 1000 | 1000 | 1000 |
| Egypt | | 1100 | 2800 | 2800 |
| France | | 100 | 200 | 200 |
| India | | 1000 | 5000 | 5000 |
| Iraq | | 80 | 80 | 80 |
| Jordan | | 300 | 300 | 300 |
| Kuwait | | | 1100 | 1100 |
| Libya | | 125 | 375 | 375 |
| Morocco | | 1000 | 1000 | 1000 |
| Palestine | | 20 | 20 | 20 |
| Saudi Arabia | | | 25 | 25 |
| Spain | | 4800 | | 4800 |
| Sudan | | | 50 | 50 |
| Tunisia | | | 300 | 300 |
| UAE | | 200 | 200 | 200 |
| Yemen | | | 100 | 100 |
| USA | | 5000 | 28,000 | 83,000 |
| **TOTAL CSP CAP (MW)** | **2500** | **16,225** | **47,750** | **108,050** |
| PV | | | | |
| Algeria | | 946 | 2800 | 2800 |
| Austria | | 1200 | 1200 | 1200 |
| Bulgaria | | 80 | 80 | 80 |
| Canada | | | 40 | 40 |
| China | | 30,000 | 40,000 | 40,000 |
| Egypt | | 220 | 700 | 700 |
| France | | 200 | 800 | 800 |
| Greece | | | 2200 | 2200 |
| India | | 6000 | 1000 | 1000 |
| Indonesia | | | 150 | 150 |
| Iraq | | 140 | 140 | 140 |
| Italy | | 23,000 | 25,000 | 25,000 |
| japan | | 8000 | 8000 | 8000 |
| Jordan | | 300 | 300 | 300 |
| Kuwait | | | 3500 | 3500 |
| Libya | | | 130 | 130 |
| Morocco | | 1000 | 1500 | 1500 |
| Nigeria | | 1 | 50 | 50 |
| palestine | | 45 | 45 | 45 |
| Qatar | | 1800 | 2000 | 2000 |
| Saudi Arabia | | | 16 | 16 |
| Serbia | | 150 | 200 | 200 |
| Spain | | 7250 | 10,000 | 10,000 |
| Sudan | | | 350 | 350 |
| Thailand | | 500 | 1000 | 1000 |
| Tunisia | | | 1900 | 1900 |
| Yemen | | | 4 | 4 |
| United States | | | 181,000 | 391,000 |
| **TOTAL PV CAP (MW)** | **65,000** | **80,832** | **284,105** | **494,105** |

## *Appendix C. Learning rates and the future costs of solar electricity generation*

Experience curves, also known as learning curves, depict the past evolution of the cost of a technology as a function of the cumulative installed capacity, and can be extrapolated to estimate the future evolution of current costs.[15] These curves have the form of a straight line in log–log space, the slope of which is the *learning rate*, that is, the percentage reduction in cost per doubling of installed capacity. The cost at a future time $t$ is derived by Ref. [18], where $C(0)$ is the cost at time $0$, $Q(0)$ is the initial installed capacity, and $Q(t)$ the installed capacity at time $t$:

$$C(t) = C(0)\left(\frac{Q(t)}{Q(0)}\right)^{\log(1-LR)/\log(2)} \tag{B1}$$

In order to estimate the evolution of the costs of PV and CSP, it is therefore necessary to project the growth of the installed capacity for each technology and apply an appropriate learning rate to the desired time horizon. Solar installed capacity is projected to grow through public policy incentives like subsidies, tax credits, Feed-In-Tariffs, Renewable Portfolio Standards etc. The values for the installed capacities through 2050 are taken from Ref. [33] except for the USA where projected installed capacities were taken from model-predicted capacity deployments as a consequence of the Sunshot Initiative [34]. The Sunshot Initiative is probably the most aggressive solar energy development program in place today and it accounts for 83 of the 108 GW of CSP global capacity by 2050 and 391 of the 494 GW of PV.

Modeling technology deployment costs is highly sensitive to the assumed learning rates so that a careful balance needs to be struck between a higher rate fueled by fast learning and technological innovation and a more conservative approach that does not underestimate the costs of deployment of a new technology [32]. Ref [18] follow the learning rates suggested by the IEA of 18% for PV and 10% for CSP starting in 2010 [32], and these values are also chosen here as the reference learning rates to calculate solar energy cost evolution through 2050. By using these learning rates and the

[15] Although see Ref. [41] for pitfalls in learning curve analyses of future costs of renewable energy technologies.

projected installed capacities described above, the specific investment cost for each technology was calculated for the period 2010–2050 using Equation (B1). The cumulative global installed capacities and the resulting specific investment cost of CSP and PV for the baseline scenario are shown in the top section of Table B2.

**Table B2**
Projected Solar installed capacity growth through 2050 and resulting COE (baseline scenario) (Sources: [33,34]; Baseline Learning Rates from [18]).

| | 2010 | 2030 | 2050 |
|---|---|---|---|
| Baseline scenario | | | |
| Projected installed capacity (GW) | | | |
| CSP | 2.5 | 47.75 | 108 |
| PV | 100 | 284.1 | 494.1 |
| Specific investment cost (2010$/KWe) | | | |
| CSP (LR = 10%) | 8000 | 5109 | 4512 |
| PV (LR = 18%) | 3500 | 2294 | 1958 |
| Alternative *Fast Learning* cost scenarios | | | |
| CSP learning rate = 20% | | | |
| CSP specific investment cost (2010$/KWe) | 8000 | 3095 | 2380 |
| PV learning rate = 25% | | | |
| PV specific investment cost (2010$/KWe) | 3500 | 1898 | 1508 |

Learning rates only account for incremental price reductions and exclude effects of disruptive innovation that can cause rapid and drastic cost reductions when deployed[16]. In order to assess the effect of diruptive innovations, an Alternative *Fast Learning* Cost Scenario was introduced in which the learning rates are increased to 25% for PV and 20% for CSP. The resulting cost progression is shown in the bottom section of Table B2 using the same capacity deployment projections as the baseline scenario. This allows a comparison of the evolution of CSP and PV competition in a spatio-temporally explicit way according to different cost evolutions of each technology.

## *Appendix D. Supplementary materials*

Fig. D1 shows the global CSP technical potential for each area subject to only the minimal land use restrictions (excluding only land use classes defined as unavailable in Table 1 and represents the technical potential for each grid cell based on available *DNI* and the technical specifications of CSP as described in Section 2. This map is roughly in agreement with most published maps of CSP global technical potential with the exception of some small blue areas in regrowth forests in Arctic regions. This is a result of the long summer days which skew the average DNI values upwards in these regions and the relatively high availability criteria chosen for regrowth forests (5%). However, although technically a CSP plant could operate in these regions, the absence of virtually any sunlight in the winter months coupled with the long distances to load centers negates economic CSP feasibility there.

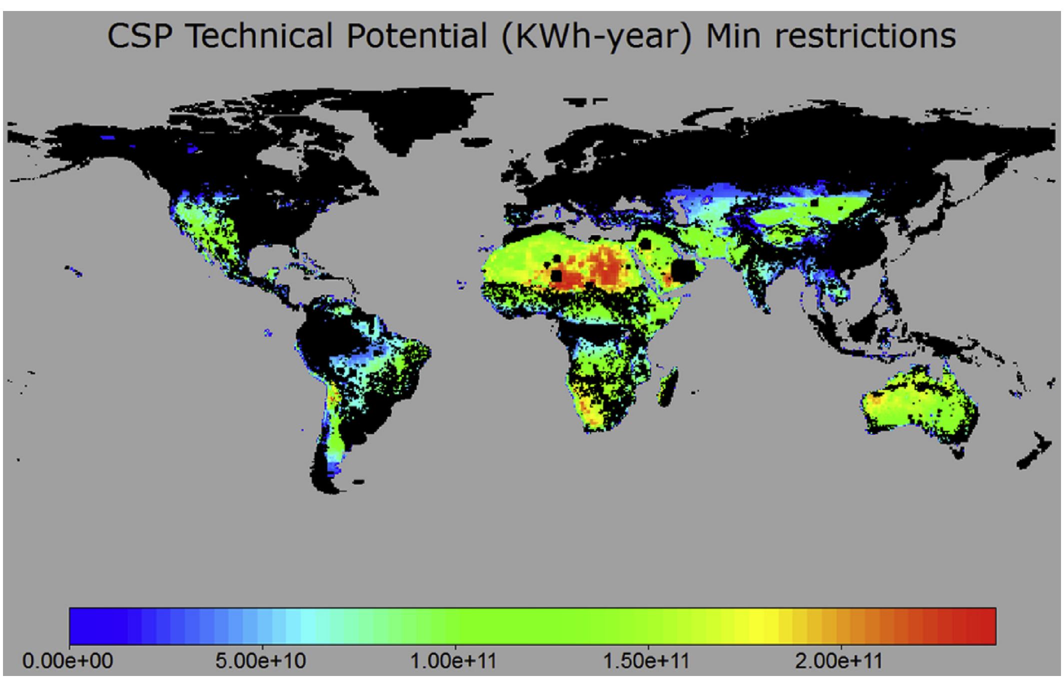


**Fig. D1.** Global CSP technical potential per grid cell with minimal land use restrictions (see text).

This map should be interpreted as a map of the most suitable areas for CSP electricity generation with only the minimal constraints on land use type, ie exclusion only from those that are set to 0 in Table 1 (agricultural land, forests etc). So for siting purposes, the red and yellow areas provide the best solar resource and are mostly located as expected in the deserts of the world. This points to North Africa as a potential hotbed of electricity generation. However, there is little chance that, for example, all of the Sahara will be covered with CSP plants so that an assessment of the regional potential using this unrestricted availability of land cover types would yield unrealistically high values.

[16] An example of such a disruptive innovation is the use of molten salt as the heat transfer fluid in parabolic trough CSP which is being tested presently at an Italian site in Sicily. Turchi et al. (2010) predict that this technology can bring about a reduction of CSP investment costs from $8000/KWe in 2010 to $6600/KWe in 2015, a reduction that would not happen through incremental reductions alone, since there will not be enough new capacity deployment to bring it about.

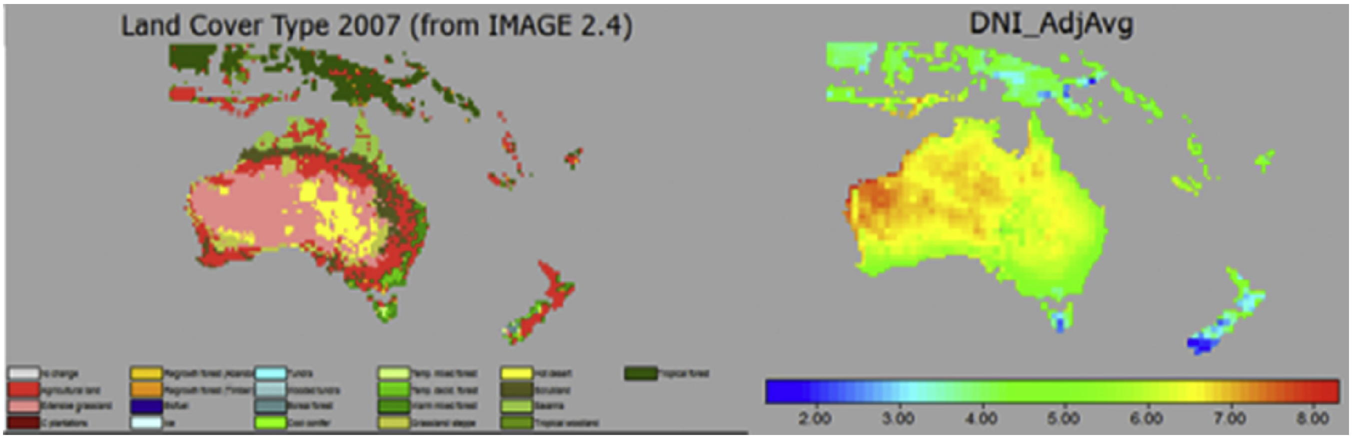


**Fig. D2.** Correlation of DNI and Land Cover type in Oceania region.

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