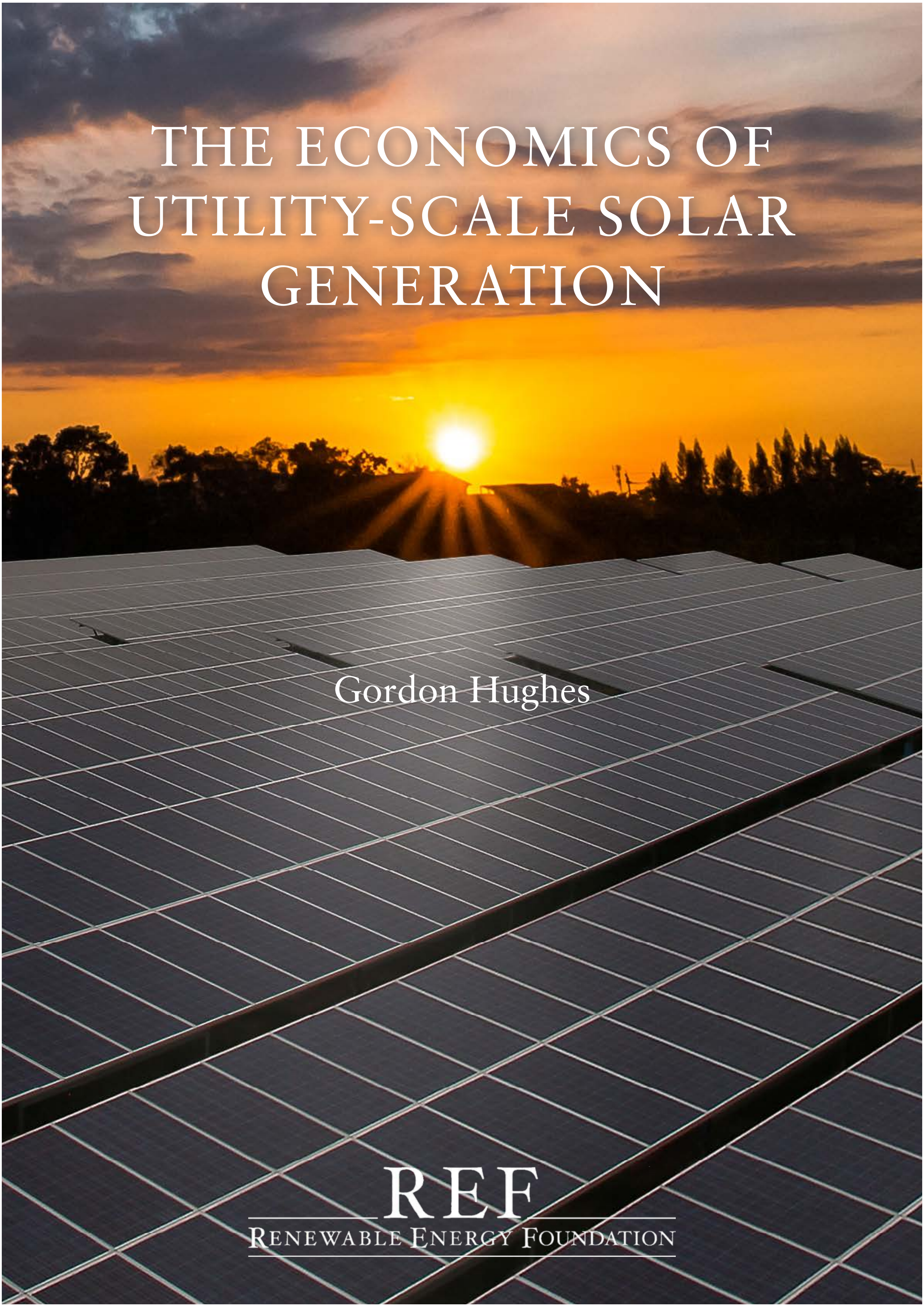

THE ECONOMICS OF UTILITY-SCALE SOLAR GENERATION

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THE ECONOMICS OF UTILITY-SCALE SOLAR GENERATION: SUMMARY

1. Between 2011 and 2020 13.4 GW of solar generation capacity was installed in the UK, two-thirds of it in the years 2014 to 2016 in response to what were seen as generous subsidies. This study uses data from company accounts to examine the actual capex and opex costs of building and operating solar plants. In addition, it examines the relationship between age and the performance of solar plants in both the UK and the US. The results are used to assess the economic viability of solar generation if subsidies are reduced or eliminated completely. The conclusions are strikingly different from the claims or assumptions made by official bodies and industry sources.

2. It is well-known that the cost of solar panels fell sharply during the 2010s. Many have assumed that the overall cost of building solar plants has fallen similarly and, even more important, will continue to fall in future. The data show that there was a 15% decline in the average capex cost per MW of capacity from 2011-13 to 2014-16 and a 10% decline from 2014-16 to 2017-20. The average capex cost per MW was £0.95 million at 2018 prices. The trend in capex costs is consistent with the fall in the costs of solar panels and inverters, but other costs have increased over the period and appear to be affected by a scarcity of equipment and skilled labour. Further falls in the cost of solar panels will only have a limited impact on total capex costs.

3. The average level of opex costs per MW of capacity for solar plants is 3 to 4 times the official assumptions at about £36,500 for a plant in the size category of 10-20 MW. Opex costs are highly variable over time and across plants because of equipment failures and other factors, but the pooled data suggests that they tend to increase with the age of the plant. The estimated rate of increase over time was about 5% per year in real terms. That rate of increase may fall as the industry matures but it would be prudent to assume that opex costs will increase by 2.5% to 3% per year in real terms.

4. There is extremely strong evidence from both the UK and the US that the output of solar plants falls at 1% to 2% per year after age 3 after controlling for the level of solar radiation. The rate of decline in output is higher in the US than in the UK which may reflect differences in maintenance practices or the greater length of experience in the US. If the US pattern prevails in the UK, solar plants reaching the end of their period of eligibility for ROCs will have an expected output for standard weather conditions which is 30% lower than in their early years of operation.

5. The combination of rising opex costs and declining performance means that existing solar plants are unlikely to cover their operating costs once their period of eligibility for ROCs comes to an end after 20 years and they move to operating as merchant generators. Recently, many of the SPVs which own and operate solar plants have changed their accounting assumptions to increase the economic life of their assets from 25 to 35 years. This modification is ill-judged and potentially damaging to investors as the evidence suggests that the economic life of solar assets is unlikely to be significantly greater than 20 years.
6. The breakeven price of electricity for new investment in solar plants is £108 per MWh over a 25-year life under the most optimistic assumptions about opex costs and performance and it is £123 per MWh under more realistic assumptions. These breakeven prices are significantly higher than for onshore wind but comparable with breakeven prices for offshore wind.
7. Solar plants in the UK are not financially or economically viable as pure merchant generators. They require either subsidies or non-commercial power purchase agreements which offer an average offtake price that is at least three times what they could expect to earn by selling at the average day-ahead price over the period 2015-19. Since solar plants have to compete with wind generation for CfD contracts, new investment in solar plants is likely to rely primarily on the willingness of companies to pay much higher than market prices for the electricity that they produce or to make sites and other resources available at below market rates.
8. It should be emphasized that the UK has much poorer solar resources than some other countries in Europe and most states in the US, while both land and skilled labour are expensive in the parts of the UK where solar resources are best. The conclusions of this study about the relationships between operating costs, performance and age are relevant to solar generation in other locations. However, the fundamental determinant of the economic viability of solar plants is the quality of the solar resources. Spending public money to promote solar generation in the UK seems to be a very poor use of limited budgetary resources.
9. The UK Government's Energy Security Strategy published in April 2022 claims that: "The cost of solar has fallen by around 85% over the past decade ... We expect a five-fold increase in deployment by 2035." The first statement is demonstrably false when applied to utility-scale solar plants which account for about 50% of total capacity. The goal of increasing solar capacity by 56 GW would destabilise the grid and impose a burden of up to £10 billion per year on either taxpayers or energy consumers for practically no benefit. It is, of course, a fantasy in practical terms but such fantasies cause enormous damage by diverting resources from addressing the real sources of high energy costs in the next 5 years.

THE ECONOMICS OF UTILITY-SCALE SOLAR GENERATION

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1. Introduction

Between the beginning of 2011 and the end of 2020 the total capacity of solar installations in the UK grew from 0.1 GW to 13.5 GW – BEIS (2022). The increase in solar capacity of 13.4 GW was greater than the increase in onshore wind (10.0 GW) or in offshore wind (9.1 GW) but it has attracted much less attention than wind generation. A little over two-thirds (9.0 GW) of the new installations occurred between 2014 and 2016. From 2017 onwards the rate of new installations slowed greatly because the subsidies offered for solar plants either ceased (the Renewables Obligation) or were reduced drastically (Feed-In Tariffs).

The large majority of solar installations have a capacity of less than 50 kW and can be regarded as non-commercial in the sense that they are not primarily designed to feed electricity into the grid or the distribution network. Such installations accounted for 3.3 GW of total solar capacity at the end of 2020. Small commercial solar installations with capacities between 50 kW and 1 MW accounted for a further 0.7 GW of total solar capacity.

In this study I examine data for 1,135 solar plants with a capacity of at least 1 MW that were registered under one or both of the Renewables Obligation (RO) or the Renewable Energy Guarantees of Origin (REGO) schemes that were administered by Ofgem – Ofgem (2021). Within this group the primary analysis focuses on utility-scale solar plants with a capacity of at least 5 MW. There were 359 solar plants of this size registered with Ofgem: 344 of them are registered under the RO scheme and 15 are registered under the REGO scheme but not the RO. Most of the latter were commissioned after the closure of the RO scheme and are financed by special commercial power purchase agreements.

The total capacity of solar plants with a capacity of at least 1 MW was 6.9 GW at the end of 2020 of which 5.4 GW were commissioned between 2014 and 2016. There were two main schemes which provided subsidies for solar plants of at least 1 MW: (a) Feed-In Tariffs (FITs) for plants of less than 5 MW, and (b) Renewables Obligation Certificates (ROCs) issued to plants registered under the RO scheme for which there was no capacity limit. Solar plants are eligible to bid for Contracts for Differences contracts (CfDs) but there was little interest in doing so up to 2020.

FITs were more favourable for plants of less than 5 MW up to January 2016 after which the level of support was drastically reduced. The upper limit of 5 MW led to the development of a substantial number of solar plants with a registered capacity of just under 5 MW.[1] RO support for ground-mounted solar installations from ROCs was gradually reduced from 1.6 ROCs per MWh in 2013-14 to 1.2 ROCs per MWh in 2016-17. The closure of the RO scheme was initially announced in June 2015 for the end of March 2017, but the closure date was extended in some cases by various transitional provisions. The timings of the reductions in support explain the concentration of new installations in the period from 2014 to 2016.

The primary data examined in this study comes from three major sources which are described more fully in the Appendix. These are: (a) the company accounts filed by Special Purpose Vehicles (SPVs) set up to own and operate solar plants; (b) data on production submitted to the Ofgem Register required as a condition for being awarded ROCs and REGO certificates; (c) data on assets and output submitted by US solar plants to the US Energy Information Agency. This data is similar to the data on onshore and offshore wind generation that I have examined in papers on the costs and performance of wind power in the UK and Denmark – see Hughes (2020a), Hughes (2020b), Hughes (2021).

On the cost side I have analysed data obtained from company accounts for a sample of 301 Special Purpose Vehicles (SPVs) out of a total population of 396 solar plants with a capacity of at least 5 MW registered under the Renewables Obligation (RO) scheme.[2] The main RO scheme for solar plants closed in 2016 and 303 out of the 396 RO plants were commissioned in the years 2014 and 2015. There are a further 8 RO plants that were commissioned between April 2017 and March 2018, most of them in Northern Ireland. Since then 7 utility-scale solar plants were commissioned in 2020 and 2021 (up to end-September) under different financial arrangements. Overall, the 2021 population of utility-scale solar plants in the UK is dominated by plants built during the brief but intensive period of construction driven by the generous subsidies that were available up to 2015.

Reporting rules and filing deadlines for company accounts affect the amount and nature of the opex cost data that can be obtained. Some SPVs take advantage of accounting rules that permit small companies to file abbreviated accounts that do not include an income statement, which means that opex costs cannot be obtained. In addition, the period allowed for filing company accounts was temporarily extended to 12 months during the pandemic. A significant number of SPVs applied for extensions or otherwise did not meet their reporting deadline. Hence, the number of SPVs which had filed accounts by the end of November 2021 (the cut-off date applied) covering at least 6 months of 2020 is much smaller than the equivalent number for 2019. The accounting year in which a solar plant is commissioned has to be excluded from any cost analysis because it is not complete and often includes erratic items. Together these factors mean that opex

1 There are 307 registered plants with a capacity of at least 4.95 MW and less than 5 MW.

2 Not all plants are operated by identifiable SPVs and some of those which are do not report useful accounting data. Because it is difficult and time consuming to collect financial data on a consistent basis, this was collected for 301 plants with a capacity of at least 5 MW.

costs are only available for a maximum of 7 years for plants commissioned in 2013 and for a maximum of 4 or 5 years for most of the plants in the sample.

The consequence is that on the cost side we can observe a snapshot of capital and operating costs in the middle and later part of the decade from 2011 to 2020. It is important to be cautious about drawing conclusions about trends over time or with the age of the plants. Even so, the dataset is large enough to question some of the claims and assumptions that are made by organisations which rely upon claims made by industry sources. In addition, as we shall see, there is a strong indication that real operating costs for solar plants increase with age in a manner similar to what has been observed for both onshore and offshore wind farms.

One important feature of the solar industry is that many of the SPVs are either owned or managed by a small group of investment funds and solar operators. As a consequence, the industry is more concentrated than the onshore wind industry even though the capital cost of entry into the industry is significantly lower. This concentration is reflected in the widespread adoption of accounting assumptions which appear to rely on a rather generous view of the long run profitability of solar plants.

Solar installations differ from wind farms in that there are no technical factors similar to those of blade diameter and hub height that affect the relative performance of different units. There are technical differences between different plants which affect performance but they are much less important than for wind farms. Location, as it affects latitude and solar irradiance, is critical so that solar plants are concentrated in the southern half of England and some favourable locations in South Wales. To enhance the analysis of the relationship between age and performance, output data was collected from the ROC-REGO registry for the full set of 712 plants with a capacity of at least 4.95 MW.

Since data on the performance of solar plants in the UK only covers the initial 5 or 6 years of operation in most cases, I have carried out a similar analysis for US solar plants using data filed by those plants with the US Energy Information Agency. There are many more solar plants in the US than in the UK and a significant number have been operating for more than 10 years, so it is possible to produce more reliable estimates of the relationship between plant age and performance after controlling for weather conditions and other factors.

2. Cost trends reported in other sources

Most US companies are not required to file annual company accounts with a public registry so that it is not possible to analyse US capex and opex costs in a manner similar to the analysis for the UK. Organisations such as the International Renewable Energy Agency (IRENA), the Lawrence Berkeley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL) publish data on the average costs of building and operating solar plants – see IRENA (2021), Bolinger et al (2021), and Feldman et al (2021).

The IRENA costs are estimates of levelised costs which are quite susceptible to apparently minor changes in assumptions. For the UK they claim that levelised costs have fallen from $279 per MWh in 2012 to $111 in 2019. The baseline of 2012 is chosen because this is the middle of the initial phase of solar plant installations in the UK from 2011 to 2013. The large fall of about

60% is completely at odds with what can be found in the actual data obtained from company accounts discussed below.

The LBNL and NREL figures are only for the United States. They use different methodologies: LBNL relies on reported project costs while NREL uses a bottom-up model to generate benchmark costs. The NREL estimates are similar to the LBNL figures after making adjustments for differences in the units used, the type of plants modelled and the size of projects.[3] Both approaches agree that capex costs fell by about 67% from 2012 to 2020. Hence, I will focus on the LBNL cost estimates since they are more relevant to the typical size and type of solar plant built in the UK.

LBNL reports that the median cost of new US plants was \$4.37 million per MW of capacity in 2012 (at 2020 prices) and this fell to \$1.42 million per MW in 2020. The median cost in California was about 40% higher than the US median in 2020, whereas costs in Texas and the South-East were 10-12% lower than the US median. Reported O&M costs fell from \$31,900 per MW of capacity in 2012 (at 2020 prices) to \$15,800 per MW in 2020 which translates to a real decline of 8.4% per year. The O&M costs reported by LBNL are less than opex costs since important items such as leasing charges, property taxes, insurance, grid charges, and corporate overheads have been completely or partially excluded.

In the solar cost benchmarks produced by NREL the largest individual cost item is for solar PV modules. IRENA's index of the global price of PV modules has declined from \$0.91 per W_{DC} in 2012 to \$0.27 per W_{DC} in 2020 at 2020 prices – IRENA (2021), Figure 3.2. Central inverter costs have also fallen from \$0.12 to \$0.05 per W_{DC} – Feldman et al (2021), Figure 6. However, the combined cost of PV modules and inverters only represented 30-35% of the average cost of a 10 MW solar plant in 2020.

Whether expressed in terms of levelised costs or separate capex and opex costs, there appears to be a consensus that the costs of building and operating solar plants fell by 60% or more in the US and the UK from 2012 to 2020. As the cost of PV modules and inverters have fallen, it is trends in the costs of mountings, civil works and other items that are increasingly important in determining whether and how far the average capex cost of solar plants will fall in future. These are items that have not experienced rapid technological change, so that solar plants are likely to experience a variant of Baumol's cost disease with respect to future trends in overall capex costs.[4]

The project data used by IRENA and the US sources only gives a partial picture of the level of and trends in average capex costs for new solar plants. In the next section, I examine an

3 The main NREL capex costs are reported as \$ per W_{DC}, whereas the LBNL costs are reported as \$ per W_{AC}. Costs per W_{AC} are about 35% higher than costs per W_{DC} for utility-scale solar plants. The NREL benchmark for utility-scale project assumes a 100 MW plant with separate costs for fixed tilt and one-axis tracker systems. Tracker systems cost 7-8% more than fixed tilt systems.

4 Baumol & Bowen (1965) pointed out that growth in real wages implies that activities with limited or no growth in labour productivity would become more expensive relative to other goods or services over time. The idea was first applied to services such as the arts, health care and government. It can be generalized to apply to composite goods or assets for which the benefits of technical progress reduce the cost share of components subject to high productivity growth. The consequence is a reversion to the mean level of growth in factor productivity for the economy as a whole. That has been low for nearly 15 years in the UK and there is no immediate prospect of a significant increase in the next decade. It is, therefore, unwise to assume that any decline in the real cost of solar installations – or other renewable generation assets – will persist for a long period.

alternative source of data which is the actual investment costs recorded in and extracted from company accounts for UK solar plants. These figures are definitive because they reflect the costs that have been incurred by developers and which have to be recovered by operating the plants.

3. Capex costs

Most utility-scale solar plants in the UK are operated by companies established as Special Purpose Vehicles (SPVs) which own and operate a single solar plant. The SPVs are required to file annual accounts including a balance sheet and, in most cases, an income account. The accounting notes to the balance sheet always give the historic cost of plant and equipment. Hence, it is possible to obtain the actual cost of developing and building the solar plant from the balance sheet in the company – full details are given in the Appendix.

For the analysis in this study I have constructed a sample comprised of 301 solar plants commissioned between 2011 and 2020 for which SPVs could be identified and their accounts located. Of these plants 242 have a (peak generating) capacity of less than 20 MW and only 13 have a capacity of greater than 40 MW. The original capex cost for the plant can be identified for 288 plants. The largest group of plants for which capex data could not be obtained are projects developed and owned by Octopus Investments who do not report figures for separate developments. There is no reason to believe that plants with missing data are materially different from those for which data could be obtained.

Table 1 – Effects of date of commissioning and capacity on capex cost
(Dependent variable is log[capex cost per MW at 2018 prices])

	Coefficient	*Standard error*	*Z-value*	*Probability*	*90% confidence interval*	
A. Period in which plant was commissioned (base 2014-16)						
2011-13	0.154	0.046	3.37	0.001	0.077	0.231
2017-20	-0.110	0.059	-1.86	0.068	-0.209	-0.011
B. Plant capacity (base 10-20 MW)						
5-10 MW	0.032	0.020	1.60	0.115	-0.001	0.065
> 20 MW	-0.013	0.024	-0.54	0.591	-0.053	0.027

Source: Author's estimates

The initial set of plants commissioned in the years 2011 to 2013 had a higher capex cost than plants commissioned later. This was to be expected as the industry was new so the combination of learning and the development of a supply chain brought down costs by about 15%. The main burst of new construction occurred in the years 2014 to 2016. The average capex cost of plants in the 10-20 MW category built in this period was £1.07 million per MW at 2018 prices. There was a small reduction in the average capex cost per MW for building larger plants. Plants in the smallest 5-10 MW category were about 3% more expensive than plants in the base 10-20 MW category.

The average capex cost for plants commissioned in the years from 2017 to 2020 was about 10% lower than that for 2014-16 holding plant size constant. Apart from the higher costs for the period 2011-13 the effects observed are not statistically significant at the 5% level, let alone the 1% level which should be the minimum required in this case. Thus, in purely statistical terms it is not possible to reject the hypotheses that (i) average capex costs were the same in 2017-20 as in 2014-16, and (ii) average capex costs do not vary with capacity.

The absence of strong evidence for a decline in capex costs in the second half of the 2010s may reflect the relatively small number of plants commissioned in this period and the wide dispersion in their capex costs. If we set aside strict statistical criteria and accept that it is likely that capex costs declined from 2014-16 to 2017-20, the evidence suggests that the rate of decline in the second half of the 2010s was significantly lower than in the first half of the decade.

The average capex cost per MW in 2017-20 for the base size category of 10-20 MW was £0.96 million per MW at 2018 prices. This is nearly twice the estimate of £0.53 million per MW at 2018 prices for a 16 MW plant commissioned in 2025 that is assumed by the Department for Business, Energy & Industrial Strategy (BEIS) for their 2020 report on future generating costs – Department for Business, Energy & Industrial Strategy (2020). Based on the actual data for 2011-20 the likelihood that solar capex costs will fall by 45% from 2020 to 2025 is close to zero. The rate of decline in underlying capex costs was clearly falling rather than increasing. Even a simple continuation of the trend for the second half of the 2010s would imply a reduction of no more than 12% from 2020 to 2025.

Table 2 – Capex cost breakdown for solar plants

(£ million per MW at 2018 prices)

Year of construction	*Total cost*	*PV modules + inverters*	*Residual costs*
2012	1.24	0.88	0.36
2015	1.07	0.51	0.56
2019	0.96	0.47	0.49

Source: Author's estimates

Table 2 shows a breakdown of capex costs for solar plants derived by using the average costs per MW in the sample plus the global series of costs for PV modules and inverters compiled by IRENA and NREL converted from USD to GBP at current exchange rates.[5] This suggests that capex costs excluding PV modules and inverters rose sharply in real terms from 2012 to 2015 and then fell once the construction boom during 2014-16 ceased. The overall fall in capex costs from 2014-16 to 2017-20 was more a consequence of the demand for limited construction resources and skills than of an underlying decline in the costs of building solar plants. Even allowing for

5 The substantial fall in the USD-GBP exchange rate in the second half of 2016 meant that the average cost of PV modules and inverters decreased from 2015 to 2019 much less in GBP terms than in USD terms.

this decline the real cost of items other than PV modules and inverters was higher in 2019 than in 2012. To meet the BEIS forecast it would be necessary for (a) the cost of PV modules and inverters to fall by about 90% in real GBP terms, and (b) other costs to stay constant in real terms. Neither assumption seems plausible, especially if subsidies for utility-scale solar plants were to be reinstated with the goal of stimulating investment in new plants.

In summary, there was a modest reduction in the real cost of developing new utility-scale solar plants in the UK from the early 2010s to the late 2010s as a consequence of the decline in the global costs of PV modules and inverters. Over the whole period capex costs other than PV modules and inverters have increased by about 20% and are clearly sensitive to the level of demand for development and construction resources. While the costs of PV modules and inverters may continue to fall more gradually the scope for further large reductions is much smaller in 2021 than it was when global prices were much higher in 2012.

Another consideration is that variations in site characteristics are likely to become more important in future. As the most favourable sites are developed, costs other than PV modules and inverters may rise and offset any reduction in the costs of PV modules and inverters. In combination these trends suggest that it would be imprudent to expect the capex costs for solar plants in the UK to fall rapidly in future.

4. Opex costs

Commentary on trends in the costs of renewable energy tend to focus on capex costs and to neglect the critical role of opex costs. In part this is because collecting reliable evidence on opex costs is only possible when a significant period of time has elapsed after the original construction of a plant. The allocation of costs incurred in the first year - or even two years - of operation between capex and opex costs is somewhat arbitrary because they may cover one-off items to rectify faults or other problems with the original construction. Many SPVs record exceptional items in their accounts relating to warranty claims against equipment suppliers and installers.

For the longer term, NREL has produced a model designed to estimate operating and maintenance O&M) costs over the life of solar plants – A. Walker et al (2020). The major categories of expense are repairs or replacement of inverters which represents 27% of the present value of predicted O&M costs plus regular asset management (19%) and cleaning (22%). The model uses a reserve account approach in which the account is topped up regularly and then drawn down to cover costs which occur randomly. This method of funding repair costs is not used by SPVs which prefer to expense items as they occur. Almost inevitably this means that operating expenses will increase over time as the cumulative probability of failure increases with either usage or age.

Opex costs are critical because they determine the answer to a key question about solar plants: what is their expected economic life? Some important solar investors and operators in the UK have adopted the assumption that the accounting life of solar assets is 35 years. That may be reasonable with respect to the physical life of the assets but it is likely that their economic life will be much shorter than their physical life. The economic life of any asset is the period over which the expected revenue from operating the asset exceeds the expected operating costs incurred to earn that revenue.

The subsidies for solar generation provided under the RO mean that expected revenues are very likely to exceed opex costs for the first 20 years of operation. However, after 20 years the plants will operate as merchant generators and expected revenues will drop by 60% or more. For the economic life of solar plants to be significantly longer than 20 years opex costs must not be too high nor can they increase substantially over time. Neither assumption can be taken for granted.

To investigate this question I have compiled a dataset of opex costs for all of the SPVs in the capex cost sample which include an income account in their annual accounts – the Appendix provides further details. The sample consists of 1312 observations with a maximum of 272 SPVs reporting data for an accounting year which covers most or all of 2018. Opex costs are converted to 2018 prices using the GDP price deflator as the price index. The sample is dominated by plants commissioned in 2014 and 2015, so the age distribution has the appearance of a wave moving through time. As a consequence it is impossible to distinguish statistically between age and time effects when the data is pooled. To surmount this problem I have adopted the approach developed and described in detail for my analysis of the performance of wind farms in Denmark – see Hughes (2020b), Appendix Section B.

The analysis proceeds by estimating the relationship between opex cost per MW of capacity and plant age, controlling for other influences, separately for each year from 2016 to 2020. These separate estimates are pooled using a method known as seemingly unrelated estimation (SUR) to take account of correlations in errors over both time and geography. In effect, the analysis assumes that the increase (or decrease) in opex costs with age for each year analysed is a draw from an underlying distribution with a mean and standard error that can be estimated. By pooling the estimates for each year and allowing for cross-correlations we obtain an overall estimate of the average rate at which opex costs increase or decrease with age and other factors.

Two variants of the basic model have been examined. The dependent variable in all cases is the log of opex costs per MW of capacity while the primary independent variable is plant age in years. This means that a positive coefficient on plant age gives the proportional increase in opex costs for each year that the plant ages. The data also indicates that opex costs per MW tend to fall with plant size. This is not a surprise as it reflects the role of fixed costs per plant for administration and some operations. However, it is not possible to determine whether the influence of plant size is best captured by plant capacity in MW or the log of plant capacity. Each specification is better for some years but worse for other years, so I have shown the results for both specifications.

The results are shown in Table 3. Depending on the specification used opex costs rose at between 4.7% and 5.2% per year of age after age 1. This is higher than the rate of increase for onshore wind in the UK and a bit lower than the rate of increase for offshore wind. In statistical terms the probability that the rate of increase in opex costs is zero or negative is no more than 1.3% for one specification and only 0.4% for the other specification. The 90% confidence interval for the rate of increase spans the range from 1.6% to 7.8% for the lower estimate. We can be reasonably sure that opex costs increase with age by enough to have a material impact on project economics. Less certain but more important is the prospect that the increase in opex costs is sufficient to drastically shorten the economic life of solar plants. Narrowing the confidence interval by enough to assess this prospect is likely to require data for at least 5 more years. It is not unusual for high initial estimates of such growth rates to fall as time passes and more data is collected, but prudence suggests that any project analyst should assume that opex costs will increase with age at 2.5% to 3% per year. This is similar to the rate of increase observed for the opex costs incurred by onshore wind farms.

Table 3 – Effects of plant age and capacity on opex cost
(Dependent variable is log[opex cost per MW at 2018 prices])

	Coefficient	*Standard error*	*Z-value*	*Probability*	*90% confidence interval*	
A. Equation with log[Capacity]						
Plant age (years)	0.047	0.019	2.48	0.013	0.016	0.078
log[Capacity (MW)]	-0.143	0.033	-4.40	0.000	-0.196	-0.089
B. Equation with Capacity						
Plant age (years)	0.052	0.018	2.84	0.004	0.022	0.083
Capacity (MW)	-0.0070	0.0014	-4.87	0.000	-0.0093	-0.0046

Source: Author's estimates

The two models imply somewhat different patterns for the reduction in opex costs per MW with plant capacity. In the first model an increase in plant capacity from 10 MW to 20 MW reduces costs by 9.5%, while an increase from 40 MW to 50 MW only reduces opex costs per MW by 3.2%. The second model with the linear specification implies that opex costs per MW fall by 6.8% for each 10 MW increase in plant capacity. It seems likely that each specification works fits a part but not all of the full range of plant sizes. Together they suggest that opex costs per MW are 20-25% lower for a 50 MW plant when compared those for a 10 MW plant.

The overall level of opex costs per MW is considerably higher than industry sources appear to assume. The BEIS report on electricity costs cited earlier assumes a total opex cost of £10,200 at 2018 prices per MW for Large Solar plants completed in 2025. This covers O&M, insurance and transmission charges with a reference plant size of 16 MW. The actual opex costs per MW for plants in the size category 10-20 MW was an average of £36,500 per MW at age 1. Allowing a conservative increase at 3% per year of age this translates to an average of £41,800 per MW over the first 10 years of operation or more than 4 times the amount assumed by BEIS. Even if opex costs were to fall as the size of the solar industry grows it is not credible that costs will fall by 75% within 5 years. For example, both insurance costs and transmission charges are fixed by reference to factors that are entirely independent of the solar industry.

These results have a consequence that is critical to the future of investments in UK solar plants. Official data – Department for Business, Energy & Industrial Strategy (2021), Table ET 6.1 - shows that the average value of the annual load factors for solar plants for the period 2016-20 was 11.0%. This covers the plants examined in this analysis and may be taken as the best outcome for these plants on the assumption that they experience no deterioration in performance with age. At a load factor of 11% the expected annual output per MW of capacity is 965 MWh. The expected opex cost per MWh averaged over all utility-scale solar plants is £37.8 at age 1, £49.3 at age 10 and £66.3 at age 20. In contrast the average GB market power price weighted by solar output for 2015 to 2019 was £45.1 per MWh.[6] At this price expected revenue per MW is below the expected opex cost per MW for solar plants from age 11 onwards. The discrepancy will grow if the GB power market converges towards the prices that prevail in nearby countries in Western Europe as more interconnector capacity is built.

For their first 20 years of operation all of the solar plants in the sample are protected by receiving subsidised prices under the RO. After that period the prospect is that many solar plants will be unable to cover opex costs, even if those costs are reduced by as much as 50%. Hence, these plants will choose to cease operation or to repower their site. In practice, therefore, the economic life of solar plants is likely to be little more than 20 years. Even large solar plants of 50+ MW face the prospect of opex costs which exceed the expected revenue at market prices once they switch to merchant operation.

This is important for investors because in the last two years many solar SPVs have chosen to increase the depreciation life of their assets from, typically, 25 to 35 years. The change in assumptions may reflect a more optimistic view of the physical life of solar equipment but it is completely at odds with the market fundamentals that determine its economic life. By extending the depreciation life and thus reducing depreciation charges owners can increase current accounting profits and pay out higher dividends. However, in the longer term this will be offset by write-offs when it becomes clear that the assets will not have an economic life of 35 years. The net effect of the change is to benefit current owners and operators at the expense of those with a long term interests in solar assets.

5. Solar plant performance in the UK

In addition to opex costs the economic life of solar plants depends on whether and by how much the output from solar plants declines as they age, conditional on the amount of solar radiation. The output for all types of generating plant tends to decline with age, because either (a) they experience more frequent breakdowns and thus lower availability, or (b) their conversion efficiency falls. There is often an association between operating expenses and performance as operators may choose to increase expenditures on maintaining or replacing equipment in order to

6 The average excludes the low prices that prevailed in 2020 as well as the high prices for the second half of 2021. The prices are the day-ahead prices taken from the N2EX power exchange. Power prices in the GB market were slowly converging towards prices in Western Europe during the second half of the 2010s as more interconnector capacity was built. The average solar-weighted price in Germany over the same period was €34.0 per MWh. After allowing for interconnector charges, price convergence is likely to bring the average solar-weighted market price in the UK below £35 per MWh.

keep availability and conversion efficiency as high as possible. Thus, the observed performance for any set of generating plants will be the outcome of a trade-off between operating expenses and availability or conversion efficiency.

In this section I will examine whether the performance of solar plants declines with age using a sample of 712 plants commissioned between 2011 and 2021 which were registered for the RO and REGO schemes and which reported monthly output data to the Ofgem register. The sample includes (a) the 396 RO plants and 10 REGO plants with a capacity of at least 5 MW, (b) 203 RO and 103 REGO plants with a capacity of between 4.95 and 4.99 MW. The latter group of plants were clearly designed to come just under the 5 MW limit on registration for a more generous band of subsidies.

In total there are just over 43,400 monthly output figures reported for the sample plants after they had reached the age of 1 year. Observations for the first 12 months of operation are dropped because this is a period during which a plant may not operate at full capacity or there may be outages to deal with teething problems. Hence, the age-performance relationship is examined from age 1 onwards. The oldest plant in the sample had reached age 10 but the data was censored at age 9 since the number of observations for age 10 was so small.

The statistical model – see Appendix Section D – uses the log of the load factor for each plant in each month as the dependent variable with the age of the plant and a small number of weather indicators as the key explanatory variables. After investigating alternative specifications the best weather indicators are: (i) the log of total solar radiation downwards in the month, which is the combination of direct and diffuse sunlight falling on the solar plant, and (b) average air temperature (measured in Kelvin) weighted by solar radiation downwards.[7] Since the dependent variable is the log of the load factor the coefficient on the age of the plant is the proportional change in the average load factor for each additional year that a plant ages.

Plants differ in their location, site characteristics, design and equipment, all of which may affect the average load factor. These factors are called fixed effects because they do not change over time and their influence on the dependent variable can be removed by subtracting the average value of the dependent variable for each plant from the monthly values. This method of estimation – called the panel fixed effects specification - provides an efficient way of estimating the influence of variables such as age and weather which vary over time and across plants at a point in time. In addition, the model includes monthly dummy variables which identify systematic factors which vary over the year – such as the angle of the sun in the sky – but not from year to year or across sites.

7 The reason for using a solar-weighted average temperature is that the reduction in generation caused by high surface temperatures is proportional to the output of the PV modules. Hence, the measure gives more weight to the average temperatures when PV output would be expected to be high. Since there are some fixed overheads in solar systems, especially in running inverters and transformers, periods when solar radiation is less than 10 W/m2 have been excluded from total radiation and the weighted average temperatures.

Table 4 – Effects of plant age and weather variables on output from UK solar plants
(Dependent variable is log[monthly load factor])

	Coefficient	*Standard error*	*Z-value*	*Probability*	*90% confidence interval*	
log(Total solar radiation)	1.159	0.015	77.99	0.000	1.134	1.183
Weighted air temperature (K)	0.005	0.001	4.19	0.000	0.003	0.007
AGE4 = max(Age-3, 0)	-0.010	0.002	-6.36	0.000	-0.013	-0.008

Source: Author's estimates

The solar radiation and temperature data have been obtained from the ERA5 re-analysis datasets constructed by the European Centre for Medium-Range Weather Forecasting (ECMWF) using satellite data – see Hersbach et al (2018). The estimates are produced as hourly averages at a grid resolution of 0.25° of latitude and longitude. The ERA5 grid squares are centred, for example, at longitudes of 0.0° E, 0.25° E, 0.50° E, 0.75° E, 1.0° E … from the Greenwich meridian. The latitude and longitude of each solar plant was identified from either its postcode or other sources of information, so that each solar plant could be assigned to an ERA5 grid square and thus linked to the weather data for that grid square. This linking exercise was performed for the full period from 2000 to end-September 2021 to allow an assessment of the long term solar potential of each site as well as the actual monthly averages over the period of operation of the solar plant.

The statistical model fits the data exceptionally well and all of standard tests indicate that it is free of bias and other problems. It accounts for more than 95% of variation over time at individual plants and for more than 65% of variation across plants.[8] A comparison of alternative specifications for the effect of plant age on output given weather conditions shows that the relationship is non-linear with no effect for the first three years – i.e. ages 1 to 3 - and then an increasing decline in performance from age 4 onwards. The most efficient representation of the relationship is to use a variable referred to as AGE4 which takes the value 0 for ages 1 to 3 and the value Age-3 (Age minus 3) for age 4 onwards. The results of estimating the statistical model using this specification are shown in Table 4.[9]

The coefficient on plant age from age 4 onwards means that expected monthly output declines at a rate of 1% per year age after age 3. This coefficient is well determined and the 90% confidence interval is for a rate of decline in the range from 0.8 to 1.3% per year. The hypothesis that there is no decline in performance with age is strongly rejected.

8 The within R-square is 0.938 (variations over time for each plant) and the between R-square is 0.466 (variations over plants averaged across time).

9 In the estimation each plant is weighted by its capacity so that the reported coefficients reflect the average effects by MW of capacity. Robust standard errors take account of clustering of weather data by grid square.

Recall that the oldest plant in the sample is aged 9 years. The rate of decline may be higher or lower as solar plants move into their second decade. Still, if the pattern persists, the expected output from a solar plant at age 15 will be 11.4% lower than at age 1, holding weather conditions constant, and by age 25 the decline will be 22.2%. This rate of decline may not seem large but it cumulates over time, which casts doubt on the increasingly frequent assumption made by operators that the economic life of solar plants is 35 years. The combination of increasing opex costs and declining output means that it is unlikely that many plants will operate for significantly longer than the 20 year length of ROC contracts.

The coefficient on the log of total solar radiation is somewhat higher than 1. In economic terms this is equivalent to the elasticity of electricity output with respect to the amount of solar radiation. An elasticity of greater than 1 suggests that there is a significant fixed overhead in operating solar plants, perhaps due to plant consumption or other losses.

The coefficient on average temperature is small but positive which means that losses due to high module temperatures are not an issue of concern in the UK. It is not clear why a higher average temperature is associated with higher output in this data, but the relationship between PV output and temperature in relatively low temperature conditions as experienced in the UK does not appear to have attracted much attention. The practical effect of this result on siting and performance of solar plants in the UK is quite small, though it reinforces the attractions of siting solar plants in the South and South-West of England.

6. Solar plant performance in the US

A similar analysis has been carried out for solar plants in the US. The history of solar generation in the US is longer than that in the UK, especially in the desert areas of the South West. There are a significant number of plants which have been operating for 12 or more years. The data used for the analysis comes from monthly and annual reports made to the US Energy Information Agency on EIA Forms 860 and 923. Form 923 covers the net output and fuel use for registered generators of all types. This data is combined with data from Form 860 which provides more detail on plant characteristics such as location, date of first operation, winter and summer capacity, solar alignment and tracking, and transmission capacity.

In the US case no version of the air temperature variable has a coefficient that is significantly different from zero, even at low levels of significance. Hence, air temperature is dropped from the model. The number of solar plants is higher than in the UK: data was obtained for a total of 3,046 plants with a reported generating capacity of 1 MW or greater, of which 1189 had a capacity of at least 5 MW. Table 5 shows the results of estimating the statistical model for (a) all plants in the sample, (b) plants with a capacity of 5+ MW, and (c) plants with a capacity of 1-5 MW.

Table 5 – Effects of plant age and weather variables on output from US solar plants
(Dependent variable is log[monthly load factor])

	Coefficient	*Standard error*	*Z-value*	*Probability*	*90% confidence interval*	
A. All solar plants >= 1 MW (3,046 plants)						
log(Total solar radiation)	0.755	0.017	44.13	0.000	0.727	0.783
AGE4 = max(Age-3, 0)	-0.019	0.003	-6.86	0.000	-0.024	-0.015
B. Solar plants >= 5 MW (1,189 plants)						
log(Total solar radiation)	0.838	0.022	37.59	0.000	0.801	0.875
AGE4 = max(Age-3, 0)	-0.020	0.002	-9.54	0.000	-0.024	-0.017
B. Solar plants 1-5 MW (1,864 plants)						
log(Total solar radiation)	0.706	0.022	31.47	0.000	0.669	0.742
AGE4 = max(Age-3, 0)	-0.019	0.004	-5.00	0.000	-0.026	-0.013

Source: Author's estimates

The statistical model performs reasonably well in all versions but there is greater variance than for the UK. Still, in the case of plants of 5+ MW the estimated model accounts for 85% of the variation over time for at individual plants and more than 65% of the variation across plants.[10] In the US case the decline in performance from age 4 onwards is 2.0% year for plants of 5+ MW and 1.9% per year for plants of 1-5 MW.

The elasticity of output with respect to total solar radiation is much lower in the US than in the UK – 0.84 for the US and 1.16 for the UK when plants of 5+ MW are compared. One possible reason is that this is the consequence of a financial trade-off. Solar resources are much greater in the US than in the UK, so that it is not so important to get the maximum production when solar radiation is at its highest. If a satisfactory yield can be obtained at a lower capex cost, there is less financial pressure to design plants to obtain the maximum output in the periods of peak solar radiation.

Taking the results for the UK and the US together there seems to be overwhelming evidence that the performance of solar plants declines with age after age 3. The rate of decline is higher in the US than in the UK. This may reflect the fact that the US sample contains more plants of

10 The within R-square is 0.721 (variations over time for each plant) and the between R-square is 0.460 (variations over plants averaged across time).

age 8 or higher. Alternatively, it may reflect an economic decision to incur lower maintenance costs and accept a higher level of faults and lower level of performance. It seems to be accepted in the US solar industry that performance will decline with age but the conventional estimate of the rate of decline is 0.5% per year, well below the actual rate of decline revealed by this study. Another consideration is that the main form of federal subsidy up to 2021 for commercial solar generation was the Solar Investment Tax Credit, a lump sum credit amounting to 30% of the investment cost of a project.[11] This does not depend upon the amount of production so the incentive to keep the level of output as high as possible is weaker than with an output-linked subsidy.

7. Solar resources in the UK and the USA

Table 6 – Comparison of solar resources at UK and US solar plants
(Monthly and annual averages weighted by plant capacity)

Month	*Average daily solar radiation (W/m^2)*		*Average hours of sunlight per day*	
	UK	USA	UK	USA
1	802	3,038	7.6	9.9
2	1,519	3,860	9.3	10.7
3	2,783	5,246	11.4	11.9
4	4,318	6,438	13.5	13.0
5	5,191	7,176	15.1	13.8
6	5,353	7,408	15.9	14.2
7	5,170	7,168	15.5	14.0
8	4,263	6,550	14.0	13.4
9	3,069	5,514	12.1	12.3
10	1,806	4,365	10.0	11.1
11	968	3,257	8.1	10.2
12	645	2,673	7.1	9.6
Year	3,012	5,234	11.7	12.0

Source: Author's estimates

It is no surprise to note that the continental United States has better solar resources than the UK since it lies entirely to the south of the 49th parallel while all of the mainland area of the UK lies to north of 49°N. However, the scale of the difference in solar resources only becomes clear when looking at the average solar radiation for solar plants in the UK and the US shown in Table 6. This shows the average daily solar radiation at solar plants by month weighted by plant capacity. Over the whole year US solar plants enjoy 74% more solar radiation than UK solar plants. The difference is especially large in the middle of winter with US plants enjoying more than 4 times the solar radiation of UK plants but it is still large in the middle of summer. The

11 The investment tax credit rate of 30% applied from 2006 to 2019. It was reduced to 26% for project which commenced in 2020 and to 22% for projects which commenced in 2021.

winter differences are partly a consequence of a higher average number of hours of sunlight per day in the US but during the middle of summer the average number of hours of sunlight per day is significantly higher in the UK than in the US.[12]

There is another, less obvious, advantage that is enjoyed by US solar plants. Most parts of the continental US have a summer peak for electricity demand and within-day demand during the summer tends to peak during or just after daylight hours. This is because the primary contributor to peak demand is air conditioning. As a consequence the average prices received by solar plants tend to be higher than load-weighted average market prices. In contrast, peak demand in the UK occurs during the winter combined with within-day peaks during non-daylight hours of the evening. The average prices received by UK solar plants tend to be lower than load-weighted average market prices.

Overall, for each MW of peak capacity US solar plants are able to generate more electricity than UK plants and they can expect to receive higher average prices relative to the general level of market prices. This combination means that the economic position of solar generation in the US is much more favourable than solar generation in the UK. However, there is one mitigating factor: gas prices in the US tend to be considerably lower than gas prices in the UK. The difference has grown larger as US shale gas resources have been exploited on a large scale. This means that the primary determinant of market prices in both the US and UK – the marginal cost of gas generation – operates in favour of UK solar plants by setting a higher general level of market prices.

8. Investment and financial considerations

Almost all of the solar plants that are operating in the UK are supported by the Renewables Obligation with a generous allowance of ROCs per MWh of electricity generated. That scheme closed in 2017 and new projects have to compete with other technologies for CfD contracts offered under the intermittent CfD allocation rounds. There are two solar projects – Charity Farm and Triangle Farm Solar Park - in operation which have CfD contracts, both awarded in CfD Allocation Round 1 (AR1).[13] Each project has a peak generation capacity of 11-12 MW and receives a strike price of £91.4 per MWh in 2021-22.

Figure 2 shows the financial projections at 2018 prices for a hypothetical solar plant operating with a CfD contract identical to that awarded to the two operating plants. The calculations assume a capex cost of £0.95 million per MW, a base load factor of 11.2%, a base opex cost of £36,500 per MW per year, and a real cost of capital of 4%. These assumptions are based on the results reported above or reflect the typical terms of financing for renewables projects at the end of the 2010s. The figure shows two scenarios: (a) the Blue scenario assumes that the load factor and average opex cost remain constant over 25 years; and (b) the Green scenario assumes that expected output declines at 1% per year from age 4 onwards and opex costs increase at 3% per

12 The average number of hours of sunlight per day is measured as the number of hours in which solar radiation exceeds 10W per square metre.

13 A third CFD contract was awarded in AR1 to Netley Landfill Solar but the sponsor did not proceed with the contract.

year in real terms. The Blue scenario is the most optimistic scenario, whereas the Green scenario is based on the empirical results of actual outcomes for UK solar plants. The red dashed line shows the sum of opex and financing costs over a repayment period of 15 years which matches the length of the CFD contract. In both scenarios it is assumed that the plant receives a real offtake price equal to the average power market price weighted by solar output from 2015 to 2019 – i.e. excluding the pandemic-affected prices in 2020 and 2021.

In the Blue scenario the plant earns a reasonable margin over opex costs during the life of the CfD contract but this is not sufficient to cover the financing costs. The project would have to make a substantial operating profit after the expiry of the CfD contract in order to cover the overall 4% cost of capital. It will not generate such a surplus unless the real level of market prices is much higher than has been the case in the recent past. Put in a different way, investing in solar generation under the most optimistic Blue scenario is, in effect, a long term gamble on the future level of power prices and equity investors cannot expect a real return until at least 20 years into the future. Financial engineering, which is common in the sector, does not change the underlying reality. Instead, it shifts the risks of future market prices onto parties who may be ignorant of what is involved and poorly equipped to manage the risks.

In the Green scenario the economic life of the solar plant is likely to be equal to the length of the CfD contract. Unless real market prices are much higher than in the past, the expected revenue of the plant will not cover its operating costs. There may be opportunities to upgrade the plant by installing new, more productive, solar modules and associated equipment, but that is a new investment decision. Both equity investors and some classes of lenders are likely to lose most or all of their original investments.

Table 7 – Market prices required for project breakeven
(Prices in £ per MWh at 2018 prices)

	Blue scenario		*Green scenario*	
	No discounting	4% cost of capital	No discounting	4% cost of capital
Post-CfD breakeven price	58	127	125	216
ROC breakeven price	19	42	39	60
ROC breakeven price + value of 1.3 ROCS per MWh	87	110	107	128
25 year breakeven price	84	108	103	123
25 year breakeven price with 33% reduction in capex & opex	51	67	68	82

Source: Author's estimates

Table 7 shows the result of calculating: (a) the post-CfD average market price required for breakeven, (b) the average market price required for breakeven on a project allocated 1.3 ROCs per MWh in 2016, (c) the breakeven price held constant over 25 years, and (d) the breakeven price held constant over 25 years but with a 33% reduction in both capex and opex costs. The breakeven prices are shown for no discounting - i.e. pure cost recovery in real terms with no return on capital – and a real cost of capital of 4%. Even in the best of all worlds Blue scenario the post-CfD market price would have to be £58 per MWh to achieve simple cost recovery and £125 per MWh to pay a real 4% cost of capital. The latter price is more than 3 times the average real market price for the period 2015-18 and implies a real increase in average market prices of nearly 8% per year over 15 years. The current angst about high energy prices will be nothing compared to the discontent that is likely to be engendered by a large and sustained increase in prices at that rate. Under the Green scenario which reflects the actual performance of solar plants up to now, the rate of increase in the average market price would be nearly 12% per year over 15 years to earn 4% real return.

Almost all of the solar plants built up to 2017 receive Renewable Obligation Certificates (ROCs). These are significantly more generous than CfDs as they are awarded for 20 years and most projects receive either 1.4 or 1.3 ROCs per MWh. ROCs are awarded for 20 years and have an expected value of about £52 at 2018 prices once the recycling of buyout revenues is taken into account. Hence, for a project registered in 2015-16 receiving 1.3 ROCs per MWh the effective revenue for an average market price of £41 is £109 per MWh at 2018 prices. This is substantially higher than the CfD strike price of £87.9 per MWh at 2018 prices, which illustrates the much higher level of subsidies received by ROC solar generators when compared to CfD solar generators. CfDs provide certainty for the offtake price over 15 years contract length. Still, operators would have to be exceedingly risk averse to choose this over the higher, though uncertain, offtake price over 20 years.

The second row in Table 7 shows the average market price required for a project earning ROCs to break even over 25 years under the combinations of the two scenarios and costs of capital, while the third row shows the combined value of the market price and the value of the 1.3 ROCs per MWh. In the Blue scenario with a 4% cost of capital the ROC breakeven price is almost equal to the average market price over the period 2015-19. Hence, optimistic investors using actual data on average capex and opex costs might have convinced themselves in 2015-16 that ROC-registered projects could cover their cost of capital at expected market prices. However, a more realistic assessment taking account of the likely decline in performance and increase in operating costs over time indicates that a significantly higher average market price is required to earn a 4% return on capital.

There is an additional feature of these results for ROC projects which is important for investors considering the acquisition of existing solar plants. Up to 2019 it was standard practice for SPVs to use an asset life of 25 years for solar plant and equipment, which is why the analysis of breakeven prices uses this project life. However, for accounting periods ending in 2020 and 2021 a considerable number of SPVs have shifted to using an asset life of 35 years. The basis for adopting this new assumption is rarely explained or justified. There is no empirical evidence that could support this assumption because the number of solar projects that have operated anywhere in the world, let alone in British conditions, for more 15 years is tiny. The assumption is convenient because it lowers the current depreciation charge and increases reported profits without affecting the tax charge calculated using quite different capital allowances.

A cautious investor might be well advised to be quite sceptical about whether the physical life of PV modules and electrical equipment is likely to be anything close to 35 years without incurring rapidly increasing opex costs combined with declining performance. In any case it is the economic life of the assets, not their physical life, which really matters. In the Green scenario the expected opex costs exceed the expected revenues in every year after the end of the period of ROC eligibility, so the economic life of the assets is only 20 years. In the Blue scenario the expected revenues exceed expected opex costs by a small margin but a small increase in opex costs or a small decrease in performance would turn the expected operating surplus into an operating deficit.

Once again the investment story for ROC-registered solar plants rests on the assumption that average market prices for electricity will rise sharply over the next 15 to 20 years. It is very hard to reconcile such an assumption with the expectation that 30+ GW of capacity in offshore wind will become available with a breakeven cost of £40-£50 per MWh at 2018 prices. Any systematic analysis of market prices shows that the periods of high prices when wind output is low and demand is high are a poor match for the peak periods of solar output. As the market in Germany has been signalling for some time, countries with high levels of reliance on renewable generation are moving to a situation in which the market price of electricity tends to zero in periods when there is significant renewable output. This undermines any prospect that the average market prices will be high enough after the end of CfD or ROC availability to cover operating costs. In this respect UK solar plants are especially disadvantaged because seasonal and time of day patterns of output and demand tend to mean that output is high when prices tend to be low. The average market price weighted by system demand is always significantly higher than the average market price weighted by solar output.

The last two rows in Table 7 show the breakeven price under (a) the standard Blue and Green scenario assumptions, and (b) modified Blue and Green assumptions in which the basic capex and opex costs are both reduced by one-third. In this context the breakeven price is the level of the market price in real terms that yields a zero present value if held constant over 25 years. Breakeven prices have no relevance for actual investment decisions but they provide a reference value for comparing the effects of changes in operating assumptions on the long run costs of generation.[14]

The 25 year breakeven price is consistently about £3 per MWh lower than the ROC breakeven price after allowing for the value of ROCs. The reason is that the economic life of solar assets is only 20 years under the ROC regime whereas it is the full 25 years if the plant receives a higher

14 Many people use levelised costs as such a reference point. Unfortunately, the standard method of calculating levelised costs has a fatal flaw. It takes no account of the fact that the economic life of assets may be much shorter than their physical life. As discussed above, when opex costs rise over time in real terms or performance declines over time, it is critical to allow the economic life of assets to be determined by the model. Most users of levelised costs make no allowance for these changes over time and for their impact on the economic life of assets. As a consequence the levelised costs that are usually reported are incorrect and often highly misleading. The difference between the breakeven costs for the Blue and Green scenarios highlights the scale of the error introduced by assuming that both performance and operating costs are constant over the life of a plant.

market price in years 21 to 25. The reduction of about £3 per MWh in the breakeven price is, thus, the discounted value of earnings past the expiry of ROC eligibility.

A reduction of one-third in both capex and opex costs lowers the breakeven price by almost exactly one-third in the Green scenario and by 38% in the Blue scenario. This is because a reduction in the initial opex cost has more of an impact when both performance and opex costs are assumed to be constant over time.

9. Conclusion

The analysis in this paper demonstrates that solar generation is not the special case which many policymakers and investors appear to believe it to be. The actual capex cost per MW of capacity for plants built in the middle of the last decade was nearly twice the level assumed by BEIS in its cost projections for 2025. The evidence available suggests that actual capex costs declined by about 10% between 2015 and 2020 even though the cost of PV modules fell sharply. This highlights the simple point that more than 50% of the total cost of building a new solar plant is spent on civil works, mounting structures, cable, grid connections and similar items. These items are not new technology whose real costs might fall rapidly and, indeed, their real costs may increase if there is a boom in new solar construction.

Actual opex costs per MW of capacity are nearly double the level assumed by BEIS but even more important it appears that they should be expected to increase over time. The rate of increase observed in the data collected for this study may be atypical, perhaps reflecting the immature state of the solar industry. Even so, a real increase of 2.5% to 3% per year as solar plants age is entirely consistent with the experience for onshore wind generation and it is certainly unwise to assume that real opex costs will remain constant over the life of solar plants.

Equally important, there is very strong evidence that the performance of solar plants declines with age after controlling for weather conditions and other factors. The rate of decline is relatively low at 1% per year for UK solar plants but it is higher at 2% per year for the much larger sample of US solar plants. The difference may reflect different operating and maintenance practices as the lower levels of solar radiation in the UK may prompt operators to spend more on maintenance in order to maximise output. On the other hand, the difference may be merely a matter of the age structure of solar plants as there are many more plants in the US that have been operating for 8 or more years than in the UK.

Irrespective of the reasons for higher operating costs and reduced performance, investors in should recognise that the economic life of solar assets is likely to be substantially shorter than the 35 years which seems to have become the default assumption made by solar operators. When eligibility for either CfD payments or ROCs expires, the abrupt fall in the expected revenue per MWh of output is likely to mean that many plants can no longer cover their operating costs from generation revenues. Thus, the economic life of the majority of the solar plants currently operating in the UK is likely to be little more than 20 years. The only escape from this squeeze is if real market prices are at least 2-3 times their average level between 2015 and 2019. Relying upon such an increase runs counter to the evidence of what has happened in other countries as reliance on intermittent renewables increases. Markets shift towards a regime in which market prices are very low for periods when renewable generation is high and are higher during periods of high demand and relatively low renewable generation. Such a market regime is highly unfavourable for solar generators in the UK. It is clearly a mistake to assume that solar plants will benefit from higher gas prices in future.

On the evidence examined in this study, the breakeven price for solar generation at the beginning of the current decade is about £123 per MWh at 2018 prices. This is considerably higher than the breakeven price for onshore wind discussed in my study of wind economics – Hughes (2020a) – but it is comparable to the breakeven price for offshore wind. Enthusiasts cite various reasons why the prospect for solar generation is very good. Some of these reasons may even be correct in some circumstances, but they run against the inescapable economic reality of conditions in the UK: solar resources are relatively poor, land is expensive, and labour costs are high. What may be true for desert areas in Mexico or Chile is irrelevant in the UK.

My final conclusion is that the solar industry in the UK is little more than the product of an excessively generous set of subsidies. It has no firm foundation for operating on a large scale without subsidies or without a demand for greenwashing. Investors should be aware that they doing little more than buying a stream of future subsidy payments. Once those subsidies cease, mostly around 2035, they will have assets that are effectively worthless. As a matter of public policy this may be deplorable. As an investment decision, this may be understandable so long as participants are clear-sighted about what they are getting.

10. Afterword: Energy Policy in 2022

One of the difficulties of carrying out serious data collection and analysis on renewable energy in the UK is that the time required for such work is greater than the time period between announcements or re-announcements of changes in government policy. The analysis in this paper up to the end of Section 9 was carried out using data available in early 2022. Adding a few more months of data will not alter conclusions based on the trends that have emerged over a decade or more.

On the other hand, both the UK Government and the lobbyists who seek to influence policy appear to be unconstrained by such trivialities as evidence and actual outcomes. Reality cannot be allowed to get in the way of convenient fantasies. The result is the Energy Security Strategy published in April 2022, followed by the Labour Party's Green New Deal published in September 2022. The latter is an attempt to outdo the Government in foolishness by promising to decarbonise the grid by 2030. Both strategies are the equivalent of a green HS2 project – wish lists based on invented costs without any apparent understanding of the timescales required to develop and build large electricity projects. As an illustration, the Green New Deal strategy, which is claimed to be "fully costed", assumes that the construction of the Sizewell C nuclear power plant by 2030 can be funded within an overall borrowing figure of £28 billion for all Green New Deal projects. Since the Hinkley Point C nuclear plant has cost nearly £30 billion at 2022 prices and will have taken nearly 12 years to construct if it is completed in 2027, the chances of these assumptions being justified are effectively zero.

The Energy Security Strategy specifies a goal to expand the total capacity of solar installations by "up to" five times the current level by 2035. Of course, "up to" could mean zero but let us take the document as expressing an intention to increase the capacity of solar installations in the UK by 56 GW in 14 years, giving a total of about 70 GW.[15] That is a rate of construction of about 4 GW per year for the whole period, which is a 50% higher rate of construction than during the previous boom in the period from 2014 to 2016. The Green New Deal goal is to triple solar output by 2030, which in practice requires tripling solar capacity and implies a similar rate of plant construction from 2024 to 2030. As noted above, construction and other costs excluding PV modules and inverters were substantially inflated to achieve this level of construction. Notwithstanding any continuing fall in the cost of PV modules and inverters the average cost of building utility-scale solar farms over this period is likely to be close to £1 million per MW of peak capacity at 2018 prices.[16]

If the ratio of utility-scale capacity to total capacity remains at about 50%, the total cost of constructing 28 GW of utility-scale capacity will be about £28 billion. Paying the difference between the breakeven price for solar power and the 2015-19 market prices over 15 years implies that the total subsidy for utility-scale solar plants will be about £3.5 billion per year. Since smaller solar installations are more expensive to build and usually have greater maintenance costs, the overall subsidy required is likely to be in the range from £8 to £10 billion per year.

It might be argued that up to £10 billion per year is small change in the context of the much larger sums being thrown at policies to support decarbonisation. But that is to neglect the fact that the target for expanding solar generation will have large unintended consequences for the rest of the UK's electricity and energy system. In very simple terms, this level of solar generation, even without allowing for the contribution of wind and nuclear power, will destabilize the grid. There are two key reasons why this is unavoidable.

First, almost all solar generation is not connected to the high voltage Transmission System itself but to lower voltage distribution networks, where it is said to be "embedded". The System Operator of the Transmission System, where the grid is balanced, has no direct sight of so-called embedded generators and it has no capacity to control them. They are just negative demand, which means that the task of maintaining frequency and voltage becomes vastly more difficult when embedded generation is substantial relative to total load. Solar plants do not want to connect to the Transmission System if they can avoid it because it increases both capex and opex costs.

Second, total system load between the times of 12.00 and 14.00, when potential solar generation will be highest, in June and July 2021 averaged 37 GW. This is only 53% of peak output of the 70 GW of solar envisaged in the Energy Security Strategy: how is the excess to be dealt with? Perhaps almost all utility-scale solar plants will have to be switched off (since the System Operator doesn't control output from smaller solar installations) but that will undermine the economics of solar investment. Alternatively, demand response is proposed as a solution but that is expensive vapourware at this scale.

15 The Energy Trends estimate of total capacity of solar installation for the UK at the end of 2021 was 13.8 GW – Table ET-6.1 for March 2022.

16 Multiply by 1.105 to convert to 2022 prices using the government's official forecast of the GDP deflator for 2022.

The saving grace is that solar resources in the UK are so poor that the median solar output in June and July 2021 was 5.75 MW from a total installed capacity of 13.7 GW, just over 40% of nominal peak capacity. Even so, the grid would be at risk on very sunny days in the middle of summer as maximum output in 2021 was 9.15 GW or two-thirds of total installed capacity. That translates to 46 GW in 2035 under the Strategy's solar target, and without any contribution from wind generation.

In summary, the renewable generation targets outlined in the Energy Security Strategy are inconsistent and absurd in economic terms if they were achievable, which is unlikely. Add in up to 24 GW of baseload nuclear and the system will face huge swings from excess, when prices fall to nothing or less than nothing, to shortfalls in generation when prices soar to extremely high levels. The economics of all generation, and especially those that are unsubsidised, becomes highly uncertain. What may be worse is that there is no plausible route from where the UK's electricity system is today to where it is supposed to be in 2030 or 2035 other than by incurring vast expense for short-term flexible generation over the intervening period. Further, none of the timescales work once allowance is made for (a) the inevitable delays in drafting and approving legislation, and (b) the fact that the typical large solar or wind project takes between 6 and 8 years to move from conception to commissioning.

The aspects of the Energy Security Strategy and the Green New Deal that deal with solar generation highlight the apparent inability of UK politicians and civil servants to prepare or implement an energy policy that addresses current market conditions and the future needs of the UK economy. Instead, these "strategies" rely upon a combination of grand fantasy and the repetition of vague intentions which have not been implemented in the past or do not lie within the power of government to achieve. Bringing forward the date for full decarbonisation of the UK electricity sector from 2035 to 2030, as proposed in the Green New Deal, just reinforces the impression of a collection of policymakers who are utterly divorced from the realities of designing, building and operating complex electricity systems. As with HS2 the costs are likely to be at least 3 or 4 times the sums claimed and the time required to achieve the goals will 2 or 3 times the periods claimed.

A more interesting development is the announcement of the results of the latest round (AR4) of CfD bids in July 2022. Partly as a consequence of the bidding conditions, they reflect a doubling up of bets on unknown sources of cost reduction and improvements in load factors. There were 5 successful bids for offshore wind CfDs with a total capacity of 7 GW at a strike price of £37.35 per MWh which translates to £47.88 at 2022 prices.[17] It is unclear how the bidders expect the finances to add up in a world in which the key costs of raw materials, support services and capital have increased between 50% and 200%. Along with the loud cries of pain from the main turbine manufacturers, this seems to be a game similar to offshore yacht racing, which has been described as spending vast amounts of money while being cold, wet and uncomfortable.

17 The increase in the CPI from October 2011 (2012-13 prices) to October 2021 (2022-23 prices) was 20.2% but the strike prices for offshore wind farms have increased by between 25% and 29% due to changes in BSUoS and transmission charges.

The bids for solar projects in AR4 can be assessed against the analysis presented in this paper. The clearing strike price for solar projects was £45.99 per MWh which translates to £51.55 at 2018 prices for comparison with other figures in this paper. This is very similar to the 25-year breakeven price in Table 7 (page 23) with a zero cost of capital – i.e. no discounting – together with the most optimistic Blue Scenario assumptions on trends in performance and operating costs plus a 33% reduction in capital and operating costs. It would seem that project sponsors believe that all of their best hopes will be fulfilled simultaneously.

Reality may be much harsher. The total amount of solar capacity offered CfD contracts in AR4 is 2.16 GW with most of the projects expected to be commissioned in 2024-25. Financial closure for most of these projects is likely to take between 12 and 18 months, so that the majority of installation work will occur in 2024. This implies a rate of solar plant construction that is close to the level in 2014-16. Table 2 (page 12) shows that the average capex cost of solar plants excluding PV modules and inverters increased by more than 50% during the previous boom when underlying price trends were favourable. With much less favourable global price trends it is very likely that the AR4 projects will incur higher costs for these residual items. Even if the cost of PV modules and inverters continue to fall, which is far from certain because of the situation in China and raw material shortages, the total capex cost of AR4 projects is unlikely to be significantly less than £1 million per MW.

On the assumptions discussed earlier the financial prospects for AR4 projects are dire. Even in the most optimistic Blue Scenario with a debt-equity ratio of 50:50 and a real debt interest rate of 2% the projects could not cover their debt service costs, let alone earn an adequate return on equity. With more realistic assumptions about trends in performance and costs, equity investors will simply be wiped out. The problem, as highlighted above, is opex costs. Even if average opex costs per MW of capacity are only a half their historical average, equity investors will not recover their initial investment in the Blue Scenario.

In the renewables industry the usual reason that investors give for believing that pigs' ears are really silk purses is technological progress, which is thought to change everything. In the case of solar generation, optimists point to improvements in the efficiency of solar PV modules. Older generation poly-crystalline and mono-crystalline modules had conversion efficiencies of 15-18% (poly) or 16.5-19% (mono) while the most modern N-type mono-crystalline modules can achieve conversion efficiencies of 20-23% – all under standard test conditions.[18] The increase in conversion efficiency can reduce capex costs as well as increasing yields because a fixed area of panels has a larger peak output, though this is partly or wholly offset by higher panel prices.

As always reality is likely to be rather more complex. Conditions approximating standard test conditions – solar irradiance of 1,000 W/m^2 and a cell temperature of 25°C – almost never occur in Britain. The maximum hourly solar radiation over 20 years is less than 950 W/m^2 for every grid square in the UK. The average solar radiation during daylight hours is less than 250 W/m^2 for every grid square. Even during the prime months of June and July the average solar radiation

18 Panel manufacturers are also promising a reduction in the rate of light-induced degradation and an extension in operating life. However, the warranties are carefully qualified as they cover peak power output not average yield. In any case, few will believe that the companies will still be in business in 30+ years to honour the warranties.

during daylight hours is between 400 and 450 W/m^2. Hence, what matters in economic terms is the performance of PV modules under (relatively) low irradiance conditions of 200-400 W/m^2. The reduction in the efficiency of PV modules under low irradiance conditions can vary a lot between module designs. The global market for solar panels is dominated by countries and regions with relatively high irradiance levels, so that performance in low irradiance conditions is a minor concern. As a consequence, the improvement in actual conversion efficiency in Britain from N-type modules is likely to be less than implied by direct comparison of conversion efficiencies under standard test conditions.

The financial analysis in Section 8 above assumed an initial load factor of 11.2% for solar plants built in the 2010s. There is a widespread misunderstanding of what improvements in module efficiency imply for the average load factor of solar plants – see Appendix E (page 40). Increasing the height of wind turbines leads to a higher load factor because average wind speeds increase with hub height. More efficient solar modules mean that panels can be smaller to achieve their rated capacity under standard test conditions. However, their average load factor is determined by average solar irradiance at the site and the performance of the modules under low irradiance conditions. There is evidence so far that N-type modules will perform better under typical British conditions expressed as a percentage of their peak conversion efficiency.

A very optimistic investor might assume that the initial load factor for AR4 projects might be 10-15% higher than projects built in the last decade – i.e. an average load factor in the range 12.3% to 12.9% – through a combination of better design and more elaborate tracking equipment. There is no evidence to believe that the decline in performance over time will be any different for new projects. Even with a higher average load factor a typical project would be unable to support a debt to equity ratio of greater than 40:60 under the standard assumptions about capex and opex costs. If the level of opex costs is reduced by 50%, then under the most optimistic – Blue Scenario – assumptions the typical AR4 project could just support a debt to equity ratio of 60:40 and would just recover its initial equity investment at a zero cost of equity. Under the more realistic Green Scenario assumptions the equity investors would lose more than 50% of their initial investment.

In summary, the AR4 solar bids demonstrate a triumph of hope over evidence. It is necessary for the investors to believe that almost everything will be different in future – that the most optimistic but reasonable assumptions will be exceeded – in order for the projects to have any prospect of earning an adequate return on capital. Will the sponsors of the projects point this out to the naïve and gullible providers of both debt and equity?

Perhaps even more pertinently, what is the responsibility of government and regulators in such circumstances? We know that both institutions and individuals almost desperately want to believe that the AR4 bids confirm that the costs of solar and other forms of renewable generation have fallen and will continue to fall in future. However, at what point does the gap between optimistic beliefs and current reality become so large that optimism crosses the boundary of being reasonable and becomes deception?

The UK, like many other countries, has a history of financial scandals in which naïve investors lose money on investments and projects sold by plausible hucksters. In retrospect, commentators and regulators observe sagely that any proposal which seems too good to be true should not be trusted. Where are they when politicians, bureaucrats and official bodies promote policies and projects that, on any objective criteria, seem too good to be true? And what will they say when the inevitable failures occur with demands to bail out those who took the claims made by promoters at face value?

This leads us to what may be the most important lesson that should be learned from both the Energy Security Strategy and the AR4 CfD bids. This concerns the issue of accountability. In both cases the public is being asked to accept goals and policies that are based on little more than optimistic fairy stories. Politicians and bureaucrats are willing to accept such fantasies because they do not expect to bear any accountability for the achievement of those goals or the consequences of the policies. Investors and operators go along with this because either (a) they too do not expect to have to account for the consequences, or (b) they are convinced that the level of political or public commitment will ensure that they will be bailed out if things go wrong.

The blunders of UK governments are too well-known and too recent to require repetition. The saddest aspect of the whole story is that they are well recognised. Even so, every time a new blunder appears on the horizon, politicians and civil servants are convinced by each other – with lots of help from lobbyists – that "this time things will be different". Common sense says otherwise but that is rarely deployed when people are in the grip of a collective delusion. That is why personal and collective accountability is so important.

It is very difficult to design reasonable mechanisms for holding both policymakers and the promoters of fantastical visions accountable for the foreseeable consequences of their actions. Still, the failure even to attempt to develop and apply some form of accountability leads to the kind of nonsense reviewed in this section.

Acknowledgements

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APPENDIX – SOURCES OF DATA

A. Capital and operating costs

As for my previous studies of the costs of wind generation, the data on the capital and operating costs of solar plants in the UK have been extracted from the annual accounts for companies (Special Purpose Vehicles or SPVs) that own and operate solar generating plants. The majority of these annual accounts are prepared by a small number of accounting firms contracted by either investment funds which own the plants or agents who manage the plants on behalf of their owners. As a consequence, the accounts tend to adopt standard accounting practices and there is a strong tendency for new owners to make changes such as adopting a standard accounting year or standard asset lives after they buy existing plants. In addition, there are frequent changes in the financial structure of the SPVs which may be prompted by strategies to minimise the tax liabilities of either the SPVs or the groups of which they are a part. Such changes will affect both financial charges and pre/post-tax profits.

Another aspect of the accounts is the frequent inclusion of "exceptional" items such as non-recurrent repair costs, compensation payments under warranties, write-downs in asset values, and other similar items. The majority of SPVs record such exceptional items in the first five years of operation, so they cannot be regarded as exceptional for the population of all solar plants. The over-riding impression is that exceptional items are a regular feature of the industry and must be included as part of opex costs when viewed over the medium and longer term. They may be unforeseen in terms of their precise timing and size, but it would be imprudent of any investor to fail to allow for such items to occur intermittently over the life of a plant.

There is another consequence of the relatively short period for which data is available. Certain pieces of equipment – notably inverters – require regular maintenance or replacement at intervals of 8-10 years. No provision is made for such expenses nor are the items usually depreciated over a shorter life than, for example, civil works and PV module mountings. As a result, companies will incur substantial costs at some point in the near future which are not included in the opex costs derived from SPV accounts covering the first 6 or so years of operation. Either average opex costs will, in fact, increase more rapidly than the analysis suggests or the average level of opex costs is underestimated by the data available.

B. Generation

United Kingdom. The data on generating plants and their output is extracted from the Ofgem Renewables and CHP Register maintained by Ofgem – see Ofgem (2021). This covers all generating plants accredited for either or both of the Renewables Obligation (RO) and the Renewable Energy Guarantees of Origin (REGO) scheme. Under these schemes generators are awarded Renewable Obligation Certificates (ROCs) or REGO certificates which provide authentication that the electricity generated by the plant is from a qualified renewable source.

All but a few of the utility-scale solar plants in the sample are registered under both the RO and the REGO schemes. The exceptions are (a) two plants which have CfD contracts, and (b) 12 plants commissioned between 2019 and 2021 which operate under corporate power purchase agreements (PPAs). There are a large number of solar plants with a capacity of less than 5 MW which are registered under the REGO scheme but which qualified for a Feed-In Tariff (FIT) and are not registered under the RO scheme.

Both ROCs and REGO Certificates can be traded but ROCs have a much higher value because they can be used to satisfy the obligation imposed on energy suppliers that some specified proportion of the electricity which they sell must come from supplies produced by an accredited RO supplier.

The requirements of RO scheme are managed so that the expected volume of ROCs issued in a year is lower than the RO obligations imposed on suppliers. The difference is made up by suppliers paying a buyout penalty which is fixed at the beginning of each year. The revenue collected from buyout penalties and some smaller levies is recycled to the owners of ROCs, so that the net market value of a ROC is equal to the buyout penalty plus the expected value of recycled revenue. This arrangement was not part of the original design of the RO, but the mechanics of the RO scheme were changed to ensure that the base (buyout) value of a ROC increases from year to year at the rate of inflation (RPI).

The details of the RO scheme are important because they mean that RO generators have a strong incentive to register their output with Ofgem in order to receive the subsidies that come via accreditation under the RO scheme and the award of ROCs. REGO certificates are much less valuable than ROCs but are used for the purpose of compliance with green energy standards.

It is reasonable to assume that the data on the numbers of ROCs and REGO certificates awarded to plants is relatively complete though it may not always be entirely up-to-date. In principle, RO and REGO generators are supposed to file data on monthly production but many of the smaller generators submit data on a quarterly or even less frequent basis. This is one reason for concentrating on utility-scale solar plants for the analysis.

Inevitably there are recording errors in the data, many of which are corrected later. Hence, as far as possible the data has been extracted from the Register at least one year after the end of the year for which generation is reported. Clearly that is not possible for 2020-21 and 2021-22, so the data for the most recent years is more likely to suffer from recording errors than data for earlier years. The data has also been cleaned to remove unreasonably high levels of output such as a monthly load factor of greater than 60% which is not possible given monthly hours of full daylight.

United States. The data on US solar plants is extracted from two forms which generators file with the U.S. Energy Information Agency (EIA) which is a part of the Department of Energy. The first form is Form 860 which is filed annually and provides data on the plant - its owners and operators, summer and winter capacity, technical characteristics, grid connection, location (state, county, latitude and longitude) and other parameters – see U.S. Energy Information Agency (2021a). The EIA publishes a preliminary version of the Form 860 data in June of each year covering the preceding year – i.e. in June 2021 covering 2020 – and the final version of the data in September. There is a special subset of the Form 860 data for solar plants – Form 860_3_3. I have used the final version of this data for each year up to and including 2020 covering both plants currently in operation and plants which have been retired. The data in its current form goes back to 2000.

The second form is Form 923 which is filed monthly by medium and large generators and annually by small generators – see U.S. Energy Information Agency (2021b). It gives data on monthly output as well as fuel consumption, emissions, fuel stocks, and some operating costs (primarily for fuel). The original purpose of collecting this data was to monitor the performance and situation of fossil fuel plants, so much of the data collected is not relevant for solar plants. The data in its current version goes back to 2001 though the name of the EIA Form has changed from Form 906 to 920 to the current 923.

The data from Forms 860 and 923 is believed to be relatively complete for medium and large plants, especially for those owned or operated by utilities. The coverage of non-utility plants has improved over time. The number of utility-scale solar plants not included in the data is likely to be small in relation to the overall size of the sample. However, the majority of utility-scale solar plants are covered by the annual version of Form 923 so that data on monthly output only goes up to the end of 2020.

C. Weather variables: solar irradiance and temperature

The weather variables used in the analysis are derived from data extracted from the ERA5 re-analysis dataset compiled by the European Centre for Medium-Range Weather Forecasting (ECMWF) and distributed by the Copernicus Climate Change Service (C3S) of the European Space Agency – see Hersbach et al (2018). The data is compiled as hourly averages for 0.25° latitude and longitude grid squares centred on 49, 49.25, … , 61° N and -8, -7.75, … , 2° E for all time periods from January 1981 to September 2021.

The brief definitions of the variables extracted from the ERA5 database are:

Surface net solar radiation [ssr] – This is the amount of solar radiation that reaches a horizontal plane at the surface of the Earth (both direct and diffuse) minus the amount reflected by the Earth's surface (which is governed by the albedo). It is accumulated over 1 hour and measured in Joules per square metre. In the dataset it is converted to watts per square metre.

Surface solar radiation downwards [ssrd] – this is the amount of solar radiation that reaches a horizontal plane at the surface of the Earth including both direct and diffuse solar radiation. It is accumulated over 1 hour and measured in Joules per square metre. In the dataset it is converted to watts per square metre.

Temperature at 2 metres above surface [t2m] – this is the temperature of air at 2 metres above the surface of land, sea or inland waters and it is calculated by interpolating between the lowest model level and the Earth's surface, taking account of the atmospheric conditions. It is measured in degrees kelvin (K). Temperature measured in kelvin can be converted to degrees Celsius (°C) by subtracting 273.15.

The reason for including air temperature is because the operating efficiency of solar panels decreases with temperature. However, this does not matter if there is little or no solar radiation to convert – e.g. during the night. Rather than use the average temperature over the month I have constructed two temperature indicators: (a) the monthly average temperature for hours when the level of solar radiation is at least 10 W/m^2 [t2ms]; and (b) the weighted monthly average temperature using solar radiation downwards as the weights [tssrd]. This is an indicator of the average temperature at times when solar radiation is strongest.

As a third measure of potential influence of temperature on solar output, I have calculated the proportion of hours in the month for which solar radiation downwards was at least 10 W/m^2 in which the air temperature was greater than 25°C. The logic for focusing on a threshold of 25°C is that the standard conditions for measuring the performance of solar panels are a solar radiation level of 1000 W/m^2 and a temperature of 25°C. While solar panels may perform more efficiently at temperatures below 25°C, this is rarely discussed in the literature. All of the focus is on the loss of output when the temperature at the solar panel is higher, especially much higher, than this threshold.

The southern half of England, where most UK solar farms are located, is much cooler than, for example, the desert areas of the SW United States or Mexico. The literature cites figures suggesting that solar output may be reduced by 10% when the temperature at the solar panels is 60°C. In practice it is likely that temperatures in the UK are rarely, if ever, high enough to cause a loss of more than 1-2% of potential solar output.

On the other hand, one factor that is important in the UK is the vertical and horizontal angles of solar incidence during winter and summer. Solar farms can be designed so that (a) the vertical angle of their panels can be adjusted to maximise output in each season of the year (tilt or horizontal axis tracking), and (b) the azimuth or horizontal angle of their panels is adjusted during the day as the sun moves from east to west (azimuth or vertical axis tracking). In practice, the much higher capital and operating cost of dual tracking – both (a) and (b) - is rarely thought to be worthwhile. Seasonal horizontal single axis tracking is relatively straightforward to implement, but daily vertical single axis tracking requires trackers that have a relatively short life. It is difficult to obtain data on which UK solar farms are designed with fixed angle panels and which incorporate different kinds of trackers. As a consequence the statistical models of solar performance include monthly dummy variables which provide a crude way of capturing the effect of changes in solar incidence over the year.

D. Econometric model for output

The general econometric model used for the analysis is:

$$\log(LF_{it}) = \alpha_0 + \beta A_{it} + \sum_k \gamma_k W_{kit} + u_i + e_{it}$$

where

LF_{it} is the load or capacity factor for plant i in period t,

A_{it} is the age of plant i in period t,

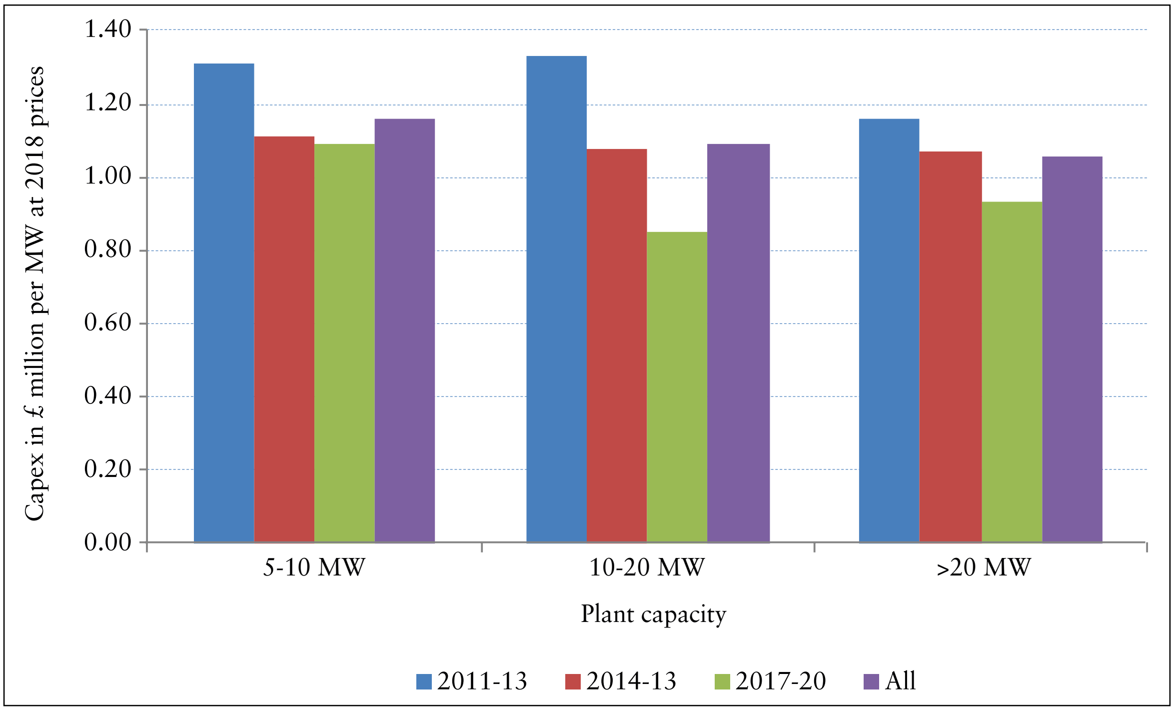
W_{kit} are weather variables (k = 1 ... K) for plant i in period t,

u_i is a fixed effect specific to plant i that is constant over time – e.g. reflecting its site and other characteristics such as whether it has solar tracking equipment, and

e_{it} is a random error that varies across plants and time period.

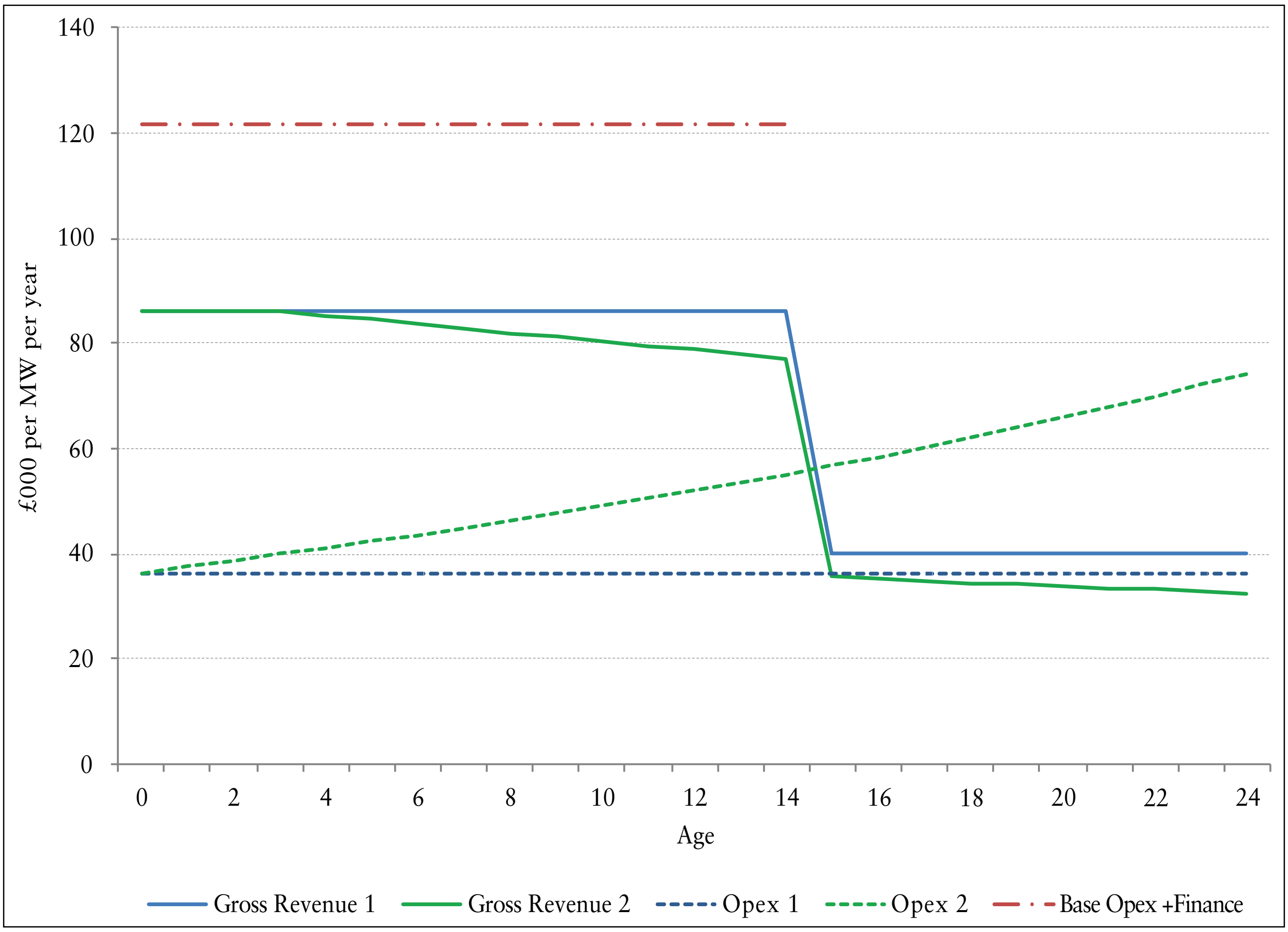
Figure 1 – Average capex cost by period and plant capacity

(£ million per MW at 2018 prices)



Source: Author's estimates

Figure 2 – Financial profile for solar plant with a CFD contract



Source: Author's estimates

E. Conversion efficiency vs load factor for solar generation

It is well known that the design and manufacture of solar panels has been improving over time. This technological progress is reflected in an increase in the peak and average conversion efficiency of solar panels, i.e. in the proportion of solar irradiance that is converted into electricity output. However, awareness of such technological progress leads to a prevalent misunderstanding of its consequences for the economics of solar plants. The critical question is: what will happen to the load factor achieved by solar plants as they deploy more advanced solar panels? The simple answer is that conversion efficiency and load factor are completely independent of one another, so that there is no necessary reason why panels with a higher conversion factor will have a higher (or lower) average load factor.

The explanation lies in a proper understanding of the specification of the performance of solar panels. It is standard to measure the capacity of a single panel or a solar plant as the amount of electricity which it generates under standard test conditions, i.e. with solar irradiance of 1,000W per square metre and a cell temperature of 25°C when the sun is at 90° to the panel. If a solar panel is rated as having a capacity of 300W and a conversion efficiency of 15%, then the collection area of the panel would have to be 2 m^2. A panel with a higher conversion efficiency of 20% would only require a collection area of 1.5 m^2. Thus, if we hold the capacity of a solar plant constant, an increase in the conversion efficiency translates to a smaller area of solar panels. This may reduce the capital cost of building the plant by a small amount, because expenditure on supports and civil works may fall, but even this is not certain.

On the other hand, the load factor for a solar plant is calculated as the amount of electricity actually generated expressed as a percentage of the maximum amount which would have been generated had the plant produced at exactly its capacity for 24 hours per day, 7 days per week. This is determined largely by the quality of the solar resource at the site – the number of hours of sunlight per day, the strength of the sun and the angle of the sun in the sky. The average load factor is also affected by the features of the site such as shading at different times of day, the mounting angle for the panels, and whether trackers have been installed. These site and installation characteristics have no direct connection with conversion efficiency, except to the extent that a different trade-off between cost and yield may lead the operator to modify its design choices.

Technological change may lead to a significant improvement in inverter efficiency – i.e. a reduction in the amount of electricity produced as DC current which is lost in conversion to AC current, usually as heat losses. However, the scope for improvement is quite limited and it is important not to mistake improvements in peak efficiency for an improvement across the full range of operating conditions. Inverters tend to have (much) lower efficiency at the low levels of solar irradiance that are common in the UK than in the high irradiance conditions for the South-West of the US or similar locations. On the other hand, outside temperatures are also lower, which improves inverter efficiency and lifetime.

Overall, the crucial point is improvements in module and inverter efficiency will not automatically translate into improvements in the average load factor of solar plants built in the future. Such improvements may reduce both capital and operating costs per MW of capacity, but *may* is the operative word. Manufacturers of modules and inverters have a strong incentive to price their products per MW of peak capacity. Economies of scale and the adoption of more sophisticated manufacturing techniques have brought down the average cost of modules and inverters measured per MW of capacity, but the tendency to extrapolate such trends one or two decades into the future is economic nonsense. In any case, if the cost of modules and inverters were to fall to close to zero the remaining 65% to 70% of other capital and operating costs still have to be met.