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Research paper

LCOE distribution of PV for single-family dwellings in Sweden

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ABSTRACT

In Sweden, the installations of solar photovoltaic systems are growing rapidly, and especially the market segment of small-scale distributed systems is experiencing positive growth. The current installation volumes exceed the expectations of the Swedish authorities. This study presents an up-to-date assessment of the levelized cost of electricity to be used for both agencies in their long-term scenario work of PV development and for private investors for estimating the upfront and future costs and risks associated with photovoltaic systems. The analysis is based on the turnkey system cost of 6,098 single-family dwelling photovoltaic systems commissioned in Sweden between the 1st of January 2019 and 1st of July 2020. The statistics of system investments costs are complemented by literature studies and by interviews of relevant stakeholders for the other input parameters needed to calculate the Levelized Cost of Electricity (LCOE). A Monte Carlo analysis was applied on all the input parameters provides relevant insight into the range of LCOE values. The unsubsidized levelized cost of electricity for most systems ranged from 0.85 SEK/kWh (25th percentile) to 1.15 SEK/kWh (75th percentile), with a mean at 1.02 SEK/kWh at reasonable real discount rate of 2%, but that extreme values can reach 0.30 SEK/kWh at a 0% discount rate and 5.70 SEK/kWh at a 5% discount rate. Taking into account the current (2023) Swedish tax reduction for investment in green technologies that amounts to an effective deduction of 19.4% of the total system investment costs lowers the LCOE to mean at 0.82 SEK/kWh at real discount rate of 2%. The LCOE for single-family dwelling photovoltaic systems are generally lower than the assumed LCOE in long-term scenario studies of the Swedish electricity system. This finding helps to explain to the authorities the unexpected fast deployment of distributed photovoltaic systems in Sweden.

1. Introduction

The role of solar energy has gained paramount significance in the context of global climate action, particularly highlighted during the 26th United Nations Climate Change Conference (COP26) (United Nations, 2023a). With a growing emphasis on renewable energy solutions, COP26 underscored the urgency of transitioning to sustainable practices to effectively mitigate climate change. Consequently, photovoltaics (PV) technology emerged as a pivotal component of countries' energy strategies, aiming to reduce greenhouse gas emissions and accelerate the shift to a low-carbon economy (United Nations, 2023b). With COP26 outcomes echoing the need for accelerated PV adoption, Sweden stands at the forefront of embracing renewable energy. Since 2017 Sweden has had a climate goal stating that there should be no net emissions of greenhouse gases into the atmosphere by 2045 at the latest (Regeringskansliet, 2017). Within that framework, it is worth noting that the electricity generation in Sweden is already almost fossil fuel free. For the last three decades, electricity generation in Sweden has been dominated by hydropower and nuclear power, while a lot of wind power has been added in the last decade, see Fig. 1. The share of energy supplied from fossil sources for electricity production in Sweden was 2% in 2021 if fossil share of waste and peat used for cogeneration of heat and power is included, see Fig. 1. The average Swedish electricity consumption during 2011–2021 was 140 TWh/yr (Statistikmyndigheten, 2022a), which is the same as in 1990 (Energimyndigheten, 2022).

However, scenarios for future electricity demand from the Swedish Transmission Operator (TSO), Svenska Kraftnät, specifies that the electricity consumption can increase to 173–286 TWh in 2045 (Brunge et al., 2021), as a result of the electrification of both the transport sector and different industries, such as the Swedish steel industry, and the establishment of new battery factories and data centers. The Swedish Energy Agency expects an increase of the electricity consumption to 210–370 TWh in their long-term scenarios for 2045 (Energimyndigheten, 2023). Hence, in the highest scenarios, the electricity consumption can be at least doubled within the next 25 years, which raises important

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Abbreviations

AC	Alternating Current
AIC	Akaike Information Criterion
AICc	Akaike Information Criterion correction
BAPV	Building Applied PhotoVoltaics
BIC	Bayesian Information Criterion
BIPV	Building Integrated PhotoVoltaics
BoS	Balance of System
CAPEX	Capital expenditure of the system
DC	Direct Current
Dg	Degradation factor
GW_p	GigaWatt peak
IRR	Internal Rate of Return
kW_p	kiloWatt peak
kWh	kiloWatt hour
L	Total lifetime (construction and operation)
$\hat{L}$	Maximized value of the likelihood function
LCOE	Levelized Cost Of Electricity
MW_p	MegaWatt peak
MCA	Monte Carlo Analysis
N	Operational lifetime
NPV	Net Present Value
O&M	Operations and Maintenance
P	Turnkey system price
PV	PhotoVoltaics
r	real discount rate
ReInv	ReInvestment
ResC	Residual Cost
S	System size
SEK	Swedish krona
T	Time period
TSO	Transmission System Operator
TWh	TeraWatt hour
COP26	United Nations Climate Change Conference
VAT	Value-Added Tax
WACC	Weighted Average Cost of Capital
Y	Yield
yr	Year

questions on how and where the needed electricity is going to be generated.

PV accounted for 0.7% of the electricity production in Sweden in 2021, but the number of PV systems are many, and the market is expanding fast, as Fig. 2 illustrates. In 2021, a record number of 26,540 grid connected installations, with a total power of 498 MW_p were installed. In 2022 a new record for PV installations in Sweden with about 797 MW_p of additional capacity. At the end of 2022, the number of grid connected PV installations was 147,692, with in total 2.38 GW_p of power installed (Energimyndigheten, 2019). A vast majority of the installations, 131,298 systems (89%), had a capacity of less than 20 kW_p, with total installed power of 1.35 GW_p. Of those, it can be assumed that most are on single-family dwellings (Lindahl et al., 2023), and the most common business model in Sweden is to sell and install turnkey PV systems installed on roofs (Bankel and Mignon, 2022). With the current installation rates, the installed PV capacity will far exceed even the most PV accommodating scenarios of the two Swedish agencies. The Swedish TSO foresees an installed PV capacity of 3.27 GW_p until 2025 in their "Small-scale renewable" scenario from 2021 (Brunge et al., 2021), while the Swedish Energy Agency in 2021 expected 1.2 TWh of PV electricity by 2025 (Energimyndigheten, 2021), which corresponds to about 1.3 GW_p with the solar radiation in Sweden (Schelin, 2019a; Yang et al., 2020; Lingfors and Widén, 2016).

1.1. PV subsidy history in Sweden

Historically, the Swedish PV market consisted of a small off-grid market of systems for holiday cottages, marine applications, and caravans. The installation of grid-connected PV systems began to increase when the first investment support for PV was launched in 2005. This scheme was initially dedicated to public buildings and operated until 2008 (Boverket, 2009). This subsidy scheme was replaced with a similar PV investment support scheme in July 2009, which was open for both private individuals and companies. Capital investment schemes, which reduce upfront costs, have been found to be effective in stimulating the residential PV segment (Polzin et al., 2019). However, the deployment of PV was effectively slowed down in Sweden by the limited annual budget for the investment support scheme, which was often insufficient to meet the demand (Lindahl and Westerberg, 2021). The troublesome budget ceiling disappeared when the investment support was replaced by a tax reduction for green technology in 2021 (Lindahl and Westerberg, 2021), but the tax reduction is only available for private individuals, as compared to the investment support that was open for all actors.

The tax reduction was 15% of the cost of work and materials in 2021–2022 with a maximum of 50,000 Swedish krona (SEK) per year and person (Skatteverket, 2022c), but was raised in 2023 to 20% (Regeringskansliet, 2022). This deduction can be made by private persons and can be used once per year and person. To facilitate the administration for both companies and the Swedish Tax Agency, a level of 97% of the total investment cost has been approved as deductible costs (Skatteverket, 2023). This means that the green technology tax reduction for private individuals equals 19.4% of the total system costs from 2023. The tax reduction for green technology has no limiting budget, which means that everyone who meets the requirements can take advantage of the tax deduction directly at the investment, and hence strengthen the certainty of this kind of capital investment scheme.

Since 2015, there has been a tax reduction of 0.6 SEK/kWh for excess PV electricity fed into the grid, with a limitation of a maximum fuse of 100-ampere at the connection point (Riksdagsförvaltningen, 2022a). The basis for the tax reduction is the number of kWh that are fed into the grid at the connection point within a calendar year. However, the maximum number of kWh for which a system owner can receive the tax credit may not exceed the number of kWh bought within the same year. In addition, one is only entitled to a maximum of 30,000 kWh per year. The grid owner will file the measurement on how much electricity has been fed into and out of the connection point in one year, and the data will be sent to the Swedish Tax Agency. The tax reduction will then be included in the income tax return information, which should be submitted to the Swedish Tax Agency in May the following year.

To feed electricity into the grid, a feed-in subscription from the grid operator is required. There is no charge for this feed-in subscription if the fuse in the connection point is highest 63 amperes (Riksdagsförvaltningen, 2022b).

If the income from the electricity sales, and other possible income from the private residential property, is less than 40,000

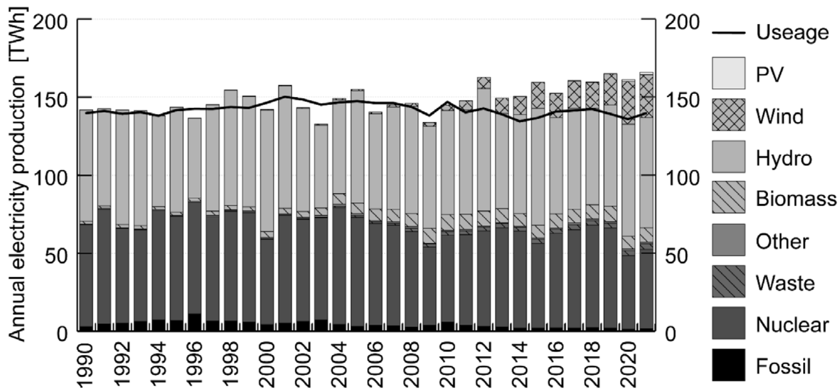

Fig. 1. The total power generation in Sweden from 1990 to 2021 from different energy sources along with the total use within Sweden (Statistikmyndigheten, 2022a).

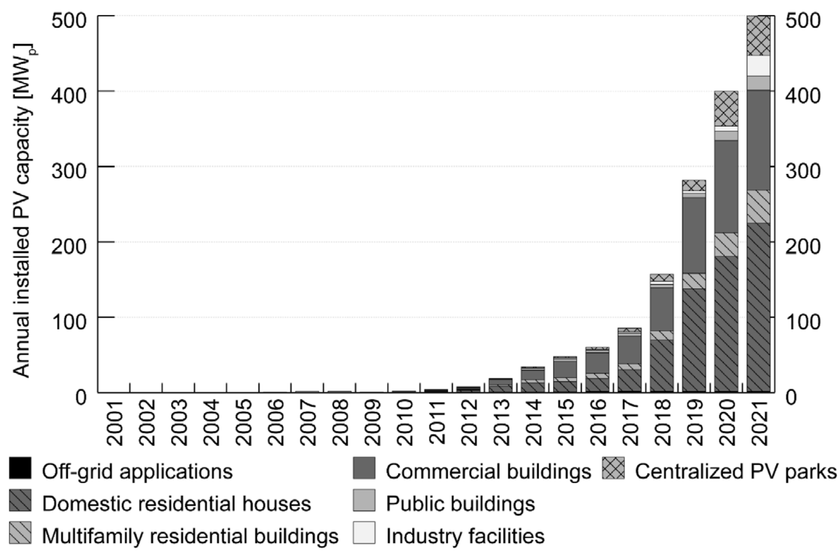

Fig. 2. Annual installed PV capacity in Sweden the last 20 years (Lindahl and Westerberg, 2021).

SEK per year, no income tax needs to be paid on the sale of surplus electricity (Riksdagsförvaltningen, 2022a).

Other factors that favor investments in PV systems for private individuals include no energy tax on self-consumed PV electricity, as long as the installed power output is below 500 kW_p, according to the Energy Taxation Act (Riksdagsförvaltningen, 2022c). The assessed value of the house is not affected, so it does not affect the property tax. If the investment is financed by a bank loan, it is possible to make a tax deduction of 30% on amounts up to 100,000 SEK of loan interest costs in the income declaration the following year (Skatteverket, 2022a). The tax deduction is 21% for loan interest costs higher than 100,000 SEK. In autumn 2018, the requirement for a building permit was abolished if solar panels follow the shape of the building and on the condition that the measure follows the detailed plan (Boverket, 2019).

1.2. Levelized cost of electricity

One reason for private individuals to install PV systems is to reduce the cost of purchased electricity. Common questions are; *how much does it cost?* and *is it profitable?* To answer those questions, a calculation of the production cost for PV electricity is needed. In the current study, we have used the method of levelized cost of electricity (LCOE) to calculate the PV electricity production cost.

LCOE calculations are commonly based on the equivalence of the present value of discounted revenues and the present value of discounted costs (Aldersey-Williams and Rubert, 2019). This method is used to compare the costs of different power plants or generating technologies (Aldersey-Williams and Rubert, 2019; Elmqvist et al., 2021; IEA, 2020; Ray, 2021; Timilsina, 2021; Sung and Jung, 2019). An LCOE calculation reveals the constant real electricity tariff needed to recover the costs of building and operating a power plant during its assumed financial lifetime, including an economical return equal to the discount rate used in the formula (Aldersey-Williams and Rubert, 2019). It is also a useful tool for assessing the current production cost of specific technologies, and is commonly used in different electricity system scenario studies (Child et al., 2019; Bogdanov et al., 2019).

As an example, LCOE calculations have been used for PV to assess the current and future production costs of electricity from centralized PV parks in different countries. The results can then be used to estimate when it reaches the market price of electricity (Vartiainen et al., 2020; Mu et al., 2021; Lindahl et al., 2022; Egli et al., 2018), to evaluate the factors that have led to efficient bidding schemes and record low tender bids (Apostoleris et al., 2018; Dobrotkova et al., 2018; Anatolitis et al., 2022), and to evaluate the input assumptions made for PV in different electricity system scenario studies (Lindahl et al., 2022; Creutzig et al., 2017).

LCOE calculations have also been conducted for small distributed PV system to assess how the production cost matches different financing schemes, like net metering and feed-in tariffs, and how likely it is that grid parity will be reached (Stridh et al., 2013; Petrichenko et al., 2019; Zhang et al., 2014; Pillot et al., 2018), as an input for rooftop PV potential estimations (Bódis et al., 2019; Mainzer et al., 2016) and for spatial distribution patterns influenced by socioeconomic factors (Wang et al., 2022; Dharshing, 2017).

As the PV market is expanding fast, both globally (Masson and Kaizuka, 2021) and in Sweden (Lindahl and Westerberg, 2021), and the system prices thereby decreases through the learning process (Fischer et al., 2022; Strupeit and Neij, 2017; Wilson et al., 2020) it is of importance for PV investors to have up to date information about costs of PV production when making investment calculations (Stridh and Larsson, 2016; Manzhos, 2013). The same applies for different agencies and stakeholders that plan and forecast the future energy system, as accurate cost assumptions are instrumental to make realistic scenarios (Lindahl et al., 2022; Egli et al., 2019). In this study, we address the production cost of small, decentralized PV systems by analyzing an extensive system cost database comprising 6098 single-family dwelling PV systems owned by individuals. We also conduct in-depth analysis of the other input parameters for LCOE calculations, based on literature reviews and interviews with stakeholders, to make relevant, up to date, assumptions on the input parameters. In addition, distribution profiles for several selected parameters are used, just as in Pillot et al. (2018), to make Monte Carlo simulations of the LCOE for such single-family dwelling PV systems. This approach allows for a realistic distribution of LCOE to be calculated. Furthermore, a sensitivity analysis was performed to point out the relative importance of different parameters in the LCOE calculations.

2. Method

2.1. LCOE method

Levelized cost of electricity calculation, LCOE, is a widely used method for calculating the production cost of electricity for different power plants. The LCOE calculation is based on the equivalence of the present value of the sum of discounted revenues and the present value of the sum of discounted costs. Another way of looking at LCOE is that it expresses the electricity tariff needed for recover the all the costs of a power plant during an assumed financial lifetime.

The real LCOE can be expressed by;

$$LCOE = \frac{\sum_{t=0}^{L}\left[\frac{CAPEX_t + O\&M_f + (Fuel + O\&M_v) * Y + ReInv}{(1+r)^t}\right] + \frac{ResC}{(1+r)^L}}{\sum_{t=0}^{L}\left[\frac{Y}{(1+r)^t}\right]}, \quad (1)$$

where r is the real discount rate, t the year number ranging from 0 to L, L the total lifetime of the power plant (construction time plus operation time), $CAPEX_t$ the total capital expenditure of the system in year t, $O\&M_f$ the fixed operation and maintenance cost in year t, $O\&M_v$ the variable operation and maintenance cost per produced unit of electricity in year t, *Fuel* the fuel costs per produced unit of electricity in year t, Y the annual electricity yield in the year when operation start, *ReInv* is any major reinvestment needed to reach expected lifetime and *ResC* is the residual value or cost of the system at the end of the lifetime. As we are interested in a real LCOE values, all costs should be stated in real values for the influence of inflation on the net present value to be handled correctly (Hanke et al., 1975).

For PV systems, the LCOE Eq. (1) can in some respects be simplified. For instance, there are no fuel costs associated with electricity production from a PV system, and the Fuel-factor can therefore be omitted. The time it takes from order to finalize a small roof-mounted PV system is commonly shorter than one year. It is therefore not necessary to discount the $CAPEX_t$ and the total capital expenditures can be handled as an 'overnight cost'. The total overnight capital expenditures will take place in year 0 and total overnight capital expenditures can instead be denominated to $CAPEX_0$. In addition, the total lifetime (construction and operation), L, in Eq. (1) then becomes only the operational lifetime, N, of the PV system, which means that operation starts at $t = 1$.

Furthermore, PV systems usually only require one major reinvestment, being a replacement of the inverter. Replacing the inverter only takes a couple of hours, so the reinvestment can be assumed to take place within one predefined year, x. This enables bringing the reinvestment factor out of the summation. These simplifications lead to the following equation:

$$LCOE = \frac{CAPEX_0 + \sum_{t=1}^{N}\left[\frac{O\&M_f + O\&M_v * Y}{(1+r)^t}\right] + \frac{ReInv_1}{(1+r)^x} + \frac{ResC}{(1+r)^N}}{\sum_{t=1}^{N}\left[\frac{Y}{(1+r)^t}\right]}, \quad (2)$$

As PV systems usually exhibit a slow degradation of the output over time (Fisher, 1896) an annual degradation factor, Dg, is added to the yield factor and the yield factor is reformulated to the initial annual yield Y_0 in year 0 without degradation. Altogether, the above discussed modifications result in equation:

$$LCOE = \frac{CAPEX_0 + \sum_{t=1}^{N}\left[\frac{O\&M_f + O\&M_v * Y_0 * (1-Dg)^t}{(1+r)^t}\right] + \frac{ReInv_1}{(1+r)^x} + \frac{ResC}{(1+r)^N}}{\sum_{t=1}^{N}\left[\frac{Y_0 * (1-Dg)^t}{(1+r)^t}\right]}, \quad (3)$$

Eq. (3) is the final real LCOE equation that is being used for calculating the LCOE of all the PV projects in this study.

2.2. Monte Carlo simulations

Instead of using a single set of input parameters for calculation of LCOE, Monte Carlo analysis (MCA) can be used to present a distribution where the inputs used in each iteration are determined by stochastic selection (Sommerfeldt and Madani, 2017). The MCA simulation can give a better insight into the distribution of expected LCOE, due to the various sources of uncertainty in the input parameters and thereby showing the most likely LCOE to support decision-makers in reducing their risks and making correct decisions (Gu et al., 2018). A summary of the inputs and their distributions used in this study is presented in Table 1.

2.3. Probability function distribution

In order to reduce uncertainty in MCA, evaluation of the fit of the probability functions is necessary (Simões et al., 2021). In this study, CAPEX and inverter cost data in Sweden 2020 are used to find the probability function distribution. The optimal distribution for the CAPEX and inverter cost data are obtained by analyzing a range of continuous distributions: (1) Beta, (2) Birnbaum–Saunders, (3) Exponential, (4) Extreme value, (5) Gamma, (6) Generalized extreme value, (7) Generalized Pareto, (8) Inverse Gaussian, (9) Logistic, (10) Log–logistic, (11) Lognormal, (12) Nakagami, (13) Normal, (14) Rayleigh, (15) Rician, and (16) Weibull.

The distribution is selected by using Bayesian information criterion (BIC), Akaike information criterion (AIC), and Akaike information criterion correction (AICc). These criteria are commonly used to select the preferred distribution (Brewer et al., 2016). The preferred distribution is the one with the lowest BIC, AIC, and AICc. The equations describing the information criterions are given as follows:

$$BIC = k\ln(n) - 2\ln\left(\hat{L}\right), \quad (4)$$

Table 1
Monte Carlo input distributions.

Input	Denotation	Distribution	Units
Operational lifetime	N	Weibull (λ, k)	Years
Annual yield	Y	Triangular (a, b, c)	kWh/kW$_p$
Annual degradation factor	Dg	Triangular (a, b, c)	%
Overnight capital expenditures	$CAPEX_0$	Loglogistic (μ, σ)	SEK
Major reinvestment	$ReInv$	Nakagami (μ, ω)	SEK
Major reinvestment year	x	Weibull (λ, k)	Year
Residual cost	$ResC$	Triangular (a, b, c)	SEK

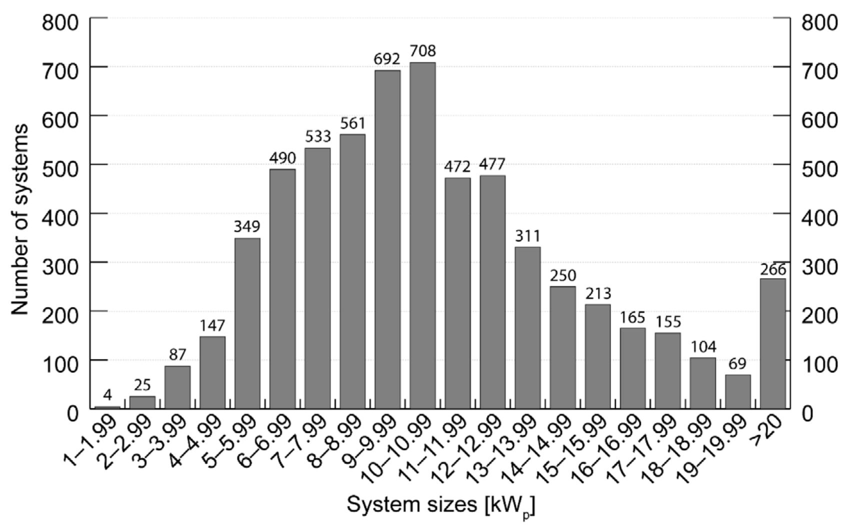

Fig. 3. The distribution of 6098 single-family dwelling PV systems installed between 1 January 2019 and 1 July 2020 in different size categories.

$$AIC = 2k - 2\ln\left(\hat{L}\right), \tag{5}$$

$$AICc = AIC + \frac{2k^2 + 2k}{n - k - 1}, \tag{6}$$

where $\hat{L}$ is the maximized value of the likelihood function of the model, k is the number of parameters estimated by the model, and n is the number of data points.

2.4. Typical size of PV systems on single-family houses

The PV systems analyzed in this study are grid-connected roof-mounted PV systems in Sweden on single-family detached houses, hereafter called single-family dwelling PV systems. This is the most common type of PV system in Sweden. 56,689 systems of the total 65,819 grid connected PV systems at the end of 2020 were below 20 kW$_p$, of which a vast majority were single-family dwelling PV systems (Energimyndigheten, 2019). The parameters for the LCOE calculation have been produced through analysis of statistical databases and through literature studies. No interviews with investors or installation companies have been conducted.

One of the statistical databases analyzed is that of the Swedish direct capital subsidy (Riksdagsförvaltningen, 2022d). All PV systems that have been granted support from the start of the public subsidy program in 2009 to the closure of the subsidy program have been recorded in the database Svanen, which is managed by the National Board of Housing. By cross-referencing this database and Sweden's national business directory, a business sector can be assigned to each system owner. Furthermore, it is also possible to sort the PV systems based on if they were installed on a single-family house, a multi-family house, a facility, etc. For this study, PV systems installed on single-family houses and owned by an individual were selected, and only PV systems that have both commence and commission dates between 1st of January 2019 and 1st of July 2020 are considered. From this setup, six systems were excluded as they have battery pack installed with the PV system, which is increasing the overall system price. After the sorting, the database included 6098 PV systems owned by individuals. In Fig. 3, these 6098 single-family dwelling PV systems are divided into size ranges of one kW$_p$ for each range. As Fig. 3 illustrates, the most common sizes of single-family dwelling PV systems are in the range 6–13 kW$_p$. Hereafter, the system size when analyzing the case of LCOE for a single-family dwelling PV system is set to 10 kW$_p$, as it is the most common size of the installed single-family dwelling PV systems in 2019–2020.

In the following chapters, each one of the LCOE parameters for a typical 10 kW$_p$ single-family dwelling PV system in 2020 are discussed. Values resulting in a low-cost, or high-cost value of LCOE are assessed for each parameter, in addition to an average value, so that a range of the LCOE can be derived.

2.5. LCOE parameters

2.5.1. Lifetime

The lifetime of a PV system is not straightforward to assess. Of the estimated total 627 GW of PV capacity that was commissioned in the world until the end of 2019, only 0.06% was older than 20 years (Jordan and Kurtz, 2013). There is therefore relatively little knowledge of the actual lifetime of PV systems, especially given the PV technology that is used today. There are a few examples of old PV systems that prove that at least the historical PV technology could have a technical lifetime of >30 years. In a Swedish context, one example is a former PV system on Bullerön from 1981 where the measured degradation of 4% (0.16%/yr) after 25 years was concluded to be within the measurement accuracy of the used method (Hedström and Palmblad, 2006; Martinsson et al., 2020). Another example is the oldest grid connected PV system in Sweden, a 2.1 kW_p system in Huvudsta from 1984, that still performs well after two exchanges of inverters, when measured at regular intervals (Lindahl and Westerberg, 2021). Most failures happen in the first five years after commission, and can in most cases be related to either component defects from manufacturing or incorrect installation procedures (Köntges et al., 2017). When identified early, such failures are covered by different warranties and should not affect the PV owner economically. However, if the failure goes undetected for a long time, it can lead to a loss of production and lower revenues. PV modules usually have a power warranty of 25 or 30 years, which is commonly used as an indicator of the economic lifetime of a PV system. In this report, we therefore assume a typical economic lifetime of 30 years for a single-family dwelling PV system, while setting the high-cost value for the LCOE calculations to 25 years and the low-cost value to 35 years.

2.5.2. Initial annual yield

The annual yield of a PV system depends on multiple factors. One factor is the geographical location, as the mean annual global radiation differs in different parts of Sweden. In general, the global radiation is higher along the coasts, reaching up to an yearly average of 1100 kWh/m^2 on a horizontal surface during the period 1991–2020, than in the inland, down towards 800 kWh/m^2 in the mountain areas in north west of Sweden (SMHI, 2023). Another factor is the variation of annual average global radiation between different years. A third factor is the azimuth and tilt angle of the PV modules. In Sweden, the optimal placing of modules to maximize the annual electricity production differs slightly depending on the location; the optimal azimuth is between $-10°$ to $+10°$ and the optimal tilt varies between 30–50° (Masson et al., 2022). However, for single-family dwelling PV systems it is by far most common to install the PV modules so that they follow the slope of the roof of the house, which then result in a wide spread of different orientations for different systems (Killinger et al., 2018; Ramadhani et al., 2023). The historical most common roof angle of single-family dwelling in Sweden is between 20–30° (Hedström and Palmblad, 2006; Ramadhani et al., 2023). This results in both an easier installation process, and thereby a cheaper system, and typically, that no building permit is required (Boverket, 2019). Other factors include shading objects, soiling, snow, and different temperature effects that all depend on the location of the installation and type of roof. To account for the real-world conditions that differs between different PV systems, a study from Mälardalen University derived the average specific yield from 828 actual PV systems in Sweden to be 798 kWh/kW_p for 2017 and 890 kWh/kW_p for 2018 (Schelin, 2019b). The study from Mälardalen University includes not only new systems, so some of the systems may have experienced some degradation. 2018 was one of the sunniest years ever in Sweden, while 2017 was below average. As the needed parameter for the LCOE calculation is initial annual yield, a yield of 850 kWh/kW_p is assumed for a new single-family dwelling PV system in Sweden. Also based on the data of Schelin (2019b), the high-cost value is set to 700 kWh/kW_p and low-cost value to 1100 kWh/kW_p in the MCA calculations.

2.5.3. Degradation

Since they operate outdoors, PV modules are exposed to various weather conditions, including ultraviolet irradiation, temperature and humidity cycles, rain, snow, wind loads, hail, dust, and soiling. These external stresses can affect their efficiency over time, resulting in degradation of the output. A meta-analysis including 2000 studies from different parts of the world regarding the degradation of PV modules over the past 40 years shows a median value of 0.5%/yr and an average value 0.7%/yr (Jordan and Kurtz, 2013). This is consistent with the median degradation rates of 0.5–0.6%/yr found by the IEA PVPS task 13 (Köntges et al., 2017).

For a Swedish context, lower temperatures are expected to impede thermal degradation modes in modules (Omazic et al., 2019). However, the increased likelihood of snowfall and strong winds in cold climate can increase the mechanical stresses, such as cell cracks or frame breakage (Köntges et al., 2017; Omazic et al., 2019). Only one study has been conducted in Sweden, which examined modules from a PV system installed 1981 on Bullerön (Hedström and Palmblad, 2006). Re-measurements after 25 years revealed that 19 of the 20 modules in this system obtained average peak power values less than 2% lower than data obtained in the beginning of the modules' operation. This corresponds to a degradation rate of only 0.17%/yr, but it was concluded to be within the measurement accuracy of the used method. One of the 20 modules showed near 50% deterioration, which could be attributed to a visible defected cell and probably a "hot-spot" at some point during operation. Similar results were obtained in studies of old PV systems in countries with similar climates, namely in Switzerland (Realini et al., 2001) and Denmark (Spataru et al., 2014). Re-measurements of 20 and 15-year-old PV systems, respectively, showed a system degradation of only 0.2%/yr in the Swiss case and no significant PV module degradation in the Danish system. In a German study 44 randomly selected modules from six 8–12 year old PV systems showed degradation rates of 0.08–0.24%/yr (Kiefer et al., 2019).

To summarize, it seems like the degradation rate of modules is lower in the Swedish climate compared to different climate zones. Therefore, a degradation rate of 0.2%/yr has been assumed as the typical rate for the LCOE calculations of single-family dwelling PV systems in this report. For the high-cost range, the international average degradation rate of 0.5%/yr is used, and for the low-cost range, the lower end of the German study (Kiefer et al., 2019) of 0.1%/yr is employed.

2.5.4. CAPEX

For single-family dwelling PV systems, the *labor costs*, *total system, and component costs,* and *grid-connections cost* part of the CAPEX are usually all handled by the installation company, and the customer pays a turnkey system price that includes all three of these (Bankel and Mignon, 2022). For roof-mounted single-family dwelling PV systems, there are no *land costs*. However, some administrative work is usually needed to be done within the first few months after the commission of the system. This administrative work constitutes for the *owner's costs* of a single-family dwelling PV system.

To obtain the typical turnkey system prices of single-family dwelling PV systems, we used the database of the Swedish direct capital subsidy (Riksdagsförvaltningen, 2022e). After sorting the database as described in Section 2.4, we concluded that the database contained 6098 single-family dwelling PV systems owned by individuals.

When it comes to the prices of turnkey grid connected roof-mounted PV systems, there is of course a wide range, even for systems with a similar size and type of owner. The range depends on many factors, such as type of house, type of roof, type of module, type of inverter and balance of system (BoS), etc. Furthermore, it is not possible to derive whether the PV systems are building-applied (BAPV) or building-integrated (BIPV), where the latter are usually more expensive and much rarer (Lindahl et al., 2023), or if the owner has carried out some of the installation work by him/herself. These factors result in several recorded PV system prices in the database that are unusually

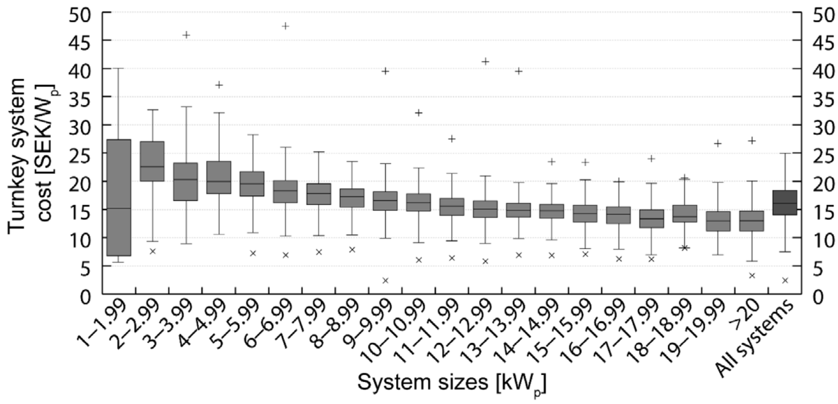

Fig. 4. Box plots of the spread of prices of single-family dwelling PV systems, in SEK/W_p (including VAT) installed in Sweden between 1 January 2019 and 1 July 2020, where the edges of the box represent the 25th and 75th percentile, the whisker length defines the upper inner and lower inner fence values, the line in the middle of the box marks out the median value, and the crosses the minimum and maximum values.

Table 2
Statistical summary of the spread of prices of single-family dwelling PV systems in the size range of 6–13 kWp, in SEK/W_p (including VAT) installed in Sweden between 1 January 2019 and 1 July 2020.

	6–6.9 kW_p	7–7.9 kW_p	8–8.9 kW_p	9–9.9 kW_p	10–10.9 kW_p	11–11.9 kW_p	12–12.9 kW_p	Sum of 6–13 kW_p
Number of systems	490	533	561	692	708	472	477	3933
Most expensive system	47.59	56.39	66.39	39.64	32.16	27.52	41.33	66.39
Upper inner fence value	26.00	25.09	23.45	23.15	22.36	21.44	20.96	24.02
75th percentile	20.11	19.55	18.62	18.17	17.78	16.95	16.53	18.46
25th percentile	16.18	15.85	15.39	14.85	14.72	13.96	13.57	14.76
Lower inner fence value	10.29	10.31	10.56	9.87	10.13	9.48	9.14	9.20
Cheapest system	6.85	7.36	7.78	2.30	5.93	6.29	5.71	2.30
Median cost	18.35	17.85	17.25	16.58	16.20	15.57	15.08	16.57
Average cost	18.33	18.01	17.24	16.55	16.17	15.45	15.06	16.69

high (>25 SEK/W_p, upper outliers) or low (<10 SEK/W_p, lower outliers). To demonstrate this spread of prices, box plots for all 6098 single-family dwelling PV systems (one boxplot per size range) in Fig. 4, along with one single box plot for all the 6098 single-family dwelling PV systems. The underlying numbers for 3933 systems between 6–13 kW_p are compiled in Table 2.

As illustrated by the box plots and the table, there is an economic scalability when it comes to single-family dwelling PV systems, as both the median and average values decrease successively as the system size increases. This scalability can be mathematically described by a trend function based on all the 6098 PV systems. A logarithmic fit gave the highest R^2 value (0.27), and the relation between system size in kW_p (S) and turnkey price per W_p (P) can be expressed as:

$$P = -5.4 \ln(S) + 28.6 \tag{7}$$

In other words, the economical scalability seems to be a price decrease of around 0.5 SEK/W_p for every increase of 1 kW_p in system size.

As shown in Section 2.4, the most common size of a single-family dwelling PV system in 2020 and 2021 was 10 kW_p. The median system cost of all systems between 9 kW_p and 11 kW_p was 16.40 SEK/W_p and is therefore considered to be the typical turnkey price for a single-family dwelling PV system. This price includes the Swedish value-added tax (VAT) of 25%. For the high-cost value 23.15 SEK/W_p is used as it is the highest of the upper inner fence values of the two ranges 9–9.9 kW_p and 10–10.9 kW_p, while 9.87 SEK/W_p is used for the low-cost value as it is the lowest of the lower inner fence values of these two ranges. The outlier values are ignored.

The homeowners are assumed to take care of different time-consuming tasks related to acquiring their PV systems, without necessarily reflecting over the cost of their time. This is especially considered the case in the early years of the Swedish PV market, when environmental concern and technophilic motives were stronger driving forces as compared to today, when economic motives play a bigger role in adoption of small-scale residential PV in Sweden (Palm, 2020). In any case, the cost of a private person's own work is estimated. The average salary in Sweden was 35,300 SEK/month (Statistikmyndigheten, 2022b), before taxes, and the average tax rates was 32.19% (Skatteverket, 2022b) in 2019. The subsequent average salary in Sweden after deductions, taxes and fees was about 26,770 SEK/month. The year 2019 contained 2024 working hours, so an estimate of a private person's own time is therefore 160 SEK/hour.

Considering *owner costs*, the internal work that needs to be done before the commencement of the system, during the construction of the system, and after the commissioning of the system should be considered. Most retailers and installers in the Swedish PV market offer consultancy, inspections, planning and quotes for prospective customers. As earlier pointed out, as of August 1st, 2018, PV system installations on buildings are generally exempt from building permits (Boverket, 2019). Certain installations still require building permits, but these are in a clear minority. Therefore, the cost for a single-family dwelling PV system customer is negligible before and under the construction of the system.

However, there are some administrative tasks that need to be handled after the commission of a single-family dwelling PV system. These tasks may include administration related to replacement of the house's electricity meter and obtaining a contract with the current (or new) electricity supplier for the sale of excess electricity. Based on personal experience, the authors estimate that these administrative tasks take about five hours in total, which corresponds to 800 SEK, assuming a private person's time is valued at 160 SEK/hour. This cost is independent of the system's size but will be 80 SEK/kW_p for a 10 kW_p single-family dwelling PV system. A 50% higher owner cost is assumed for the

Table 3
Estimated fixed yearly O&M costs for a single-family dwelling PV system.

Cost categories	Estimated cost [SEK/yr]
Annual electricity maintenance and monitoring costs	320
Annual physical monitoring costs	160
Annual land and site maintenance costs	–
Annual module cleaning costs	160
Annual administrative costs	0
Annual insurance costs	–
Annual fixed grid costs	–
Annual system operating electricity	–
Annual land expenses	–
Annual real estate tax	–
Annual electricity trading and balancing costs	–
Other taxes	0
Total fixed O&M costs	640

high-cost value and a 50% lower own cost for the low-cost value, which results in 1200 SEK and 400 SEK, respectively.

Summing up the typical turnkey with the estimated *owner costs*, the total typical CAPEX of a 10 kW_p single-family dwelling PV system becomes 164,800 SEK, including VAT, the high-cost CAPEX ends up at 232,700 SEK and the low-cost CAPEX at 99,100 SEK.

An important factor in the assessment of CAPEX is the tax reduction program for green technology, which gained legal effect January 1, 2021, in Sweden. As described in the introduction, this program provides a percentage-based tax deduction for the hardware and installations costs. PV installations are offered a 20% deduction, which equals 19.4% of the total system costs. Taking this tax rebate into account, the typical CAPEX of a 10 kW_p single-family dwelling PV system becomes 132,980 SEK, including VAT. The high-cost CAPEX ends up at 187,790 SEK and the low-cost CAPEX at 79,950 SEK.

To obtain an additional assessment of the influence of the tax reduction program for green technology on the LCOE distribution, the CAPEX of all individual systems with the sizes between 9 and 11 kW_p where recalculated using the following formula;

$$CAPEX_{Tax} = (1 - 0.194) \times CAPEX_0, \tag{8}$$

where $CAPEX_{Tax}$ represents the system costs under the assumption that the 2023 tax reduction for green technology could have been and was used for the PV systems installed in 2020.

2.5.5. Yearly fixed operation and maintenance cost

The Swedish PV market is still in its infancy, and so is the knowledge about actual O&M costs, especially for the distributed PV market. For the centralized PV parks, the yearly fixed O&M costs have been divided into different cost categories in a previous study (Lindahl et al., 2022) and to follow the same approach, the same is done for single-family dwelling PV systems in Table 3. Some of the fixed O&M costs associated with centralized power production facilities are not compatible or relevant for single-family dwelling PV systems. For example, no *land and site maintenance costs* for a roof-mounted single-family dwelling PV system is assumed as it claims no land and has a minuscule impact on the roof it is installed on. A few BoS components might need to be changed under the lifetime of the single-family dwelling PV system, but these costs are considered under *Major reinvestments*. In addition, there are no *annual fixed grid costs* or *annual electricity and balancing costs* for 10 kW_p single-family dwelling PV systems, as the law states that an electricity user with a fuse subscription of no more than 63 amperes and a power of maximum 43.5 kW shall not pay any fee for the feed in Energimarknadsbyrån (2022). Furthermore, insurance costs of PV systems are usually covered by the normal home insurance and there is no additional real estate tax if the PV system is mounted on the roof of a single-family dwelling building. The electricity needed to run a single-family dwelling PV system can also be neglected.

The fixed O&M costs that are left are a*nnual electricity maintenance and monitoring costs*, a*nnual administrative costs*, and *annual module cleaning costs.* As discussed earlier, most homeowners probably take care of their PV system without reflecting over the cost of their time. However, using the same reasoning as for the *owner costs,* an estimate of the time spent can be made.

Almost all inverter companies working in the small-scale distributed PV market segment offer free software, such as homepages or mobile applications, in which the system owner can follow the production of the PV system in real-time and access summarized graphs and tables. It is therefore very easy to follow the performance of a single-family dwelling PV system, as it only requires a glance at these graphs and tables now and then to control the a*nnual electricity maintenance and monitoring*. In total, approximately two hours a year is needed to follow the production (even if many spend much more time tracking their PV production for the fun of it), so the estimated *annual electricity maintenance and monitoring costs* are 320 SEK/yr. With regards to *annual physical monitoring costs,* a quick glance at the roof with PV modules are usually enough to determine if there are any mechanical failures, which is estimated to take in total one hour per year at a cost of 160 SEK/yr.

When it comes to *annual module cleaning costs,* single-family dwelling PV systems in Sweden are usually installed with a certain tilt, which allow the regular rainfall to remove most of the dust and pollen particles from the modules (Appels et al., 2013; Pedersen et al., 2016). Snow-covered modules do not supply electricity, but if a system in Stockholm is covered in snow for a full month in January, the annual electricity loss will only be reduced by about 2%. Therefore, shoveling away the snow will likely cost more in terms of time spent than the gain in production can motivate (Stridh, 2012). Additionally, there is a risk of personal injury or causing damage to the PV modules, which is why it is not recommended for private individuals to remove the snow from the PV panels to increase the PV yield. However, heavy soiling, such as bird droppings, can reduce the system's output (Ghazi and Ip, 2014; Imenes et al., 2011), and may need to be removed mechanically. It is estimated that such a mechanical cleaning takes approximately one hour per year for a 10 kW_p single-family dwelling PV system, which corresponds to an annual module cleaning cost of 160 SEK/yr based on the manhour-cost.

With regards to *annual administrative costs* for an owner of a single-family dwelling PV system, most of them occur within the few first months after the commission of the system. After that there is very little administrative work needed as most things are automated. One example is the smooth handling of the tax credit for micro-producers of renewable electricity (Riksdagsförvaltningen, 2022a). The grid owner is responsible for the reporting of annual excess fed in-electricity to the Swedish Tax Agency and the equivalent tax reduction is then pre-printed in the annual tax return form sent to the system owner. The need for further administrative work for the single-family dwelling PV system owner springs from either changing the electricity supplier or moving from the house. As this usually does not happen on an annual basis, the annual administrative costs are considered negligible and set to zero in this project.

In total, the fixed O&M costs are estimated to be 640 SEK/yr, and they are to a large extent size independent. For an assumed 10 kW_p PV system, the cost per kW will be 64 SEK/kW/yr. For the high-cost value 50% higher fixed O&M costs is assumed and for the low-cost value 50% lower, which is 96 SEK/kW/yr and 32 SEK/kW/yr respectively.

2.5.6. Variable operation and maintenance cost

The PV technology is based on the energy of solar radiation, which is free for all. There is therefore no fuel cost associated with the production of a unit of PV electricity. Furthermore, a standard single-family dwelling PV system does not contain any moving parts, so the maintenance needed is not associated to the amount of electricity produced, but rather to general degradation mechanisms. As described in Section 2.5.5, a typical single-family dwelling PV system of 10 kW_p fulfills the requirements to be free from paying any fee for the feed-in of electricity. Consequently, there are no variable maintenance nor operational costs for a single-family dwelling PV system in Sweden.

2.5.7. Major reinvestments

In general, inverters are the most common cause of breakdown in PV systems (Kiefer et al., 2019; Ristow et al., 2008) and usually, the components within a PV system with the shortest warranty. In the early years of the global PV market, a study carried out by the IEA PVPS (Laukamp, 2002) showed that the inverter was the most troublesome component accounting for about 66% of reported troubles. Later studies have found that between 75% and up to 90% of the reported PV system failures can be attributed to the inverters (Moser et al., 2017). In comparison, studies have shown that less than 0.25% of modules have needed to be replaced due to defects over a time period of 10 years (Kiefer et al., 2019) and that modules in the field have showed mean time between failure of 522 to 6666 years for residential and utility systems (Ristow et al., 2008).

The inverter forms the heart of a PV system and is responsible for several functionalities, where the major one is to convert the direct current (DC) power output from the modules to alternating current (AC) power. The inverter types are commonly divided into central inverters, string inverters, multistring inverters and micro inverters, but due to the many functionalities there exist over 45 different inverter topologies (Dogga and Pathak, 2019). Central inverters are usually connected to arrays consisting of several parallel strings of PV modules and have high power ratings. String inverters are lower power inverters which handle a single string of PV modules. Multistring inverters handle several strings which are individually connected to DC/DC converters which provide a higher voltage than the DC/AC inverter. Micro inverters are connected to a single PV module and are usually physically located behind their respective module.

An inverter is a type of power electronic device that converts and controls electrical power, using switching semiconductor relays. The underlying aging mechanism during an inverter's life is generally the thermal load cycling (Petrone et al., 2008; Obeidat and Shuttleworth, 2017), which causes mechanical stress in the power semiconductors between materials with different coefficients of thermal extension. In addition to failure of electronic parts, it has been found that many failures occurring in the field are related to malfunction of contactors, the failure of protective equipment under environmental stresses, such as very high and very low ambient temperatures, high humidity, the entrance of water or snow or soil, and lightning strikes (Moser et al., 2017).

Inverters can also fail due to other component failures or configuration errors. Inverter failures can be absolute, meaning the inverter ceases to operate entirely, or partial, which means the inverter operates at a lower conversion or maximum power point tracking efficiency. Absolute failures are easier to detect, as the problem is obvious. On the other hand, partial failures can lead to larger total production losses since it can take time before the failure is detected, defined, and corrected.

It has been found that central inverters are less frequently affected by malfunctions than decentralized string inverters (Kiefer et al., 2019). However, central inverters are not a common choice for a single-family dwelling PV system. And even if the market share of micro inverters is increasing within the market segment of single-family dwelling PV systems, as they promise lower shading losses and longer lifetimes (Obeidat and Shuttleworth, 2017; Alferidi and Karki, 2017), the most common inverters for the small-scale residential sector in Sweden is still considered to be string inverters (Oller Westerberg and Lindahl, 2020).

Over the total operational period of an inverter, the failure rate varies and is often considered to follow a, within reliability-engineering considered traditional, 'bathtub curve' (Obeidat and Shuttleworth, 2017; Tariq et al., 2018; IEA PVPS, 2017). A bathtub curve consists of a decreasing failure rate, known as early failures (the infant period), followed by a second part with a constant failure rate, known as random failures (the useful life period) and lastly, an increasing failure rate, known as wear-out failures (the wear-out period).

The bathtub cycle for inverters might be repeated multiple times depending on how long the bathtub curve of the inverter is and the total lifetime of the PV system. Field studies including over 2000 operational PV systems have shown that the replacement rate rapidly decreases from more than 4% in the first year to less than 1% in the fifth year of operation, indicating that most replacements are linked with early failures (Moser et al., 2017). However, for the purpose of assessing the need of *major reinvestments*, the infant period is not considered in this study, as regular warranties of a few years enable replacement of failing inverters during the infant period at no extra cost to the PV system owner. Neither are the rare random failures during the useful life period of interest, as the LCOE calculation only considers the typical lifetimes of the major components. The focus therefore lies on the wear-out period, which is characterized by the need for replacement of a specific inverter due to a non-repairable failure. With regards to wear-out failures, the technical life of a string inverter is usually considered to be between 10–15 years (Pillot et al., 2018; IEA PVPS, 2017; Energiewende et al., 2015).

Failure of PV inverters are primarily caused by exposure to high thermal and electrical stress as well as the thermal management system itself (Moser et al., 2017). The lifetime of inverters can therefore be strongly affected by the operating conditions, since the solar irradiance and ambient temperature have a direct impact on both the operation temperature of the inverter, if mounted outdoors, and the PV module output, which also affects the thermal loading of the PV inverter due to the power losses dissipated in the power electronics. Another factor is PV module degradation, which also affects the lifetime of the inverter, as the thermal loading of the inverter will be reduced over time as the power output of the modules decreases. For instance, the expected inverter lifetime is estimated to increase with about

20% in cold climate conditions if a PV module degradation rate similar to the 0.2%/yr estimated for this study is considered (Sangwongwanich et al., 2018). As the ambient temperature in Sweden, or indoor temperature in single-family dwellings, when the PV systems produce their most, is generally lower than the outdoor temperature for most places in the world, the technical lifetime of the inverter (i.e., the end of the wear out failure period) is assumed to be 15 years in this study. This means that one replacement of the inverters is considered during the lifetime of a typical single-family dwelling PV system. In end-of-life studies for power electronics, Weibull distribution is commonly used to describe their end-of-life (Sommerfeldt and Madani, 2017; Li, 2004). Therefore, in this study, the MCA is assumed to have a similar distribution to describe the inverter and PV system end-of-life.

Assessing the future nominal cost of replacing the inverter 15 years into the future is not straightforward. The retailer price of a typical string inverter for a 10 kW_p PV system was about 17,300 SEK, (excluding VAT) in Sweden 2020 (Oller Westerberg and Lindahl, 2020). However, the price of inverters has successively gone down historically. Between 1990 and 2014 the price decline followed a learning curve[1] of about 19% (Energiewende et al., 2015), i.e., each time the cumulative PV capacity doubled, the prices of PV inverters have declined with 19%. At a predicted global cumulative PV capacity of 6000 GW in 2035 (Vartiainen et al., 2020), the cumulative PV market will have doubled about 3 times, which leads to an inverter price of about 9200 SEK for a 10 kW_p PV system. In this study, we are a little bit more conservative and assume an inverter price of 12,000 SEK for the exchange of the inverter after 15 years for a 10 kW_p PV single-family dwelling PV system.

Besides the actual hardware costs, a company's travel costs, work and a profit margin need to be included in the cost of replacing the inverter. These costs are not subjected to a future experience curve in the same way as the inverter. As of 2020, traveling costs have been found to be on average 1000 SEK per installation (Oller Westerberg and Lindahl, 2020). Traveling time plus the time to change the inverter is estimated to be four hours. At an hourly rate[2] of 500 SEK/h, this corresponds to 2000 SEK for an inverter change. The installation companies general profit margin for a whole single-family dwelling PV system is assessed to be about 10% (Oller Westerberg and Lindahl, 2020). As a result, adding up the different costs a typical estimated cost of replacing the inverter becomes $(12{,}000 + 1000 + 2000) * 1.1 = 16{,}500$ SEK excluding VAT and 20,625 SEK including VAT. For the high-cost scenario, the inverter replacement is assumed to occur after 12.5 years instead of 15 years, and no future price decline is expected. This results in a total replacement cost of 27,900 SEK, including VAT. For the low-cost value replacement of the inverter is assessed to take place after 17.5 years, and the traveling times and time to change the inverter are instead considered to be two hours. This leads to a total inverter replacement cost of 18,500 SEK, including VAT.

2.5.8. Residual cost or value

The total residual cost, or value, of a decommissioned PV system can be divided into five major parts: (1) the residual value of parts or complete hardware that can be re-used, either on-site or off-site, (2) the dismantling of the parts of system that cannot be re-used on-site, (3) the cost of handling and transport the dismantled hardware to a retailer (in the case of re-use on another site) or to a recycling center (in the case when the dismantled hardware is considered waste), (4) the cost of recycling the dismantled hardware that is considered waste, and (5) the material value of the recycled hardware.

In the assessment of these costs and values, only the modules, the inverter, and the mounting structure are considered. BoS components are omitted as they only make up for 3% of the total cost of a single-family dwelling PV system (Oller Westerberg and Lindahl, 2020).

With regards to dismantling an end-of-life single-family dwelling PV systems, there are two major scenarios:

1. Only the old modules and inverters are dismantled, and the mounting structure is kept on the roof. This would be the case if the underlying roof is still in good condition and the house owner would like to have another PV system after the first one has failed. The mounting structure could then be reused for the second round of modules if the original PV system was installed on a new roof. This assumes that the roof thereby has a lifetime of >60 years, allowing it to accommodate two sets of PV modules, each with an estimated lifetime of 30 years. This process is commonly known as repowering a PV system.
2. The whole system, including mounting structures, is dismantled. This would be the case if the underlying roof is in poor condition and needs to be replaced or if the house owner does not want a new PV system after the first one has failed, or if the house owner chooses to replace the mounting structure.

The second scenario will not be analyzed in greater depth in this study, as it is difficult to separate the actual cost of dismantling the PV system from the costs of tearing down a complete roof that needs to be replaced as it is likely that these two actions will take place at the same time.

In the first scenario, it is natural that the dismantling of old modules, inverter and (possibly) mounting structures take place at the same time as the new system is installed, due to the synergy of some costs, like travel expenses and erection of scaffolding. As such costs are associated with the newly repowered PV system, they can therefore be withdrawn from the dismantling costs of the old system. We assume that the old mounting structures can be reused for the new system. This assumption might be questionable, as the standard module sizes are foreseen to slightly increase in the coming years (Fischer et al., 2022), but there might still be a possibility to find modules in 30 years with the same size as today. The cost of dismantling the old system will consequently only include the time it takes to take down the old PV modules from the roof and dismantle the inverter.

According to interviews with Swedish installers, the estimated time to dismantle and pack an old PV module is half an hour. The typical power of the modules installed in Swedish single-family dwelling PV systems in 2020 was 330 W_p (Oller Westerberg and Lindahl, 2020). For a 10 kW_p single-family dwelling PV system, the estimated time is therefore about 15 man-hours. At a cost of 500 SEK/h, the dismantling cost of the modules becomes 7500 SEK before VAT and installer margins.

The time it takes to replace an inverter with a new one is estimated to be one hour. This leads to a cost of 250 SEK, as only the time spent on dismantling the old inverter should be associated with the old PV system, excluding VAT and installer margins. If the mounting structures of the old PV system can be reused, they will constitute a direct residual value associated with the site of old PV system. As already mentioned, a relevant question is whether modules 30 years from now will fit a mounting system from today. This is a big uncertainty, so we neither assume a

[1] In industry, models of the learning or experience curve effect express the relationship between experience producing a good and efficiency of production, i.e., efficiency gains that follow investment in the effort.

[2] Information from 5 of the larger installation companies in Sweden.

Table 4
Estimated residual costs and values for a decommissioned 10 kW_p single-family dwelling PV system.

Cost categories	Estimated cost [SEK]	Estimated cost high scenario [SEK]
Residual value of re-used parts or components	0	0
Dismantling costs	10,700	18,000
Material handling and transport	0	1000
Recycling cost	0	0
Residual value of re-used part or recycled material value	0	0
Total residual cost	10,700	19,000

dismantling cost nor a residual value for the mounting system. The assessed total dismantling cost then becomes 10,700 SEK including a 10% installer margin and the VAT.

In recent years, several companies and platforms offering refurbished second-life PV modules have emerged (Tsanakas et al., 2020). Indicative repair/refurbishment costs for PV modules range from approximately 20 € up to 90 € per module, depending on factors such as the handled volumes of discarded PV modules, the severity and type of defects in the discarded modules and the required characterization/testing prior to and after repair. However, the remaining efficiency of repaired/refurbished PV modules will depend on their years of field exposure and as this study considers 30 years old PV modules, there is a significant uncertainty regarding whether it will be economically viable to repair such old modules. The modules are therefore assumed to enter the waste stream for recycling.

In the European Union, the Waste Electrical and Electronic Equipment (WEEE) Directive (2012/19/EU) specifies the waste management requirements for all electronics, including PV modules (European Union, 2012), and stipulates that as of August 15th, 2018, 85% of the waste should be recovered and 80% should be prepared for reuse and recycling. This is also postulated in the Swedish legislation (Riksdagsförvaltningen, 2022e).

Details on the intrinsic cost of current PV recycling processes are limited, but the WEEE directive makes use of the extended producer responsibility principle (Deng et al., 2019; Besiou and Van Wassenhove, 2016). This means that it is the producers of goods, rather than end-users, who are responsible for recalling and recycling their end-of-life products, either individually or by joining a collective scheme (Besiou and Van Wassenhove, 2016), such as for example the non-profit European based PV Cycle Association (PVcycle, 2022). In both EU and Sweden, a producer is broadly defined as any manufacturer, distributor, reseller, importer, or distant seller involved in the PV industry of an EU country (Riksdagsförvaltningen, 2022e; European Union, 2012). This directive makes it compulsory for producers to collect and recycle at least 85% of their PV modules in the market free of charge. The same applies to inverters. An example of a collective recycling system is the non-profit European organization PV Cycle (PVcycle, 2022), to which module producers make payments and in return PV Cycle take over responsibility for module producers' modules when they become waste.

In theory, the single-family dwelling PV system owner should have paid for these costs when the PV system was purchased, i.e., these costs should have been included in the CAPEX. Therefore, the material handling and transport costs, recycling cost and residual value of recycled hardware are all set to 0 SEK.

The total residual cost of a single-family dwelling PV system is estimated to be 10,700 SEK, according to Table 4. The same value is used for the low-cost value as the repowering scenario is the most economic beneficial. For the high-cost value, it is assumed that the entire system, including the mounting structure, needs to be dismantled and that transportation costs are not included. This leads to a higher dismantling cost as it will take longer to also dismantle the mounting structure and means that residual value for the mounting structure will be zero. A 50% longer dismantling time leads to a total residual cost of 18,000 SEK and the cost for transport after dismantling is estimated to be 1000 SEK based on 2 h at an hourly rate of 500 SEK/h for the high-cost value.

2.5.9. Discount rate

For households investing in PV systems, the discount rate should be adjusted according to the household's cost of debt. For most private investors, the relevant discount rate would be the mortgage interest rate in real terms. This is largely determined by the policy rate set by Sveriges riksbank, Sweden's central bank. Sveriges riksbank expects its long-term policy rate to be between 2.5% and 4% (Sveriges Riksbank, 2017). Calculating with a policy rate of 3.5% and a mark-up of 1.5% for mortgage rates (SBAB, 2022), a long-run nominal interest rate of 5% on mortgages would be reasonable for most households. Sveriges riksbank has set an inflation target of 2% (Sveriges Riksbank, 2022). At the time of writing, Sweden's inflation rate is much higher, but assuming that the Riksbank achieves its target in the long run, this yields a real mortgage rate of 3%. Since interest payments are tax-deductible, after-tax interest real interest costs would only be 70% of costs before tax. Thus, after-tax real discount rates would be close to 2%.

The relevant real discount rate varies between households. If the PV investment is financed by selling stock market funds or if such funds are regarded as an investment opportunity alternative to the PV investment, the opportunity cost of the investment may actually be the expected stock market return, which may be conservatively estimated to be 7% in the long run (Nordea, 2022). With a 2% inflation rate, the household may then demand a real rate of return on the PV investment of 5% before tax or 3.5% after tax. In analogy with reasoning for a firm's weighted average cost of capital (WACC), a weighted average between typical mortgage interest rates and typical stock market returns may be relevant. While it is true that in itself, the PV investment could be regarded as reasonably risky, its total effect on risk in the household's economy is likely to be small. The capacity to produce a significant fraction of its electricity consumption may even reduce total economic risk experienced by the household. The technical financial term for this is that electricity production has a low beta. Therefore, discounting with the mortgage interest rates without risk adjustment seems reasonable. Though calculations use an after-tax real interest rate on mortgages of 2% as typical case, Monte Carlo simulations consider real discount rates from 0% up to 5%.

2.5.10. Typical LCOE value for a single-family dwelling PV system

The LCOE value for a typical single-family dwelling PV system was determined as 1.08 SEK/kWh based on the data and assumptions presented in the sections above. The results, as shown in Table 5, indicate a variation between 0.37 to 2.85 SEK/kWh for low-cost and high-cost scenarios, respectively.

3. Results

For a single-family dwelling PV system, the most likely LCOE provides a basis for assessing the profitability of a PV investment

Table 5
Summary of most likely LCOE values and typical LCOE parameters for a typical 10 kW_p single-family dwelling PV system in Sweden 2020.

LCOE parameter	Unit	Low-cost value	High-cost value	Typical value
Lifetime of the PV system	[years]	35	25	30
Initial annual yield in year 0	[kWh/yr]	11,000	7000	8500
Annual degradation of the nominal power of the system	[%]	0.1	0.5	0.2
Total capital expenditure of the system, made at t = 0	[SEK]	99,100	232,700	164,800
Total capital expenditure of the system, made at t = 0[a]	*[SEK]*	*79,950*	*187,790*	*132,980*
Fixed operation and maintenance cost	[SEK/yr]	320	960	640
Variable operation and maintenance cost	[SEK/kWh]	0	0	0
Major reinvestment at t = x1 needed to reach expected lifetime	[SEK]	18,500	27,900	20,625
Years after operation start when first major reinvestment is needed	[years]	17.5	12.5	15
Real discount rate	[%]	0	5	2
Residual cost	[SEK]	10,700	19,000	10,700
Levelized cost of electricity	**[SEK/kWh]**	**0.37**	**2.85**	**1.08**
Levelized cost of electricity[a]	***[SEK/kWh]***	***0.32***	***2.37***	***0.91***

[a] Including the Swedish tax reduction of 19.4% for green technology in 2023.

Table 6
Statistical LCOE result with MCA for a 10 kW_p single-family dwelling PV system in Sweden 2020 using a 0%, 2%, and 5% discount rate, unsubsidized respective including the Swedish tax reduction for green technology of 2023 (Tax r.).

Discount rate LCOE	0%	0% + Tax r.	2%	2% + Tax r.	5%	5% + Tax r.
Min	0.30	0.28	0.36	0.32	0.46	0.39
Median	0.78	0.64	0.99	0.80	1.38	1.08
Mean	0.80	0.66	1.02	0.82	1.42	1.12
Max	2.90	1.76	3.89	2.31	5.70	3.32
25th percentile	0.67	0.57	0.85	0.70	1.17	0.94
75th percentile	0.90	0.74	1.15	0.92	1.61	1.26
Standard deviation	0.17	0.14	0.23	0.19	0.33	0.28
Upper adjacent	1.24	1.00	1.61	1.26	2.28	1.74
Lower adjacent	0.33	0.30	0.39	0.36	0.51	0.46

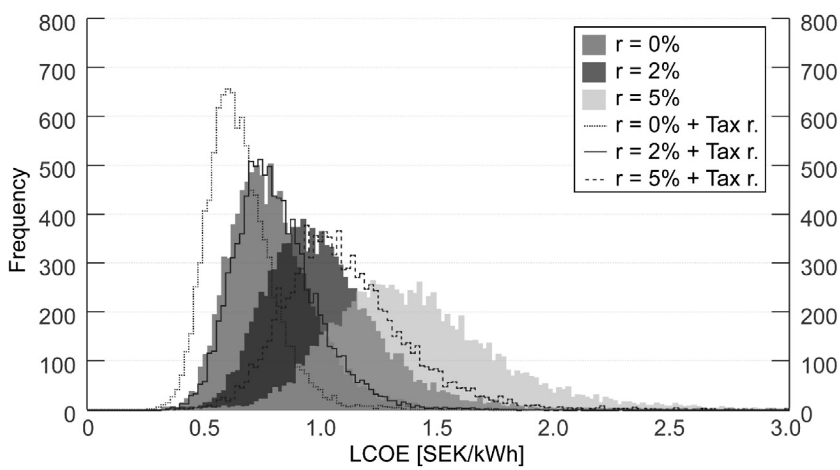

Fig. 5. LCOE with MCA for a 10 kW_p single-family dwelling PV system in Sweden 2020 at 0%, 2%, and 5% real discount rate, unsubsidized and including the Swedish tax reduction of 19.4% for green technology in 2023 (Tax r.).

for prosumers in Sweden. As can be seen from the three different cases of typical cost, low-cost and high-cost, there is a considerable spread in LCOE depending on the different assumptions made in the different cases. However, the low-cost corresponds to best-case scenario and the high-cost to worst-case scenario, both of which have a very low probabilities to occurring. In addition, the MCA conducted displays the probability of different LCOEs, and thereby further reduces the investment uncertainties that may exist for investors.

The LCOE from the MCA varied significantly with the discount rate, which can be seen in Fig. 5 and Table 6. The LCOE values are provided for each discount rate, both unsubsidized and including the impact of the Swedish tax reduction of 19.5% for green technology in 2023 (Tax r.). The mean LCOE for a typical case with a 2% discount rate is 1.02 SEK/kWh, with a variation from 0.36 SEK/kWh to 3.89 SEK/kWh, while the mean value at a 0% discount rate was 0.80 SEK/kWh and 1.42 SEK/kWh at a 5% discount rate. The minimum and maximum LCOE with a discount rate of 0% was 0.30 and 2.90 SEK/kWh, respectively, as compared to 0.46 and 5.70 SEK/kWh with a discount rate of 5%. In addition, the standard deviation increased from 0.17, with a discount rate of 0%, to 0.33 SEK/kWh with discount rate of 5%, and hence the spread in the distributions of LCOE increases with higher discount rate. This shows that the MCA distribution has a wider variance than the distribution for typical LCOE for a 10 kW_p single-family dwelling PV system in Sweden 2020. Thus, with the high variance, the median with a discount rate of 5% did not reach values higher than 1.38 SEK/kWh and outliers that occur less frequently were above 2.28 SEK/kWh.

Adding the Swedish tax reduction for green technology to the actual CAPEX values naturally lowers the LCOE even more. In addition, it reduces the standard deviation. So, in addition to lowering the actual LCOE values and consequently increases profitability, the Swedish tax reduction for green technology also

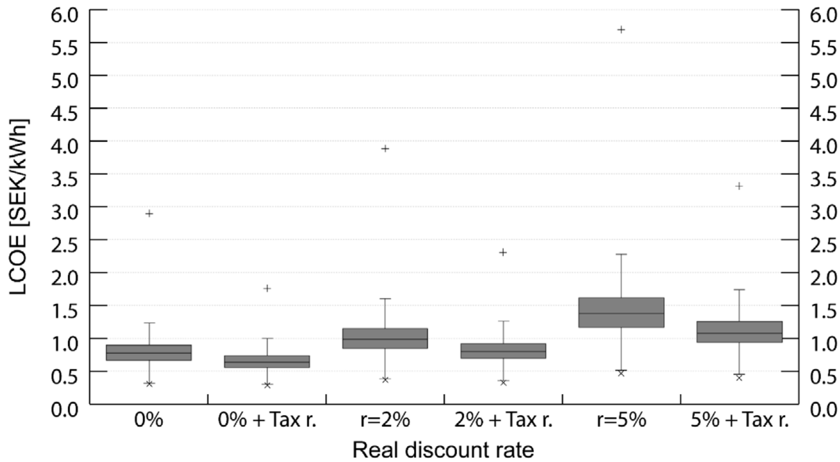

Fig. 6. LCOE distributions with MCA for a 10 kW_p single-family dwelling PV system in Sweden 2020 at 0%, 2%, and 5% real discount rate, excluding the current Swedish tax reduction for green technology, where the edges of the box represent the 25th and 75th percentile, the whisker length defines the upper inner and lower inner fence values, the line in the middle of the box marks out the median value, and the crosses the minimum and maximum values.

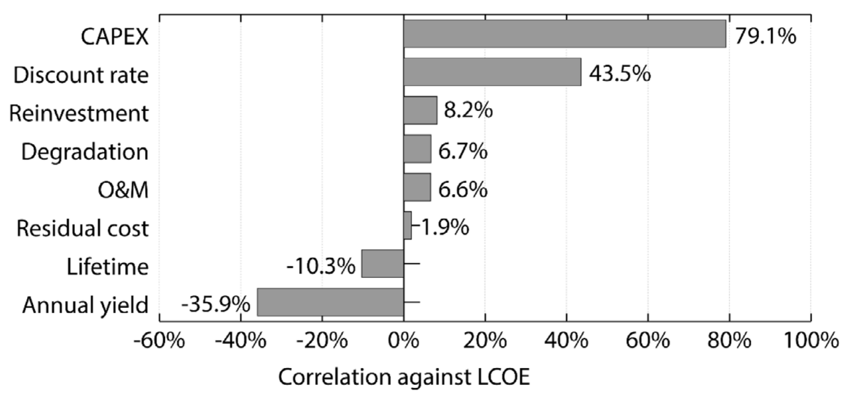

Fig. 7. LCOE parameter sensitivity analysis as contribution to variance for a typical single-family dwelling PV system in Sweden 2020, excluding the current Swedish tax reduction for green technology.

reduces the risk for investors as the spread of LCOE is reduced with this subsidy scheme included.

The LCOE distribution results of the MCA calculations from Table 6 are also presented as box plots to compare each scenario of discount rates more easily in Fig. 6.

The LCOE input variables have various contributions to the variance. In a previous study (Lindahl et al., 2022), the CAPEX and annual yield had the highest impact on the LCOE for PV parks in Sweden. In another study (Stridh and Larsson, 2016), it was found that CAPEX and annual yield were the most important factors on LCOE for single dwelling houses. A similar trend can be observed for single-family dwelling PV systems in Sweden in the sensitivity analysis presented in Fig. 7, where the correlation between the sensitive parameters and LCOE is presented. A positive correlation means increasing LCOE values and a negative correlation means decreasing LCOE values, with increasing parameter values. It can be observed that CAPEX had the highest relative impact on LCOE, with a positive linear correlation of 79%, and the second highest relative impact is from discount rate, with a positive linear correlation of 44%. The parameters with the least impact on LCOE, in order, are residual cost, O&M, degradation, reinvestment, and lifetime.

4. Discussions

The number of PV installations in Sweden have increased substantially during the last decade, and to reduce economic uncertainty, it is necessary for investors to be able to conduct accurate risk analyses. By comparing three different discount scenarios of 0%, 2%, and 5% using MCA, a comprehensive risk assessment can be achieved. There are several uncertainties when deploying distributions for the MCA, as there is a lack of data for finding a distribution that fits the input parameters to accurately calculate LCOE. However, in this study, data for CAPEX and reinvestment have been used to deploy distributions that reflect the gathered data to improve the MCA. This is new compared to earlier LCOE studies in Sweden and valuable especially since capital expenses have the highest impact on the LCOE, which amplifies the importance of providing an accurate distribution for this parameter. Even though CAPEX has the highest impact on the LCOE, it will not contribute to its uncertainty in a real case, since it is a known parameter when receiving a quotation. However, it is the most important parameter that an investor can influence by choice of system and installer.

The discount rate also has a large influence on LCOE. The discount rate can be viewed as a semi-unknown parameter at the time of investment, as the nominal interest rate is known when signing a loan. However, the loan needs to be renewed during its lifetime, which creates uncertainty, as does the long-term inflation rate.

The other studied parameters are not fully known in advance, but they are also difficult for the PV system owner to affect once the PV system has been built. Since annual yield has the highest impact of the *more or less*-known parameters it is important to make a good prediction of the expected annual yield to reduce the uncertainty of the LCOE. Unfortunately, this is a parameter that varies substantially for the same PV system depending on which of the available calculation tools in Sweden an investor turns to for consultation (Energiforsk, 2017; Stridh et al., 2020; Sommerfeldt et al., 2022). The creation of industry standards and a neutral, authoritative information source is desirable in this aspect to lower the risk for small, distributed PV systems.

The risk of investing in PV can be mitigated by ensuring a low LCOE standard deviation and ensuring that the PV system is working as expected by regularly following the production when it is in operation. However, the LCOE standard deviation was doubled with an increased discount rate from 0% to 5% corresponding to an increased risk as the variance is larger. On the other hand, the price of PV in Sweden has been decreasing significantly since 2010 (Lindahl and Westerberg, 2021). But in 2021, the price trend changed and system prices went up for the first time in more than a decade (Lindahl and Westerberg, 2021), which could be explained by major events following the COVID-19 pandemic, and is likely to be further affected by the ongoing war in Ukraine. This further emphasizes the importance of conducting a more thorough risk assessment.

Previous studies with regards to LCOE for PV systems in Sweden include a study from 2013 (Stridh et al., 2013), in which LCOE for distributed PV was estimated to 1.22 SEK/kWh without any subsidies. For recent studies, based on more up-to-date system costs, the National Survey of PV Power Applications in Sweden 2021 calculated an LCOE of 0.79 SEK/kWh for a 10 kWp residential system using a discount rate of 0% (Lindahl and Westerberg, 2021). In comparison, the LCOE from MCA in this study with a discount rate of 0% had a mean LCOE of 0.80 SEK/kWh. Furthermore, Energiforsk conducted an LCOE benchmark between common intermittent and dispatchable power sources in 2021 (Elmqvist et al., 2021). The LCOE calculated for single dwelling 10 kW_p PV systems by Energiforsk varied between 0.53 SEK/kWh to 1.07 SEK/kWh with a discount rate of 0%, respectively, with a typical value of 0.79 SEK/kWh. However, there is still a variation between each installation and in extreme cases, the LCOE could reach values up to 5.70 SEK/kWh with a discount rate of 5% as noted in our MCA, which is significantly higher than the LCOE values presented by Energiforsk.

Worth mentioning in this context is the long-term scenarios of the development of the Swedish energy system report from 2021, prepared by the Swedish Energy Agency (Energimyndigheten, 2021). In this report, the Agency assesses, based on a study from 2018 (Blomqvist and Unger, 2018), that there is a potential in Sweden to until 2040 build 1 GW_p single-family dwelling PV systems at a cost of 1.0 SEK/kWh, followed by additional 1 GW_p at 1.1 SEK/kWh, 1 GW_p at 1.2 SEK/kWh and 1 GW_p at 1.4 SEK/kWh. In contrast, the Swedish TSO Svenska Kraftnät does not disclose what production cost they have assumed for different power sources in their long-term scenario modeling until 2050, including PV (Brunge et al., 2021). The result of our study reveals a larger and more detailed distribution of production costs for single-family dwelling PV systems. More importantly, our study shows that the Swedish Energy Agency assesses a higher LCOE in general and thereby underestimates the potential and deployment rate of single-family dwelling PV systems in their long-term scenario evaluations. Especially since the current tax reduction for green technology lowers LCOE even more which leads to more installations than without it.

Lastly, it is of interest to compare the median unsubsidized LCOE at a 2% discount rate of 0.99 SEK/kWh derived in this study with the average LCOE of 0.43 SEK/kWh from six Swedish PV parks commissioned in either 2019 or 2020 (Lindahl et al., 2022). This difference clearly illustrates the economies of scale that exist for PV.

The profitability of residential PV systems is related to electricity prices in Sweden, which are based on the spot prices. Determining the actual value of electricity from a certain power generation technology on a shifting spot market over a certain period is usually done by calculating the *market value* (Hirth, 2015, 2013; López Prol et al., 2020). As a continuation, the *value factor* is calculated as the *market value* of certain production relative to the average price on the market for the same period (Hirth, 2015, 2013; López Prol et al., 2020). At low PV penetration, the *value factor* of PV is usually higher than one because of the positive correlation between the diurnal production profile of PV and load pattern in most countries, and this is also the case in Sweden (Lindahl et al., 2022). However, the near-zero marginal operating costs (Vartiainen et al., 2020; Lindahl et al., 2022) of the PV technology lead to a short-term decline of wholesale electricity prices when it produces most during mid-day hours due to the merit-order effect (Hirth, 2015, 2013; Welisch et al., 2016; Antweiler and Muesgens, 2021; Gilmore et al., 2015). The phenomenon when a power technology undermines its own market value on spot market by merit-order effect is usually referred to as *"cannibalization effect"*, and is well documented in the literature for countries or regions with a high PV penetration (López Prol et al., 2020; Welisch et al., 2016; Antweiler and Muesgens, 2021; Brown and O'Sullivan, 2019; Martin de Lagarde and Lantz, 2018). Even if the renumeration of produced electricity is not part of LCOE calculation, and thereby out of the scope for this study, reduced value factor over time for PV electricity is worth mentioning as highly relevant long-term risk factor. However this phenomenon might not apply with full strength to residential applications as such PV systems may be installed in many different directions (Killinger et al., 2018; Ramadhani et al., 2023), which affects the daily electricity production profiles.

This study intends to present realistic LCOE distributions for a typical single-family dwelling PV system to point out the relative importance of different parameters. Other common economic indicators such as net present value (NPV) and internal rate of return (IRR) were not included as they require multi-tiered pricing. Another limitation is reinvestment cost, where we have assumed that the only reinvestment required is the inverter as other parts of the system also can fail. Additionally, there is a chance for early-year failures in components, such as inverters, which require specific scenarios. This has not been included in this study.

5. Conclusions

This study aimed to calculate a realistic distribution of LCOE and point out the relative importance of different parameters by including an economic risk assessment using Monte Carlo simulations, and we conclude a median unsubsidized LCOE at a 2% discount rate of 0.99 SEK/kWh. There have been a few studies conducting LCOE calculations for single-family dwelling PV systems in Sweden, but without any thorough economic risk assessment to understand the distribution of LCOE as well as the extreme cases. The unsubsidized LCOE for the majority of systems fell within the range of 0.85 SEK/kWh (25th percentile) to 1.15 SEK/kWh (75th percentile), with a mean of 1.02 SEK/kWh at a discount rate of 2%. Notably, in extreme scenarios, the LCOE values exhibited significant variation, reaching as low as 0.30 SEK/kWh at a 0% discount rate and as high as 5.70 SEK/kWh at a 5% discount rate.

The three parameters with the strongest linear correlation to LCOE were capital expenses, annual yield, and lifetime. The capital expenses for single-family dwelling PV systems have been decreasing in the latest decade. But now the situation in Europe has changed significantly in the latest year, and in 2021, the capital expenses generally increased for single-family dwelling PV systems. This emphasizes the importance of including a thorough risk assessment to understand which parameters that influence the investment and find realistic LCOE distributions for single-family dwelling PV systems.

The economic risk of investing in a solar PV investment is increasing significantly with a 5% discount rate, compared to the assumed typical 2% discount rate. But even at 0% discount rate, extreme cases are increasing the LCOE significantly. On the other hand, these extreme cases have a very low probability of occurring, as shown by the Monte Carlo distributions.

The highest economic risk factor is the CAPEX, and since this is known at the quotation stage, the risk can be avoided by not proceeding with the investment if the CAPEX is too high. furthermore, the Swedish tax reduction for green technology reduces the CAPEX, and consequently the LCOE, and also lowers the standard deviation and hence the risk. The second highest economic risk is the calculated annual yield. This risk can be reduced by making a good prediction of the expected annual yield to reduce the uncertainty in LCOE and to ensure that the PV system is working as expected by regularly following the production when it is in operation. Therefore, it is suggested to create an industry standard and a neutral, authoritative information source regarding the calculation of annual yield to lower the risk in small, distributed PV systems.

CRediT authorship contribution statement

Sebastian Zainali: Conceptualization, Methodology, Validation, Formal analysis, Writing – original draft, Writing – review & editing. **Johan Lindahl:** Funding acquisition, Data curation, Conceptualization, Methodology, Writing – original draft, Writing – review & editing. **Johan Lindén:** Writing – original draft, Review & editing. **Bengt Stridh:** Writing – original draft, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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