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Prospects for PV: a learning curve analysis

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Abstract

This article gives an overview of the current state-of-the-art of photovoltaic electricity technology, and addresses its potential for cost reductions over the first few decades of the 21st century. Current PV production cost ranges are presented, both in terms of capacity installation and electricity generation, of single crystalline silicon, multi-crystalline silicon, amorphous silicon and other thin film technologies. Possible decreases of these costs are assessed, as expected according to the learning-curve methodology. We also estimate how much PV could gain if external costs (due to environmental and health damage) of energy were internalised, for example by an energy tax. Our conclusions are that, (1) mainly due its high costs, PV electricity is unlikely to play a major role in global energy supply and carbon emissions abatement before 2020, (2) extrapolating learning curves observed in the past, one can expect its costs to decrease significantly over the coming years, so that a considerable PV electricity share world-wide could materialise after 2020, (3) niche-market applications, e.g. using stand-alone systems in remote areas, are crucial for continuing 'the ride along the learning curve', (4) damage costs of conventional (fossil) power sources are considerable, and their internalisation would improve the competitiveness of PV, although probably not enough to close the current cost gap.

1. Introduction

Photovoltaic (PV) cells, consisting of thin layers of semiconductor material, convert sunlight directly into electricity. Solar electricity is one of the promising options for sustainably providing the future energy requirements of mankind, since it constitutes a renewable energy resource and involves far less pollution, including emissions of CO_2, than most other power sources (the only pollution arises upstream and downstream, from production and disposal of PV equipment). The first silicon solar cell was discovered, by accident, by Russell Ohl in 1940, after which the semiconductor revolution of the 1950s brought forward the first efficient solar cell (1954) and its first commercial application on spacecraft (1958) (Green, 2000). Only after the oil crises of the 1970s, the solar cell industry took root with applications closer to home. Until today, PV technology has been largely based on silicon wafers as semiconductor material, as used in microelectronics. At present, however, a transition seems to be in progress to a second generation of so-called thin-film PV technologies.

The (24 h) average annual power density of solar radiation is typically in the range of 100–300 W/m^2 (on a horizontal plane). Thus, with a PV efficiency of 10%, an area of 3–10 square kilometres is required to establish an average electricity output of 100 MW (about one tenth of a large coal or nuclear power plant). Compared to the area needed for conventional electricity plants, the corresponding figures required for PV are large. Still, the total average power available at the Earth's surface in the form of solar radiation exceeds total human power consumption by roughly a factor of 1500 (WEA, 2000). Also, the power incident on the roofs of buildings is in many cases comparable to the average power consumption inside, e.g. for houses. Whereas these numbers give a clue to the absolute boundaries of the potential of PV, respectively globally and locally, they possess little significance for its practical applicability and employability. Many other factors, among which technical, geographical and economic, play a fundamental role in determining PV energy's

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true potential. For example, one needs to consider the match between electricity demand and the availability of solar radiation, in particular its variability.

The high cost of PV cells and associated BOS (balance of system) constitutes one of PV's main present handicaps. Nevertheless, during the 1980s and 1990s PV cell production has been increasing on average by more than 15% per year. During the sole year of 1999 nearly 200 MW_p [1] of solar cell modules were produced, such that at present about 1 GW_p capacity of PV is in operation globally, generating about 1 TWh a year. In the early 1990s solar home systems and village power systems accounted for some 20% of the PV market, while grid-connected PV systems accounted for 11%, and the remaining 69% originated from widely ranging applications, among which water pumping, communication, leisure and various consumer products (such as pocket calculators). Recently, the relative importance of grid-connected systems has been increasing considerably, to about a quarter of the current PV market. Compared to the 3300 GW total electricity capacity installed world-wide (EIA, 2002), the contribution of PV is today still very small.

Yet, from many perspectives the development potential of PV is high, and its promise vis-à-vis clean and sustainable energy provision large. This article addresses a number of questions that are essential for making a proper analysis of the future prospects of PV:

- Which PV technologies possess promise for future large-scale development, what are their current costs, and what is their learning potential?
- What is the total cost gap that needs to be bridged to make these PV technologies competitive with other energy technologies?
- What is the value of PV electricity, in view of its particular characteristics, and in comparison to its primary (conventional) counterparts?
- How much could PV gain if external costs (due to environmental and health damages) of all energy sources were internalised, for example by an energy tax?
- How do the required PV learning investment costs compare to current PV expenditures?
- How do the costs of reaching economic break-even for PV compare to the costs involved with the internalisation of the damage costs of e.g. fossil-fuelled electricity?

Here we consider only simple flat PV panels. Concentrating systems involve other technologies and are generally less suitable for the relatively small-scale applications that are likely to dominate the market in the near term (except for systems with such low concentration that they do not require tracking).

[1] The subscript p indicates the peak output when solar radiation = 1 kW/m^2.

Section 2 of this paper describes the present state-of-the-art of different PV technologies, and assesses the current costs of capacity and electricity production for these technologies. Section 3 examines electricity production costs of the conventional technologies against which PV has to compete. Section 4 investigates PV and its main competitors in terms of damage costs. Section 5 assesses, through the learning curve methodology, the potential for future PV cost reductions. Section 6 describes the implications of the preceding sections for policy-making regarding efforts to promote PV electricity generation. Section 7 summarises the results.

2. State-of-the-art: PV technologies and their costs

The photovoltaic solar module, usually consisting of a number of solar cells, is the main component of a photovoltaic solar energy system. Solar cells can be categorised in two main groups: wafer-type (single crystalline or multi-crystalline) and thin-film. The former are made from wafers cut from a silicon ingot. Thin-film PV cells are deposited directly onto a substrate like glass, plastic or steel. Of the 1998 commercial PV market some 85% were wafer-type, while the remaining 15% were mainly amorphous silicon (thin film) solar cells (WEA, 2000).[2] Other thin film technologies are being developed in the laboratory, are in a pilot production phase, or start emerging as commercial technologies. Among the latter are notably CIGS (copper–indium/gallium–diselenide) and CdTe (cadmium–telluride) solar cells. It is too early to pick winners or losers among the PV technologies available commercially or under development. Still, there seems reasonable consensus that thin-film technologies offer the best long-term prospects for low production costs, even when considerable cost reductions are to be expected for crystalline wafer technologies resulting from technological improvements and economies of scale. On the other hand, wafer-type silicon PV cells achieve today higher efficiencies (typically 12–15% for flat panels on the market) than those reached by thin-film technologies (around 6–11%), an empirical fact that might continue to hold for the longer-term future, even while efficiency improvements will probably be achieved for various technologies to some 20% in the medium term (up to 2020) and perhaps to some

[2] Single crystalline wafers are sawn from a relatively small single crystal that is gradually drawn from a melt of refined silicon, whereas multi-crystalline wafers are obtained from slicing a generally large block of silicon that is formed by directly solidifying molten silicon in a container (therefore giving a structure consisting of multiple crystals). In amorphous silicon, atoms are connected in much the same way as in crystalline material, but many small deviations from perfection are accumulated, so that perfect ordering over relatively large distances no longer holds (see, for example, Green, 2000).

30% in the long run (after 2020).[3] Thus, it seems likely that also in the future compromises (tradeoffs) need to be made between cost and efficiency.

PV system costs consist of module costs and costs of the so-called balance-of-system (BOS), the latter representing all other system components, among which electrical installation, inverters, support structure, and building integration. Prices of PV modules and systems vary widely, depending on supplier, type, size and country.[4] We therefore present merely cost *ranges*, to give the bandwidths over which PV costs can vary. For present and near-term crystalline silicon technologies, solar module costs vary between about 2–4 \$ per W_p (WEA, 2000).[5] For the corresponding BOS for rooftop and ground-based PV systems, when it is connected to the grid, costs vary between approximately 1 and 4 \$/W_p, so that the total system costs lie within a range of some 3–8 \$/W_p (see Table 1).[6] For thin film technologies, today's and short-term solar module costs can be expected to be 1–3 \$/W_p, so that total system costs vary between 2 and 7 \$/W_p. For stand-alone systems, costs are significantly larger, e.g. as a result of additional battery and charge controller costs that are required for energy storage. For representative present and near-term stand-alone PV systems, the costs one needs to add in this respect are readily 2 \$/W_p, but can be as much as 20 \$/W_p. Adding these figures to the costs already encountered with grid-connected PV systems, one arrives at present and near-term costs for stand-alone PV systems that lie in a range of about 5–30 \$/W_p for crystalline silicon, and about 4–30 \$/W_p for thin film technologies (see also Table 1). Because of the prevailing uncertainties, we have not distinguished between single and multi-crystalline silicon technologies, and between amorphous silicon and other thin film technologies. The upper range of 30 \$/W_p is very approximate.

Table 1
Ranges of current and expected near-term capacity costs for four PV technologies (the ranges cover variations in supplier, type, size and country). Sources: WEA (2000); Oliver and Jackson (2000)

Capacity costs (\$/W_p)	Stand-alone PV system	Grid-connected PV system
Single crystalline silicon	5–30	3–8
Multi-crystalline silicon	5–30	3–8
Amorphous silicon	4–30	2–7
Other thin film	4–30	2–7

3. Cost and value of PV electricity

The cost per kWh of PV electricity is obtained by dividing the annual cost of the system by its annual output. The total annual cost c_{ann}, including both capacity (capital investment) and operation and maintenance costs, is according to the annuity relation for writing off investment capital:

$$c_{ann} = C_{cap}\left(r_{O\&M} + \frac{r_{int}}{1-(1+r_{int})^{-N}}\right) \tag{1}$$

where C_{cap} is the capacity cost, $r_{O\&M}$ the annual cost of operation and maintenance (O&M, as percentage of C_{cap}), r_{int} the real interest rate (per year), and N the economic system lifetime (in years). We assume that $r_{O\&M} = 2\%$, $r_{int} = 5\%$, and $N = 25$ y.[7] Table 2 depicts the electricity costs of both stand-alone PV systems and grid-connected PV systems, in relatively sunny and cloudy climates (implying different annual electric outputs or yields, expressed in kWh/W_p, see the calculations shown in Table 4), obtained by assuming the lower values of capacity costs as displayed in Table 1 and by using Eq. (1).[8]

The value of PV electricity is the cost of the electricity production that would be avoided by the use of PV. Table 3 lists the principal present power technologies and indicates, roughly, which ones are likely to constitute competitors for grid-connected PV, by virtue of both cost and availability (dispatchability). We consider only grid-connected systems, because of the high cost of battery storage. The grid obviates the need for storage, as long as the PV capacity does not exceed the percentage of total installed capacity that can readily and economically be dispatched when the sun fails to shine.

Since PV is dependent on intermittent solar irradiation, during daytime only and centered around noon, it is generally not fit for base or intermediate load electricity

[3] These (conversion) efficiencies are the fraction of the incident solar power that is transformed into electricity.

[4] PV system *prices* (on commercial markets) are generally some 20–40% higher than PV system *costs* (of fabrication), since the former also reflect design and installation costs, as well as a profit margin. In the remainder of this paper, we will only present values for PV (fabrication or manufacturing) *costs*.

[5] PV capacities are expressed in watt-peak (W_p), the maximum capacity a given module can reach when the incident solar radiation is 1000 W/m^2. All costs (and prices) are in principle expressed in US\$(2000), in short \$.

[6] BOS costs are determined from BOS prices, while present BOS prices are derived from the difference between complete PV system prices (5–10 \$ per W_p) and PV module prices (3–6 \$ per W_p). The resulting present BOS costs (2–5 \$/W_p) can be expected to fall to 1–4 \$/W_p in the near term.

[7] An economic system lifetime of 25 years is, especially for stand-alone systems, assumed to be at the high side of what is technically feasible.

[8] As with capacity and electricity cost differences resulting from variations in a number of relevant factors as shown in Tables 1 and 2, differences may occur as a result of whether PV systems are installed in a centralised or distributed composition. These are not further analysed here.

Table 2
Electricity costs for four PV technologies, for the lower limit of the capacity cost range in Table 1, in relatively sunny (2.0 kWh/W_p) and cloudy (1.5 kWh/W_p) climates

Electricity costs (¢/kWh)	Annual output			
	Stand-alone		Grid-connected	
	2.0 kWh/W_p	1.5 kWh/W_p	2.0 kWh/W_p	1.5 kWh/W_p
Single crystalline silicon and multi-crystalline silicon	22.7	30.3	13.6	18.2
Amorphous silicon and other thin film	18.2	24.3	9.1	12.1

Table 3
Alternative power technologies and degree to which they could be replaced by PV

Technology	Competitor for PV	Comments
Hydropower	Yes	Except for sites with strong seasonal constraints on water flow, hydropower can offer complete flexibility for dispatching (unless high capital cost necessitates maximal utilization). But costs and dispatchability can vary greatly from site to site.
Simple gas turbine, gas-fired	Yes	Usually the least expensive technology for peak loads.
Simple gas turbine, oil-fired	Yes	Well suited for peak loads.
Combined cycle, gas-fired	Marginal	Fairly capital intensive, suitable for base and intermediate loads, but less for peak loads.
Steam turbine, oil-fired	Marginal	Capital intensive, suitable for base and intermediate loads, but less for peak loads.
Steam turbine, coal-fired	Marginal	Very capital intensive, suitable for base and intermediate loads, but not for peak loads.
Nuclear energy	No	Much too capital intensive for peak loads.
Wind energy	No	For optimal cost-effectiveness all produced electricity must be sold, hence no control over availability.

production[9]. Because peak loads, on the other hand, are best provided by low capital intensive electricity sources, technologies that are both dispatchable and of low capital intensity are likely to be PV's main competitors. For example, the simple gas turbine has low capital costs (but high fuel costs) and is therefore attractive for peak loads. The other extreme is nuclear power, very capital intensive and therefore uneconomical for peak loads and in most cases also for intermediate loads.

The costs of the alternative competitive technologies are the result of the complex interplay between supply and demand, possibly subject to additional considerations such as the pollution emitted by power plants. Several methods exist for estimating the costs of presently employed energy technologies. The first method is to simply take the actual hourly cost data of real utility grids, if they are available. In the second method, by contrast, the hourly electricity costs are calculated via a detailed analysis of the various cost components (mainly capacity, operation and maintenance, and fuel costs) for each technology, together with assumptions about the technology mix involved and the load distribution of the utility grid. With either method one needs to extrapolate these costs into the future, to the time frame of interest.

The first method is used here, since it is rather straightforward, and hourly cost data for a fairly typical utility

[9]The considerations are very different for another intermittent energy source, wind, which provides intermittent baseload power because the wind can generally blow at any time of day and year.

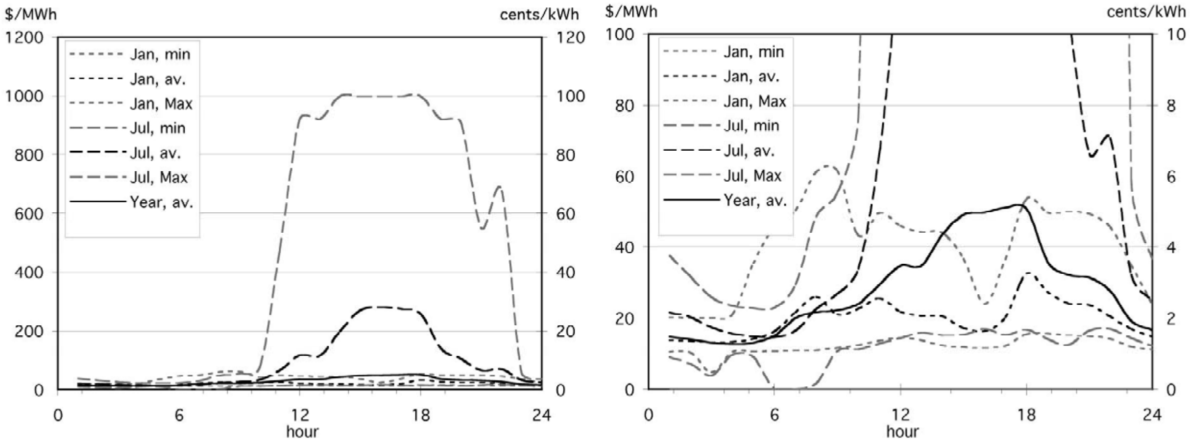

Fig. 1. Diurnal cost profiles obtained by averaging the cost for each hour during January, during July and during the entire year (black lines, solid and dashed); the grey lines (dashed) show highest and lowest costs for these periods. Because of the wide range we show the same data on two scales (0 to 1200 \$/MWh, left, and 0 to 100 \$/MWh, right).

grid, that of Pennsylvania during the period 1999–2000, happen to be readily available (PJM, 2000). Choosing this case is reasonable, because the Pennsylvania technology mix is typical of industrialised countries, and the load pattern has a strong summer peak due to air conditioning—a common situation in sunny regions where PV may well find its primary market in the foreseeable future. To provide a concise summary of the key features of the PJM cost distribution, Fig. 1 depicts the daily cost profiles obtained by averaging the cost for each hour during January, during July and during the entire year. The highest and lowest costs for these periods are also shown. Since these are wholesale costs, they can be compared with the other costs in this paper.

As one can see from Fig. 1, during the peak (daytime July) the cost is very high, up to 1000 \$/MWh, 35 times the annual average cost of 28 \$/MWh. The output of PV is centered around noon, except for climates with systematic cloudiness either in the morning or in the afternoon. Since air conditioning is correlated with solar radiation, the match with the load is fairly good, although not perfect.

Regarding solar radiation, Philadelphia (PA, at 40 degrees latitude) and Bakersfield (CA, at 35 degrees latitude) represent typical sites in, respectively, relatively cloudy and sunny climates. Radiation data for these two locations are obtained from the National Renewable Energy Laboratory (NREL, 2002).[10] NREL provides hourly data for global horizontal and beam irradiation, from which the radiation incident on PV panels can readily be calculated (see e.g. Rabl, 1985, or Goswami et al., 2000). We assume fixed flat panels at a tilt that corresponds to the latitude of the location considered. For the system efficiency we take a nominal value of $\eta_{nom} = 10\%$. To account for the variation with temperature, we assume that the real system efficiency is:

$$\eta = \eta_{nom} - 0.001\,(T - T_{av}) = 0.10–0.001\,(T–T_{av}), \qquad (2)$$

where T is the ambient temperature, and T_{av} the annual average of T (12 °C for Philadelphia and 19 °C for Bakersfield). The monthly average output, in $kWh/(m^2 \cdot day)$, of a PV system with these specifications and using these NREL data, is plotted in Fig. 2, together with the corresponding cost of alternatives for the PJM grid. From Fig. 2 one can conclude that when the maximum in electricity cost is reached, during the summer month of July, the monthly average output of PV electricity is also at a maximum (which lasts from late Spring to early Fall). But the match between PV and loads is not perfect: cooling loads persist well into the evening, and the peak cooling loads are likely to occur on days with high humidity and somewhat reduced insolation.

The results for the annual PV output and PV value are shown in Table 4. The average value of PV output, 37.4 \$/MWh in Philadelphia and 38.3 \$/MWh in Bakersfield, is higher than the average (24 h, 365 days) cost of alternatives of 28.2 \$/MWh because the value of electricity during daytime is higher than at night. For the system with the efficiency of Eq. (2) and the PJM cost data, the PV value is 5.65 $\$/(y \cdot m^2)$ in Philadelphia and 7.40 $\$/(y \cdot m^2)$ in Bakersfield. To test the sensitivity of these results to the various assumptions made so far, some additional results are presented. The second data row of Table 4 shows the output if the efficiency were assumed constant at 10%. The smallness of the difference between the corresponding result and the one with Eq. (2) (see first data row) implies that the precise modelling of effects such as the temperature dependence of PV efficiencies is not necessary for the

[10]Typical meteorological year (TMY) data can be downloaded from the website of NREL at http://www.nrel.gov.

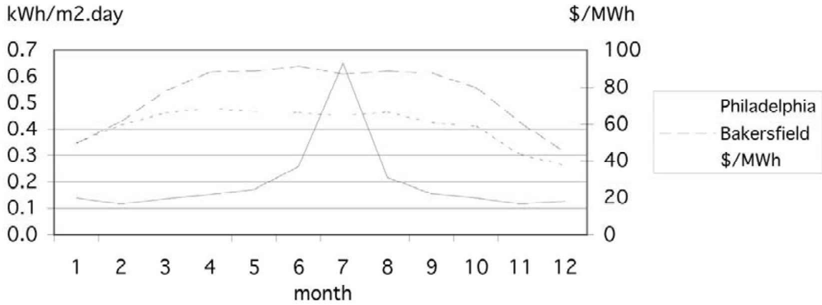

Fig. 2. Monthly average output, in kWh/(m^2·day), of a PV system with 10% nominal efficiency, and the corresponding cost of alternatives for the PJM grid.

present purpose. The last row of Table 4 shows the value for a winter peaking utility, whose cost data are those of PJM but shifted by 6 months. The difference between a summer and a winter peaking utility is not large, about 10% for Philadelphia and 20% for Bakersfield.

To eliminate the dependence on the PV efficiency, it is convenient to express the results in terms of kW_p rather than per m^2. For example, if the nominal efficiency η_{nom} is different from 10%, the output for Bakersfield changes from 193 kWh/(y·m^2) to:

$$Q_{m^2} = 193\ \mathrm{kWh}/(\mathrm{y} \cdot \mathrm{m}^2) \times (\eta_{nom}/0.1).$$

Since the unit kW_p is based on an irradiance of 1 kW/m^2 on the PV panel under consideration, the area per W_p is:

$$QW_p = 1\ \mathrm{m}^2/(\eta_{nom} \cdot 1000\ W_p),$$

so that, with $\eta_{nom} = 0.1$, the corresponding area is 10 m^2/kW_p. Hence, the output for Bakersfield is:

$$QW_p = 193\ \mathrm{kWh}/(\mathrm{y} \cdot \mathrm{m}^2) \times (\eta_{nom}/0.1) \times 1\ \mathrm{m}^2/(\eta_{nom} \cdot 1000\ W_p) = 1.93\ \mathrm{kWh}/(\mathrm{y} \cdot W_p).$$

As a last point, we need to extrapolate the value of PV to the time frame of interest. Perhaps the best guide is a look at historical trends. As one can see from data provided by EIA (2002), the average retail price of electricity in the USA was 57 $/MWh, in constant $ of 1992, at the beginning of the seventies. During the oil shocks, it increased to a maximum of 88 $/MWh. Since 1982, however, it has been decreasing steadily, reaching 60 $/MWh in 1998. Trends for wholesale prices, relevant for the present paper, are comparable. Thus, we find it reasonable to consider that the levelised (i.e. effective average, taking into account the interest rate) value of PV electricity will be within ±20% of 38 $/MWh (see line 6 of Table 4).

4. Costs of environmental damage

Of course, PV offers benefits beyond its value on the market. Low environmental damage is one of the main justifications for promoting solar energy, in addition to supply security, although for the moment (beginning of 2003) the latter is not at the focus of public concern. Environmental considerations have become especially important in the EU which has a stated goal of internalising the external costs of energy, in particular environmental damage. Thus one can expect PV to gain an advantage because of its low damage cost. It is therefore interesting

Table 4
Results for annual output of a PV system with 10% nominal efficiency (see Eq. (2)) and PJM cost data

	Philadelphia, PA	Bakersfield, CA
Output per m^2 per y[a]	151 kWh/(y·m^2)	193 kWh/(y·m^2)
Output per m^2 per y, if $\eta = 10\%$ constant	158 kWh/(y·m^2)	203 kWh/(y·m^2)
Output per W_p per y[a]	1.51 kWh/(y·W_p)	1.93 kWh/(y·W_p)
Value per m^2 per y, η of Eq. (2)[b]	5.65 $/(y·$m^2$)	7.40 $/(y·$m^2$)
Average value of PV per MWh[b]	37.4 $/MWh	38.3 $/MWh
Value per W_p per y[a,b]	0.056 $/(y·$W_p$)	0.074 $/(y·$W_p$)
Value per W_p per y[a] shifted price sequence (winter peak)	0.050 $/(y·$W_p$)	0.060 $/(y·$W_p$)

[a] η of Eq. (2).
[b] PJM cost data.

to present a brief summary and comparison of damage costs for the major energy technologies.

In recent years there has been much progress in the analysis of environmental damages, in particular thanks to the ExternE (External costs of Energy) Project series of the European Commission (ExternE, 1995, 1998, 2000).[11] One of the authors (AR) has been one of the principal participants in all phases of ExternE. The damage cost estimates in these various publications are not always the same because the methodology has been evolving. Here we use the numbers of Rabl and Spadaro (2001), which are typical results for power plants in the EU, based on ExternE (1998). The damage costs of ExternE (2000) for particulate matter (PM), nitrate aerosols and sulphate aerosols are about 0.6 times, and the ones for global warming about 0.08 times those of ExternE (1998). These changes are a reflection of the uncertainties of damage costs, especially large for the cost of global warming which depends not only on scientific input but also on ethical choices such as the intergenerational discount rate and the value of lives that could be saved.

Being sceptical of the more recent numbers, we continue to cite the larger numbers published in 1998. For global warming there is another reason for considering the higher number. The EU and most other industrialized countries have committed themselves to the Kyoto protocol. The cost of its implementation is high. In Germany, for instance, it has been estimated at about 20 $ per tonne of avoided CO_2 (Fahl et al., 1999), probably with similar numbers for many other countries. Assuming 20 $ per tonne of avoided CO_2, while a typical current coal-fuelled power station emits about 800 g/kWh, boils down to an implementation cost of some 1.6 ¢/kWh. This implies that in Germany the relevant avoided cost is this value rather than the real damage cost, whatever it may be. This value is much closer to the global warming damage cost of ExternE (1998) than to the one of ExternE (2000).

4.1. Methodology

To evaluate the impact and damage cost of a pollutant, one needs to carry out an impact pathway analysis, tracing the passage of the pollutant from the place where it is emitted to the affected population. The principal steps of this analysis can be grouped as follows:

- Emission: specification of the relevant technologies and the environmental burdens they impose (e.g. kg of NOx per TWh emitted by a power plant, for specific site and stack height);
- Dispersion: calculation of increased pollutant concentrations in all affected regions (e.g. incremental concentration of ozone, using models of atmospheric dispersion and chemistry for ozone formation due to NOx);
- Impact: calculation of the dose from the increased exposure and calculation of impacts (damage in physical units) from this dose, using a dose–response function (e.g. additional cases of asthma due to this increase in ozone);
- Cost: monetary valuation of these impacts (e.g. multiplication by the cost of a case of asthma).

The impacts and costs are summed over all impact types and receptors of concern. For air pollutants from fossil fuels (other than globally dispersing greenhouse gases) the geographic range usually extends over many hundreds of km. The entire fuel chain (or fuel cycle) is evaluated and compared on the basis of delivered end use energy. For the fossil fuel chain most of the damage cost arises from combustion in power plants. For nuclear and renewable energy (with the exception of biomass combustion), by contrast, most of the impacts arise upstream and downstream from the power generation.

4.2. Damage cost per kg of pollutant

Damage costs per kg of pollutant for typical power plant emissions under European conditions are presented in Table 5. Some indication of the variability with site and stack conditions (exhaust height, exhaust temperature, exhaust velocity) is given in the notes under the table.

Table 5
Typical damage costs per kg of pollutant emitted by power plants in Europe. Source: Rabl and Spadaro, 2001

Pollutant	Impact	Cost (€/kg)[a]
PM_{10} [b] (primary)	Mortality[d] and morbidity[e]	15.4
SO_2 (primary)	Crops, materials	0.3
SO_2 (primary)	Mortality and morbidity	0.3
SO_2 (via sulfates)	Mortality and morbidity	9.95
NO_2 (primary)	Mortality and morbidity	small
NO_2 (via nitrates)	Mortality and morbidity	14.5
NO_2 (via O_3)	Crops	0.35
NO_2 (via O_3)	Mortality and morbidity	1.15
VOC[c] (via O_3)	Crops	0.2
VOC (via O_3)	Mortality and morbidity	0.7
CO (primary)	Morbidity	0.002
CO_2	Global warming	0.029

[a] Variation with site and stack conditions: 1) No variation for CO_2; 2) Weak variation for secondary pollutants: factor of ≈0.5 to 2.0; 3) Strong variation for primary pollutants: factor of ≈0.5 to 5 for site, and ≈0.6 to 3 for stack conditions (up to 15 for ground level emissions in big city).
[b] Particulate matter with diameter below 10 μm.
[c] Volatile organic compounds.
[d] Premature deaths.
[e] Illness.

[11] Since the damage costs presented here are from European origin, we show them in euro, €(2000) and euro cents, ¢(2000); at the current exchange rate € and $ are nearly equal.

Table 6
Emission of air pollutants for typical European fossil power plants. ‘Current’ corresponds to typical emissions of existing fossil plants in the USA and France in 1995; ‘new’ refers to estimated emissions of large new power plants built in the EU since January 2000

Emissions (g/kWh)	PM_{10}	SO_2	NOx
Coal, current	0.15	6	3
Coal, new	0.06	0.30	0.50
Oil, current	0.15	6	1.4
Oil, new	0.07	0.40	0.60
Gas, current	negligible	small[a]	1.1
Gas, new	negligible	small[a]	0.2

[a] SO_2 emission depends on composition of natural gas; in most cases it is negligible.

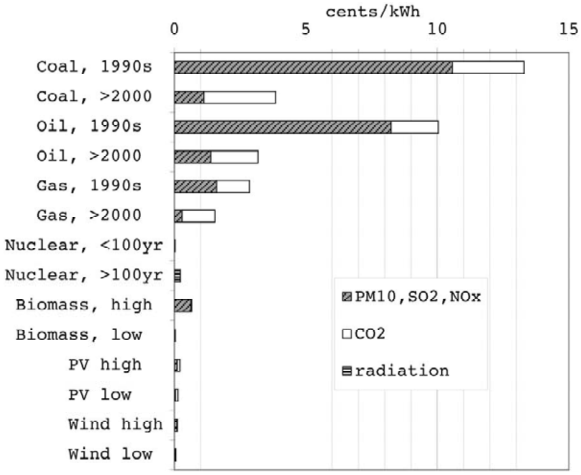

Fig. 3. Comparison of damage costs, for fuel chains in the EU, with costs (€/kg) of Table 5 and emissions (g/kWh) of Table 6. ‘High’ and ‘low’ for renewables indicate the typical range of estimates of ExternE (1998). For nuclear only a single technology is shown (French, with reprocessing), but costs are separated into near term and far future. Damage costs for hydro are extremely variable from site to site, but generally comparable to other renewables. For comparison, production cost of base load electricity in EU and USA is around 2 to 4 ¢/kWh.

4.3. Results for fuel chains

Multiplying the cost per kg of pollutant by the emission rates, as depicted in Table 6, one readily finds the pollutant cost per kWh of electricity. However, we warn against the temptation to cite cost/kWh numbers out of context, for instance as ‘the damage costs of coal’. Quite apart from the variation of impacts with the site of an installation, the very term ‘fuel chain’ is misleading, because it suggests a simple monolithic system while the reality is a chain whose elements can consist of a variety of different processes and technologies at different sites, emitting very different rates of pollution. Furthermore, thanks to ever more stringent environmental regulations, there has been a continual reduction of specific emissions (in the EU by a factor of 3 to 10 during the past decade, except for CO_2, for which reductions have been smaller). To illustrate this point we list in Table 6 the measured emissions of PM_{10}, SO_2 and NOx, for typical fossil plants in the USA and France during the 1990s, as well as estimated emissions for large new plants built in the EU after January 2000.

The damage costs are plotted in Fig. 3, showing separately the costs due to the classical air pollutants (PM_{10}, NOx and SO_2), due to global warming (including upstream emissions of CO_2 and CH_4, expressed as CO_2 equivalent), and due to radionuclides. It is interesting to note that the damage costs for existing oil and coal fired power plants are very large, larger than the current production costs of electricity, of about 2 to 4 ¢/kWh.

The number for nuclear energy is based on the current technology of France, including reprocessing (ExternE, 1995). It comprises the impacts over the entire globe and a time horizon of 100,000 years. Assessments for other countries have found roughly comparable results (ORNL/RFF, 1994; Rowe et al., 1995; ExternE, 1998). The damage costs for nuclear energy are an upper bound because they correspond to a zero effective discount rate (= discount rate minus escalation rate of costs). Because of the uncertainties and controversies surrounding intergenerational discounting, we show separately the costs imposed in the near term (first 100 years) and in the far future (beyond 100 years). For nuclear energy, the numbers cover all stages of the fuel cycle, including waste disposal, as well as major accidents. Still, any estimate of the latter two items remains controversial.

Even though the uncertainties are large (Rabl and Spadaro, 1999), the results provide substantial evidence that the classical air pollutants (particles, NOx and SOx) from fossil fuels impose a heavy toll, in addition to the cost of global warming. The damage costs are especially large for coal. Even with new technologies the damage costs for coal may be comparable to the price of electricity. For natural gas, the damage costs are about a third to a half of those for coal. The damage costs of nuclear are small (at most a few %) compared to the price of electricity, and so are the damage costs of most renewable energy systems. If damage costs were internalised, the results in Fig. 3 imply that PV would gain a cost advantage of the order of 1 to 4 ¢/kWh relative to fossil fuels, and more so for older plants. In view of the increasing use of natural gas, and since the other main competition for PV is hydropower, the lower range will probably be more relevant for the future, i.e. about 1 ¢/kWh.

With 1 ¢/kWh and an output of 1.5 to 2.0 kWh ($W_p \cdot y$) during 20 to 25 years, the damage cost avoided by PV is 0.3 to 0.5 $\$/W_p$ if the discount rate is zero. Discounting at a reasonable social discount rate of about 5% reduces this by a factor of about 0.6 to 0.7. Hence we assume that the credit for avoided damage costs amounts to about 0.25 $\$/W_p$, the number we will use in Table 7.

5. The potential of cost reductions

Cost (and price) reductions for PV modules and systems can be evaluated in a number of ways.[12] First, cost reductions can be evaluated through a detailed technology assessment and an analysis of manufacturing costs as a function of technological improvements (WEA, 2000). By investigating the cost reductions that correspond to likely technical innovations in the various PV system components, one can arrive at estimates for their future expected cost levels. Second, cost reductions can be assessed through the learning curve methodology (IEA/OECD, 2000). With learning curves, the experience gained with a certain technology is expressed as learning rate, i.e. the percentage at which the unit cost decreases with every doubling of cumulative production. Learning curves are usually expressed as:

$$c_t = c_0\,(n_t/n_0)^{\alpha}, \tag{3}$$

where c_t is the unit cost at time t, c_0 the unit cost at time 0, n_t the cumulative production at time t, n_0 the cumulative production at time 0, and α the learning elasticity parameter. With every doubling of cumulative production, costs decrease to a value expressed as the initial cost multiplied by a factor called the progress ratio pr (=1−learning rate):

$$\mathrm{pr} = 2\alpha. \tag{4}$$

Costs that fall according to learning curves have been found for a wide range of industries, including energy production, and learning rates have been determined for them (see, for example, McDonald and Schrattenholzer, 2001). Learning curve data for PV module prices, for the years 1976–1999, are shown in Fig. 4. By plotting these data on a double logarithmic scale one can directly derive the learning rate from the slope of the graph.

Typical learning rates range from 10% to 30% (although for some technologies values outside this range have been found). A learning rate of 20% (progress ratio of 0.80) is an often-used best estimate future cost reduction potential for a variety of (energy) technologies. Learning rates are based on historic data for technologies that emerged, were commercialized and matured in the past (Grübler et al., 1999). There are many examples of technologies that did not achieve this evolution, but reached an early death in an immature stage of development (e.g. losing out to competing technologies). Hence, it is not guaranteed that the learning rates of PV observed so far will continue to be applicable for future cost evolutions of PV technologies. Still, since a number of technological advancements are at hand that suggest that PV costs will indeed continue to fall, it is likely that further experience will be acquired with PV technologies and that their costs will decrease according to some learning rate over the decades to come.

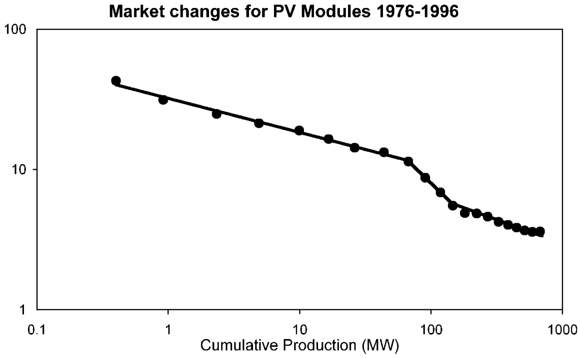

Fig. 4. Learning curve, with different segments, for PV modules between 1976 and 1996. The overall learning rate is about 20% (progress ratio of 0.80). Source: IEA/OECD, 2000.

Fig. 4 shows that PV market changes can be observed when one distinguishes between different segments of the learning curve, and calculates learning rates for each segment. The overall PV learning rate determined from the depicted data, of about 20%, confirms earlier findings that PV module selling prices on the global market followed a learning rate of about 18% between 1976 and 1992 (Williams and Terzian, 1993), as well as results of a 20% learning rate observed on the Japanese market between 1981 and 1995 (Watanabe, 1999).

It is interesting to estimate how large a deployment of PV is needed to reach break-even, defined as the cumulative production at which PV becomes competitive with conventional power plants. Let us assume that current PV systems cost about 5 $\$/W_p$, the average of the grid-connected values given in Table 1, and that, in order to render PV competitive with its conventional counterparts, it has to reach a unit cost of some 1.0 $\$/W_p$.[13] Let us also assume that the (central value of the) progress ratio is 0.80 (80%),

[12] We do not consider, for our assessment of PV cost reduction potentials, an analysis of 'energy payback times', defined as the time required for a PV system to operate after which the electricity gained has reached the level of the energy that was required for the manufacturing of the system (see Alsema and Nieuwlaar, 2000). When the energy payback time of a system is larger than the lifetime of a PV system (which was the case for early PV systems), no net gain is made. Only when the energy payback time is considerably lower than the system lifetime can PV become an interesting energy option (at present, payback times of standalone PV systems vary between 5 and 10 years, while the technical lifetime of a battery is of the same order of magnitude).

[13] Calculations for electricity generation (see Eq. (1)) costs show that capacity costs should be lowered to about this value, if the PV cells are installed in a sunny region, in order to arrive at currently competitive electricity prices (of around 4 ¢/kWh).

Table 7
Effort required for reaching break-even, in terms of cumulative production and cost gap, as function of the learning rate. Source: authors' calculations. Assumptions: current cumulative production $n_0 = 1\ \mathrm{GW_p}$, current unit cost $c_0 = 5\ \$/\mathrm{W_p}$, break-even unit cost $c_b = 1.0\ \$/\mathrm{W_p}$

Progress ratio, pr	0.7	0.75	0.8	0.85	0.9
Break-even PV cumul. production, n_b ($\mathrm{GW_p}$)	23	48	148	957	39,700
Break-even cumul. production (% of 3300 GW, the present world capacity)	0.7%	1.5%	4.5%	29.0%	1200%
Cost of reaching break-even, C_b ($ billion)	37	74	211	1240	46,800
Cost of reaching break-even if unit cost were already at break-even, $(n_b - n_0)\ c_b$ ($ billion)	22	47	147	956	39,700
Cost gap, $C_b - (n_b - n_0)\ c_b$ ($ billion)	15	27	64	288	7110
Cost gap (% of cost of reaching break-even)	41%	36%	30%	23%	15%
Avoided damage of $n_b - n_0$ (at 0.25 $\$/\mathrm{W_p}$, in $ billion)	5	12	37	239	9920
Avoided damage (% of cost gap)	37%	44%	58%	83%	140%

which can be justified by the empirically determined progress ratios given above.[14] Results are shown in Table 7, as a function of the progress ratio. To put the numbers in perspective, we have also expressed them as percentage of the current world-wide power plant capacity, 3300 GW (EIA, 2002). If the learning is better than 20% (progress ratio lower than 0.80), the break-even cumulative production n_b is at most a few percent of this number, which may be acceptable. But should the future learning rate turn out lower, break-even may remain elusive, because it would require an unrealistically large deployment at costs that are not competitive. Note that when the PV capacity is larger than roughly 20% of the total globally installed electric capacity, it must be designed as stand-alone systems, implying that costs get much higher.

The cost of reaching break-even, C_b, is readily calculated by integration under the learning curve:

$$C_\mathrm{b} = \int_{n_0}^{n_b} c_n\,\mathrm{d}n = \frac{c_0}{\alpha+1}\cdot\frac{n_b^{\alpha+1} - n_0^{\alpha+1}}{n_0^{\alpha}}, \qquad (5)$$

in which c_0 is the present unit cost ($5\ \$/\mathrm{W_p}$), α the parameter derived from Eq. (4) (pr being given in Table 7), and n_0 the current cumulative production ($1\ \mathrm{GW_p}$). The results are shown in Table 7, together with the cost of the break-even cumulative production if the unit cost were already at the break-even level. The difference is the cost gap, i.e. the excess cost required to reach break-even. For example, with a learning rate of 20% it is $64 billion of the $211 billion required to reach break-even. The excess cost has to be paid by installations where PV offers sufficient benefit compared to conventional technologies or by consumers who are willing to pay extra for cleaner electricity sources.

The cost gap could also be bridged by government subsidies, but experience shows that subsidies are problematic: they tend to distort the market and lobbying groups make them difficult to remove when they are no longer justified. A more promising approach, that can achieve the same objective, would be to require utility companies to have a specified minimum percentage of PV in their generating mix; the extra cost would be passed on to the consumers. From the perspective of society, the cost of such a measure could be as large as the damage costs that are avoided when PV replaces conventional power plants. As explained in Section 4, we estimate that the avoided damage might be in the order of $0.25\ \$/\mathrm{W_p}$. The damage avoided thanks to PV is shown in the second to last line of Table 7. This of the same order of magnitude as the cost gap, for example at a learning rate of 20% it is $37 billion, well over half of the cost gap. This suggests that a major societal effort to increase the market share of PV can indeed be justified.

Given that current capacity costs can vary considerably, depending on location, type and manufacturer, it is insightful to investigate the value of the cost gap as a function of the current capacity costs. Fig. 5 shows this dependency, again under different assumptions regarding the value assumed for the learning rate, for the ranges of capacity costs as given in Table 1 for grid-connected systems. For central values of the relevant variables, the cost gap that needs to be bridged to reach the PV break-even point amounts to at least some $50 billion. Under less optimistic assumptions, the expected cost gap rapidly increases to levels beyond $100 billion.

[14] Note that in our analysis we apply this progress ratio to entire PV systems, whereas the quoted sources (Williams and Terzian, 1993) and (IEA/OECD, 2000) report progress ratios that in principle apply to PV modules only. A priori, BOS progress ratios are, of course, not necessarily equal to those of PV modules or entire PV systems. Preliminary results from the PHOTEX project (EU, 2002) — designed to understand learning phenomena in more detail and determine progress ratios for PV subsystems — however, seem to indicate that, in the German case at least, the BOS part of PV systems learns as rapidly as the PV module. While this preliminary result may perhaps seem surprising (is there indeed still so much to learn in constructing the balance-of-system?), it validates our choice to use a central value of the progress ratio of 0.80 for the complete PV system.

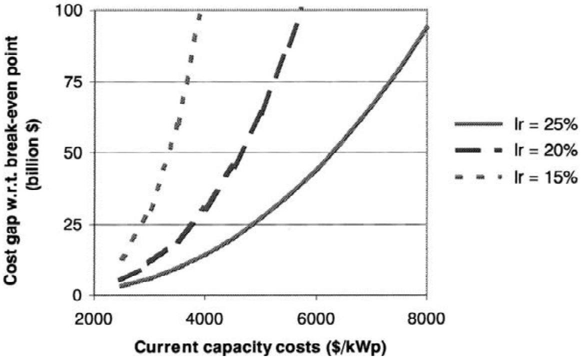

Fig. 5. The cost gap as a function of current unit cost, under different assumptions on the learning rate lr. Source: authors' calculations.

6. Implications for solar energy policy

What does the above imply for solar energy policy making, in particular for photovoltaic electricity? While for many technologies cost reductions according to learning curves have been observed in the past, one cannot be certain that a learning rate automatically applies to the future development of any specific technology, or that the associated cost decreases can invariably be extrapolated over the decades to come. The examples of technologies that perished in an early stage of introduction to the marketplace compel us to bear this caveat in mind. Having considered this uncertainty with a sensitivity analysis of the learning curve parameter, we think that for PV technologies there is ample reason to assume that experience curves based on learning parameters observed so far provide an appropriate means to assess their future cost reductions.[15] Some of the main arguments are that

- PV is today beyond its initial introduction to the energy market and has reached already a point of commercialisation in a range of applications;
- so far, PV cost decreases have been following rather well the learning curve model;
- PV has found sizable niche markets, in which it can be employed in a way that is competitive to current electricity alternatives;
- over the past two decades, the PV market has been expanding by some 15% annually, and recently larger increases have been realised, which provides opportunities for cost reductions as a function of cumulative installed capacity; and
- cost reductions can be expected over the years to come from a technology assessment point of view (WEA, 2000).

Assuming the validity of the learning curve methodology, the cost gap that needs to be bridged to reach the PV break-even point (at which PV can compete with currently available alternatives) is likely to be in the order of 50 billion $ but may well exceed this number, to levels of an order of magnitude of 100 billion $. This is a considerable figure, and should be born in mind in any assessment of policy instruments intended to promote renewable energy, and in any analysis of investments in environmentally friendly energy technologies. Especially for grid-connected applications, PV is still far from being a competitive option, and it still needs to go through a considerable process of innovation before reaching a self-evident advantage among its competitors. It is useful to provide some additional figures to put the cost gap into perspective. The ratio of the break-even capacity and the currently installed capacity (of about one GW_p) is about 150, when the cost gap is assumed to be some 50 billion $, and amounts to many hundreds, when a 100 billion $ cost gap is expected.

From a comparison between the cost gap and current annual PV sales, one sees that, with a continuation of the current global PV investment rate, over two decades are required to reach the break-even point in the former (optimistic) base case, while annual investments should be tripled if the break-even point is to be reached within the coming two decades in the latter (less optimistic) case.[16] The Gross Domestic Product (GDP) of the OECD (including the 30 most industrialised countries) in 2000 was about 25,000 billion $. Compared to this figure, the required PV investments—spread over a couple of decades—amount to a few per million at most of one year of global income.

PV investments offer considerable environmental benefits, especially in those cases where PV can replace fossil fuelled power plants. Since PV is not fit for base or intermediate load electricity supply, it will find its competitors mainly in other peak load energy sources. Among these are in particular supply technologies that are readily dispatchable and/or of low capital cost, such as hydropower, and gas- and oil-fuelled gas turbines. Lesser competitors will be steam turbines and combined cycles, for reasons of cost and dispatchability; nuclear and wind are unlikely to be any competition for PV.

As our Pennsylvania case study has shown, electricity production costs tend to be high during summer months and day-time. One of PV's main advantages is that it is operational during these periods. Since the load pattern in our example has a strong summer peak, due to air conditioning—a common situation in many sunny re-

[15] See, for example, the EU PHOTEX project that has as its main purpose to analyse PV cost reductions through the development of learning curves for both complete PV systems and PV system components (EU, 2002).

[16] In recent years, some 300 MW_p PV has been installed annually world-wide. Supposing an average cost (grid- and non-grid connected) of about 6000 $/$kW_p$, one arrives at an annual global investment in PV of close to 2 billion $.

gions—PV may well find its primary market in this niche in the foreseeable future.

PV would gain a cost advantage of the order of 1 ¢/kWh, or 0.25 $/$W_p$, relative to new fossil-fuelled plants, and more so for older fossil-fuelled plants, if environmental and health damage costs were internalised. Table 7 indicates that with a progress ratio of 0.8 the damage avoided by PV before break-even would be $37 billion compared to the cost gap of $64 billion. These figures indicate that the gains for PV could be considerable, even if they are not sufficient to surmount the expected cost gap. An additional advantage of PV, not quantified here, is to enhance energy supply security.

Expanding the present 1 GW_p of installed PV to a capacity of, e.g. 150 GW_p (while replacing PV systems whose lifetime is completed) requires a major technological transformation and adaptation of current energy infrastructures. The time of such transition processes is expressible in decades, rather than years. Hence, no major changes for PV's global importance are to be expected before about 2020. After that, however, PV could make a real contribution to global energy supply. Today, PV should therefore be included in long-term energy scenarios. Many applications of PV are foreseen, also beyond PV's current use (in e.g. solar home systems, village power systems, grid-connected systems and applications like water pumping, communication, leisure and consumer products), such as associated with air-conditioning, water-heating and the use of building-integrated PV modules. The promotion of PV in a variety of useful niche markets is essential for its required cost reduction and ride down the experience curve.

7. Conclusions

This article has given an overview of the cost and performance of PV and addressed its potential for cost reductions over the first few decades of the 21st century. We have assessed cost reductions that could be expected according to the learning-curve methodology, as well as the investments needed to reach economic break-even. We have investigated the value of extensive PV deployment, in terms of PV replacing other technologies, with which it could compete on the market place. We have also estimated how much PV could gain if external costs (from environmental and health damages) of energy resources were fully internalised, for example via an energy tax. Key results are shown in Table 7.

Our analysis yields four main conclusions:

1. Mainly due to its high costs, PV electricity before 2020 is unlikely to play a major role in global energy supply and carbon emission abatement. PV should nevertheless be included in long-term energy scenarios, since beyond 2020 its contribution to electricity production could become very significant, given its expected cost reductions and the general desire for reduced environmental damage and enhanced energy supply security.
2. Given its presumed learning potential, PV costs are likely to decrease significantly over the coming years, so that a considerable energy supply share from PV world-wide could indeed materialise after 2020. The cost gap that still separates PV from reaching break-even with conventional technologies could be bridged during this time frame.
3. If niche-markets, such as stand-alone applications in remote areas or in consumer goods, are not sufficient for bridging the cost gap, policy measures to encourage the construction of grid-connected PV systems are probably required to realise a long-term large-scale deployment of PV. Such policy measures could be justified in large part, although probably not entirely, by the avoided damage costs. Additional justification comes from supply security; however, to our knowledge no estimates exist of the monetary value of the supply security that PV could bring.
4. Damage costs (external costs) due to pollution emitted by conventional power sources are considerable, especially for older fossil fuelled power plants, and their internalisation, e.g. by a pollution tax, would improve the competitiveness of PV, although probably not enough to close the current cost gap.

The opportunities for PV are large and increased investments in this renewable energy source are most likely justified. A final critical note should still be made. The high investments currently required to render PV competitive could well turn out, in the long run, to result in an overall social saving. The question remains, however, whether these investments should thus now be supported extensively, and if so, whether this support should be materialized through e.g. energy taxes, tax exemptions, renewable subsidies, or other regulations. As for the former question, certain choices now could imply commitments, or technological lock-ins, for the future (for example, new technologies might be developed that prove superior to PV, rendering PV subsidy programs obsolete), so that large PV investments today should be carefully analyzed before implementation. As for the latter question, precisely how to stimulate renewable energy sources is a subject of intricate expert discussion, beyond the scope of this article. At any rate, since PV holds great promise and many desirable qualities, it deserves at least increased attention.

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