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Impact of weighted average cost of capital, capital expenditure, and other parameters on future utility-scale PV levelised cost of electricity

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Abstract

Solar photovoltaics (PV) is already the cheapest form of electricity generation in many countries and market segments. Market prices of PV modules and systems have developed so fast that it is difficult to find reliable up to date public data on real PV capital (CAPEX) and operational expenditures (OPEX) on which to base the levelised cost of electricity (LCOE) calculations. This paper projects the future utility-scale PV LCOE until 2050 in several European countries. It uses the most recent and best available public input data for the PV LCOE calculations and future projections. Utility-scale PV LCOE in 2019 in Europe with 7% nominal weighted average cost of capital (WACC) ranges from 24 €/MWh in Malaga to 42 €/MWh in Helsinki. This is remarkable since the average electricity day-ahead market price in Finland was 47 €/MWh and in Spain 57 €/MWh in 2018. This means that PV is already cheaper than average spot market electricity all over Europe. By 2030, PV LCOE will range from 14 €/MWh in Malaga to 24 €/MWh in Helsinki with 7% nominal WACC. This range will be 9 to 15 €/MWh by 2050, making PV clearly the cheapest form of electricity generation everywhere. Sensitivity analysis shows that apart from location, WACC is the most important input parameter in the calculation of PV LCOE. Increasing nominal WACC from 2 to 10% will double the LCOE. Changes in PV CAPEX and OPEX, learning rates, or market volume growth scenarios have a relatively smaller impact on future PV LCOE.

KEYWORDS

investment cost projections, LCOE, learning curve, PV economics

1 | INTRODUCTION

Solar photovoltaics (PV) is already the cheapest form of electricity generation in many countries and market segments.[1,2] Especially, utility-scale PV has broken many records of the world's lowest power purchase agreements (PPAs).[3] Solar PV module prices have gone down by more than 90%[4] and system prices by almost 80%[5] in real terms during the last decade and continue to decrease according to a steady and high learning rate (LR) of 39.8% for PV modules between 2006 and 2018,[6] which has led to the very fast cost decline due to fast market growth of 46% compound annual growth rate (CAGR) of cumulative PV capacity in the same period.[3] As pointed out by Green,[7] PV is the energy technology with the steepest and fasted cost decrease, driven by Chinese manufacturing excellence and US investor support. A key triggering element had been the strong demand increase driven by European policies in the 2000s, led by the German Feed-in Tariff law, as concluded by Nemet.[8] Already in 2017, utility-scale PV capital expenditure (CAPEX) has achieved levels of less than 0.80 $/Wp for more than 50% of the entire market.[3] The continued cost decline in 2018 and 2019 has led to regular utility-scale PV CAPEX of even below 0.50 $/Wp for utility-scale PV power plants realised in 2019 in leading markets.[9] ITRPV estimated an average utility-scale PV CAPEX in 2019 of 0.65 $/Wp.[6] An important element of future cost projections for utility-scale PV will be single-axis tracking systems, which reduce the LCOE when increased yield offsets the increase in CAPEX and operational expenditures (OPEX),[10] as their market share is expected to expand from 45% in 2019 to 55% at the end of 2020s.[6]

PV market and prices of systems have developed so fast that it is difficult to find reliable up to date public data on which to base the levelised cost of electricity (LCOE) calculations. This is of upmost importance since the debate on how to react on the ongoing climate crisis and the necessary transformation of the energy system towards 100% renewable sources demand urgent measures and political decisions based on realistic information on the potential of different technologies. The societal tipping point for tackling the climate crisis may have been passed right now due to the global Fridays for Future movement of the youth all around the world with support by scientists,[11,12] so that it can be hoped that fast and massive measures will be encouraged in the short term to midterm. This should be done on a best possible data basis.

Major institutions lag behind the real market development, which leads to a lack in ambitious cost and market projections. Well documented are the utility-scale PV CAPEX assumptions in the integrated assessment models used for the Intergovernmental Panel on Climate Change (IPCC) reports,[13] resulting in PV CAPEX of 1.79 $/Wp in 2020, 1.50 $/Wp in 2030, and 1.15 $/Wp in 2050. These reported values indicate that decision making in international climate crisis policy is based on vastly outdated, and practically wrong cost data for one of the most important energy technologies of the present and decades to come, since the 2019 utility-scale PV CAPEX is around 0.45-0.65 $/Wp.[6,9]

Several authors have claimed in recent years that the role of solar PV has to be drastically revised in major reports and in international energy and climate policy. Creutzig et al[14] pointed out that not only International Energy Agency (IEA) but also IPCC reports drastically underestimate the contribution potential of solar PV, which is estimated to be about 30-50% in competitive markets. For the case of European Union (EU), it is pointed out by European Technology and Innovation Platform for Photovoltaics (ETIP PV)[15] that the recently published energy transition pathway options by European Commission[16] do not reflect the contribution potential of solar PV, also a consequence of too high CAPEX and thus LCOE projections. This is further emphasised by several EU member states calling for more ambitious energy scenarios up to 100% renewable energy.[17] Child et al[18] find 41 to 45% solar PV contribution for the European power system and Ram et al[19] find 62% solar PV contribution for the entire European energy system. Breyer et al[20] showed that the average expectation of major reports and IPCC projections for solar PV for 2050 is around 20%, whereas least cost estimates for 2030 assumptions clearly indicated a global average share of around 40%. Bogdanov et al[21] have presented an hourly resolved least-cost energy transition analysis for the global power sector leading to 69% solar PV electricity contribution in 2050. Ram et al[19] have confirmed the solar PV supply share of 69% for the entire energy system comprising the sectors power, heat, transport, and desalination. Pursiheimo et al[22] concluded for an all-sector energy system transition analysis that 75% solar PV supply for electricity demand and 39 to 44% for primary energy demand in 2050 would be feasible. All these considerations have in common that the PV financial assumptions are critical for the results and conclusions. Such insights are complemented by Goodstein and Lovins in postulating a solar dominance hypothesis.[23] This already starts to become reality, as since 2017, the newly added global solar PV capacity is higher than the net power capacity change of coal, gas, oil and nuclear together.[24]

High shares of solar PV can be only achieved if storage solutions overcome the variability and impossibility of production of solar energy at night. At present and most probably also in the future, the storage technology leading the competition for diurnal large-scale storage solution for PV power plants is batteries. The fundamental battery technology for mobile and stationary applications is lithium-ion technology. The energy supply share of utility-scale PV power plants will strongly benefit from an ongoing cost decline of battery system cost. Several major reports and publications do not report on battery capacity, which is linked to the temporal resolution of the underlying model. This paper presents insights on battery system cost in the present and respective projections, since these insights are a key driver for achieving high shares of PV penetration in the energy system. The highest reported stationary battery demand is 74 TWh_{cap} for the year 2050[19] to the knowledge of authors.

Since PV has no fuel cost and relatively small OPEX, the CAPEX, paid up front of the investment, becomes an important term in the LCOE calculation. Obviously, system size has an impact on the share of CAPEX and OPEX in the LCOE, which is shown for utility-scale PV in Section 4. The weighted average cost of capital (WACC) used in the LCOE calculation is the single most important input parameter, more important than CAPEX and comparable to yield.[25] In this paper, WACC is varied in order to evaluate the full range of PV LCOE with different kind of investors and projects. WACC for utility-scale PV can be as low as 2.5%, as reported for the case of Germany.[26]

This paper aims to project the future CAPEX and also LCOE of utility-scale PV until 2050 in general, and in more detail for several European countries. Most recent and best available public input data are used for PV LCOE calculations. Moreover, a thorough sensitivity analysis is reported, including parameters like WACC, CAPEX, and OPEX, yield, system lifetime, degradation, and efficiency improvement. The results are presented with informative LCOE graphs. The paper is structured by the following sections: Methods and Data (Section 2), Results (Section 3), and Discussion and Conclusions (Section 4).

2 | METHODS AND DATA

The LCOE here is defined as the average generation cost, ie, including all the costs involved in supplying PV electricity at the point of connection to the grid. Possible grid integration costs have been extensively studied, eg, by the PV Parity project and shown to be in the order of 0.01 to 0.02 €/kWh for most European countries by 2030.[27] Possible grid integration cost is excluded here, and it can be argued whether it is fair to burden such cost solely on PV. After all, the old inflexible baseload generation technologies like coal and nuclear power do not have to pay grid integration cost either. On the other hand, this study does not take into account the various societal and environmental benefits of PV.

The PV LCOE here includes all the costs and profit margins of the whole value chain including manufacturing, installation, project development, operation and maintenance (O&M), and inverter replacement. Residual value of the PV system and dismantling cost is set as zero here. For the time being, there is no agreed price neither for the value of second hand modules nor for the income from recycling. For example, the recycling of waste modules has not yet been documented in the European Union statistics.[28] But typically, the residual value of a dismantled PV system should be positive,[29] thus decreasing the LCOE. PV LCOE also includes the cost of financing but excludes the profit margin of electricity sales and thus represents the generation cost, not the electricity sales price which can vary depending on the market situation.

The PV LCOE, expressed in €/kWh in real money, can be defined by Equation 1:

$$LCOE = \frac{\left(\text{CAPEX}_{\text{PV,total}} + \sum\left[\frac{\text{OPEX}(t)}{(1+\text{WACC}_{\text{nom}})^t}\right] + \frac{\text{InvRepl}}{(1+\text{WACC}_{\text{nom}})^{N/2}} - \frac{\text{ResValue}}{(1+\text{WACC}_{\text{nom}})^N}\right)}{\sum\left[\frac{\text{Yield}(0)\ (1-\text{Degr})^t}{(1+\text{WACC}_{\text{real}})^t}\right]}, \quad (1)$$

where

N is economic lifetime of the system

t is year number ranging from 1 to N

$\text{CAPEX}_{\text{PV,total}}$ is total capital expenditure of the system, made at $t = 0$ in €/kWp

OPEX(t) is operation and maintenance expenditure in year t in €/kWp

InvRepl is the cost of inverter replacement, made at $t = N/2$ in €/kWp

ResValue is the residual value of the system at $t = N$ in €/kWp, can be either positive or negative

Yield(0) is initial annual yield in year 0 in kWh/kWp without degradation

Degr is annual degradation of the nominal power of the system

WACC_{nom} is nominal weighted average cost of capital per annum

$\text{WACC}_{\text{real}}$ is real weighted average cost of capital per annum

The relationship between WACC_{nom} and $\text{WACC}_{\text{real}}$ is expressed with the formula below:

$$\text{WACC}_{\text{real}} = \left[\frac{(1+\text{WACC}_{\text{nom}})}{(1+\text{Infl})}\right] - 1, \quad (2)$$

where Infl is the annual inflation rate.

Discounting the expenditures with nominal WACC and electricity generation with real WACC ensures that the net present value for the investment with nominal WACC is zero when valuing the generated electricity for the real LCOE. An alternative method is to assume that the inflation rate is zero in the equation and to use real WACC for discounting both the expenditures and the generation. Both methods give the same value for LCOE.

2.1 | WACC and inflation

In a previous paper by Vartiainen et al[25] it was concluded that apart from the location, the WACC is the most crucial parameter affecting the PV LCOE. Since there is no fuel costs related to PV, the CAPEX has a relatively stronger influence than the OPEX on PV LCOE.

In this report, all results are given in real 2019 money. As nominal WACC rates are used here, inflation has to be taken into account in order to arrive at real values. For example, a 4% nominal WACC with 2% inflation rate corresponds to a 2% real WACC. Because the WACC rates are highly subjective and depend among other things on the country, market segment, investor type, and risk appetite, a set of four different nominal WACC rates are included in the analysis: 2%, 4%, 7%, and 10%.

Nominal WACC can be defined as

$$\text{WACC}_{\text{nom}} = [D \cdot k_D \cdot (1-\text{CT}) + E \cdot k_E]/(D+E), \quad (3)$$

where

D is debt financing

k_D is interest rate of debt financing

CT is corporate tax rate

E is equity financing

k_E is interest of equity financing

For example, a 4% interest on debt and 14% on equity with a 70/30 debt to equity ratio would give a 7% nominal WACC assuming corporate tax is zero. With green bond financing for utility-scale renewable projects, debt rates as low as 1.5% can been achieved.[30]

A 1.5% interest on debt and 10% on equity would give about 4% nominal WACC with a 70/30 debt to equity ratio.

Inflation rate is set at 2%, which is the recent historical average inflation of the Euro zone. This means that 2% nominal WACC corresponds to 0% real WACC.

2.2 | CAPEX (modules, inverters, and other BoS)

CAPEX development is estimated with the help of LRs, which are split to modules, inverters, and other balance of system (BoS) components. Same approach is applied to OPEX price development. Historical LRs and projected PV market volume growth with different scenarios form the basis on the LCOE analysis.

The LR approach is used in the formulation of Breyer and Gerlach,[31] which allows to substitute the historic cumulative capacity by growth rates for future projections, in cases of data uncertainty of the present status:

$$c_x = c_0 \cdot \left(\frac{P_x}{P_0}\right)^{\frac{\log PR}{\log 2}}, \tag{4}$$

$$\mathrm{LR} = 1 - \mathrm{PR}, \tag{5}$$

$$P_x = \sum_{t=0}^{T} P_t, \tag{6}$$

$$P_t = P_{t-1} \cdot (1 + GR_t) \quad \text{for } t \geq 1, \tag{7}$$

$$P_x = P_0 \cdot \prod_{t=0}^{T} (1 + GR_t), \tag{8}$$

where

P_x is a historically cumulative output level

P_0 is the initial output level measured in capacity

P_t is the output level of a specific period in time typically used in calendar years,

c_x is CAPEX at a historically cumulative output level P_x

c_0 is CAPEX at the initial output level P_0

PR is the progress ratio and *LR* is the LR,

GR is the growth rate of a specific period in time typically used for calendar years

The capital expenditure, ie, the total investment, of a PV system can be divided into three components: PV modules, inverters, and Other BoS:

$$\mathrm{CAPEX}_{\mathrm{PV,total}} = \mathrm{CAPEX}_{\mathrm{PV,Modules}} + \mathrm{CAPEX}_{\mathrm{PV,Inverters}} + \mathrm{CAPEX}_{\mathrm{PV,Other\ BoS}}. \tag{9}$$

$\mathrm{CAPEX}_{\mathrm{PV,total}}$ in this paper is the all-inclusive turnkey PV system price that needs to be paid up front. It is assumed here that the $\mathrm{CAPEX}_{\mathrm{PV,total}}$ is paid in full during the year of the installation of the system and the system starts producing electricity after the year of installation.

2.2.1 | Modules

The PV module price is assumed to follow the learning curve which has been observed for many decades. Each time the global cumulatively produced volume of modules has doubled, the average price has been reduced by 23 to 24%.[6] However, during the past decade, when more than 95% of all historic cumulative PV capacity has been installed, the price has decreased significantly faster, due to a combination of accelerated economies of scale, massive industrialisation, and most probably a change in the equipment cost due to new equipment manufacturers from Asia. From 2010 to 2019, the average LR calculated from the inflation-adjusted prices of multicrystalline modules reported by PVinsights[4] and market volumes by SolarPower Europe (SPE)[32] has been about 40%. This value is confirmed by ITRPV.[6] In order to cope with the market realities, this paper assumes a 30% LR for the base case. For the sensitivity analysis, a slow price decrease scenario with 20% LR and a fast price decrease scenario with 40% LR is used. Starting point for a utility-scale PV module price is the first half of 2019 average multicrystalline price reported by PVinsights[4] plus 0.005 €/Wp for insurance and freight. With the average exchange rate of the time (1.13 $/€), the starting module price for 2019 is 0.197 €/Wp.

To establish the future price for PV modules according to the learning curve, a projection for global cumulative installation volumes is needed. SPE[32] reported the annual PV market for 2018 to have been 102 GWp and cumulative capacity 509 GWp at the end of 2018. For 2019, the annual market growth here is assumed as 20% for the base case. This would give an annual market of 122 GWp in 2019 in the base case. Bloomberg New Energy Finance (BNEF) projects a 131 GWp PV market in 2019.[33] SPE's medium scenario for 2019 annual market[32] is 128 GWp and 180 GWp for 2023. Using 10% CAGR here for the base case gives annual market of 180 GWp in 2023. International Renewable Energy Agency's (IRENA) projection[34] gives a 300 GWp market for 2030, which equals 9.4% CAGR from 2018. It is assumed here that the 10% CAGR would continue from 2020 to 2035 in the base case after which it would decrease linearly to 2.5% by 2050. The 2.5% growth rate would hardly beat the 2.3% CAGR of global electricity demand projected in the IEA Current Policies Scenario from 2017 to 2040.[35] Industry experts have highlighted that a 20% CAGR can be sustained by the current gross margins, which can be generated by the PV industry.[1]

To have a sensitivity analysis, slow and fast growth scenarios are also considered. In the slow growth scenario, annual growth is 10% for 2019, after which CAGR would be 5% until 2050. In the fast scenario, annual growth would be 30% in 2019, from 2020 to 2030 CAGR would be 20%, decreasing linearly to 5% by 2040 and to 0% by 2050. The fast scenario would give an annual market of about 1 TWp in 2030 and 3.7 TWp in 2050. This is in line with Ram et al[19] in a recent scenario for a cost-neutral energy transition scenario towards a 100% renewable energy system needed to limit the global temperature increase to not more than 1.5°C above preindustrial levels. In essence, this would mean an almost total electrification of the global energy system with two thirds of the energy supplied by solar PV. The low growth scenario would give an annual market of about 0.2 TWp in 2030 and 0.5 TWp in 2050. This is in line with the 2018 IEA World Energy Outlook Sustainable Development Scenario,[35] which is considered to be the absolute most pessimistic scenario, whereas the scenario according to Ram et al[19] is the most optimistic. The projections of Ram et al[19] are comparable to the upper limit of Haegel et al.[1] The base scenario here is estimated to be the most likely although still conservative scenario, giving an annual market of about 0.35 TWp in 2030 and 1.3 TWp in 2050. The annual market scenarios are shown in Figure 1 and respective cumulative capacities in Figure 2.

Total installed cumulative PV capacity in 2050 would reach about 9, 20, and 62 TWp, for the slow, base, and fast growth scenarios, respectively. It can be noted that the difference of the base scenario to the very extreme slow and high growth scenarios in 2050 is only about 1.2 to 1.5 doublings in the cumulative volume, meaning that the module price uncertainty from the volume is within ±40% with a 30% LR.

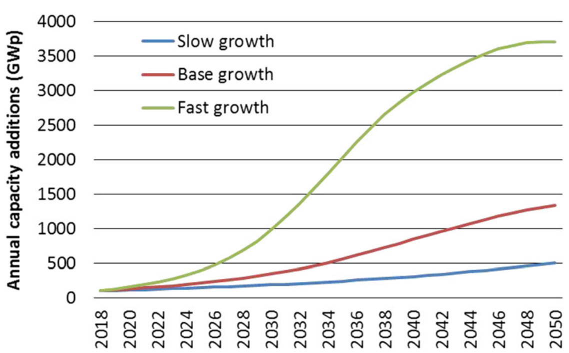

FIGURE 1 Annual global photovoltaics market development for the years 2018 to 2050 in three different scenarios. Slow growth scenario close to[35] and fast growth close to[19] [Colour figure can be viewed at wileyonlinelibrary.com]

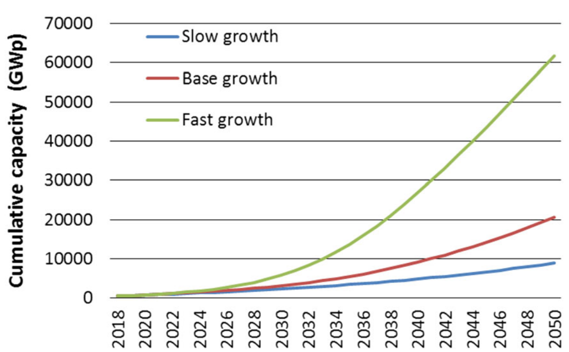

FIGURE 2 Cumulative global photovoltaics capacity development for the years 2018 to 2050 in three different scenarios. Slow growth scenario close to[35] and fast growth close to[19] [Colour figure can be viewed at wileyonlinelibrary.com]

2.2.2 | Inverters

Solar inverter prices also follow a learning curve, although a slower one than the PV modules.[36] For the base case, 20% LR is assumed here, which is confirmed by industry data[37] for the past of a moderate level of industrial competition. For the slow price decrease, 15% LR is assumed and 25% for the fast scenario. For utility-scale installations, both central and string inverters are currently used. Market prices are not as easily available as they are for PV modules. In India, a benchmark inverter cost for the Northeastern state of Uttarakhand was 2.14 INR/Wp for the financial year 2018-19,[38] which translates to 0.027 €/Wp with the end of June 2019 exchange rate of 80 INR/€. A recent European utility-scale project got offers of 0.030 to 0.038 €/Wac for 100 to 200 kWac inverters.[39] Assuming a DC/AC ratio of 1.30-1.40, this would give 0.021 to 0.029 €/Wp. Inverter price of 0.025 €/Wp is used here for the starting point in 2019 for the learning curve. Inverter lifetime is assumed to be half of the PV module and system lifetime. This means that the inverter must be replaced once during the lifetime of the system. The cost of replacement is taken into account in the calculation of the LCOE, separately from the OPEX.

2.2.3 | Other BoS

The BoS includes, eg, mounting structures, cabling, inverters, transformers, and other electrical components, grid connection, infrastructure, installation work, planning, documentation, and other work, ie, everything else except for the PV modules. Other BoS here denotes the BoS excluding inverters, which have a different LR from the other BoS components.

The methodology introduced by Fraunhofer ISE[37] is used here for BoS components. They can be divided into three categories:

1. components following a learning curve
2. components depending on the area of the PV array
3. components depending on the power

For example, inverters fall into the first and third category. In reality, all components have a LR and therefore fall into at least two categories. However, it is possible to establish an average share of components, which depend on the area. A price-weighted average area dependence of individual BoS components based on the Fraunhofer ISE[37] study was found to be about 50% and excluding the inverter about 65%.[25] This would mean that over 50% of the Other BoS price decreases according to the efficiency improvement of the PV modules. Other BoS area dependence of 50% is assumed here for the base case, 35% for the slow, and 65% for the fast BoS price decrease scenario.

According to Fraunhofer ISE,[40] the average crystalline silicon PV module efficiency during the past decade has increased by about absolute 0.4% annually. It is assumed here that this development will continue until 2050. This would mean that the average module efficiency would increase from 17.2% in 2018[40] to 30% by 2050. Although single-junction silicon cells have a theoretical limit of about 30% efficiency, with multijunction cells it is possible to reach much higher efficiencies.[40] Tandem cell structures on perovskite and crystalline silicon are currently prepared for market introduction and may lead to PV system efficiencies of 30% well before 2050.[41] It is assumed here that the annual efficiency improvement is absolute 0.3, 0.4, and 0.5% in the slow, base, and fast BoS price reduction scenarios, respectively.

Apart from the efficiency improvement, a 7.5% LR is assumed for the Other BoS in the base case. For the slow price decrease scenario, 5% is assumed, and for the fast scenario 10%.

Current market price references for the Other BoS are even more difficult to find than inverter prices. However, it is possible to calculate it from reports that have a system cost breakdown. Central Electricity Regulatory Commission of India (CERC) published a cost benchmark for PV CAPEX[42] for financial year (FY) 2016 to 2017 in which the Other BoS cost excluding the land cost was 13.6 INR/Wp, ie, about 0.17 €/Wp. A similar breakdown to CERC cost benchmark in Uttarakhand[38] had the Other BoS without the land cost as 9.0 INR/Wp or 0.113 €/Wp for FY 2018-19.

It must be noted that India with their reverse auctions for utility-scale PV is the most competitive market in the world and the Other BoS prices cannot be used as such for European projects. It is assumed that the Other BoS in Europe would be 75% higher than in Uttarkhand or about 0.20 €/Wp to which we add 0.04 €/Wp for the grid connection. Thus, the starting point Other BoS price for 2019 is 0.24 €/Wp. Land cost is excluded from the Other BoS; it is included in the OPEX.

In reality, BoS prices vary by country and project. For example, the length of grid cables to the point of connection of the transmission line can be very short or several kilometres. Uneven surface increases the mounting cost, and project development cost can sometimes include park fees or other official charges. However, it is assumed that the BoS price is the same for all countries that are considered here. The impact of different prices on PV LCOE can be seen in the sensitivity analysis.

2.3 | Total CAPEX

Total CAPEX development in different scenarios for 2018 to 2050 is shown in Figure 3. It can be seen that the CAPEX will decrease by about 65% by 2050 in the base scenario and more than 50% even in the slow price decrease scenario. In the high growth scenario, the reduction would be about 75%. The current 2019 CAPEX assumed for Europe is about 0.46 €/Wp, which is still significantly higher than in many Indian projects.[9,38]

2.4 | Operational expenditure (OPEX)

The main component of OPEX is usually the O&M. O&M cost varies greatly depending on the size of the system, scope of the O&M, and location. In the past, when lucrative feed-in tariffs were the dominant

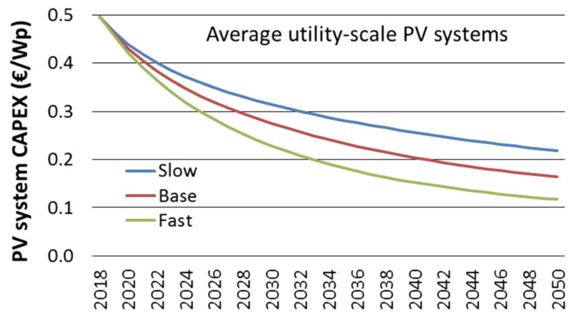

FIGURE 3 Utility-scale photovoltaics (PV) capital expenditure (CAPEX) in Europe for the years 2018 to 2050 in three different scenarios [Colour figure can be viewed at wileyonlinelibrary.com]

PV business model, O&M prices were extremely high. BNEF reported in 2013[43] that the average full service O&M contract price in Europe had already come down from 35 €/kWp/a in 2011 to 21.7 €/kWp/a in 2 years. Full service in this case includes monitoring, periodic or preventing maintenance, corrective maintenance, module cleaning, and grass cutting. More recently, another BNEF study[44] reported the O&M price in 2014 as 19.4 €/kWp/a and in 2017,[45] it had decreased to 9.35 €/kWp/a from 13 €/kWp/a in 2016. Considering that the global cumulative market doubled 2.9 times from 2010 to 2016, LR for O&M would have been about 37%. Following the same 37% LR, average O&M price in 2019 would be 6.7 €/kWp/a or 28% less than in 2017.

Steffen et al[46] reported that the utility-scale O&M cost in Germany had decreased from about 30 €/kWp/a in 2005 to about 7 €/kWp/a in 2017. They found that the key drivers for the cost reductions were pressure from lower feed-in tariffs, larger O&M portfolios, and the optimisation of the O&M companies' processes. Further cost reduction potential is expected from digitalisation and LCOE optimisation. With 28% reduction from 2017, the utility-scale O&M cost in Germany in 2019 would be about 5 €/kWp/a.

It must be considered that of the O&M contracts included in the BNEF study,[45] the majority had system sizes below 10 MWp. Majority of contracts with system sizes between 10 and 50 MWp had an O&M price of about 5 €/kWp/a. Since we are considering utility-scale projects of 50 MWp and larger in this paper, the O&M price must be less than 5 €/kWp/a. We set the starting point for O&M in 2019 as 1% of the CAPEX or 4.6 €/kWp/a.

Apart from O&M, other components of OPEX include land lease, insurance, grid fees, balancing, asset management, and various taxes. The amount of these cost components varies by country and project. It is assumed that the total amount of them equals the O&M price; ie, the total OPEX in 2019 is 9.2 €/Wp/a. The impact of lower or higher OPEX can be seen in the sensitivity analysis.

Most of the OPEX components, like maintenance, module cleaning, grass cutting, and land lease, have a strong area-dependence, ie, the cost decreases with the improvement of module efficiency. It is assumed that in the base case, 50% of OPEX components depend on the area of the module array. In the slow price decrease scenario, this share is set to 35% and in the fast price decrease scenario to 65%. In addition to this area-dependence of OPEX, a 10% LR is assumed for the base case, 5% for the slow price decrease scenario and 15% for the fast price decrease scenario. Figure 4 shows the OPEX development in 2018 to 2050 for the three different scenarios. It can be seen that the OPEX will decrease by about 30% by 2030 and 50% by 2050 in the base case.

2.5 | Yield, degradation, and system lifetime

The annual yield of a PV system depends on the local irradiation and performance ratio (PR). Five locations from some of the most populous European countries were selected for a detailed study: London, Munich, Toulouse, Rome, and Malaga. In addition, Helsinki is chosen as the northernmost capital in the EU and only second to Reykjavik in the world. The irradiation values are given according to Solargis database averages for 20 years.[47]

The average PR of PV systems has been increasing over the years. IEA PVPS Task 13 study[48] found that the average PR for the analysed utility-scale installations in Southern Italy in 2008-2012 was 81%. A study by Fraunhofer ISE[49] showed that the median PR of the monitored German systems increased by more than 5 percentage points during the first decade of this century. This trend is expected to continue because of, eg, more efficient inverters, less ohmic losses with higher voltage modules, better temperature coefficients and better low light response of the modules. Moreover, bifacial modules are gaining ground and increasing the yield. It is assumed here that the PR of all systems have increased and will continue to increase from 2012 by absolute 0.5% per year up to 2030 and then remain the same from 2030 to 2050. The annual irradiation is assumed to be stable.

The average PR in 2019 is assumed to be 84.5% in Toulouse, Rome, and Malaga and 87% in Helsinki, London, and Munich. The main reason for the difference is the negative temperature coefficient of the majority of PV modules, which means that the average operating efficiency of modules is lower in warmer climates and with higher irradiation.

Table 1 shows the annual yields for the chosen locations with global horizontal irradiance and irradiation for a surface tilted 30° towards South, which gives almost the maximum annual yield for all locations. The annual yields are calculated for the tilted surface with the given PRs.

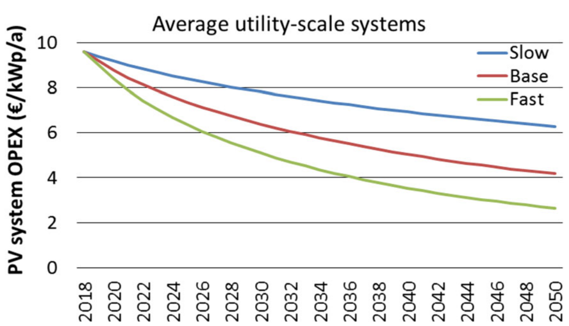

FIGURE 4 Operational expenditure (OPEX) development for the years 2018 to 2050 in three different scenarios [Colour figure can be viewed at wileyonlinelibrary.com]

TABLE 1 Annual GHI, irradiation on surface tilted 30° to south, and yield for different locations in 2019 and 2030

	Irradiation, kWh/m^2		Yield, kWh/kWp	
	GHI	30°S	2019	2030
Helsinki	950	1160	1010	1070
London	1020	1190	1040	1100
Munich	1170	1370	1190	1270
Toulouse	1370	1590	1340	1430
Rome	1600	1860	1570	1670
Malaga	1840	2100	1770	1890

Note. Source for irradiation data: Solargis (2018).

Abbreviations: GHI: global horizontal irradiation.

The annual yields in Table 1 are initial values, ie, without any degradation. The power guarantees (typically 80% of nominal power after 25 years) of most PV module manufacturers would mean maximum average degradation of 0.9% per year. In reality, most systems in Europe degrade far less and, eg, an average degradation of 0.2% per year has been reported for German rooftop systems.[50] A conservative value of 0.5% per year is used here for properly installed PV systems, based on findings of the IEA PVPS Task 13 report[51] and ITRPV.[6] The initial first year degradation is set to 2%.[6]

Clearly, system lifetime is related to the degradation of the system. The applied system lifetime of 30 years was recommended by IEA PVPS Task 12 for life cycle assessment studies[51] and reflects the quality of current PV systems, even though it is expected that the technical lifetime will increase in the future and give added financial, environmental and social benefits.

2.6 | Battery storage

BNEF reported in September 2018[52] that the benchmark CAPEX for a fully installed utility-scale battery storage system (80 MWh capacity/20 MW power) in 2018 was 357 $/kWh (316 €/kWh) in 2018 and would decrease to 338 $/kWh (299 €/kWh) in 2019. BNEF assumes an energy-to-power ratio of 4, implying substantial electricity storage. The same energy-to-power ratio for batteries is applied in this paper.

The price learning curve for battery systems, especially Li-ion batteries, has been a topic of a lot of discussion in recent years. One of the first estimates made by Hoffmann[53] was a LR of 15 to 20% for Li-ion batteries. Schmidt et al[54] reported that LR for residential Li-ion battery systems in the past would have been 12% ± 4%, whereas LR for consumer electronics batteries has been as high as 30% ± 3%. Kittner et al[55] reported a LR of 15.5% for Li-ion batteries. BNEF[56] estimated the LR for Li-ion battery packs as 18%.

It is advisable to break down the battery system price into different components since they might have different LR. In this paper, the battery system is divided into battery pack, inverter, and other BoS, which is analogous to the method used for PV systems. A LR of

17.5% is used for the battery pack, 20% for the inverter (aligned to those for PV systems), and 12.5% for other BoS in the base case.

BNEF reported in December 2018[57] that the average Li-ion battery pack price in 2018 was 176 $/kWh, ie, 156 €/kWh. Assuming 10% price reduction for 2019, 140 €/kWh is used for the starting point in 2019. Inverter price of 18 $/kWh (16 €/kWh) and Other BoS of 135 $/kWh (119 €/kWh) is reported[52] for a 80 MWh/20 MW battery system, which are used for the starting point in 2019. Thus, the total utility-scale storage system CAPEX of 275 €/MWh is used in this paper for 2019.

As the price will decrease by 12.5 to 20% every time the global cumulative volume of the respective component doubles, a projection for the battery volume growth is also needed. The cumulative volume of stationary battery storage systems was about 20 GWh at the end of 2018 according to a BNEF.[57] At the same time, the cumulative volume for battery electric vehicle (EV) batteries, including buses, 2/3-wheelers and trucks, was already almost 200 GWh. Since both stationary and EV batteries use similar modules or packs, it is possible to consider their volumes together with the same learning curve. However, since consumer electronics use often individual battery cells instead of modules or packs, they have been excluded from the learning curve volume here. The annual global battery market was close to 70 GWh in 2018, excluding consumer electronics.[57]

The next thing to consider is the future volume growth of battery systems. The task of replacing fossil fuels in the transport sector will be huge, and accordingly, the battery volumes needed will be enormous. According to BNEF projection,[57] global annual stationary battery storage market will be below 15% of the EV battery market during the next decade. Only about 2% of the new passenger cars sold in 2018[58] were EVs. This is expected to grow to about 28% by 2030, to 55% by 2040,[58] and to 75% by 2050 in the base scenario here. For stationary battery systems, the current annual global market is only about 0.1 kWh per 1 kWp installed new PV capacity.[32,57] This could conceivably grow to 1 to 2 kWh/kWp by 2050 if all PV systems had an optimally sized storage system.[2,59] Moreover, assuming conservatively that a storage system will have to be replaced at least once during the lifetime of a PV system, the annual stationary battery market could eventually be about 50% of the EV battery market.

Assuming conservatively that the average EV battery system size is 50 kWh, the annual EV battery volume growth can be estimated according to the number of EVs sold, which was about one million in 2017.[58] To that, the smaller stationary storage system volume is added. It is projected here that the CAGR of the annual battery market will be 50% for the years 2018 to 2020, decreasing linearly by 2025 to 30%, by 2030 to 15%, and by 2040 to 5% at which rate it stays after 2040. These growth rates would lead to about 1900 GWh annual market in 2030. BNEF[57] projected about 1700 GWh by 2030. By 2050, the annual global battery market would grow to about 7600 GWh with these CAGR rates. This would mean that 90 million EVs were sold in 2050 and 2-kWh battery storage capacity per kWp of PV was installed that year.

Because the uncertainty of the volume growth is very high, two other scenarios in addition to the base case have been devised. In the slow growth scenario, the CAGR is 30% in 2018 to 2020, decreasing by 2025 to 20%, by 2030 to 10%, and by 2040 to 5% at which rate is stays after 2040. In the fast growth scenario, the CAGR is 70% in 2018 to 2020, decreasing by 2025 to 40%, by 2030 to 20%, and by 2050 to 0%. The slow growth scenario would lead to an annual market of about 600 GWh in 2030 and 2000 GWh in 2050, whereas the fast growth would have about 5300 GWh in 2030 and 32 000 GWh in 2050. Slow growth would mean that only 30 million EVs would be sold and 1-kWh battery storage capacity per kWp PV was installed in 2050. Fast growth would require that 180 million EVs were sold and 3 kWh of storage capacity per 1 kWp was installed in 2050. Figure 5 shows the projected annual volume growth in the different scenarios.

Cumulative volume growth is shown in Figure 6 for the different scenarios. It must be noted that these figures include the replacement of every stationary battery system after 15 years. In the base scenario, the cumulative market grows from 200 GWh in 2018 to about 10 000 GWh in 2030 and to about 100 000 GWh in 2050. Slow growth would lead to about 30 000 GWh and fast growth to more than 400 000 GWh cumulative market by 2050. It must be noted that such high market volumes will probably require very efficient recycling processes for batteries since there could be scarcity of materials like lithium, or the introduction of new storage technologies that complement the huge volumes needed for Li-ion batteries.

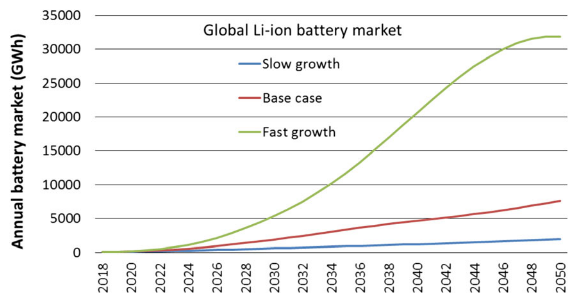

FIGURE 5 Global annual Li-ion battery system market volume development for the years 2018 to 2050 for three different scenarios. Consumer electronics is excluded from the figures [Colour figure can be viewed at wileyonlinelibrary.com]

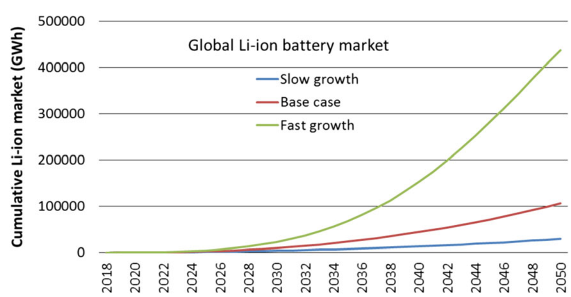

FIGURE 6 Global cumulative Li-ion battery system market volume development for the years 2018 to 2050 for three different scenarios. Consumer electronics is excluded from the figures [Colour figure can be viewed at wileyonlinelibrary.com]

After establishing the volume growth scenarios, it is possible to estimate the future price development for battery systems, which is shown in Figure 7.

In addition to price, the battery system lifetime is a very important parameter influencing the profitability of the storage investment. It is assumed here that the battery calendar life is 15 years. This means that the battery needs to be renewed once during the lifetime of the PV system. In all simulated cases in a study by the authors,[60] the storage was used for less than 4000 full cycles or 5000 80% deep cycles, since the average maximum usable capacity during the lifetime of the battery is set to 80% of the nominal capacity. This means that the end of calendar life is more probable than the end of cycle life for the battery systems. In addition, the round-trip efficiency of the storage was set to 90%, leading to a less than 5% loss of the PV generation in all simulated cases.[60] The round-trip efficiency could actually be higher if the number of DC/AC conversions in the system can be kept at minimum.

OPEX price for the utility-scale industrial battery system was set at 1.5% of CAPEX price per year in 2019, and decreasing with 7.5% LR thereafter in the base case. Figure 8 shows the OPEX price development for the different growth scenarios.

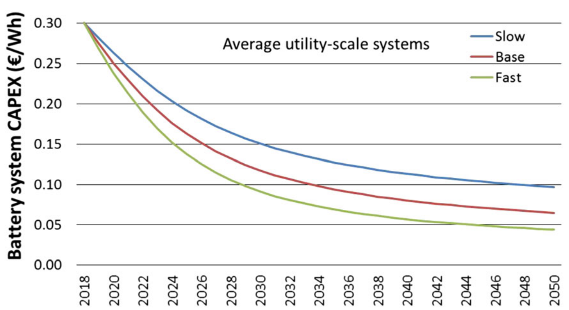

FIGURE 7 Li-ion battery system capital expenditure (CAPEX) price development projection for the years 2018 to 2050 for different growth scenarios, prices in 2019 real money without value added tax [Colour figure can be viewed at wileyonlinelibrary.com]

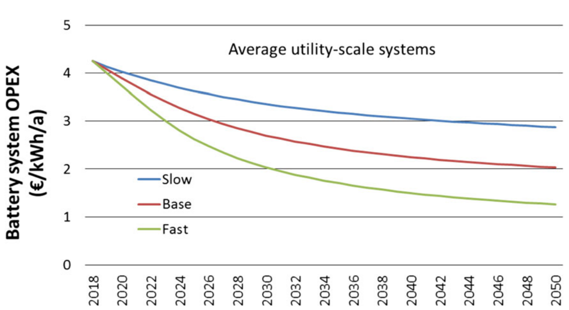

FIGURE 8 Li-ion battery system operational expenditure (OPEX) price development projection for the years 2018 to 2050 for different growth scenarios, prices in 2019 real money without value added tax [Colour figure can be viewed at wileyonlinelibrary.com]

3 | RESULTS

3.1 | PV LCOE 2019-2050

Figure 9 shows the PV LCOE development in 2019 to 2050 for the six European locations. The blue bar in the figure shows the LCOE with 2% nominal WACC, red the additional LCOE with 4%, green the additional LCOE with 7%, and brown the additional LCOE with 10%. LCOE with 7% nominal WACC in 2019 ranges from 24 €/MWh in Malaga to 42 €/MWh in Helsinki. In 2030, this range would be 14-24 €/MWh and 9-15 €/MWh in 2050. It is notable that increasing the nominal WACC from 2 to 10% doubles the LCOE.

Since the era of feed-in tariffs is coming to a close, the probable future business model for utility-scale PV is either PPAs or to sell directly to the electricity spot market. It can be argued whether the current spot market design based on marginal cost can survive since the two major future electricity sources, solar PV and wind power, do not have any marginal costs. Nevertheless, Figure 10 shows a comparison between PV LCOE and average day-ahead spot market price in the six European countries, both in 2018.

It can be seen that in 2018, utility-scale PV could have been sold profitably in all six countries with 7% nominal WACC at average spot market price. Apart from Finland and Germany, this could have been possible even with higher than 10% nominal WACC. However, the average spot market price does not take into account the fact that the price is varying at different times of day and irradiation levels. Figure 11 shows a comparison of monthly volume-weighted averages of hourly spot market prices 2018 in Finland for total generation, solar PV, and wind power.

Solar PV actually gets an annual 12.5% premium on average spot market prices in Finland, whereas wind gets 5.5% less than average. This can be explained by the fact that the daytime electricity price in Finland in 2018 was still higher than the average. It is obvious that the daytime market prices will decrease as more and more PV comes to the electricity system. However, with continuously decreasing PV CAPEX and OPEX prices, it is likely that PV will stay profitable in the electricity spot market for a considerable time.

3.2 | PV plus storage LCOE 2019 to 2050

The business case for PV can be enhanced with electricity storage. Rooftop PV plus battery storage is already a big market in countries like Germany, and Li-ion batteries can also be used with utility-scale PV installations. As discussed in Section 2.6, the optimal storage size is likely to be 1 to 2 kWh per kWp of PV capacity. Figure 12 shows the utility-scale PV plus storage LCOE for the six European locations with a 50- or 100-MWh battery capacity with 50 MWp PV system and with 7% nominal WACC.

PV plus storage LCOE in 2019 ranges from 39 €/MWh in Malaga to 69 €/MWh in Helsinki with 1 kWh/kWp storage and from 54 to 95 €/MWh with 2 kWh/kWp storage. PV with 2 kWh/kWp storage would already be competitive now with average spot market

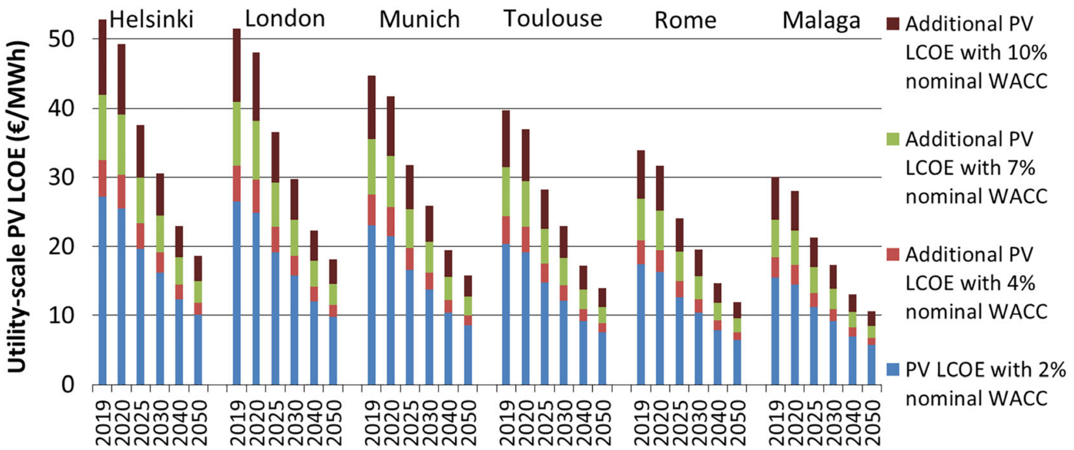

FIGURE 9 Photovoltaics (PV) levelised cost of electricity (LCOE) in six European locations for the years 2019 to 2050; in 2019 euros, taxes not included [Colour figure can be viewed at wileyonlinelibrary.com]

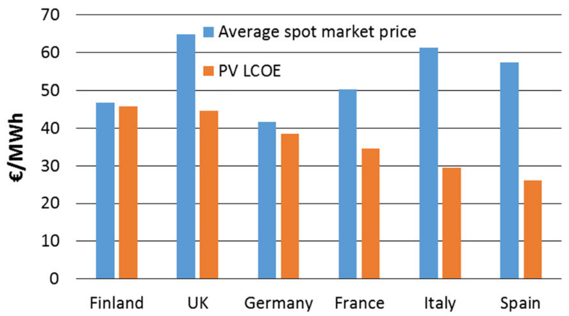

FIGURE 10 Comparison of photovoltaics (PV) levelised cost of electricity (LCOE) and average day-ahead spot market prices 2018 in six European locations. 2018 capital expenditure (CAPEX) assumption 0.50 €/Wp and operational expenditure (OPEX) 10 €/kWp/a, nominal weighted average cost of capital 7%, annual inflation 2% [Colour figure can be viewed at wileyonlinelibrary.com]

electricity price in Rome and Malaga. PV with 1 kWh/kWp storage will become competitive in 2020 in London and Toulouse and by 2025 in Helsinki and Munich.

3.3 | Sensitivity analysis

Figure 13 shows the sensitivity of PV LCOE on the major input parameters in 2050. The comparison is for the base case in Toulouse, France, with 7% nominal WACC and 2% inflation. Location or yield is the most important parameter: LCOE in Malaga is 24% lower and in Helsinki 33% higher than in Toulouse. WACC has the next biggest impact on PV LCOE with over ±20% difference to the base case with 4/10% nominal WACC. Compared with 2% inflation, 4/0% has about ±16% difference. Essentially, the difference between nominal WACC and inflation, or real WACC, is the dominant factor. CAPEX decrease or increase by 20% or ±50% OPEX change makes a ±14% difference.

PV LCOE is quite robust against LR variation, the difference to base case is around ±11% for all changes. It is also remarkable that even though there is a huge difference between the volume growth scenarios used in the CAPEX and OPEX price development models (62/20/9 TWp global cumulative PV capacity by 2050 in fast/base/slow growth scenarios respectively), the change in LCOE is only about ±15%. Increasing system lifetime to 40 years has only a small effect

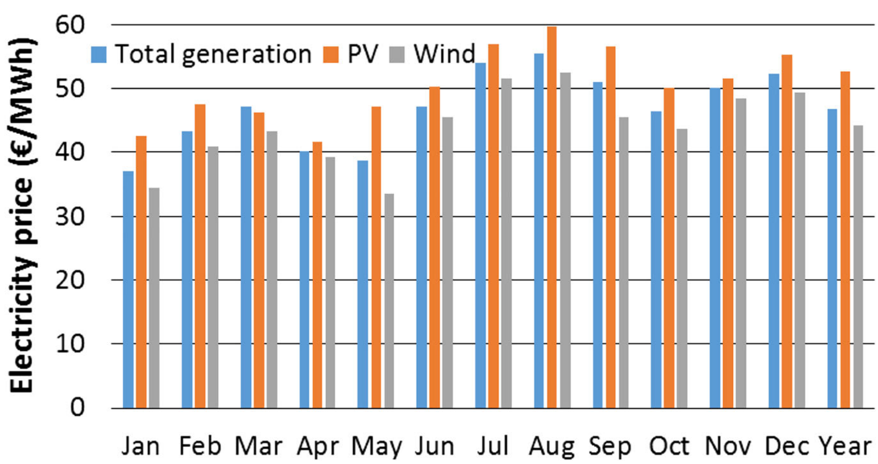

FIGURE 11 Monthly volume-weighted averages of hourly spot market prices 2018 in Finland for total generation, solar photovoltaics (PV) and wind power. Source for day-ahead spot market electricity prices Nord Pool[61] and generation data Fingrid[62] [Colour figure can be viewed at wileyonlinelibrary.com]

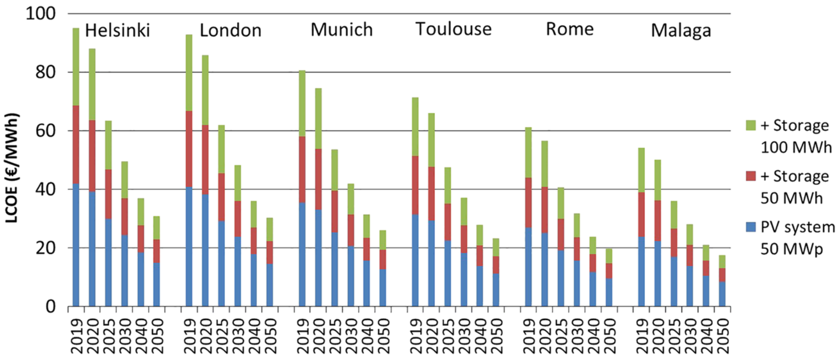

FIGURE 12 Utility-scale photovoltaics (PV) plus storage levelised cost of electricity (LCOE) for the years 2019 to 2050 for six European locations with 7% nominal weighted average cost of capital [Colour figure can be viewed at wileyonlinelibrary.com]

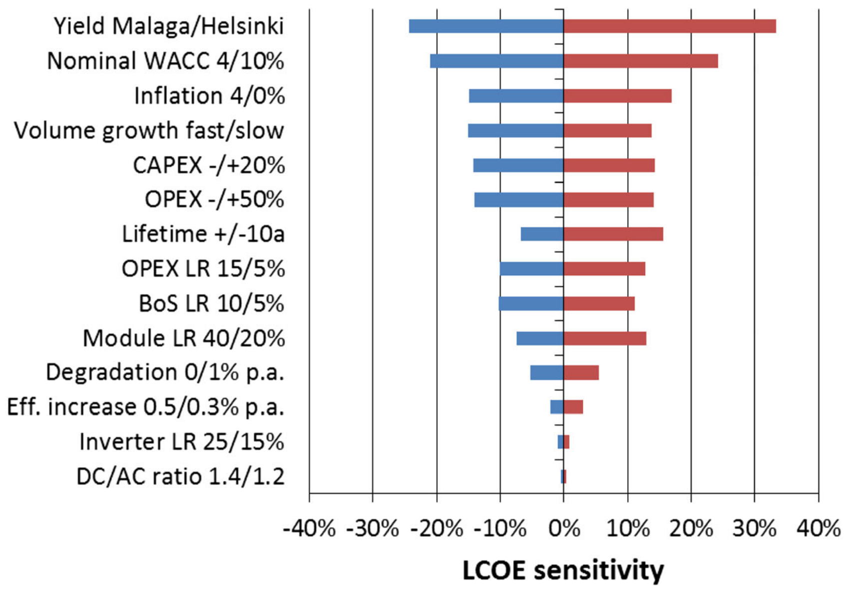

FIGURE 13 Sensitivity of photovoltaics (PV) levelised cost of electricity (LCOE) in 2050 on input parameters for a utility-scale PV system in Toulouse with 0.164 €/Wp capital expenditure (CAPEX), 4.2 €/kWp/a operational expenditure (OPEX), 7% nominal weighted average cost of capital (WACC), 2% inflation, 30 years lifetime, 0.5% annual degradation, 0.4%-points annual efficiency improvement, 1.3 DC/AC ratio, base volume growth scenario, and learning rate (LR) of 30% for PV modules, 20% for inverters, 7.5% for other BoS and 10% for OPEX [Colour figure can be viewed at wileyonlinelibrary.com]

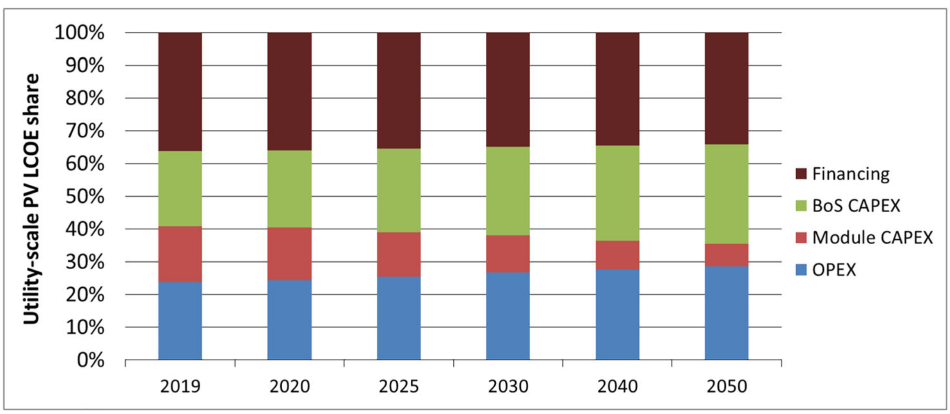

FIGURE 14 Share of operational expenditure (OPEX), module, and BoS capital expenditure (CAPEX) and financing in a utility-scale system levelised cost of electricity (LCOE) in Toulouse with 7% nominal weighted average cost of capital (WACC) and 2% inflation for the years 2019 to 2050. Financing is the LCOE difference between 7% and 2% nominal WACC [Colour figure can be viewed at wileyonlinelibrary.com]

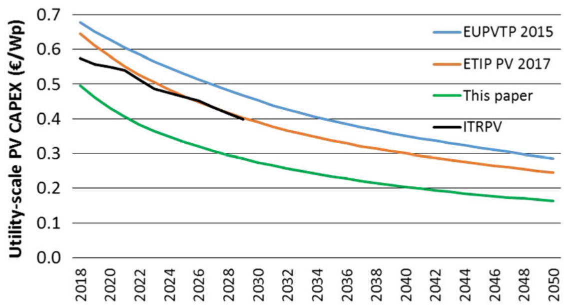

FIGURE 15 Comparison of different utility-scale photovoltaics (PV) capital expenditure (CAPEX) scenarios for the years 2018 to 2050 with this paper: EUPVTP 2015,[25] European Technology and Innovation Platform for Photovoltaics (ETIP PV) 2017,[63] ITRPV 2019[6] [Colour figure can be viewed at wileyonlinelibrary.com]

TABLE 2 Total installed solar PV capacity of major global energy transition scenarios and publications.

	2020, TWp	2030, TWp	2040, TWp	2050, TWp
Jacobson et al[64]	n/a	n/a	n/a	27.1
Teske et al[65]	0.80	5.1	10.0	12.7
Bogdanov and Breyer et al[21]	1.17	7.0	13.8	22.0
Ram and Breyer et al[19]	1.10	10.2	30.5	63.4
Pursiheimo et al[22]	0.15	19.5	35.8	48.5
Löffler et al[66]	n/a	9.9	11.1	15.2
Haegel et al[1]	n/a	10.0	n/a	30-70
IEA WEO SDS 2018[35]	n/a	2.3	4.2	n/a
IRENA REmap 2050 2019[34]	n/a	2.9	5.7	8.5
Maximum	1.17	19.5	35.8	70
Minimum	0.15	2.3	4.2	8.5
Average	0.80	8.4	15.9	28.2

Abbreviations: IEA: International Energy Agency; IRENA: International Renewable Energy Agency; PV: photovoltaics.

with 7% nominal WACC but decreasing it to 20 years makes a 16% difference. The degradation or efficiency improvement rate has only a minor effect and inverter has such a small share of the system cost that changing the LR or DC/AC ratio has a less than ±1% difference in LCOE.

4 | DISCUSSION AND CONCLUSIONS

The main problem regarding PV LCOE assessment is that there is not total openness on the whole range of price information of CAPEX and OPEX. Investors do not usually publish their budgets, and if they do, it is not sure whether the budget was eventually met or not. Module prices are generally well known and fairly universal, but BoS prices are not and they vary from project to project. There is even more ambiguity and variability over OPEX prices.

Figure 14 shows the relative shares of module and BoS CAPEX, OPEX, and financing during the lifetime of the system for the base case in Toulouse with 7% nominal WACC and 2% inflation. CAPEX and OPEX without financing are with 2% nominal or 0% real WACC. As can be seen, the share of BoS and OPEX is increasing and modules decreasing. This is obvious since the LR for modules is higher than for BoS and OPEX. The share of BoS and OPEX will increase from the current 23% to about 30% in 2050 and modules decrease from 17% to 7%. This emphasises the importance of realistic prices for BoS and OPEX.

Several studies have been made on the historical CAPEX prices. The challenge with these studies is that they are almost always out of date after the publication. For example, IEA PVPS[3] reported thoroughly in their latest Trends in PV publication in 2018 the average CAPEX prices for various countries and market segments in 2017. At the time of writing of this paper (June 2019), the information of[3] is already about two years old. During the last two years, the module prices alone have decreased by 38% or 0.13 $/Wp (0.115 €/Wp)[4] in real terms.

IEA PVPS[3] reported that the total utility-scale PV power plant market in 2017 had a size of 61.4 GWp with an average volume-weighted market price of 0.857 $/Wp, which equals 0.759 €/Wp with the current average $/€ exchange rate of 1.13. However, 74% of the total market in gigawatts was found to be below the average price, whereas Israel and Germany were already in 2017 on the CAPEX level of 0.55-0.60 $/Wp (0.49-0.53 €/Wp). Deducting from this the module price decrease over the last 2 years would give a CAPEX of 0.435 to 0.485 $/Wp or 0.38-0.43 €/Wp, ie, much less than the starting point of 0.46 €/Wp in 2019 used in this paper. From the major European markets in addition to Germany, the UK would have been closest to the starting point in 2019 here, whereas Italy and Spain had clearly higher CAPEX in 2017. This can be partly explained by the fact that those markets were quite low in 2017 with only a limited number of small projects. From large international markets, India would now match the starting price in 2019 in this paper.

Another challenge is that the solar PV industry is developing so fast that it is difficult to forecast even the near future price development. As an example, Figure 15 shows a comparison of a couple of fairly recent EUPVTP/ETIP PV[25,63] PV CAPEX projections where the authors have been involved with the base case CAPEX projection of this paper. Latest ITRPV[6] large-scale CAPEX projection is included as well. As can be seen, 4- and 2-year old EUPVTP/ETIP PV CAPEX projections[25,63] for 2019 were 0.60 to 0.65 €/Wp, ie, 30 to 40% higher than the CAPEX used here. ITRPV's[6] projection 2019 is about 20% higher than here.

However, it has to be said that a 20% difference in CAPEX is not very significant in future LCOE projections, as seen in the sensitivity analysis. It would only make a difference of ±14% in 2050 LCOE, ie, ±1-2 €/MWh for generated PV electricity depending on the location. A ±50% difference in OPEX would have a similar effect. In fact, this level of difference would cover the majority of global utility-scale installations, as shown by the IEA PVPS report.[3] Even using the very extreme slow and fast global volume growth scenarios instead of the base case do not change the future PV LCOE by more than ±1-2 €/MWh.

The total PV capacity growth has a significant impact on the CAPEX due to the LR approach. It has been already shown in the sensitivity analysis that the cumulative installed PV capacity in 2050 has an impact of ±15% on the LCOE for the applied values of 9 TWp (slow growth case) and 62 TWp (fast growth case) in reference to the 20 TWp base case. Table 2 provides an overview on solar PV capacity assumptions of major energy transition scenarios and publications.

Table 2 indicates that the chosen values represent very well the existing literature on energy transition studies since the minimum value of 8.5 TWp in 2050 of IRENA[34] matches the slow growth case and the upper limit of 70 TWp in 2050 of Haegel et al[1] supports the fast growth case, whereas the average of 28.2 TWp is even higher than the chosen base case of 20 TWp in 2050 here. These literature insights may indicate a slightly higher LCOE reduction potential than shown in the base case in this paper.

The assumed battery sizes of 1 to 2 kWh_{cap} per kWp of PV installed capacity is confirmed by a value of 2.3 kWh/kWp for a 100% renewable power sector[21] and 1.1 kWh/kWp for a 100% renewable energy system[19] for utility-scale battery and PV systems as major components for the global energy transition. The decreasing battery storage demand for the entire energy system clearly reveals that more flexibility in the sectors heat and transport reduces the relative need for storage and thus stationary batteries. The role of batteries for future energy systems are increasingly investigated, since batteries offer a very valuable flexibility to substantially increase the penetration of solar PV not only in the power sector[21] but for the entire energy system.[1,6]

It can be concluded that the financial parameters, nominal WACC and inflation, have the biggest impact on the PV LCOE, apart from the location. Very progressive vs conservative solar PV growth assumptions have a smaller impact on PV CAPEX, the resulting PV LCOE is not varied by more than ±15%. Increasing the nominal WACC from 2 to 10% would double the LCOE. Combining the effect of 4%/10% nominal WACC and 4/0% inflation instead of 7% nominal WACC and 2% inflation, ie, having a real WACC range of 0 to 10% around 5%, would have an even bigger effect than changing the location from Toulouse to Helsinki or Malaga. This proves that it is of utmost importance for the solar PV industry to convince the financial community that utility-scale PV is a safe and profitable investment. Policy makers need to be informed that PV is the cheapest form of electricity, especially if its inherent low economic, technical, and environmental risks are taken into account. In addition, it has to be highlighted that the high dynamics in the solar PV industry has led to PV CAPEX and PV LCOE levels not yet well reflected in literature and major reports typically taken into account for decision making. PV plus batteries are the cornerstones of the future energy system if we wish to tackle the climate crisis in a fast and cost-neutral way.

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APPENDIX A
TABULATED VALUES FOR UTILITY-SCALE SOLAR PV AND BATTERY SYSTEM CAPEX AND OPEX

	PV CAPEX, €/Wp	PV OPEX, €/kWp/a	Battery CAPEX, €/Wh	Battery OPEX, €/kWh/a
2019	0.462	9.2	0.275	4.1
2020	0.431	8.8	0.251	3.9
2021	0.406	8.4	0.229	3.7
2022	0.384	8.1	0.209	3.6
2023	0.365	7.8	0.192	3.4
2024	0.348	7.6	0.176	3.3
2025	0.333	7.4	0.163	3.2
2026	0.319	7.1	0.151	3.0
2027	0.307	6.9	0.141	2.9
2028	0.296	6.7	0.132	2.9
2029	0.285	6.6	0.124	2.8
2030	0.275	6.4	0.117	2.7
2031	0.266	6.2	0.112	2.6
2032	0.257	6.1	0.106	2.6
2033	0.249	5.9	0.102	2.5
2034	0.242	5.8	0.098	2.5
2035	0.235	5.6	0.094	2.4
2036	0.228	5.5	0.091	2.4
2037	0.221	5.4	0.088	2.3
2038	0.215	5.3	0.085	2.3
2039	0.209	5.1	0.082	2.3
2040	0.204	5.0	0.080	2.2
2041	0.199	4.9	0.078	2.2
2042	0.194	4.8	0.076	2.2
2043	0.189	4.7	0.074	2.2
2044	0.185	4.6	0.073	2.1
2045	0.181	4.6	0.071	2.1
2046	0.177	4.5	0.070	2.1
2047	0.174	4.4	0.069	2.1
2048	0.170	4.3	0.067	2.1
2049	0.167	4.2	0.066	2.0
2050	0.164	4.2	0.065	2.0