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How to judge whether supporting solar PV is justified

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How to judge whether supporting solar PV is justified*

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Abstract

Renewable electricity, particularly solar PV, creates external benefits of learning-by-doing that drives down costs and reduce CO_2 emissions. If eventually commercial, these technologies will thereafter continue to create increasing net social value. This paper sets out a method for assessing whether a trajectory of investment that involves initial subsidies is justified by the subsequent learning-by-doing spillovers and whether it is worth accelerating current investment rates. Given current costs and learning rates, accelerating the current rate of investment appears globally socially beneficial, particularly if that investment is deployed in high insolation locations.

1 The case for supporting PV

Solar PV has been heavily subsidized for many years, and is finally at the point of becoming commercially viable without subsidies in some locations, but new installations continue to enjoy significant, if now much lower, support in many jurisdictions. This paper asks whether past and continued support is justified, and, more fundamentally, how to determine the appropriate level of support now and in the future. While it is easy to present qualitative augments for such support, the practical question is to quantify the level of justified support, and relate it to observable features of the environment. The strongest case is one in which all countries recognize

*This is an updated version of the earlier paper dated March 21 with extensions to computing the spill-over benefits generated by various countries. An abbreviated version of the earlier paper was included as an appendix in Newbery (2017). This paper corrects the original of June 27, 2017 by changing b to be positive to simplify the formula, correcting the Proposition and tables, but otherwise leaving it unaltered.

†Faculty of Economics, University of Cambridge, Director, EPRG. This paper was prompted by Neuhoff (2008), who was pessimistic about the social profitability of PV when its cost was much higher, but noted that increasing current investment might relax constraints on future investment rates, which conferred an additional and potentially large extra benefit. I am indebted to insightful comments from Rutger-Jan Lange.

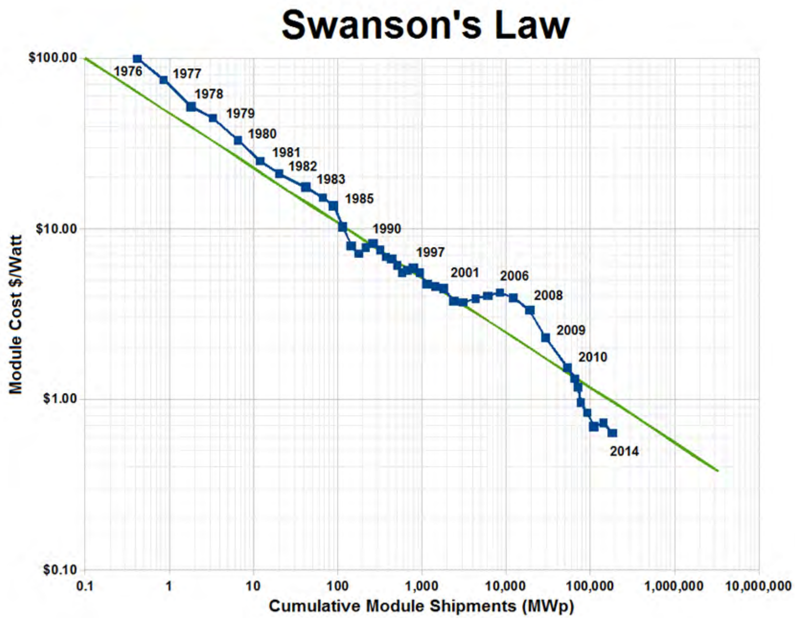

Figure 1: PV Module price reductions

the social value of supporting immature zero-carbon technologies, of which solar PV is a leading example, and collectively subscribe to fund that support. The *Global Apollo Programme* (King et al., 2015) is one of the more recent calls for collective action, and later in the paper we consider possible bases for subscription and allocating funds, should it gain traction.

The case for supporting solar PV (and other immature renewables) is primarily to compensate for the otherwise unremunerated learning spill-overs arising from cumulative production. Each additional installation adds to the cumulative production of solar models, which figure 1[1] persuasively suggests is the prime driver of cost reductions (see also Fraunhofer, 2016).

If technology developers can see a viable market for their products, they will be encouraged to research, develop, test, and, if the results are promising, scale up production and drive down costs. The resulting cost reductions are typically measured by the learning rate – the proportional drop in cost per unit for a doubling of the installed capacity. While there is uncertainty not only about past learning rates (Rubin et al., 2015) but clearly about future rates[2] and even their attribution to deployment or R&D (Jamasb, 2007; Nordhaus, 2014), the learning rates for some

[1] Source: Delphi234 - Own work, CC0, https://commons.wikimedia.org/w/index.php?curid=33955173. The straight green line predicts that modules decrease in price by 20% for every doubling of cumulative shipped modules. The other line (with squares) shows world-wide module shipments vs. average module price. The data are from ITRPV 2015 edition and can be updated to 2015 with ITRPV (2016).

[2] Which may be better modelled as an assembly of components each of which is subject to different learning rates – see Rubin et al. (2015) and references therein.

technologies like solar PV seem impressive. ITRPV (2016), which as an industry source may be more optimistic, claims a continuation of a 21.5% learning rate for PV modules from cumulative production of 227 GW_p.[3] Fraunhofer (2016) suggests a fairly steady learning rate of 23% since 1980, consistent with (EC, 2009), which reports a steady learning rate of 22% for PV since 1979. These figures are consistent with Rubin et al. (2015) for one-factor models that attribute all cost reductions to deployment (mean 23%, range 10-47%), while two-factor models that separately identify R&D lower this figure to 18% (range 14-32%) (Rubin et al., 2015, table 1). To the extent that R&D is induced by the market for the product, demand for new PV installations will amplify the direct deployment benefit via the induced R&D, and make the overall spill-over closer to the one-factor learning rate of 20-23%. The 2015 annual rate of PV installation was 50 GW_p or 28% of the installed base, which alone could cause an annual cost reduction of 6%.

The solar PV market is intensely competitive, making it hard for PV manufacturers to capture these learning benefits, which primarily benefit subsequent installations. Patents and licenses provide some protection of innovations, but this is a distortionary way of rewarding producers, as the planet benefits from reducing emissions earlier, providing a strong case for making these technologies available without a license fee to encourage their take-up and resulting climate change mitigation. Deployment (and R&D) support is therefore preferable to hoping that license fees and an unsupported market would lead to optimal production.

The second case for supporting solar PV (and all low-carbon technologies) is that even in countries that have an explicit carbon price, such as the European Union with its Emissions Trading System, that price is well below any plausible estimate of the social cost of carbon - the present value of the future damage caused by a higher stock of greenhouse gases (Dolphin et al., 2016; US EPA, 2016). If the carbon price-setting mechanism or carbon tax cannot be reformed in a way that provides adequate assurance to investors in low or zero-carbon technologies, one natural solution is to offer long-term contracts with an explicit element for the carbon abatement value. Other policies, such as the Carbon Price Support (CPS, as in Britain)[4] combined with an emissions performance standard that discourages investment in carbon-intensive generation may provide sufficient investment assurance. Subsidizing the output of low-carbon generation by the short-fall in the efficient price set by more carbon-intensive generation may be a more accu-

[3]Subscript $_p$ refers to peak output; average output can be above 25% in favoured locations like the South-West of the US, or as low as 10% in Northern Europe (ITRPV, 2016; EPRI, 2016). In figure 1, from data in ITRPV (2016), the green line shows Swanson's law, a 20% decrease in price for every doubling of cumulative shipped photovoltaics. The blue line shows actual world wide module shipments vs. average module price, from 1976 ($104/Wp) to 2015 ($0.58/Wp). Prices are in 2015 dollars. The actual decrease has been slightly greater than a 20% decrease with each doubling.

[4]The CPS raises the cost of CO_2 emissions from electricity generation up to a pre-specified level. The additional carbon tax (added to the ETS price) was set at £14.86 per tonne CO_2 for 2016/17 (HoC, 2016).

rate short-run price signal but likely lacks credibility to make long-lived low-carbon investments bankable at justifiably low interest rates.

2 Learning-by-doing cost reductions for PV

The one-factor learning model has the unit cost at date t, c_t, given by

$$c_t = aK_t^{-b}, \text{ so } \frac{\Delta c}{c} = (1 + \Delta K/K)^{-b} - 1, \tag{1}$$

where K_t is cumulative production of the units to date t, and b measures the rate of cost reduction. The learning rate, λ, is the reduction in unit cost for a doubling of capacity, so setting $\Delta K = K$ in (1), $\lambda = -\frac{\Delta c}{c} = 1 - 2^{-b}$. For $\lambda = 22\%$, (ITRPV, 2016) $b = 0.358$. The factor b can then be used to estimate the future unit cost from (1). Over longer periods of time, it is implausible to assume that learning rates can continue until costs fall almost to zero. Equation (1) can be modified to allow for an irreducible minimum production cost, c_m:

$$c_t = c_m + aK_t^{-b} = c_m + (c_0 - c_m)(\frac{K_t}{K_0})^{-b}. \tag{2}$$

Initially, $\Delta c/(c - c_m) \simeq \Delta c/c$, and the estimated learning rate will not be much affected by this change, but at lower costs the difference can become appreciable.

2.1 Predicting unit costs

ITRPV (2016) states that the global average module price in 2015 was US\$ 0.58/W$_p$, and that the installed base at the end of 2015 was 234 GW$_p$.[5] However, the module for large (>100kW systems) in the US and Europe is only 55% of the total system cost (excluding "soft costs"), so the full system cost was then US\$ 1.05/W$_p$ and the assumed system price US\$ 1,090/kW$_p$. The module cost is forecast to fall to \$US 0.26/W$_p$ by 2026 when it will only be 36% of the system costs, which in total fall to 68% of its 2015 value or to US\$ 0.72/W$_p$. This implies that the Balance of System (BoS) costs are projected to remain relatively constant at around US\$ 0.46/W$_p$, although others predict that these costs should fall with experience, R&D and learning.

NREL (2016) gives US cost estimates for the total installed cost of utility-scale installations for Q1, 2016, based on a module price of US\$(2016) of 0.64/W$_p$, and the full system cost, including all the installation, permitting and grid connection costs and (expensive) US labour costs, to give US\$ 1.14/W$_p$ for a fixed-tilt 100 MW array in Oklahoma (the cheapest state, with non-unionised labour). The cost of a one-axis tracking unit there would be US\$ 1.19/W$_p$, and

[5] Prices may be above or below costs. The US data discussed below are built up from cost components and will be higher than costs in China. Properly speaking, the costs relate to a level of cumulative production that would be lower than the end of the year value, so future cost reductions are slightly under-estimated.

tracking is cost-effective given the resulting higher capacity factor (CF, often measured in full hours per year, or kWh/kW$_p$/yr). Installation costs should be lower in countries with lower labour costs as the US labour element is US\$ 0.16/W$_p$. If we take the average module price (rather than the US figure) and halve the US labour cost but estimate for a tracking system, then the 2015 starting value would be US\$ 1.05/W$_p$. From now on we use a learning rate for the whole system, not just the module, and consider different possible values.

Estimates of the levelized cost of energy (LCoE) depend critically on location (insolation) and local installation costs. ITRPV (2016, fig 45) forecasts costs for 2,000 kWh/kW$_p$yr (23% capacity factor, CF, but this appears to be for tracking panels)[6] as US\$ 44/MWh, and this can be achieved in sunny areas of the US. Already some Power Purchase Agreements in the US have been signed for 20 years at less than US\$ 40/MWh (indexed, without "meaningful tax state credits", EPRI, 2016, fn 6). European capacity factors (CFs) are lower and 1,000 hrs/yr or 11.4% CF gives current LCoE costs of US\$ 87/MWh. Estimating capacity factors is not straightforward as it depends not on location, orientation and whether the panels track the sun.[7] The data that can be downloaded[8] suggests lower CFs for fixed-tilt arrays, presumably as it refers to smaller panels, and hence understates utility-scale performance. For the estimates presented below we therefore take the 2015 unit cost as \$1,050/kW$_p$.

2.2 Estimating the spill-over benefits of PV capacity

Investment now lowers future installation costs, and hastens the date at which PV might become cheaper than fossil generation. If we were to take the cost reduction model of (1) or (2) at face value regardless of the rate of investment and hence the rate of growth of experience, then the globally optimal solution would be either to do no further investment (if PV will never be sufficiently competitive), or to accelerate investment at the maximum possible rate, as the cost of delivering learning is lowest when the stock of knowledge is lowest. The cost of doubling cumulative production from 1 GW is far lower than doubling it from 100 GW. In mathematical terms, the optimal solution would be 'bang-bang' – to immediately jump to the optimal cumulative production that delivers competitive PV from here on.

[6] Bolinger et al., (2016) reports that over half the US utility-scale PV installations are tracking. The median CF for all types together in 2014 was 25.7%, and the average was 25.5% with a range from 16% to 30%. Tracking appears to increase CF's by 5.9% in high insolation areas, but clearly increases cost. The main determinant of CF is the global horizontal irradiance.

[7] See http://euanmearns.com/solar-pv-capacity-factors-in-the-us-the-eia-data/ that discusses the very high EIA CFs, which in California exceed 28%. Roof-top arrays are less likely to be optimally aligned, may experience some shading and as a result may have CFs 3% less. For our purposes grid-scale PV CFs are more relevant.

[8] Data can be downloaded from http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/ which gives both irradiance in kWh/m^2/d and in kWh/yr from 1 kW$_p$ panels.

As Neuhoff (2008) cogently argued, this strategy is implausible for at least two reasons. The first is that scaling up PV production capacity takes time, and second, more fundamentally, learning itself takes both experience and time for that learning to disseminate and be incorporated into best practice. Indeed, the two-factor model suggesting the importance of R&D would likely find it hard to discriminate between R&D and the elapse of time for dissemination. It is often remarked that Silicon Valley is more innovative than Japan because of the high turnover of staff carrying their knowledge to competing firms, in contrast to life-time employment practices in Japan that make such people-mediated knowledge transfer less likely.

The implication is that even if current PV investment is not commercially attractive, it may be (globally) desirable to accelerate that investment to the point that absorption becomes an issue and the rate of innovation or cost reduction appears to falter. In practical terms that means looking for the highest plausible rate of growth of cumulative production, and checking that this trajectory of investment in PV is justified – if it has a positive present discounted value (PDV) when properly accounting for the social cost of the fossil generation displaced, including the social cost of CO_2. As a check, it will appear to be socially profitable to accelerate this investment if a small increase in investment now has a positive impact on the PDV of the trajectory, which is an indication that the constraint limiting investment is either industrial capacity to produce, or the fact that further acceleration would no longer deliver the assumed learning spill-overs.

This 'constrained optimal' cost trajectory will be determined by the amount of capacity added each year, from which one can estimate the cost of additional units as a function of cumulative *gross* investment (measured in MW_p). Note that the installed stock at any moment will be less than cumulative gross investment as PV arrays only have an estimated life of 25-30 years. Properly computed learning rates should be based on cumulative production of PV modules as in fig.1, not the current installed capacity.

The default trajectory for PV assumed in most of the calculations below assumes a learning rate, $\lambda = 22\%$, $c_m/c_0 = 25\%$ and a growth rate of PV, $g = 15\%$ until 2040, after which the growth slows to that of global electricity and penetration ceases to rise. The assumed growth rate is conservative compared to past rates. Over the period 2010-2015, the growth rate of the top seven countries that accounted for 80% of cumulative installations by 2015 was 44% p.a. (and for the world as a whole was 42%). However, clearly such historic growth rates are unsustainable, and a continued growth rate of 42% for 10 years would reach the same cumulative capacity as a growth rate of 15% for 25 years. Germany, Italy and France (all in the top seven) have experienced declining growth rates in the last five years compared to the previous five, indicating either saturation or support fatigue.

The capacity factor, $h = 2,000$ hrs/yr equivalent to a highish value of 22% and the initial cost

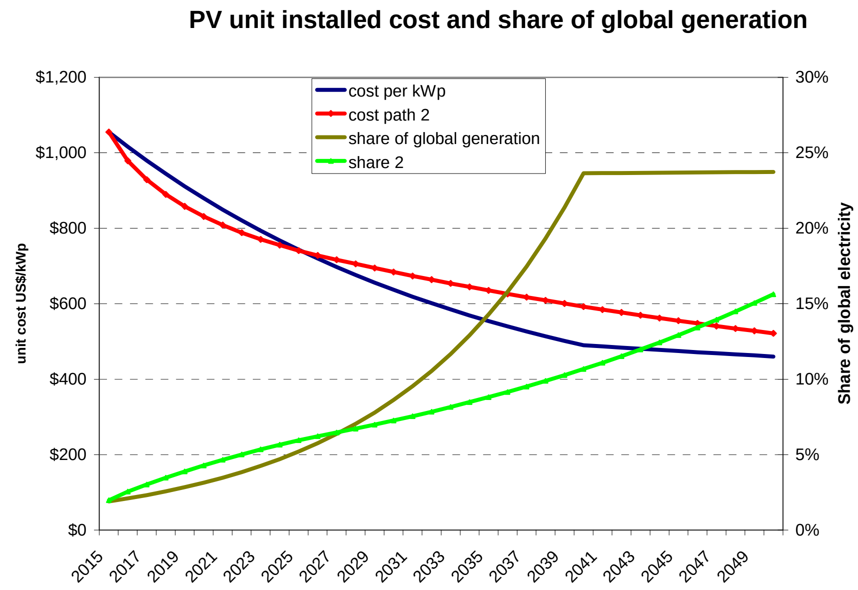

Figure 2: PV system cost and share trajectories

is $\$1,050/\text{kW}_p$. Fig. 2 shows the implied unit system cost and share of PV in global electricity production. The second set of plots (path or share 2) is based on recent projections by ITRPV (2016), which notes that cumulative module shipments were 234 GW by the end of 2015, forecast to rise to 850 GW by 2024. Fig. 2 takes the actual capacity in 2015 as 234 GW (assuming that the earlier capacity now being decommissioned was negligible at that date, and assumes that the installed capacity grows by initially 70 GW/yr rising slowly to reach 75 GW/yr by 2027 and thereafter growing at 5% faster than global electricity. Replacement investment (the actual investment 25 years earlier) raises gross investment above this capacity expansion and it is gross investment that drives cost reductions. Global electricity forecasts are taken from EIA (2016).

3 Modeling the benefits of PV investment

Let y_t be PV output at date t, I_t the current gross investment in PV capacity, whose unit cost is c_t and total cost is C_t, k_t current PV capacity, which degrades at rate δ, and L be its lifetime (assumed to occur before it has fully degraded as other components fail or become obsolete). PV generation is $h_t k_t$, where h_t is the equivalent full hours output per year of PV installed at date t and will depend on location. The rate of PV installation, I_t, grows at rate g until date T. Total accumulated production of PV units is K_t, and this determines the level of accumulated learning to date t according to (2). The amount of age v capacity remaining at t is $I_{t-v}e^{-\delta v}$, $v \leq L$, so if

$\psi(x, T) \equiv (1 - e^{-xT})/x,$

$$\begin{aligned}
I_t &= I_0 e^{gt}, \quad K_t = \int_{-\infty}^{t} I_u du = K_0 e^{gt} = I_t/g, \\
\frac{dk_t}{dt} &= I_t - I_{t-L} e^{-\delta L} - \delta k_t, && (3) \\
k_t &= \int_{t-L}^{t} I_u e^{gu} e^{-\delta(t-u)} du = I_t \psi(g+\delta, L), \ \frac{k_t}{K_t} = g\psi(g+\delta, L) < 1. && (4) \\
c_t &= c_m + (c_0 - c_m)(K_t/K_0)^{-b} = c_m + (c_0 - c_m)e^{-gbt}, \ y_t = h_t k_t. \\
C_t &= c_t I_t = [c_m + (c_0 - c_m)e^{-gbt}] I_0 e^{gt}. && (5)
\end{aligned}$$

Equation (3) shows that the change in current installed capacity is the current investment, *less* the amount retired that was installed L years before, and the amount that degrades in the current year, and can be derived from the equivalent formulation in (4).

The first question to address when considering whether it is worth subsidizing current PV is to estimate the value of future cost reductions, discounting at the social discount rate, r. Future investment costs are $c_t I_t$, given by (5). The present discounted value (PDV) of the cost of investment at date t, A_t, assuming steady growth until date T,[9] is:

$$A_t = \int_t^T (c_m + (c_0 - c_m)(\frac{K_u}{K_0})^{-b}) I_u e^{-r(u-t)} du,$$

A change in current investment, dI_t, will change all future values of $K_u, u > t$, by dI_t, so the net PDV of the cost of an extra unit of investment at t will be:

$$\frac{dA_t}{dI_t} \equiv n_t = c_t - \int_t^T b(c_0 - c_m)(\frac{K_u}{K_0})^{-b-1} \frac{I_0 e^{gu}}{K_0} e^{-r(u-t)} du. \tag{6}$$

This can be evaluated at date t,[10] replacing I_0/K_0 by g and substituting for c_t:

$$n_t = c_m + \frac{(c_o - c_m)}{1 + r/(bg)} \left(e^{rt} e^{-(r+bg)T} + re^{-bgt}/(bg) \right). \tag{7}$$

The second term in (6) is negative for $t < T$, indicating the benefit of future cost reductions. As a fraction of the reference investment cost, c_0, this spill-over *benefit* at date t is

$$\frac{s_t}{c_0} = (1 - \frac{c_m}{c_0}) \frac{e^{-bgt} - e^{rt} e^{-(r+bg)T}}{1 + r/(bg)}. \tag{8}$$

To give a sense of magnitude, with a learning rate $\lambda = 22\%$, $b = 0.358$, $g = 15\%$, $bg = 5.37\%$, $c_m/c_0 = 25\%$, $r = 3\%$, $T = 25$, at $t = 0$, the learning benefit would be 42% of the cost (and increasing in both the learning rate, λ, and g). The evolution of this spillover is

[9] Continued growth at higher than the overall growth in electricity demand is infeasible, so truncating at date T represents a compromise that understates the spill-over, though for large T the effect will be muted. Similarly a lower average g than the current rate will understate the NPV.

[10] I_u for $u > t$ is unchanged, but I_t is changed.

well-defined as its time derivative is negative for $t < T$, so the benefits were clearly higher in the past, justifying higher subsidies (assuming the whole trajectory is justified). However, the investment cost net of the subsidy is also falling over time for $t < T$, as

$$\frac{dn_t}{dt} = \frac{r(c_o - c_m)}{1 + r/(bg)} e^{-(r+bg)T} e^{-bgt} \left(e^{(r+g)t} - e^{(r+bg)T}\right).$$

The net PDV of the cost of early support per unit was therefore higher, although as the number of units was growing at rate g, the total net PDV of the support cost (ignoring the benefits of subsequent zero carbon generation) was lower in the past and increasing over time. This can be summarised as

Proposition 1 *Both the unit subsidy and the unit net PDV of the support cost decrease over time, while the total net PDV of the support cost increases with time.*

In order to justify this as a subsidy, it must also be the case that the whole trajectory is socially profitable – it is not enough just to be able to reduce future costs if the technology never achieves adequate future success in the market place. That will depend on the value of the fossil fuel displaced, including the carbon benefit. The derating factor of PV, τ, is the amount of derated fossil capacity needed to meet the reliability standard that can be avoided, in total τk_t ($0 \leq \tau < 1$). In winter-peaking systems PV output is zero in peak hours so $\tau = 0$, and the only benefit is the energy and carbon cost avoided. In summer peaking systems (with high air-conditioning load), $\tau > 0$, perhaps as high as 30% with low PV penetration.

If the carbon *price* paid per MWh_e[11] of fossil generation at date t is Γ_t, which developers expect to rise at rate I, and the PV output-weighted annual average extra variable fossil cost (fuel + the excess of the fossil variable O&M over the PV variable O&M *less* any extra balancing costs required to manage the PV) is p_t, both per MWh, then the profit of the PV output is $h_t(p_t + \Gamma_t)$ per year per MW_p PV. Ignoring the spill-over of learning benefits, and granting PV a capacity credit of τP_t per unit of capacity per year, where P is the payment per unit per year for de-rated capacity,[12] the net present discounted cost of a unit investment at date zero when discounting at a commercial discount rate R is:[13]

$$f_0 = c_0 - m_0, \quad m_0 = \int_0^L e^{-\delta u}[h_u(p_u + \Gamma_0 e^{Iu}) + \tau P_u]e^{-Ru} du. \tag{9}$$

[11] Subscript $_e$ refers to the carbon content of the electricity generated. The carbon price is the one the developers face, not necessarily the social cost of carbon, γ_t.

[12] This is most readily determined in a capacity auction, or is estimated as the net Cost of New Entry, net of sales in competitive energy and ancillary service markets.

[13] The assumption is that the developer takes on marketing risk but will be provided with the equivalent of a capital subsidy, e.g. via a fixed price per MWh sold up to 20,000MWh/MW_p. The discount rate is then the weighted average cost of capital given the various contracts for output and capacity designed to minimise the cost of the support.

If p_u and τP_u are constant

$$m_0 = (hp + \tau P)\psi(\delta + R, L) + h\Gamma_0\psi(\delta + R - I, L).$$

If this is positive the investment will need to be subsidized to persuade developers to install the capacity, but if it becomes negative, the developer needs no inducement (other than perhaps a long-term contract to assure the future energy and carbon value; under most capacity market designs the capacity payment would take the form of a long-term contract). This can be evaluated and the results for various parameter values are shown in Fig. 3 below. The examples provided tell us that solar PV is already commercially viable without subsidy in high insolation areas ($h = 2,000$ hrs/yr), but only with an adequate carbon price and reasonably low cost of capital (Fig. 3, col B vs. Col A). In Northern Europe subsidies (or higher energy prices) would still be necessary even with cheap finance and a reasonably high carbon price (Fig. 3, col C).

3.1 Evaluating global learning benefits

One can imagine two possible ways of organizing the *Global Apollo Programme* (King et al. 2015) to deliver the PV deployment programme. The least cost solution would be to concentrate all deployment in locations requiring the least subsidy cost at each moment. This would likely be in the highest insolation areas provided the PV displaced fossil fuels (and the default assumed is gas, but if coal is displaced, as in China, lower insolation could be consistent with low subsidy rates). The more likely alternative is that the *Global Apollo* agreements require each country to undertake its fair share of the subsidy and would likely concentrate support within its own borders, unless some regional pooling could be arranged. One approach would be for the funds collected from each participating country to be allocated by competitive auction, in which case it might be attractive to allow all countries to bid, as this would maximize the installed capacity for the funds collected. The outcome would then be in effect a partially funded but still global programme.

In the first case h would be initially high, but as good sites are preferentially used first, it can be expected to decline over time as less favoured locations are developed when the high insolation areas become saturated, driving down the local wholesale price. The annual average net value of displaced energy, p_t, could also fall as areas of high PV depresses local nodal prices, possibly to the extent of driving prices down to zero in some hours, while the cost of balancing, flexibility services, storage and interconnection increases, again lowering the average fossil displacement value, p_t (Newbery, 2016). Similarly, the value of PV capacity, τP_t, will also fall as additional PV competes less successfully with existing PV. All these elements could be given decreasing time trends:

$$h_t = h_0 e^{-\zeta t}, \quad p_t = p_0 e^{-\pi t}, \quad \tau P_t = \tau_0 P_0 e^{-\xi t}, \tag{10}$$

Figure 3: Profitability of solar PV for various parameters

parameters		A	B	C	D	E	F	G	H	I	J
PV learning rate %	λ	22%	22%	22%	22%	22%	22%	22%	20%	22%	18%
min cost/current PV cost	c_m/c_0	25%	25%	25%	25%	25%	25%	25%	25%	30%	25%
PV annual degradation % p.a.	δ	0%	0%	0%	1%	1%	0%	0%	1%	1%	1%
PV growth rate % p.a.	g	15%	15%	15%	15%	15%	15%	15%	15%	15%	18%
CF kWhrs/kWyr hrs/yr	h	2,000	2,000	1,000	1,200	2,000	1,200	1,000	2,000	2,000	1,200
decline in hrs % p.a.	ζ	0%	0%	0%	1%	1%	0%	0%	1%	1%	1%
WACC for PV % pa	R	7%	5%	4%	5%	7%	7%	5%	7%	7%	5%
displaced net energy value	p	$35	$35	$60	$35	$35	$35	$36	$35	$35	$35
rate of decline of price % p.a.	π	0%	0%	0%	1%	1%	0%	0%	1%	1%	1%
market price CO2 $/MWh	Γ	$5	$2	$10	$5	$5	$5	$5	$5	$5	$5
PV de-rating factor	τ	10.0%	10.0%	0.0%	10.0%	10.0%	5.0%	5.0%	10.0%	10.0%	10.0%
results											
PDV PV market revenues	m	$993	$1,110	$1,058	$654	$861	$587	$611	$861	$861	$654
private value of PV /kWp	f	-$57	$60	$8	-$396	-$189	-$463	-$439	-$189	-$189	-$396
subsidy cost of trajectory	F_0/I_0	-$54,183	-$69,155	-$78,594	$27,706	$1,590	$4,351	$1,875	$6,183	$6,581	$48,341
external value of trajectory	S_0/I_0	$7,379	$13,978	-$1,809	$3,732	$6,220	$4,427	$3,689	$6,220	$6,220	$5,339
social value of trajectory	V_0/I_0	$61,562	$83,132	$76,785	-$23,974	$4,631	$76	$1,814	$37	-$360	-$43,002
social value of increasing I0	dV_0/I_0	$604	$826	$473	$351	$719	$111	$113	$693	$690	$341

so that (9) can be explicitly written and evaluated on constant growth paths:

$$
\begin{aligned}
f_t &= c_t - \int_t^{L+t} e^{-\delta t}[h_0 e^{-\zeta t} p_0 e^{-\pi t} + h_0 e^{-\zeta t}\Gamma_0 e^{It}) + \tau_0 P_0 e^{-\xi t}] e^{-Rt} dt, \\
f_t &= c_t - h_0[p_0 e^{-(\zeta+\pi)t}\psi(\delta + R + \zeta + \pi, L) + h\Gamma_0 e^{-(\zeta - i)t}\psi(\delta + R + \zeta - I, L)] \qquad (11) \\
& \quad -\tau_0 P_0 e^{-\xi t}\psi(\delta + R + \xi, L)].
\end{aligned}
$$

Fig. 3 lists the parameters that are allowed to vary in the calculations reported below. Col A is the base case and individual differences in parameters are highlighted. (In all calculations, $L = T = 25$ years, $r = 3\%$, $I = 0.5\%$, $i = 1.5\%$, $P = \$75/\text{kWyr}$, $\gamma = \$10/\text{MWh}_e$, $\xi = 0$ to reduce the number of variations).

The social benefit of providing this stream of subsidies assumes that the future PV gross profits once the PV costs become competitive with fossil fuel are counted as social benefits. In addition, some of the price decline that affects the commercial viability of PV would not have occurred in the absence of the subsidy programme and so are additional spillover benefits reaped by consumers. The simplest assumption is that without PV, fossil prices would not decline, so all of the price decline is a consumer benefit. The other adjustment to make is that the carbon price that developers face may understate the global social cost of carbon, and the rate at which developers assume the carbon price will be allowed to rise may again differ from that of the social cost. As before, we use capitals to denote the carbon market *price*, Γ, and an expected rate of growth I, and lower case for the social values, γ and i.

The total net social *benefit* of this trajectory, discounting at a social discount rate of r, is then the social gains accruing to other parts, S_0, *less* the cost of the required subsidies, F_0:

$$\begin{aligned} V_0 &= -F_0 + S_0, \text{ where } F_0 = \int_0^T f_t I_t e^{-rt} dt, \text{ and} \quad (12) \\ S_0 &= \int_0^T h_t k_t [(p_0 - p_0 e^{-\pi t}) + \gamma_0 e^{it} - \Gamma_0 e^{It}] e^{-rt} dt. \end{aligned}$$

The PDV of the required unit subsidy, F_0/I_0, is:

$$\begin{aligned} F_0/I_0 &= c_0[(c_m/c_0)\psi(r-g,T) + (1-c_m/c_0)\psi(r-(1-b)g,T)] \\ &\quad -h_0[p_0\psi(\delta+R+\zeta+\pi,L)\psi(\zeta+\pi+r-g,T) \\ &\quad +\Gamma_0\psi(\delta+R+\zeta-I,L)\psi(\zeta+r-I-g,T)] - \tau_0 P_0\psi(\delta+R+\xi,L)\psi(\xi+r-g,T). \end{aligned}$$

The remaining corrective social benefits can also be evaluated replacing k_0/I_0 by $\psi(g+\delta,L)$:

$$\begin{aligned} S_0/I_0 &= h_0\psi(g+\delta,L)[p_0\{\psi(\zeta+r-g,T) - \psi(\zeta+r+\pi-g,T)\} \\ &\quad +\gamma_0\psi(\zeta+r-g-i,T) - \Gamma_0\psi(\zeta+r-g-I,T)]. \end{aligned}$$

The two components of V_0/I_0 and their sum are shown for various parameter values in Fig. 3. (The highlighted values indicate changes from the base case shown in Col A. If $\xi > 0$, all benefits will be somewhat decreased.) The base case shows that while privately unprofitable without subsidy, F_0 is negative, so providing the future fossil savings can be clawed back or counted as social gains, the trajectory has positive social value even ignoring the spill-overs, S_0. Allowing for declining h_t and p_t, ($\zeta = \pi = 1\%$), Col E shows unsubsidized PV unprofitable (at $R = 7\%$) but socially profitable. Lower insolation ($h = 1,200$ hrs) requires a lower market weighted average cost of capital, WACC, ($R = 5\%$) to be socially profitable (Col D). Lowering the learning rate λ, (Col H vs Col E) lowers social profitability, as does raising the minimum PV cost (Col I) in this case making the trajectory unviable, but see section 2.3 below. Rasing the rate of growth, g, can offset quite a large fall in λ, (col J).

3.2 A decentralized *Apollo Programme*

If the funds for supporting PV cannot be directed to developers with the least required subsidy across the globe, then at best regional support programmes could achieve this regionally with some loss of average insolation, lowering the average value of h, but perhaps, through using a wider set of countries, decreasing the rates of cannibalization. We can test this by setting $h = 1,200$ hrs, $\zeta = \pi = \xi = 0$ in (10), and an average value of $\tau = 5\%$, as shown in Fig. 3 Col F. Viability with lower insolation and/or higher rates of cannibalization would require lower discount rates, higher market and/or social carbon prices and/or higher wholesale prices.

3.3 Accelerating investment - deviations from steady growth

The next test is whether it would be desirable to accelerate investment now or delay it. Consider the net benefit of a small increase in initial PV investment, dI_0, leaving future investment at $I_0 e^{gt}$ unchanged. k_0 will be increased by dI_0, and so will k_t, $t < L$, but by diminishing amounts as a result of degradation. k_t, $t > L$, will be unchanged. Future cumulative investment K_t will, however, be permanently raised by dI_0 and so $dK_t/dI_0 = 1$. The net benefit of this small increase can be found by differentiating (12):

$$\begin{aligned}
\frac{dV_0}{dI_0} &= -\frac{dF_0}{dI_0} + \frac{dS_0}{dI_0}, \text{ where} \qquad (13)\\
\frac{dF_0}{dI_0} &= f_0 + \int_0^T I_t \frac{df_t}{dI_0} e^{-rt} dt,\\
\frac{dS_0}{dI_0} &= \int_0^T [h_0 e^{-\zeta u} \frac{dk_t}{dI_0} \{(p_0 e^{-\pi t} - p_0) + \gamma_0 e^{it} - \Gamma_0 e^{It}\}] e^{-rt} dt
\end{aligned}$$

These can be evaluated by noting that I_0 affects all future costs:

$$\begin{aligned}
I_t \frac{df_t}{dI_0} &= I_t \frac{dc_t}{dI_0} = (c_0 - c_m) - b(\frac{K_t}{K_0})^{-b-1} \frac{I_0 e^{gt}}{K_0} = -gb(c_0 - c_m) e^{-g(1+b)t}, \text{so}\\
\frac{dF_0}{dI_0} &= f_0 - gbc_0(1 - c_m/c_0)\psi(r + gb, T). \qquad (14)
\end{aligned}$$

In contrast k_t is only affected for L periods, and $dk_t/dI_0 = e^{-\delta u}$, so

$$\begin{aligned}
\frac{dS_0}{dI_0} &= h_0 \int_0^L [(p_0 - p_0 e^{-\pi t}) + \gamma_0 e^{it} - \Gamma_0 e^{It}] e^{-(r+\zeta+\delta)t} dt, \qquad \text{(dS/dI0)}\\
\frac{dS_0}{dI_0} &= h_0[p_0\{\psi(r+\zeta+\delta, L) - \psi(r+\zeta+\delta+\pi, L)\} + \gamma_0 \psi(r+\zeta+\delta-i, L) - \Gamma_0(r+\zeta+\delta-I, L)].
\end{aligned}$$

The effects of raising the current rate of investment are shown in the last line of fig. 3. Note that while Col I shows the trajectory to be socially unprofitable, raising the rate of current investment would improve social value, so there may be another initially higher trajectory with a positive social value. The implication is that accelerating the rate of investment in PV is globally socially justified in all these cases. More important, a global programme to fund continued investment in solar PV seems socially justified, particularly if it can be located in good resource locations, and evaluated using a sensible carbon price and public sector (low) discount rate.

4 Individual country contributions to the public good

It is possible to compute the value of each country's contribution to reducing future costs by its current and previous investment, either roughly or more accurately. The rough estimate takes the estimated unit cost c_t from (2) and the amount of capacity added in that year, using (8) to estimate the spill-over benefit, but replacing c_0 by c_t, and using the assumed growth rate, g and learning rate, λ. That would considerably underestimate the subsequent growth rates up to 2015 and hence underestimate the present value of the spill-over benefit. Recent cost declines have if anything been faster than average, judging from Figure 1, which might suggest a higher learning rate. However, some of that cost fall may be competitive shading of margins rather than genuine cost reductions, and so there is as yet no compelling evidence that learning is accelerating. Working back from the current cost to earlier costs using (2) might undervalue those costs and hence the learning benefits, again erring on the conservative side. A more accurate estimate would track the evolution of cumulative capacity more accurately instead of assuming a constant global growth rate.

Under the approximate constant growth rate approach, the spill-over benefit per kW_p installed in year t from (6) is $s_t \equiv c_t - dA_t/dI_t$ or

$$s_t = (c_0 - c_m)\frac{(e^{-bgt} - e^{rt}e^{-(r+bg)T})}{1 + r/(bg)}. \tag{15}$$

With the default assumptions that $T = 2040$, $bg = 5.37\%$, $r = 3\%$, $c_0 - c_m = \$788$, and t includes the five years from 2010 (accounting for over three-quaters of cumulative capacity), we can calculate the spill-over value each year and, given the cumulative capacity installed in each country shown in Figure 4,[14] the total spill-over by country in Figure 5 (calculated from the spill-over per kW_p in Figure 4 and the annual increments to capacity).

4.1 Funding a global Apollo Programme

The spill-overs calculated in Figure 5 are substantial and unequally divided, with the top two countries contributing nearly half the subtotal identified. It is interesting to ask how this total sum might have been made available for subsidy support globally under some international agreement along the lines of the Global Apollo Project. Figure 6 shows cumulative emissions for countries accounting for 80% of CO_2 emissions since 1950, and their share in the global total over that period.[15]

If, plausibly, countries were asked to contribute on the basis of their past contributions to the stock of CO_2, then the US might be asked to contribute 25% whereas of the subset of countries in table 2, it contributed 11% of the global spill-over benefits (the table accounts for 80% of cumulative investment). China over-contributes (18% compared to a 14% CO_2 share)

[14] Figures taken from Wikipedia at https://en.wikipedia.org/wiki/Growth_of_photovoltaics. Detailed notes on sources are provided there. Global figures 2012-15 are taken from ITRPV (2016) and for 2010-2011 extrapolated backwards from (incomplete) country totals.

[15] Source: CAIT Climate Data Explorer. 2017. Washington, DC: World Resources Institute. Available online at: http://cait.wri.org

Figure 4: Installed capacity (GW_p) and spillover ($\$/kW_p$)

					GWp cumulative		
Country	2010	2011	2012	2013	2014	2015	shares
China	0.8	3.3	6.8	19.7	28.2	43.5	19%
Germany	17.4	24.9	32.5	35.8	38.2	39.8	17%
Japan	3.6	4.9	6.6	13.6	23.3	34.2	15%
USA	2.5	4.4	7.3	12.1	18.3	25.6	11%
Italy	3.5	12.8	16.5	18.1	18.5	18.9	8%
UK	0.1	0.9	1.9	3.4	5.1	8.9	4%
France	1.2	3.0	4.1	4.7	5.7	6.6	3%
subtotal	29.1	54.1	75.6	107.3	137.2	177.5	76%
Global cumulative capacity	*47.0*	*78.0*	110.0	144.0	184.0	234.0	100%
spillover per kWp	$608	$572	$537	$504	$473	$443	

Figure 5: Spillover value ($ million) per year and cumulative

Country	2010	2011	2012	2013	2014	2015	cumulative	share
Germany	$10,559	$4,279	$4,084	$1,666	$1,151	$693	$22,431	16%
China	$486	$1,429	$1,880	$6,515	$4,010	$6,795	$21,115	15%
Japan	$2,199	$741	$923	$3,513	$4,588	$4,809	$16,773	12%
USA	$1,537	$1,060	$1,552	$2,424	$2,933	$3,244	$12,749	9%
Italy	$2,129	$5,319	$1,958	$817	$183	$206	$10,610	8%
UK	$47	$473	$535	$744	$817	$1,690	$4,306	3%
France	$732	$1,012	$599	$324	$438	$412	$3,517	3%
subtotal	$17,687	$14,312	$11,530	$16,003	$14,121	$17,849	$91,501	66%

Figure 6: Emissions of CO_2 by country and share of total emissions from 1950-2013

country	cum CO_2 1950-2013	share	cumulative share
United States	280,249	25%	25%
China	156,643	14%	39%
Russian Federation	97,243	9%	47%
Germany	56,844	5%	52%
United Kingdom	35,789	3%	55%
Japan	51,470	5%	60%
India	35,049	3%	63%
France	22,941	2%	65%
Canada	24,185	2%	67%
Ukraine	25,591	2%	70%
Poland	19,312	2%	71%
Italy	19,884	2%	73%
Mexico	14,334	1%	74%
South Africa	14,099	1%	76%
Australia	13,968	1%	77%
Korea, Rep. (South)	13,557	1%	78%
Iran	11,856	1%	79%
Spain	11,424	1%	80%

as does Germany (20% compared to 5%) and Italy (11% compared to 2%). The other countries contribute roughly twice as much as their share in global emissions.

A proper global programme would collect funds according to some criterion such as cumulative contributions to the current CO_2 stock (perhaps progressive with GDP/head and cumulative emissions per head as part of the formula) and allocate them efficiently. That would be achieved by an annual auction for the least amount needed to deliver the annual target, payable per MWh delivered up to some total per kW_p installed (e.g. 20MWh/kW_p). That would encourage delivery (i.e. proper installation, connection and maintenance) and allocations to places of high insolation and high avoidable fossil costs. An additional requirement might be an explicit carbon tax or equivalent subsidy to zero-carbon generation.

The decision on the annual amount to auction will need to balance the supply of suitable sites with the manufacturing capacity of the solar PV industry, and would ideally provide credible commitments for sufficiently far into the future to justify building new PV manufacturing capacity. As PV prices fall, the amount of subsidy required will fall below the future value of the spill-overs, although as better sites are used up, the time taken to earn back the installation costs will rise and tend to offset the fall in installation costs.

5 Conclusions

The models demonstrate how to judge whether current and proposed future rates of investment in solar PV are justified, given assumptions about the future prices of fossil fuel and carbon displaced, as well as, critically, the learning rate and discount rate, the projected future growth path and insolation in the supporting countries. In the decentralized *Apollo Programme,* the average insolation will be lower but might change more slowly, and the viability of the *Programme* is more marginal, but even here raising the rate of investment looks attractive. The method here has been applied to constant growth cases as for such there are explicit formulae that allow a study of the impact of changing particular assumptions, but the approach can be readily extended to any projected PV trajectory, such as the second case in Fig 2, using the original formulae with time subscripts and spreadsheets to evaluate the annual values.

Given a more fully reasoned model of how learning disseminates and the role of induced (or planned) R&D, it might be possible to compute the optimal trajectory, which would almost certainly start with higher rates of investment, falling over time as the costs of subsidizing an ever larger investment rise while the future cost reductions decline. In this simplified model, the main conclusion is that accelerating the current rate of investment appears socially attractive under a wide range of assumptions.

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