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Economic analysis of the early market of centralized photovoltaic parks in Sweden☆

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ABSTRACT

Sweden are one of the countries that experience growing installation volumes of Solar photovoltaic. Traditionally, in Sweden, most of the solar photovoltaic investments and policy incentives have focused on distributed photovoltaic systems. Yet, despite limited policy incentives and pessimistic forecasts, an increasing number of centralized photovoltaic parks have been commissioned and plans for substantial new capacities are communicated. Hence, the current paper investigates why. Detailed information about the underlying costs of six PV parks commissioned in2019 and 2020 in Sweden were obtained by in-depth interviews with stakeholders and were analysed through levelized cost of electricity calculations. We conclude that the unsubsidised levelized cost of electricity ranged from 27.37 to 49.39 €/MWh, with an average of 40.79 €/MWh. This is lower than what are assessed for photovoltaic parks in some recent Swedish electricity system scenario studies. The main reason for the discrepancy is identified to be the assumed interest rates in the system scenario studies and the actual cost of capital experienced in the market. Comparing the levelized cost of electricity values with the market value of solar photovoltaic electricity on the spot market show that four of the six studied parks would be profitable under a merchant business model with the last years spot prices. If the downward price trend continues, Sweden may face an unexpected expansion of photovoltaic parks.

1. Introduction

The global photovoltaic (PV) market has grown substantially in the last decade. At the end of 2020, the global PV installed capacity reached at least 760 GW, which contribute to about 3.7% of total electricity consumption [1]. Historically, the global PV market has mainly been driven by a few big national markets, powered by different subsidy and investment schemes. But as prices for PV, mainly hardware [2–5], but also soft costs[4] [4–7], operations and maintenance (O&M) [8] and cost of capital (CoC) [9–11], have dropped dramatically in recent years, PV has become more economically competitive in additional regions of the world. As a consequence, large shares are now installed in different emerging markets around the world [12]. Sweden is one of these emerging markets. After years of annual steady growth of between 45 and 85% [13], 398.5 MW of grid connected PV were installed in Sweden

☆ Ingrid Mignon have overseen the whole research project and contributed to the writing of the paper.

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[1] Johan Lindahl have conducted all the six interviews about the economics of PV parks, collected the basic data of all other PV parks in Sweden, supervised the work of calculating the market value and value factors of power production in Sweden, gathered additional data and done a majority of the writing of the paper.

[2] David Lingfors have conducted the simulations to gain PV production data, supervised the work of calculating the market value and value factors of power production in Sweden and contributed to the writing of the paper.

[3] Åsa Elmqvist contributed to the six interviews about the economics of PV parks and contributed to the writing of the paper.

[4] Soft costs include factors such as installation labor, traveling expenses, permitting costs and customer acquisition.

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Abbreviations

a	annum
AC	Alternating current
C_d	Cost of debt
C_e	Cost of equity
CAPEX	Capital Expenditure of the system
CoC	Cost of Capital
CT	Corporate Tax
D	Debt financing
DC	Direct current
Dg	Degradation factor
DSO	Distribution System Operators
E	Equity financing
€	Euro
$g_t^{t^*}$	Generation of technology t^*
GW	Gigawatt
Infl	Inflation rate
kW_p	Kilowatt peak
kWh	Kilowatt hour
L	Total lifetime (construction and operation)
LCOE	Levelized Cost of Electricity
MW_p	Megawatt peak
MWh	Megawatt hour
N	Operational lifetime
O&M	Operations and Maintenance
p_t	Spot price at that timestep t
$\overline{p}$	Time-weighted average wholesale electricity price
$\overline{p}^{t^*}$	Market value of technology t^*
P_y	Real electricity tariff
PPA	Power Purchase Agreement
PV	Photovoltaics
r	real interest rate
ReInv	Reinvestment
ResC	Residual Cost
SEK	Swedish crowns
T	Time period
TGC	Tradable Green Certificate
TSO	Transmission System Operator (TSO)
TWh	Terawatt hour
VF	Value Factor
$WACC_n$	Nominal weighted average cost of capital per annum
$WACC_r$	Real weighted average cost of capital per annum
Y	Yield

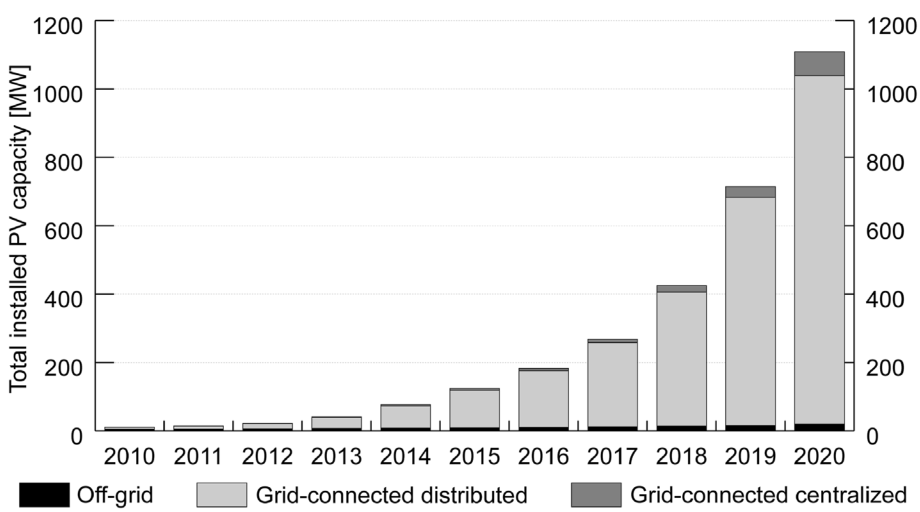

Fig. 1. Total installed PV capacity in Sweden [13,14].

in 2020, resulting in a total PV capacity of 1 089.4 MW [14]. In contrast to the global market, where 63% of cumulative installed capacity is made up of centralized utility-scale PV [12], the market in Sweden has so far almost exclusively consisted of decentralized[5] distributed off-grid and grid-connected systems, see Fig. 1.

The major scheme for increasing renewable electricity production in Sweden has been a renewable electricity certificate, or tradable green certificate (TGC), a system that was introduced in 2003 [15]. The energy sources that are entitled to receive certificates in the Swedish TGC system are wind power, some small hydro power, certain biofuels, PV, geothermal, wave power and peat in CHP power plants. Renewable electricity certificates are granted to a production facility for a maximum of 15 years. TGC systems are, due to their fundamental setup, suitable to stimulate investments in relatively mature technologies, whereas immature technologies in an early learning stage have difficulties taking advantage of the support [16–18]. Biomass dominated the issuance of electricity certificates until 2012 [19], which was the year when CHP plants that already existed at the introduction of the TGC system started to detach from the system [17]. The individual power source that has received most certificates each year since 2012 is wind power [19], in line with its rapid growth in Sweden the last decade.

Sweden has, in contrast to many other European countries, never a applied a feed-in-tariff scheme, which in general has been the favoured and most effective policy for introducing new technologies [20]. Instead, the PV market took off in 2005 when a PV

[5] Decentralized PV systems are systems that are connected to a certain electricity consumer or point of consumption and were the produced electricity usually firstly is used to cover the electricity consumption of the consumer and secondly is fed into the electricity grid. Decentralized PV systems is typically grid-connected roof-mounted PV systems on residential, commercial or industrial buildings.

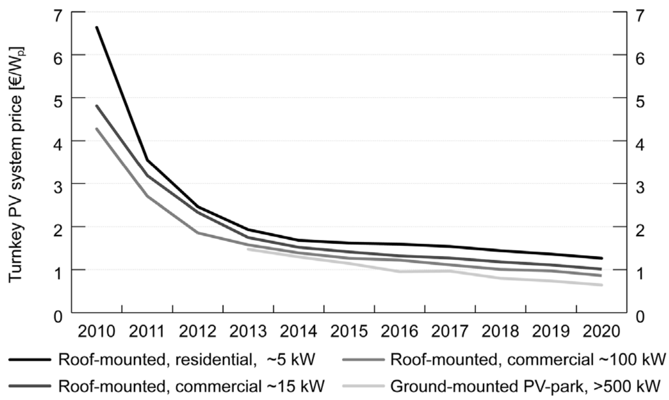

Fig. 2. Historic development of the weighted average typical prices for turnkey PV systems (excluding VAT), reported by Swedish installation companies [13].

specific capital investment scheme was introduced [13,21]. Capital investment schemes has been found to especially increasing the return in the residential segment by reducing upfront costs [20], which is confirmed by the decentralized market development in Sweden [13] illustrated in Fig. 1. Versions of this ordinance has been in place in Sweden until the end of 2020. When the capital investment subsidy was introduced in 2005, a PV investor could get 70% of the installation costs covered by the government. Since then, the maximum coverage of the installation costs has successively been lowered [22] as the price of PV in Sweden has decreased, see Fig. 2. In 2020, it was equal to 20%. The ordinance has always included an upper cost limit per PV system. In 2006–2008 the limit was 5 million Swedish crowns (SEK) per system, in 2009–2011 it was 2 million SEK, in 2012 it was 1.5 million SEK, in 2013–2014 it was 1.3 million SEK and since 2015 until 2020 it was 1.2 million SEK [13].

Sweden currently has one of the top ranked electricity systems in the world [23], due to its (1) *high operational reliability* - the delivery security was 99.974% in 2019 [24], (2) *high electrification level* – 100% of total population have access to electricity [25], and (3) *low greenhouse gas emissions* – emissions from fossil fuels associated with the domestic electricity production, in 2020 was only 0.21 TWh, which corresponds to 0.1% of the total Swedish electricity production of 159.89 TWh [26]. Yet, in Sweden, the share of PV is low; in 2020, PV contributed to merely 854 GWh (simulated in this study). Given the low greenhouse gas footprint of the Swedish electricity production and the fact that solar radiation is relatively low as compared to countries further to the south,[6] few have expected unsubsidised centralized PV to contribute significantly to the future electricity production. Like on a global level, where many scenarios assessing global decarbonization pathways predicts far lower future PV capacity than projected by parts of PV community [27], the contribution of centralized PV parks in the Swedish electricity mix is either estimated or modelled to be low in the future [28–32]. For instance, the Swedish national transmission operator (TSO), Svenska Kraftnät, estimates that PV will contribute to about 7 TWh, or 4%, in a 100% renewable scenario for 2040 in their 2018 long-term scenario [28]. Furthermore, the Swedish Energy Agency expects PV to contribute to about between 8.6 and 9.7 TWh of electricity production in 2050 in their different long-term scenarios, where a clear majority comes from decentralized rooftop installations [29]. An academic example is a techno-economic cost optimization study for 2045, where centralized PV power production was modelled to be only 1.8 TWh if the transmission interconnection to neighbouring countries was kept at the current level and 0 TWh if the model allowed new transmission interconnection [31].

However, despite the; (1) limited policy incentives aimed at centralized PV parks in Sweden, (2) the very pessimistic forecasts regarding future PV, and (3) the fact that Swedish incumbent utilities have so far marginally contributed to PV diffusion through own investments in centralized PV parks, but rather have taken roles as brokers in turnkey decentralized PV system sales, purchasers of PV electricity and community solar intermediators [13,21,33,34], an increasing number of PV parks have been commissioned in Sweden in recent years (see Appendix A) and plans for more and larger PV parks are being communicated. As can be seen in Appendix A, many of the recent investors are not incumbent utilities. The ownership is rather a mix of utilities, institutional investors and private persons, which are in line with findings in e.g. Germany [35,36].

As the PV penetration in Sweden is low, the explanation for the discrepancy between the scenario studies and the development is likely to be found in the economic assumptions, rather than grid and energy system integration or land-use limitation, which can limit the contribution of PV in global scenarios [27]. Therefore, detailed economic parameters of six PV parks commissioned between 2019 and 2020 in Sweden was collected to evaluate if the actual situation in Sweden are in line with the assumptions made in the mentioned scenario and modelling studies [28–32]. The economic parameters are then used to calculate the unit cost of energy by the dominant LCOE metric [37], where the discounted sum of costs is divided by the discounted sum of energy production, and are compared the result to the renumeration offered by the spot market. All in an attempt to understand and explain the recent trend of the increasing deployment of centralized PV parks and fill the knowledge gap about this expansion in the Nordic region.

In addition to answer the main research question above, the major contribution to the research field of this study is elicitation of up to date detailed costs components for real individual centralized PV park projects, including project specific CoC which usually is hard to acquire [38]. In the literature, the economical parameters for centralized PV parks are usually either generically assessed through literature studies, market intelligence and expert estimations, e.g. Refs. [35,39–41] or reversely calculated by decomposing the cost structure from officially publicized power-purchase agreements (PPA) or auction bids [10,42].

The rest of the paper is organized as follows. In the next section, methods used to collect data are presented. The findings are then introduced in Section 3 and discussed in Section 4. The paper ends with some conclusions and implications for policies and future research.

2. Methods

Different data and calculation methods have been used to first get a picture of the economical case of each PV park, and then compare that case with the revenues from the electricity market. These data and calculation methods are described in the sections below. Microsoft Excel has been used for all calculations, except for the simulation of PV power production data were a model developed in MATLAB was used.

2.1. Data collection

To get an overview of the centralized PV park market segment in Sweden, information about all centralized PV parks with a capacity

[6] In Sweden the global radiation varies between 1 050 kWh/m^2 along the costs in the south to 725 kWh/m^2 in the mountain areas in the north west of Sweden [8].

above 0.5 MW_p, commissioned before the start of 2021, was collected. The information was gathered through secondary data and individual contacts with PV park stakeholders, and cross-checked with the databases of the two major Swedish subsidy schemes; the renewable electricity certificate system (CESAR)[19] and the capital investment scheme (SVANEN). The result of this survey is presented in Table A1 in Appendix A.

To obtain information about the economic parameters of centralized PV parks in Sweden, in-depth semi structured interviews were conducted between February and June 2020 with stakeholders, such as investors, PV park owners or developers, representing six of the completed PV parks. These six projects were all commissioned in 2019 or 2020. The studied projects varied in size between 3 and 14 MW_p. The interviews were conducted to receive the underlaying economical parameters necessary to do a LCOE calculation for each of the six PV parks. All the data collected in the interviews were collected in real values and in the currency of Swedish crowns (SEK). The costs for the PV parks commissioned in 2019 have been converted to euros (€) by the average rate of 2019; 1 SEK = 10.5892 €, and the PV parks commissioned in 2020 by the average rate of 2020; 1 SEK = 10.4867 € [43].

The historical day-ahead spot prices and the values of the electricity certificates were extracted directly in € from the Nord Pool day-ahead spot price statistics [44] and database CESAR of the subsidy system [19], respectively.

2.2. Levelized cost of electricity

Levelized cost of electricity (LCOE) calculations are widely used as a tool for comparing the costs of different power plants or generating technologies [37,45]. The most commonly calculation of the *LCOE* 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 [37]. Another way of looking at *LCOE* is that it expresses the constant real electricity tariff needed to recover the costs of building and operating a power plant during an assumed financial lifetime, and return the rate of return on capital invested equivalent to the discount rate used in the formula [37].

For PV parks, a number of simplifications of the standard LCOE can be made due to the characteristics of the technology, such as omitting fuel costs and handling the initial investment as an "overnight cost". The LCOE equation used in this study is the following:

$$LCOE = \frac{CAPEX_0 + \sum_{t=1}^{N}\left[\frac{O\&M_f + O\&M_v * Y_0 * (1-Dg)^t}{(1+WACC_r)^t}\right] + \frac{ReInv_1}{(1+WACC_r)^{x_1}} + \frac{ReInv_2}{(1+WACC_r)^{x_2}} + \frac{ResC}{(1+WACC_r)^N}}{\sum_{t=1}^{N}\left[\frac{Y_0 * (1-Dg)^t}{(1+WACC_r)^t}\right]}. \quad (1)$$

where t is the year number ranging from 0 to N, N the operational lifetime of the PV park, $CAPEX_0$ the total capital expenditure of the system in year 0 expressed in €, $O\&M_f$ the fixed operation and maintenance cost in year t expressed in €, $O\&M_v$ the variable operation and maintenance cost per produced unit of energy in year t expressed in €/MWh, Y_0 the initial annual electricity production (yield) in the year when operation start expressed in MWh, Dg an annual degradation factor expressed in %, $ReInv_1$ the first major reinvestment needed to reach expected lifetime in year x_1 expressed in €, $ReInv_2$ the second major reinvestment needed to reach expected lifetime in year x_2 expressed in €, $ResC$ and the residual cost of the system at the end of the lifetime expressed in € and $WACC_r$ the real weighted average cost of capital per annum in %.

A full derivation of Equation (1) is presented in Appendix B.

2.3. Market value and value factors

To evaluate the economic conditions for of PV parks in Sweden, the LCOE of the produced electricity should be compared with value of the electricity on the electricity spot market. The varying price on the spot market needs to be considered in cost-benefit or competitiveness analysis of electricity generation technologies. For PV, which generation is more concentrated in time due its weather dependency, analysis of the spot prices fluctuations is of higher importance than for dispatchable generators that adjust output as a reaction to prices [46–48].

One method of determining the actual value of power from a certain electricity generation technology on a shifting spot market is to calculate the market value over a certain period [46,49–51]. The market value, $\overline{p}^{t^*}$, of technology t^*, over a time period, T, represents the relationship between the average spot price of the electricity produced by a power source and its' production share on the market and can be expressed by:

$$\overline{p}^{t^*} = \frac{\sum_{t=1}^{T}\left(g_t^{t^*} * p_t\right)}{\sum_{t=1}^{T} g_t^{t^*}}, \quad (2)$$

where $g_t^{t^*}$ is the generation of the technology at time step t, p_t the corresponding spot price at that timestep and T is the number of time steps of the investigated period.

By comparing the market value $\overline{p}^{t^*}$ of an electricity generation technology with the time-weighted average wholesale electricity price, $\overline{p}$, of the same market and time period T, a "value factor", VF (or sometimes referred to as "capture rate"), can be determined. The value factor is a metric for the value of electricity production with a certain time profile relative to electricity production with a constant flat profile [52].

The equation for calculating the average price $\overline{p}$ is:

$$\overline{p} = \frac{\sum_{t=1}^{T} p_t}{T}, \quad (3)$$

and the equation for determine the value factor consequently becomes

$$VF = \frac{\overline{p}^{t^*}}{\overline{p}} = \frac{T * \sum_{t=1}^{T}\left(g_t^{t^*} * p_t\right)}{\sum_{t=1}^{T} p_t * \sum_{t=1}^{T} g_t^{t^*}}. \quad (4)$$

A value factor above one is a result of a positive correlation between the production profile of an electricity generating technology (or an individual power plant) and the price fluctuations on the spot market. It can therefore be seen as an indication that the power system would benefit from more production with a similar

Table 1
Summary of the economic parameters for the six PV park projects studied within this project.

	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Average
Lifetime [years]	20	45	30	40	30	30	**33**
Annual yield [MWh/MW$_p$/a]	910.1	927.6	1 018.2	975.0	1 012.1	970.0	**968.8**
Annual degradation [%]	0.3	0.2	0.3	0.2	0.4	0.2	**0.27**
CAPEX [€/MW$_p$]	662 912	703 758	776 091	650 030	603 250	712 251	**684 715**
Yearly fixed operation and maintenance cost [€/MW$_p$/a]	4 546	11 277	11 576	9 182	4 201	8 908	**8 282**
Variable operation and maintenance cost [€/MWh]	0.95	−0.83	−1.04	0.08	−1.89	1.79	**−0.16**
First major reinvestments [€/MW$_p$]	15 188	88 071	51 510	27 813	73 269	75 549	**55 233**
Year after commissioning for the first major reinvestment [year]	15	25	15	15	15	15	**16.7**
Second major reinvestment [€/MW$_p$]	–	–	–	11 920	–	–	**11 920**
Year after commissioning for the second major reinvestment [year]	–	–	–	30	–	–	**30**
Residual cost [€/MW$_p$]	10 849	0	0	0	0	0	**1 808**
Nominal weighted average cost of capital per annum [%]	3.10	0.75	2.18	6.50	3.97	4.00	**3.42**
Real weighted average cost of capital per annum [%]	1.07	−1.23	0.17	4.41	1.93	1.96	**1.39**
Annual inflation [%]	2	2	2	2	2	2	**2**
Levelized cost of electricity [€/MWh]	**49.39**	**27.37**	**39.95**	**47.65**	**32.93**	**47.43**	**40.79**

production profile.

The nominal hourly spot price data used for market value and value factor calculations were the day-ahead data from Nord Pool. The corresponding hourly electricity production data were retrieved from the Swedish TSO. However, an exemption was made for the PV power production data. The reason is that a large share the PV power production in Sweden is self-consumed behind the meter, and therefore not included in the statistics from the Swedish TSO. Instead, the PV power production data were generated through simulations using a method described in Ref. [53]. The simulation result was generated in proportion to the installed capacity in each price area, the geographical location of the population and the available solar radiation, in order to ensure that the PV power production is distributed realistically. For each year, the production was calculated from the average installed power at the beginning and the end of the year (see Fig. 1). The distribution of PV capacity in the four different price areas of Sweden was based on the installed PV power per municipality statistics from the Swedish Energy Agency [14]. Some assumptions were made in the simulation to provide the most realistic data. For instance, the simulation was made with a fixed tilt of 45° towards cardinal south, even though some solar panels have another degree of tilt, as this was proven to give a realistic power generation profile [53].

3. Results

In this section the resulting LCOE calculations are first presented, then followed by descriptions of each of the cost parameters and with complementary information derived from the interviews. Then follows the results of the market value and value factor calculations and lastly a comparison between the LCOE values and the revenues from the electricity market is presented.

3.1. Levelized cost of electricity for the PV parks

The economical parameters received from the interviews are presented in Table 1 and thorough discussions of each cost are presented in this section. Here, in order to preserve anonymity, the reported values have been recalculated to costs per installed capacity (€/MW$_p$). Table 1 also contains the corresponding LCOE values that were calculated by using equation (1). The final unsubsidised LCOE values varies between 27.37 €/MWh and 49.39 €/MWh. The average values presented in Table 1 are averages for each cost item and should not be used for a single LCOE calculation as, above all, the assumed life expectancy controls the need for the number of reinvestments. The average LCOE value is therefore an average of the individually calculated LCOE values and not the result of an LCOE calculation with the averages as inputs.

As Table 1 illustrates, the economic parameters differed quite substantially between the projects. In the following, each major economic parameter is examined closer based on the information received from the interviews.

3.1.1. Lifetime and degradation

The respondents estimated the lifetime of the various PV park projects to be between 20 and 45 years. Three of the projects had an expected lifetime of 30 years in their investment calculation, which is based on the length of the PV module warranties. The lifetime of 20 years for Project 1 is due to alternative use of the industrial land it is located on. The lifetime of this project is thus to be viewed as an economic lifetime linked to the value of the land, rather than a lifetime linked to the technology. Two projects estimated a life expectancy of 40 and 45 years, respectively. In both cases, the planned reinvestments are larger than for the other parks (see Section 3.1.6).

All projects have included degradation as a factor that affects the economic calculation. The assumed degradation varies between 0.2 and 0.4%/year, which indicates that the project owners are aware that degradation of PV have been experienced to be somewhat lower in colder climates [54–57].

3.1.2. Annual yield

The six PV parks studied in this project are located in completely different parts of Sweden and three of the four Swedish electricity trading areas are represented. This geographical distribution results in differences in the annual global radiation [58] and the ambient temperature, which both have an effect on the annual yield [59].

Additionally, there are technical characteristics that impact the annual electricity production. All six projects are installed with regular modules and a fixed tilt facing south to maximize production. Yet, for PV parks, it is common for the inverter capacity to be dimensioned lower than the rated power of the modules, which results in a lower alternating current (AC) capacity for the park.[7] As Table A1 in Appendix A shows, the AC/DC ratio varies between 0.77

[7] This relationship between the capacity of the modules in direct current (DC) and the capacity of the inverters (or transformer station) in AC is often referred to as the AC/DC ratio. The reason why the AC capacity is often dimensioned lower than the DC capacity is that the modules only produce at maximum capacity for a few hours each year. The AC/DC ratio is thus mostly an economic balance between higher inverter costs to match the modules' capacity compared to the value of the energy spilled when the inverters curtail production.Sometimes it is the transformer station, or the capacity of the overlying grid, that limits the amount of AC power the park can feed into the grid. Insufficient transformer stations or overlying grid capacity are usually included in the broad term of PV curtailment [58].

and 1.0 for the PV parks that use a configuration with regular modules and a fixed tilt towards the south. One of the six interviewed PV parks in this study, and in total two PV parks listed in Table A1, reported that their AC output are limited by grid constraints. For all other PV parks, it is the inverter capacity that is reported to set the AC output capacity.

To summarize, the geographical location to a greater extent, and the selected AC/DC ratio to a lesser, affect the annual yield. The values for initial annual electricity production that were specified during the interviews varied between 910 $MWh/MW_p/a$ and 1 036 $MWh/MW_p/a$. Some projects, namely those commissioned in 2019, had production data available while the other reported calculated values based on simulations.

3.1.3. Investment costs

The initial investment cost, $CAPEX_0$, is the single largest cost for a PV park. During the interviews, the $CAPEX_0$ was divided into; (1) total cost for subcontractors (which were divided into labor costs and component and material costs), (2) grid connection costs, (3) land costs and (4) owner costs, see Table 2.

The total cost for subcontractors includes all costs for building the park. In most cases, a main contractor was hired to coordinate the acquisition of the necessary hardware and the construction of the park. The average cost for subcontractors, i.e., the cost of the actual construction of a solar park, was 631 070 €/MW_p. Two of the respondents were not able to separate the total cost of building the park into labor costs from component and material costs, which is the reason for these fields being blank in Table 2. However, data from the other four parks indicate that the largest single cost item in the construction of a solar park was the cost for the PV modules, in average 232 231 €/MW_p. This cost item was followed by the average cost for labor (125 505 €/MW_p), mounting systems (78 495 €/MW_p), inverters (40 085 €/MW_p) and pre-construction and ground preparation (39 234 €/MW_p). Other costs (i.e., categorized under "component and material costs") are costs for cabling and other electronics, transformer station, safety and monitoring equipment, system and product warranties, signs, service houses, fiber routing, etc. Among the costs, the category that turned out to vary the most was the costs for pre-construction and ground preparation. This was a result of the differences among the types of land the parks were built on and the condition of the site before construction. For example, in one case forest was to be cut down and in two cases new roads had to be built.

The initial grid connection costs also varied substantially among the projects. Since the six PV parks are located in different parts of the country, six different distribution system operators (DSOs) were involved, which all have their own cost structure. Additionally, the variation can be traced to the access of physical infrastructure in place prior construction, e.g., the distance to existing transformer stations or if new transformer stations had to be installed.

Land costs must be distinguished from pre-construction and ground preparation. As illustrated in Table 2, only one of the projects had a land cost. This cost constitutes the purchase of the land from the previous landowners. In one of the other projects, the PV park owner already owned the land. The other PV park owners chose to lease the site on which PV solar park is built on, which results in an annual operating cost instead of an initial investment cost.

The last cost item under $CAPEX_0$ is owner costs. These are internal costs that the customer or the final park owner has had during the construction period, such as preliminary site investigations, permit processes, project management, inspection of the park and project margins. As Table 2 shows, this cost category varies rather much among the projects, i.e., from 0 €/MW_p to 63 573 €/MW_p. The owner costs are highly dependent on the relationship between the typical roles in the project, namely; (1) main contractor, (2) other contractors, (3) the client of the park and (4) the final owner, and the allocation of work and costs between these typical roles. For several of the six interviewed PV park projects, one or more of these typical roles could be attributed to the same company.

In summary, the total $CAPEX_0$ for the six PV park projects ranged between 603 250–712 251 €/MW_p, with an average cost of 684 715 €/MW_p. The factors that seem to have had the greatest impact on this variation was the size of the park and the choice of site, that impacted the costs for ground preparation and access to infrastructure (roads and grid).

3.1.4. Annual fixed maintenance and operating costs

In the interviews, several annual costs that were common to all projects, were identified. These were; (1) costs for electrical maintenance and production monitoring, (2) site maintenance costs, (3) administrative costs, (4) physical monitoring costs, (5) insurance costs, (6) annual fixed grid costs, (7) operation electricity costs, (8) land leasing costs and (9) property tax.

Costs for electrical maintenance and production monitoring include the costs for electrical operation of the park and varied between 814 €/MW_p/a and 2 861 €/MW_p/a, with an average of 1 536 €/MW_p/a. In some of the cases, the final park owner handles the maintenance and monitoring, while in other, this is outsourced to an external service provider. These two different approaches may explain the differences in the estimated costs.

Site maintenance costs refer to maintenance and management of the surrounding land and include, e.g., costs for grass cutting or mowing of flower meadows. These costs were estimated at between 50 €/MW_p/a and 1 459 €/MW_p/a, with an average of 612 €/MW_p/a. The differences are largely due to the characteristics of the site, e.g., two of the projects had their site inundated on occasions, which has driven up the costs of site management and thus the overall average value.

Module cleaning costs have not been included in the calculation in any of the six projects, as the regular rain is expected to remove the dust and pollen particles from the modules that are installed with a certain tilt in Sweden [60,61]. However, other types of cleaning, e.g., the costs of mechanical cleaning of bird droppings, which tend to get stuck and can affect the output [62,63], were included in site maintenance costs according to the respondents.

The administrative costs for managing the parks' finances and

Table 2
Summary and breakdown of the investment costs ($CAPEX_0$) of the six solar parks in €/MW_p.

	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Average
Total labor costs	*247 489*	*100 433*	-	-	*113 323*	*164 693*	***156 485***
Total component and material costs	*389 821*	*559 052*	-	-	*429 683*	*475 156*	***463 428***
Total cost for subcontractors	637 310	659 484	744 154	562 617	543 006	639 850	**631 070**
Grid connection costs	23 650	44 274	9 615	23 840	19 538	56 662	**29 596**
Land costs	0	0	0	0	40 705	0	**6 784**
Owner costs	1 953	0	22 321	63 573	0	15 739	**17 264**
Total $CAPEX_0$	**662 912**	**703 758**	**776 091**	**650 030**	**603 250**	**712 251**	**684 715**

operation varied a lot between the six projects, with costs from 87 €/MW_p/a to 3463 €/MW_p/a, with an average of 1 674 €/MW_p/a. These differences can be traced to the chosen business model. The parks in the interview study have been built according to either types of cooperative ownership or corporate-PPA business models. For cooperative ownership business models, an economic association is usually formed, which takes over the ownership of the park from the client who ordered it and sells shares of the cooperative to private individuals or companies [34]. This business model requires larger administrative resources since statutes, accounting, annual meetings and management of shares are required to be handled by the economic association. For corporate-PPA business models, a bilateral agreement is created between the PV park owner and a customer [64–66]. After the setup of the bilateral contract less administration is needed to run this business model.

The physical monitoring costs mainly consist of either the running costs for a surveillance camera with IR equipment and an alarm system (the most common approach among the studied projects) or on-plant inspections performed by security personnel. The cost for the physical monitoring was reported to vary between 159 €/MW_p/a and 1 374 €/MW_p/a, with an average of 548 €/MW_p/a.

The insurance costs varied between 0 €/MW_p/a and 1 458 €/MW_p/a, with an average cost of 681 €/MW_p/a. Two of the respondents stated that they had an insurance that covered the entire corporate group's operations, and that they assessed that their PV park did not affect their insurance premium. As a result, there were no additional insurance costs for these two projects.

The annual fixed grid costs differed quite significantly between the parks, due to that there are six different DSOs and thus six different grid fee structures. When divided with the module capacity, the lowest cost was calculated to 488 €/MW_p/a, the highest to 6 824 €/MW_p/a, and the average to 2 339 €/MW_p/a.

Most of the studied PV parks also have a consumption subscription to be able to purchase electricity for heating and ventilation of service houses, monitoring systems, communication systems, weather stations, etc. Since the electricity purchased for these purposes is not affected by the electricity production of the park, the electricity purchase is classified as a fixed annual operating cost. The electricity cost for the operation was estimated between 18 €/MW_p/a and 276 €/MW_p/a, with an average of 125 €/MW_p/a. This cost is correlated to the amount of electrical equipment in each park.

As mentioned in section 3.1.3, four of the six project owners have chosen an arrangement where the land on which the PV park is built is leased. In all four cases, these leasing agreements covers the entire expected lifetime of the park. These land leasing costs varies between 278 €/MW_p/a and 2 473 €/MW_p/a, with an average of 685 €/MW_p/year. The variation can be explained by the type of land (i.e., its alternative use) and where it is geographically located.

The last annual fixed cost identified in this study is the property tax. In Sweden, property tax is affected by whether an electric power plant stands alone or if it is an extension of another building (e.g., roof mounted PV). An independent facility that is set up for commercial production of electricity is a power plant building, which, together with its associated land, must be taxed as an electricity production unit.[8] Due to current uncertainties in the Swedish legislation, one of the projects did not account for any property tax. Two of the projects have a notification in their leasing contracts, indicating that any property tax shall be paid by the landowner, resulting in no costs associated with property tax for these projects. For one of the PV parks, the property tax does not burden the LCOE calculation, as it is paid by the landowner exploiting the land. The other two parks pay 238 and 244 €/MW_p/a, respectively.

The variation in the total annual fixed maintenance and operating costs is relatively high. If combined with the initial annual production, the lowest assessed cost for an individual plant was 4.15 €/MWh and the highest 11.37 €/MWh with an average of 8.55 €/MWh. The average cost of 8 282 €/MW_p/year derived in this study is slightly higher than the 7 050 €/MW_p/year that has been reported to be the average O&M cost for centralized PV parks in Germany in 2017 [38]. However, annual fixed grid costs and insurance costs are not included in the O&M in Ref. [38], and extracting these costs from our data leads to an average 5 261 €/MW_p/year. This is substantially lower than the reported O&M costs in Germany in 2017, which can either be an indication that the Swedish stakeholders underestimates the O&M costs of PV parks, or a sign that the downward experience curve of O&M costs has continued since 2017 and that Swedish actors have been able to draw experience from countries such as Germany despite the much lower installed capacities of centralized PV parks in Sweden until now.

3.1.5. Variable operation and maintenance cost

The PV electricity requires no fuel whatsoever. Furthermore, for PV parks where the modules are installed with a fixed tilt there are no moving parts that are worn out during electricity production. The need for maintenance is thus not correlated to the amount of electricity produced. Hence, there are no variable maintenance costs, and the only variable operating costs are those that are linked to the electricity grid, electricity trading and balance responsibilities. Regarding electricity trading and balance responsibility, the respondents have stated that costs range from 0.9 to 2.9 €/MWh. Among the six PV parks studied, none had any grid costs based on how many MWh that were fed into the grid. Instead, five of the six projects receive compensation per MWh from their grid operator as this electricity is considered to perform beneficial grid services (i.e., it helps reducing the losses in the grid and makes it possible to utilize the capacity more efficiently as the electricity is produced closer to the user) [67]. These five parks have been compensated between 1.1 and 2.8 €/MWh for the provided grid services. It can be argued that this is a compensation and therefore should not be included in LCOE calculations. But since it is a part of the grid operators' total cost structure, we have chosen to include the grid benefit compensation. However, if the LCOE values in this report are used in profitability calculations where production costs are compared with revenue streams, the grid benefit compensation should be omitted from the revenue as it in our calculation already been included in the production cost.

When combining the grid benefit with the cost for electricity trading and balance responsibility, it was found that the variable operating and maintenance costs were between 0.1 €/MWh and −1.9 €/MWh for the six projects.

3.1.6. Major reinvestments

Since inverters are currently estimated to have a technical lifetime of 10–15 years [68,69]; for all six solar park projects it was calculated that the inverters needed to be replaced at least once. For project 1, which only has accounted for a life expectancy of 20 years, it was assumed that some of the inverters would last through the entire lifetime of the PV park, and thus has the lowest projected cost for reinvestments. For the three parks that have an accounted life expectancy of 30 years, a replacement of inverters after about 15 years and no need for replacement of the transformer stations was assumed. Project 4 is designed for a lifespan of more than 40 years, hence requiring two reinvestment rounds in the inverters around year 15 and year 30 after commissioning. Project 2 also

[8] How the assessed value for a PV park is to be calculated is at the time of writing undefined, since PV is not defined as an individual type of power production under Ch. § 1 of the Swedish property taxation legislation [82].

expects a lifetime longer than 30 years; hence, the owner plans a major reinvestment around year 25 after commissioning, which includes inverters and the transformer station.

As Table 1 illustrates, the assumed costs for the needed major reinvestments vary, even though all cases (except for project 2) only included inverter changes. The reason is that some projects has used current prices for inverters in their calculation of the costs for future replacements, while some owners have assumed that the historical price development will continue and that the prices for inverters will fall [68].

3.1.7. Residual cost

The residual cost (or value) at the end of life was the cost category that the respondents felt most uncertain about. This is understandable as there is no PV park in Sweden, and possibly only a few globally, that has completed an entire life cycle. Therefore, there exist no references for the residual cost.

The costs of demolishing a PV park are low compared to other types of power sources. To dismount PV modules, inverters, mounting racks and their foundations cost significantly less than demolishing entire buildings or large structures with concrete foundations. The current legislation in both the European Union [70] and in Sweden [71] states that both modules and inverters are electronic waste and that it is the producers' responsibility to collect at least 85% of the discarded modules and inverters and recycle 80% of the material in these discarded products. The residual costs for the modules and inverters will thus cease for the solar park owner once they have been dismantled. The costs of collection and recycling are probably included in the initial price since most module producers pay fees to organizations, such as PV Cycle (PV [72], for them to take care of their modules when they become waste.

With this in mind, the stakeholders pointed out that there is a scrapping value in the cables and mounting racks (which are usually steel), along with an increased residual value of the land, due to the existence of a high-capacity grid connection on the site. They all estimated that these two residual values would correspond to the cost of demolishing the park and handling all components. Thus, these projects have been projected for a residual value/residual cost of a total of 0 €. For project 1, where the plan is to use the land after around 20 years, a cost of 10 849 €/MW_p to quickly demolish the park has been projected.

3.1.8. Cost of capital

PV parks involve a proportionally high investment cost compared with operating costs, which makes the financing conditions of high importance. Different arrangements have been used to finance the different projects in this study. One of the parks was financed entirely through loans, i.e., by debt financing, while two of the parks were funded entirely by equity financing. In the other three cases, there was a combination of the two types, resulting in equation B.4 being used to calculate the $WACC_n$ followed by equation B.5 to convert these values into $WACC_r$.

The nominal interest rates on debt financing were between 1.0% and 3.1%. On average, the interest rate for debt financing was 2.09% for the four projects that were entirely or partly financed through loans. This is low as compared to the assessed debt interest rates of 3.5% in the record tender in the Middle East [42], but in line with the reported rates in Germany [9]. The nominal interest rate for equity financing varied considerably, with reported interest rates from 0.0 to 6.5%, resulting in an average of 4.72%. The resulting $WACC_n$ for the projects was between 0.75% and 6.5%, with an average of 3.42%. With the assumed inflation rate of 2%, this corresponds to an average $WACC_r$ of 1.39%. The CoC derived in this study are in level with previously reported CoC for PV parks in Germany, another northern European country, where [9] stated average $WACC_n$ at 2.4% in 2017.

The result of the LCOE parameter investigation shows that some of the LCOE parameters were similar for most of the projects, while other parameters differed considerably. An in-depth sensitivity analysis of the cost parameters is performed in Appendix C.

3.2. The market value and value factor of PV electricity

The result of the simulation to get the PV power production in Sweden, including the self-consumed, are presented in Table D1 in Appendix D together with the PV production according to the Swedish TSO, the installed PV capacity, the PV production per installed capacity and self-consumptions ratios for all the Swedish price areas. The price areas are from north to south: SE1 — price area Luleå, SE2 — price area Sundsvall, SE3 — price area Stockholm and SE4 — price area Malmö.

As can be seen in Table D1 the Swedish TSO have, as an example, registered 457.7 GWh of PV production in 2020, while the simulation resulted in 854.1 GWh. The difference between these two values, i.e., 261.8 GWh, are to be understood as the self-consumed PV electricity in Sweden.

The market value and corresponding value factors of the major electricity generation technologies in Sweden, were calculated with equations (2) and (4) respectively, for each year between 2014 and 2020 and for all four price areas. The result of these calculations is presented in Table 3. Using longer time periods than one year when calculating the market values can lead to misleading results. An increasing overall penetration of an electricity generation technology, due to increasing installation rates, can match the annual fluctuations of the spot market. The installed capacities of wind and PV power have increased comparatively fast in Sweden over this time period, and consequently their production share has increased each year for the hours with related weather conditions. In Sweden, this matches an overall trend of increasing day-ahead spot prices, especially between 2015 and 2018. Using a time period that extend over the entire time period of 2014–2020 would rather represent the match between the increasing installed capacity of wind and PV power and the increasing day-ahead spot prices than reflect the market value of individual power plants of these two technologies (as the production share of individual power plants has not increased over time).

Table 3 shows that PV, hydropower and CHP have in general experienced value factors above 1.0. The value factor for Nuclear has during the last years been very close to 1.0, while for wind power it has consistently been below 1.0. This indicates that it would be positive for the Swedish electricity system if production share from hydropower, PV and/or CHP is increased.

With regards to PV, one can see that PV electricity has a higher value in the south of Sweden. The difference in value for PV electricity on the spot market between SE1 and SE4 was on average 3.25 €/MWh for 2014–2020.

3.3. Revenues from the electricity market

In addition to the market value from the spot market, PV parks have been eligible to receive tradable green certificates (TGCs). The certificates are, as described in section 1, traded on a market and the additional income from these certificates has therefore varied over time. Fig. 3 illustrates the historical development of the monthly average day-ahead spot prices along with the market price of the TGCs in Sweden. It can be noted that certificate prices have dropped substantially over the examined time period and that the average day-ahead spot prices fluctuate significantly between different years. Historically, there has only been a slight difference in prices between the four different price areas in Sweden, but in 2020 there was a large discrepancy between the spot prices in the

Table 3
The market value, in €/MWh, and corresponding value factor for the major electricity generation technologies in Sweden from 2014 to 2020 in each of the price areas. Nuclear power only appears in SE3 since every active reactor under this time period is located in that region.

Spot price area	Year	PV		Hydropower		Wind power		CHP		Nuclear power	
		Market value	Value factor	Market value	Value factor	Market value	Value factor	Market value	Value factor	Market value	Value factor
SE1	2014	33.49	1.066	33.03	1.051	30.65	0.976	30.86	0.982	–	–
	2015	20.15	0.952	22.59	1.068	21.59	1.020	23.95	1.132	–	–
	2016	29.74	1.027	30.39	1.050	28.12	0.971	28.65	0.989	–	–
	2017	32.02	1.038	32.66	1.059	30.13	0.977	30.70	0.995	–	–
	2018	47.47	1.073	46.17	1.044	43.14	0.975	43.32	0.979	–	–
	2019	36.70	0.967	41.12	1.084	36.63	0.965	39.59	1.044	–	–
	2020	14.49	1.008	15.47	1.076	12.94	0.900	15.38	1.069	–	–
	Average	**30.58**	**1.019**	**31.63**	**1.062**	**29.03**	**0.969**	**30.35**	**1.027**	–	–
SE2	2014	33.27	1.059	32.14	1.023	30.37	0.967	30.98	0.986	–	–
	2015	20.46	0.966	21.50	1.015	21.03	0.993	24.26	1.146	–	–
	2016	29.95	1.034	29.77	1.028	27.84	0.961	29.25	1.010	–	–
	2017	32.24	1.045	32.21	1.044	29.48	0.956	31.21	1.012	–	–
	2018	46.82	1.059	44.48	1.006	42.19	0.954	43.76	0.989	–	–
	2019	36.90	0.972	39.35	1.037	36.78	0.969	39.38	1.038	–	–
	2020	14.07	0.978	14.94	1.038	12.60	0.876	15.60	1.085	–	–
	Average	**30.53**	**1.016**	**30.63**	**1.027**	**28.61**	**0.954**	**30.63**	**1.037**	–	–
SE3	2014	33.54	1.061	31.55	0.998	29.95	0.947	31.34	0.991	31.30	0.990
	2015	21.68	0.985	22.61	1.028	21.47	0.976	25.24	1.147	22.55	1.025
	2016	30.11	1.030	29.13	0.997	28.56	0.977	30.94	1.058	28.93	0.990
	2017	32.86	1.052	32.70	1.047	29.62	0.948	31.66	1.014	30.95	0.991
	2018	46.55	1.045	43.02	0.966	42.31	0.950	44.12	0.991	44.10	0.990
	2019	37.10	0.967	38.84	1.012	37.10	0.967	41.84	1.091	38.55	1.005
	2020	23.74	1.120	22.95	1.083	16.86	0.796	23.51	1.110	20.48	0.966
	Average	**32.22**	**1.037**	**31.54**	**1.019**	**29.41**	**0.937**	**32.67**	**1.057**	**31.00**	**0.994**
SE4	2014	33.74	1.057	31.97	1.002	30.50	0.956	32.59	1.021	–	–
	2015	23.27	1.016	25.13	1.097	21.39	0.934	26.46	1.155	–	–
	2016	30.45	1.031	27.27	0.923	28.24	0.956	29.59	1.002	–	–
	2017	33.38	1.037	33.29	1.035	29.94	0.930	32.77	1.018	–	–
	2018	49.32	1.064	42.41	0.915	43.35	0.935	45.27	0.976	–	–
	2019	38.90	0.977	41.07	1.032	38.12	0.958	42.46	1.067	–	–
	2020	27.73	1.072	25.34	0.980	19.98	0.773	26.92	1.041	–	–
	Average	**33.83**	**1.036**	**32.35**	**0.998**	**30.22**	**0.920**	**33.72**	**1.040**	–	–

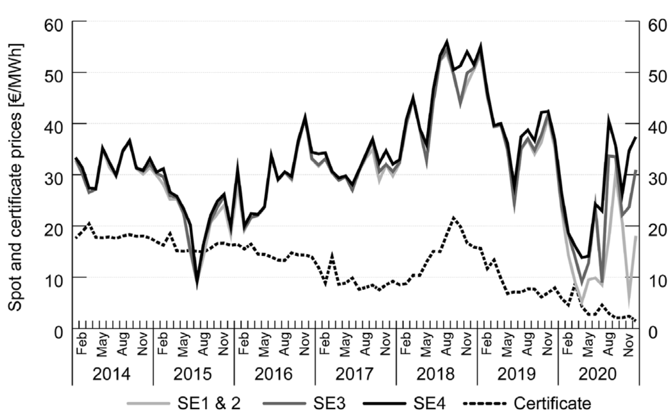

Fig. 3. The development of monthly average day-ahead spot prices in the four Swedish price areas [57] along with monthly average renewable electricity certificate prices [19].

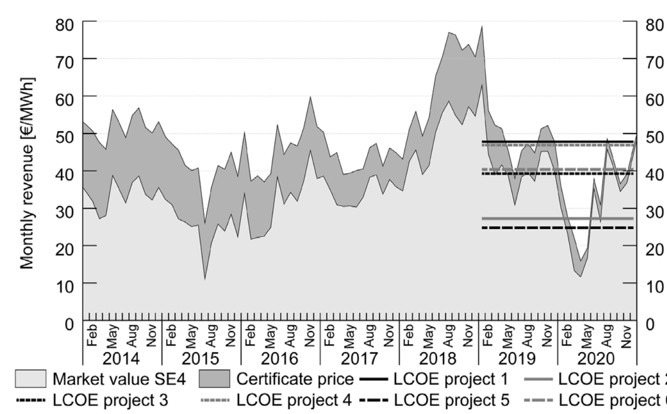

Fig. 4. Historical PV market values calculated with a time period of 1 month in SE4. together with the monthly average renewable electricity certificate prices. compared with the subsidised LCOE of the six PV park projects when the capital investment subsidy has been included.

south and north of Sweden for several months.

To deduce what revenues the Swedish electricity market has offered electricity production from PV parks in Sweden historically, the market value of PV in the different price areas can be complemented with the income from renewable electricity certificates. In Fig. 4 the PV market value calculated on a monthly basis for price area SE4 is presented along with the monthly average renewable electricity certificate price for all months from 2014 to 2020. For a PV park project to be profitable based solely on the incomes received from the electricity market, the LCOE of a project needs to match these two revenues in the long run.

In Table 1 the calculated *unsubsidised* LCOE values of the six PV park projects commenced and commissioned during 2019 and 2020 are presented. In addition, as described in section 1, PV systems are entitled a capital investment subsidy in Sweden. As the studied projects represent large PV systems, they all reached the upper cost limit of 1.2 million SEK (about 114 000 €) per PV system. However, two of the study objects were built on two or more juridically separated estates, which under the current legislation means that these parks are considered as two (or more) individual PV systems, even if the park physically can be regarded as one system. These two PV park projects therefore received more than 114 000 € from the capital investment subsidy. Subtracting the obtained capital investment subsidy from the $CAPEX_0$ values of Table 1 and recalculating gives the *subsidised* LCOE of the six PV park projects. These subsidised LCOE values have been included in Fig. 4 for comparison. They are only visible for 2019 and 2020, as they all were commissioned in these two years.

4. Discussion

Comparing the LCOE values for the six PV park projects with the revenues obtained from the spot market and certificates in 2019 and 2020, indicates that the profitability of PV parks in Sweden is not yet always a reality under merchant business models, even if investment subsidies are included as in Fig. 4. Projects 2 and 5 seem to be within a good margin of being profitable, if their assumed cost of debt and cost of equity are constant and if the market value of PV power in the long run stays at the same level as experienced in the period 2014–2020. Projects 3 and 6 are on the brink of being profitable compared with the market values. Projects 1 and 4 would need prices and market values of the level seen in 2018 to be profitable. These results are in line with the estimated LCOE and market values for PV parks in Finland [39].

Hence, only four of the PV park projects investigated would be profitable under a merchant PV business model at the spot prices levels of the last years. This indicates that there is a need for added values for investors. These can be either economic, such as premium renumeration through corporate-PPA contracts, which in addition also reduces the risk for the producer and consequently the end CoC [10,11,20,36,64–66], or of other character, such as increased sustainability, fair cost, social identity, induced innovativeness in the involved companies [73] corporate goals and customer acquisition [34]. Indeed, the parks in the interview study have either been realized under corporate-PPA or cooperative ownership business models. The added values of the applied business models have not been investigated in this study but should be examined in future research to in-depth describe the dynamics of the Swedish market of centralized PV parks.

Comparing the result of this study to the assumed economic key parameters for centralized PV parks in some recent modelling studies of future Swedish power system [29–32], give quite large differences for some parameters, which can be seen in Table 4. The assumed lifetime varies from 25 years [31] to 40 years [32] which is the same deviation as the presumed lifetimes of the PV parks in this study. When it comes to the yield of PV parks, the only value that stands out is the 1 375 MWh/MW_p assumption made in Ref. [31]. This is probably an overestimation as none of the investigated PV parks in this study come close to this value.

With regards to the initial investment, all of the studies except the one from the Swedish Energy Agency [29], assumed lower CAPEX than what was derived in this study. However, the scenario studies are assessing the initial investment cost of PV parks in 2045. If the trend of decreasing hardware costs continues (Fischer et al. n.d.) [3–5], CAPEX will decrease. Industry leaders expect that the CAPEX for large systems >0.1 MW_p will go down by 40% in the next ten years (Fischer et al. n.d.). Based on the average CAPEX derived in this study, it would correspond to a CAPEX of about 410 000 €/MW_p in Sweden by 2030. This CAPEX is close to the assessed CAPEX in 2045 by Refs. [30,32], while Chalmers and the Swedish Energy Agency's CAPEX values for 2045 probably are too high if the price reduction continues.

Looking at the $O\&M_f$ [29,30,32], estimate costs that are a little bit lower, but in the same range as the result of this study, while [31] greatly overestimated the cost for running a PV park.

The CoC is the parameter that deviates the most between the studies of the future of the Swedish electricity system and the result of this study. Firstly, this study confirm the low CoC for PV in northern Europe [9,38]. Secondly, a CoC at 5% respectively 7%, instead of the 1.4% derived in this study, would increase the LCOE of the studied PV parks from the average of 40.79 €/MWh to 57.85 €/MWh and 68.99 €/MWh, respectively. Such a high LCOE for PV parks in Sweden would indeed make them economical unattractive in future power system scenarios.

The difference in the assumed uniform interest rate in the recent studies of the future of the Swedish electricity system and the current actual CoC experienced on the market, are likely the main explanations for the inconsistency between the actual experienced roll out of centralized PV parks in Sweden and the expected market development by major Swedish stakeholders and academic research groups. As previous studies have pointed out [37,74,75], the choice of discount rate has a significant effect on the LCOE, and consequently the probability of a power source to be built in scenario modelling. In Sweden, incumbent state owned or municipality owned utilities are used to build new power plants with 100% equity finance at the rates assumed in the scenario studies. However, the discrepancy of the assumed interest rates and proven CoC of the current investors, which nowadays are more likely to be private persons through cooperative ownership or institutional investors [36], needs to be addressed properly if future predictions of the electricity market will manage to predict the likely increase in centralized PV production capacity in Sweden. Similar alerts that uniform CoC assumptions, and the use of market inadequate interest rates [37,38], for renewables may lead to bias in energy system models and scenarios has been raised before [27,76].

The profitability of future PV park expansions in Sweden depends on several factors. One factor is of course the future costs. If the decreasing trend of the initial investment cost continues and CAPEX levels down to 410 000 €/MW_p are reached, PV parks with LCOE values in the range 22–33 €/MWh may appear in the next few years in Sweden. This provided that the O&M costs and the CoC do not increase dramatically. This may lead to a rapid expansion of centralized PV power, which will go against the current predictions made by academics [31,32] and Swedish authorities [28,30].

This possible expansion of centralized PV parks, along with predicted larger quantities of decentralized PV in Sweden [29,32], may in turn lead to new market values for PV. At low penetration levels, the market value of PV is usually higher than the average spot prices because of the positive diurnal correlation between the production profile and the load pattern, while at high penetration it falls below the average spot prices [46] as PV tends to reduce the system marginal cost during the mid-day hours [48]. The phenomenon, appearing when an increasing penetration of a certain generation technology undermines its own market value on the spot market by the merit-order effect, is usually referred to as the "cannibalization effect", and it is well documented in the literature [48,50,51,77,78]. This effect has been shown to be even more important for variable renewable technologies, as their output is confined to the hours of favourable weather conditions and they have an inherent inability to adjust their production according to the spot prices [46]. It has also been found that the value factor of PV drops faster when the penetration increases than that of wind power, since the production is concentrated to fewer hours of the day [46,50]. For instance, it has been estimated to go down from 1.3 at zero penetration to 0.6 at 15% penetration in Germany [46] and from 1.06 at 2.5% penetration to 0.86 at 11.2% penetration in California [50]. Also, in Germany, calculations on spot prices between 2014 and 2016 have shown that an addition of 1 GW of PV will decrease the spot price of 0.73 €/MWh during low price time periods and 0.96 €/MWh in high price periods. In addition, the length of low-price time periods would increase by 7.7% and the high-price periods would decrease by 2.6% [77]. How strong the cannibalization effect for PV is in Sweden have not yet been investigated, and a direct transfer of the results from other electricity markets is ineligible, as different electricity markets are more or less able to incorporate large share of renewable energy sources [78]. Hence, changes

Table 4
Compilation of the key assumptions related to PV in the reference scenarios of some recent studies of the future of the Swedish electricity system [31]. reported all their estimated costs in US-dollars while [29,30] in SEK, so the average exchange rates of 2020 of 1 € = 1.12 $ and 1 € = 10.5 SEK has been used to convert these costs in this table. The values of [30] was reported in per W-AC, so the average AC/DC ratio of 0.85 in Appendix A was used to convert the values into W_p-DC. The calculated LCOE is based on the main assumptions in the different studies, and complemented by the average degradation, variable O&M, reinvestment and residual cost values derived in this study.

		Swedish Energy Agency [29]	Confederation of Swedish Enterprise [30]	Chalmers University of Technology [31]	Lappeenranta University of Technology [32]	Result from this study
Year of publication		2021	2020	2020	2018	2021
Simulated Year		2045	2045	2045	2045	2020
Assumed power demand in Sweden		171 TWh	200 TWh	156 TWh	190 TWh	–
Main study constraint(s)		Six different scenarios are simulated	Cost-optimized system with 0 gCO_2/kWh direct emissions	Cost-optimized system with <10 g CO_2/kWh direct emissions	1. Cost-optimized system with 100% RE in 2050 2. No new nuclear may be built 3. The development is simulated in steps of 5 years	–
Notes with regards to PV		A tax reduction is included as an extra revenue for the smallest decentralized systems	Decentralized PV and the self-consumption business model are not included in the simulation	Decentralized PV and the self-consumption business model are not included in the simulation	Decentralized PV and the self-consumption business model are included in the simulation	–
Main economic assumptions for centralized PV	Lifetime [Years]	30	30	25	40	33
	$Yield_0$ [$MWh/MW_p/a$]	975–1075	1 000	1 375	985	969
	CAPEX [€/MW_p]	693 524	437 143	616 071	330 000	684 715
	$O\&M_f$ [€/MW_p/a]	7 029	4 476	26 786	5 000	8 282
	$WACC_r$	6%	6%	5%	7%	1.4%
Produced electricity from centralized PV		1.5 TWh	0 TWh in all technology-neutral scenarios [a] or ~5 TWh in 100% RE scenarios	1.8 TWh if interconnections are kept at the current level [a] or 0 TWh if interconnections may expand	4.6 TWh [b]	–
Produced electricity from decentralized PV		8.2 TWh	0 TWh	0 TWh	38.2 TWh [b]	–
PV penetration		5.7%	0 or ~2.3%	1.3 or 0%	22.5%	–

[a] The most cost-effective scenario.
[b] Calculated to a corresponding share of 35% of total installed PV capacity for Sweden as the study is modelling the whole Baltic Sea Region.

in electricity production in a Nordic price area can impact the spot price in the neighbouring areas substantially differently [79]. The large hydro power capacities and reservoirs in Sweden and Norway [51], PVs negative correlation with wind power in Sweden [49,80,81] and the high interconnection capacities between the Nordic countries [49,51] are all factors that previously have been shown to have mitigating influences on the merit-order effect of increasing PV power production.

5. Conclusions

The aim of this study was to investigate why there is a trend towards more PV parks in Sweden, despite the limited national policy incentives aimed at centralized PV parks and the very pessimistic forecasts regarding future PV.

When comparing the LCOE values from six of the PV parks commissioned between 2019 and 2020 in Sweden with the revenues obtained from the spot market and tradable green certificates in 2019 and 2020, we conclude that the profitability of PV parks can be achieved, but are not assured, under a merchant PV business model. This suggests that there must be other direct or indirect economical values obtained through the different ownership structures or business models applied. In the future, we encourage further studies going deeper into the understanding of what the other values considered by investors may be and how there are accounted for in the investments.

Lastly, we conclude that the assumed interest rate for centralized PV parks in some recent Swedish scenario studies are much higher than the current cost of capital experienced by the market, and that this probably is the main reason for discrepancy between the expected market development by Swedish agencies, interest groups and scientists and the actual current increasing deployment of centralized PV parks. For the future, such studies need to take into account the increased ownership in renewables by private and institutional investors, and the lower cost of capital those implement, to better assess the future development.

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.

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Appendix A

Table A1 complies information of all centralized PV parks with a capacity above 0.5 MW_p in Sweden commissioned before 2020-12-31. In the "Technology" column; regular means fixed tilted silicon modules facing to the south. In the "Current business model" column; corporate-PPA stand for power purchase agreement. Merchant refers to a business model where the revenues for the owner come from selling the produced electricity on the electricity market (the spot price plus eventual revenues from selling certificates and guarantees of origin). COOP.-Fin. represents a cooperative ownership business model where investors buy shares in the PV park and get the financial revenue of the electricity production corresponding to the numbers of shares and COOP.-El. stands for a cooperative ownership business model where investors buy shares in the PV park and the electricity production corresponding to the numbers of shares from the PV park is withdrawn from the share owners electricity bill. In the "Revenues from electricity" column; SPOT. stands for spot price. CERT for electricity certificates and GOs for guarantees of origin.

Table A1
Compilation of all centralized PV parks with a capacity above 0.5 MWp in Sweden commissioned before 2020-12-31.

Commissioning date	Size [MW_{dc}]	Size [MW_{ac}]	AC/DC ratio	Technology	Owner	Main contractor	Current business model	Revenues from electricity	Type of land	Location	Price area
jul-09	2.20	No info	–	Many different technologies and directions	Elproduktion I Stockholm	Elproduktion I Stockholm	Education & demonstration	SPOT. CERT & Gos	Forest land	Katrineholmnext to RV52	3
feb-14	1.10	No info	–	2-axis tracking	Kraftpojkarna	Kraftpojkarna	PPA	Fixed PPA for 15 years	Unused industrial land	Västerås. next to E18	3
okt-15	1.00	0.85	0.85	Regular	Arvika Kraft	Windon	Merchant	SPOT. CERT & Gos	Former landfill	Arvika. next to RV61	3
jun-16	2.70	No info	–	Regular	Varberg Energi	Solkompaniet	Merchant	SPOT. CERT & Gos	Pastureland. shared with sheep	Tvååker. next to E6	4
aug-16	1.10	0.70	0.64	Fixed tilt east-west	Klara Energi	Klara Energi	Merchant	SPOT. CERT & Gos	Pastureland. shared with sheep	Kjula. next to E20	3
feb-17	0.53	0.48	0.90	Regular	Solar Park Ek. Förening	Solect Power	COOP.-Fin.	SPOT & CERT	Former landfill	Helsingborg. at VERA recycling park	4
jun-17	0.77	0.60	0.78	Regular	Svenska Hus	Svenska Solcellsanläggningar	Merchant	SPOT. CERT & Gos	Pastureland. shared with sheep	Äskatorp. Kungsbacka	3
sep-17	2.23	1.72	0.77	Regular	Törneby driftförening Ek. Förening	Solkompaniet	COOP.-El.	SPOT & CERT	Grass land in airport area	Kalmar airport	4
sep-18	0.79	0.60	0.76	Regular	Svenska Solcellsanläggningar	Svenska Solcellsanläggningar	Merchant	SPOT. CERT & Gos	Pastureland. shared with sheep	Burås. Orust	3
nov-18	0.70	0.70	1.00	Fixed tilt south. bifacial modules	Luleå Energi	Svea Solar	Merchant	SPOT. CERT & Gos	Pastureland. shared with sheep	Luleå. next to RV97	1
dec-18	5.50	5.04	0.92	Regular	Göteborg Energi	Svea Solar	PPA/Leasing	Fixed premium for 10 years/SPOT	Grass land in airport area	Göteborg. Säve airport	3
jan-19	1.20	0.96	0.80	Regular	Karlskrona Solpark drift Ek. Förening	Swede Energy	COOP.-Fin.	SPOT & CERT	Former landfill	Karlskrona	4
jan-19	1.01	0.80	0.79	Regular	Brinkarna Construction	Svea Solar	Merchant	SPOT. CERT & Gos	Grass land in airport area	Hudiksvall airport. next to E4	2
maj-19	1.00	1.00	1.00	Regular	Vallebygdens Energi Ek. Förening	Vallebygdens Energi Ek. Förening	Offset grid-losses	SPOT	Meager agricultural land	Hornborgsjön. north shore	3
jun-19	5.80	4.80	0.83	Regular	Sjöbo Solpark	Svea Solar	PPA	Fixed premium for 10 years	Pastureland. shared with sheep	Tågra. Sjöbo	4
nov-19	3.00	2.64	0.88	Regular	Östersunds Solpark Drift Ek. Förening	Solkompaniet	COOP.-El.	SPOT & CERT	Former shooting range	Östersund. next to E14	2
jul-20	12.00	9.60	0.80	Regular	Alight	Better Energy	PPA	Fixed PPA for 20 years	Former energy forest	Linköping. next to CHP plant	3
sep-20	14.00	11.60	0.83	Regular	HSB Sörmland	Energi Engagemang	COOP.-El.	Fixed PPA for 30 years	Agricultural land	Strängnäs. next to E20	3
sep-20	1.56	1.44	0.93	Regular	Farmer	E.On	PPA	Fixed premium for 10 years	Meager agricultural land	Billeberga. Svalöv	4
okt-20	1.20	1.12	0.93	Regular	Bredstorp Sol Ek. Förening	DJ's Sol & Energiteknik	COOP.-Fin.	SPOT & CERT	Forest land	Bredstorp. Tranås	3

(continued on next page)

Table A1 (*continued*)

Commissioning date	Size [MW_{dc}]	Size [MW_{ac}]	AC/DC ratio	Technology	Owner	Main contractor	Current business model	Revenues from electricity	Type of land	Location	Price area
nov-20	4.00	3.38	0.84	Regular	C4 Energi/ Solpunkten Kristianstad Ek. Förening/unkown investor	Solkompaniet	PPA/ Cooperative. financial revenue per share	Fixed price for at least 5 years/SPOT & CERT	Swampy pastureland	Kristianstad. next to E22	4
nov-20	0.79	0.70	0.89	Regular	Farmer	Farmer	Merchant PV	SPOT. CERT & Gos	Pastureland in fallow	Håfors. Frillesås	3
dec-20	5.50	4.50	0.82	Regular	Göteborg Energi	Svea Solar	Not set at time of writing	Not set at time of writing	Industry ground	Utby. Göteborg	3
nov-20	4.40	3.50	0.80	Regular	Vasakronan	Vattenfall	Intern PPA	Fixed price for 3 years	Industry ground	Fyrislund. Uppsala	3
Total:	**74.1**	**Average:**	**0.85**								

Appendix B

In cost–benefit analysis, such as comparing investments in different power plants, where the present value of expected net revenues or costs are calculated, one needs to assess the proper future prices when valuing the expected future revenue and cost streams. As the inflation in a country influences future prices, it must therefore be managed in a proper way. According to Ref. [82] inflation can be handled in two different ways in cost–benefit analysis. First, when calculating the present value of expected net benefits, prices and interest rates can be projected in real terms. That is, no inflationary components are included in either the prices or the interest rates. The second approach includes inflation in both the price and the interest rate calculations. That is, calculations are made in nominal terms. Both approaches are equivalent as long as both prices and interest rates are projected in real terms, or both projected in nominal terms.

Levelized cost of electricity, LCOE, is a transparent measure of generating costs of different power plants and a widely used tool for comparing the costs of different power generating technologies. The definition of the LCOE can be expressed as the real fixed price of electricity that would exactly cover the sum of costs in terms of present value. To simplify, two assumptions are usually used. Firstly, that the real interest rate, *r*, used for discounting costs and revenues is constant during the lifetime of the power plant. Secondly, that the real electricity tariff, P_y, is assumed not to change during the lifetime of the power plant and that all the produced electricity is sold at this tariff. The equivalence can then be expressed as;

$$\sum_{t=0}^{L}\left[\frac{P_Y{*}Y}{(1+r)^t}\right]=\sum_{t=0}^{L}\left[\frac{CAPEX_t+\ O\&M_f+(Fuel+O\&M_v){*}Y}{(1+r)^t}\right]+\frac{ReInv}{(1+r)^x}+\frac{ResC}{(1+r)^L}, \tag{B1}$$

where t is 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 power plant in year t expressed in €, $O\&M_f$ the fixed operation and maintenance cost in year t expressed in €, $O\&M_v$ the variable operation and maintenance cost per produced unit of energy in year t expressed in €/kWh, *Fuel* the fuel costs per produced unit of energy in year t expressed in €/MWh, Y the annual electricity production (yield) in the year when operation start expressed in kWh, *ReInv* a major reinvestment needed to reach expected lifetime expressed in € and *ResC* the residual cost of decommissioning the power plant at the end of the lifetime expressed in €. The residual cost factor can be negative, which would be the case if a decommissioned power plant has a residual value that is higher than the cost of dismantling the power plant.

As P_y is assumed to be constant over time it can be brought out of the summation, and equation (B.1) becomes the commonly used equation for LCOE;

$$LCOE=P_Y=\frac{\sum_{t=0}^{L}\left[\frac{CAPEX_t+\ O\&M_f+(Fuel+O\&M_v){*}Y+ReInv}{(1+r)^t}\right]+\frac{ResC}{(1+r)^L}}{\sum_{t=0}^{L}\left[\frac{Y}{(1+r)^t}\right]}. \tag{B2}$$

It should be noted that the LCOE value, or in other words the electricity tariff, as well as all costs are expressed in real values, and that the influence of inflation on the net present value therefore is handled correctly according to Ref. [82].

For PV parks, the basic LCOE equation is unnecessarily complex and can be simplified. For instance, there are no fuels associated with electricity production from PV. Additionally, the actual construction times were shorter than one year for all six centralized PV parks investigated. Hence, it is unnecessary to discount the $CAPEX_t$ and the total capital expenditures can be handled as an “overnight cost” — as though the plant was built overnight. The total overnight capital expenditures will then 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 equation (1) becomes only the operational lifetime, N, of the PV parks, which means that operation starts at $t = 1$.

Furthermore, it is usually simpler for investors to assume that the major reinvestments needed to reach the projected lifetime of the PV park will take place under one certain predefined year, x, rather than dividing the total needed reinvestment costs over several years. If this simplification is applied, the reinvestment factor can be brought out of the summation. It should be noted that the equation can cope with several major reinvestments if a PV park project plans for that.

The above-mentioned simplifications lead the following equation:

$$LCOE = \frac{CAPEX_0 + \sum_{t=1}^{N}\left[\frac{O\&M_f + O\&M_v * Y}{(1+r)^t}\right] + \frac{ReInv_1}{(1+r)^{x_1}} + \frac{ReInv_2}{(1+r)^{x_2}} + \ldots + \frac{ResC}{(1+r)^N}}{\sum_{t=1}^{N}\left[\frac{Y}{(1+r)^t}\right]}. \tag{B3}$$

As PV systems usually exhibit slow degradation of the output over time due to external stresses [83](IEA PVPS task 13 et al., 2017), such as UV irradiation and temperature or humidity cycles, an annual degradation factor, Dg, expressed in %, is added to the yield factor and the yield factor is reformulated to the initial annual yield Y_o in year 0 without degradation.

Additionally, investors usually have two different interest rates to consider. One for the debt financing, D, and one for the equity financing, E. The interest rate of debt financing (Cost of debt), C_d, and the interest rate of equity financing (Cost of equity), C_e, can be combined into the nominal weighted average cost of capital per annum, $WACC_n$, by the equation:

$$WACC_n = \frac{[D * C_d * (1 - CT) + E * C_e]}{D + E}, \tag{B4}$$

were CT being the corporate tax. In Sweden, taxable income is subject to corporate tax at a fixed tax rate of 20.6% as of January 1st, 2021 [84], and this tax rate has been used throughout the whole lifetime of the PV parks.

The data for the LCOE calculation in this study is collected directly from investors, PV park owners, developers or contractors of actual projects through interviews and surveys. For these actors, it is quite straight forward to calculate their $WACC_n$, but they usually find it easier to estimate or summarize the different future costs for their PV park in present values, i.e., in real values. Thus, all costs collected in this study are therefore in real values, and to handle the inflation correctly, these real costs must be discounted with a real weighted average cost of capital per annum, $WACC_r$ [82]. The relationship between $WACC_n$ and $WACC_r$ is expressed by the classic Fisher equation [85]:

$$WACC_r = \left[\frac{(1 + WACC_n)}{(1 + Infl)}\right] - 1, \tag{B5}$$

where $Infl$ stands for the annual inflation rate. In this study an inflation rate of 2% has been assumed as this is the target rate set by the national bank of Sweden [86].

Combining equations (B.3)–(B.5) results in the final equation:

Equation (B.6) is, thus, the final real LCOE equation that is used for calculating the LCOE of all the PV projects in this study and the same as equation (1) in the article.

Appendix C

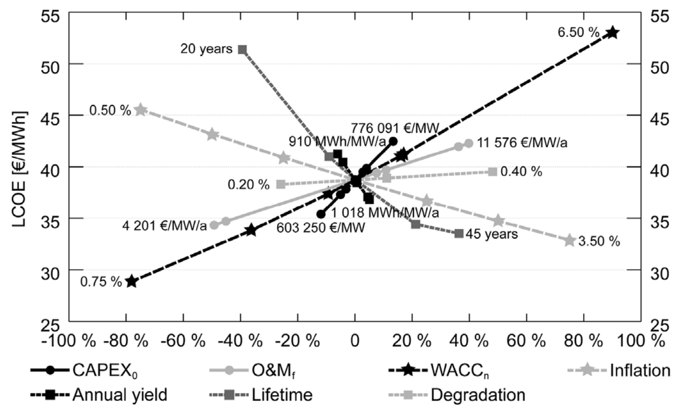

Figure C.1. Sensitivity analysis of the parameters affecting the LCOE from PV parks, without subsidies. The reference case is the resulting LCOE if the average value of parameters in Table 1 is entered into equation (1). The lines are the function of a variation of the marked parameter, while the rest of the parameters are kept constant at the average value of Table 1. Each marker on the line represents one of the reported values of the parameter that is varied from the six PV park project listed in Table 1. Each line consequently consists of six markers with the reported cost values for the individual plants investigated in this study, plus the average value in the centre. The end marker of each line consequently represents the highest and lowest reported value of each parameter in this study.

A sensitivity analysis is illustrated in Figure C1, where the spread of the different parameters is plotted from the starting point of an LCOE calculation based on the average values of the parameters of all six PV park projects. Starting with the operational conditions, the assessed initial yields of between 910 and 1 018 MWh/MW$_p$ and the assumed degradation of between 0.2 and 0.4% are fairly similar among the projects, and the differences have a limited impact on the variation of the LCOE values presented in Table 1. The operational condition that contributed most to the spread of the LCOE among the different projects is the assumed lifetime. In three of the projects (i.e., project 3, 5 and 6) a similar lifetime of 30 years is considered. Yet, for project 1, the use of the industrial site of the PV park for other purposes was planned already after 20 years, which results in an increase of the LCOE with about 10 €/MWh. It is not possible to assign an exact value on the effect of the shorter lifetime, as there is a direct correlation between the lifetime and the cost of the major reinvestment needed for the inverters. This correlation has been considered in the making of Figure C1 as an average major reinvestment cost of 55 233 €/MW$_p$ after 15 years has been assigned to the three projects with a lifetime of 30 years, while corresponding major reinvestment costs and time of reinvestments have been assumed for projects 1, 2 and 4. This explains the curvature of the lifetime line in Figure C1 for longer lifetimes. The statistical basis is too weak to draw a definite

$$LCOE = \frac{CAPEX_0 + \sum_{t=1}^{N}\left[\frac{O\&M_f + O\&M_v * Y_0 * (1 - Dg)^t}{(1 + WACC_r)^t}\right] + \frac{ReInv_1}{(1 + WACC_r)^{x_1}} + \ldots + \frac{ResC}{(1 + WACC_r)^N}}{\sum_{t=1}^{N}\left[\frac{Y_0 * (1 - Dg)^t}{(1 + WACC_r)^t}\right]}. \tag{B6}$$

conclusion, but the results from this study indicate that projecting a lifetime of at least 30 years is important to achieve a low LCOE for a PV park in Sweden. However, there is limited gain in terms of production costs that motivates pushing the lifetime above 40 years.

Regarding the different costs, the initial total capital expenditure of building a PV park, $CAPEX_0$, is the cost with highest relative impact on the final LCOE (i.e., the initial annual yield, $Y_{0,}$ and $CAPEX_0$ lines have the steepest slopes in Figure C1). However, both the total fixed operation and maintenance cost, $O\&M_{f,}$ and the CoC (In Figure C1 llustrated by the nominal value, $WACC_n$), influence the final LCOE of PV parks to a larger extent than the capital expenditures. This is explained by the relatively larger differences in $O\&M_{f,}$ and $WACC_n$, reported by the stakeholders.

The difference in CoC can mainly be explained by the two different business models used in the studied PV park projects: cooperative ownership or corporate-PPAs. The stakeholders reported in the interviews that the cooperative ownership business model enables an arrangement where the project owner can wait to initiate the construction until all shares of the park have been subscribed by external investors, such as local companies or private persons. With this arrangement, the costs for equity turned out to be very low, even down to 0% according to one respondent, and thus, also the weighted average costs for capital. The CoC for the corporate-PPA business model turned out to be noticeably higher. The downside of the cooperative ownership business model is a higher annual administrative cost associated with running a cooperative compared to a PPA solution. A PPA agreement primarily requires administrative resources when the agreement is established but can be administrated with very little effort for the whole period of the corporate-PPA. Consequently, as shown in Figure C1, the reported LCOE difference of about 24 €/MWh for the variation in CoC is a little misleading as it seems to be a correlation between lower CoC and higher annual fixed operational cost through higher administrative costs in this study.

One remark to Figure C1 is that the total variable operation and maintenance costs, O&Mv, were not included as these costs had a negligible effect of about 1 to −2 €/MWh on the final LCOE values. Another comment to Figure C1 is that the sensitivity analysis of the figure included inflation, which has been set at a constant 2% for all the projects in this study. However, as Figure C1 shows, a variation of the inflation between realistic values of 0.5–3.5% has a significant impact on the final LCOE of PV parks.

Appendix D

Table D.1 shows a compilation of PV market data. The installed capacity at the end of the year for 2016–2020 are from the official statistics of the Swedish Energy Agency [14]. For 2014–2015 the data comes from the Swedish IEA PVPS task 1 participation [13]. The annual PV production is either collected from the Swedish TSO, Svenska Kraftnät [87], or generated through simulations using a method described in Ref. [53]. The PV production per installed capacity has been calculated by dividing the annual PV production from the two sources by the installed power calculated at the middle of the year. The self-consumption ratio has been calculated by subtracting the simulated PV production by the PV production according the Swedish TSO and dividing this number by the simulated PV production.

Table D1
Compilation of PV market data and electricity production values over the years.

		2014	2015	2016	2017	2018	2019	2020
Installed capacity at the end of the year [MW]	SE1	0.3	0.5	0.8	2.2	4.2	4.9	8.7
	SE2	2.6	4.3	6.6	10.6	21.6	37.2	59.6
	SE3	45.1	76.4	116.5	172.1	275.8	460.4	736.1
	SE4	18.7	31.7	48.4	70.3	110.0	188.4	285.0
	Total	**66.7**	**113.0**	**172.3**	**255.2**	**411.6**	**690.9**	**1089.4**
Installed power calculated at the middle of the year (linear interpolation) [MW]	SE1	0.2	0.4	0.7	1.5	3.2	4.5	6.8
	SE2	1.9	3.5	5.5	8.6	16.1	29.4	48.4
	SE3	33.8	60.7	96.5	144.3	224.0	368.1	598.3
	SE4	14.1	25.2	40.0	59.3	90.1	149.2	236.7
	Total	**50.1**	**89.8**	**142.7**	**213.8**	**333.4**	**551.2**	**890.2**
PV production according the Swedish TSO [GWh]	SE1	0.0	0.24	0.3	0.4	1.0	2.0	2.9
	SE2	0.5	1.4	2.9	3.9	7.1	11.3	24.9
	SE3	7.9	19.1	32.8	52.3	97.8	169.2	301.4
	SE4	3.7	8.3	14.9	22.5	41.7	74.0	128.5
	Total	**12.2**	**29.0**	**51.0**	**79.1**	**147.6**	**256.5**	**457.7**
Simulated PV production [GWh]	SE1	0.2	0.35	0.5	1.2	2.9	3.7	5.4
	SE2	1.3	2.8	4.3	6.6	15.5	24.5	40.2
	SE3	31.6	58.6	87.2	133.1	228.7	354.1	565.8
	SE4	14.0	23.5	39.9	60.2	100.4	160.7	242.8
	Total	**47.1**	**85.3**	**131.9**	**201.0**	**347.4**	**543.0**	**854.1**
PV production (according the Swedish TSO) per installed capacity at the middle of the year (linear interpolation) [MWh/MW_p]	SE1	165	553	469	280	315	440	429
	SE3	264	401	527	459	440	383	514
	SE2	235	314	340	362	437	460	504
	SE4	265	328	373	379	462	496	543
Simulated PV production per installed capacity at the middle of the year (linear interpolation) [MWh/MW_p]	SE1	799	823	748	773	904	815	792
	SE2	691	823	776	766	963	834	830
	SE3	934	964	905	922	1021	962	946
	SE4	997	932	995	1015	1113	1077	1026
Self-consumption Ratio	SE1	79%	33%	37%	64%	65%	46%	46%
	SE2	62%	51%	32%	40%	54%	54%	38%
	SE3	75%	67%	62%	61%	57%	52%	47%
	SE4	73%	65%	63%	63%	58%	54%	47%
	Total	**74%**	**66%**	**61%**	**61%**	**58%**	**53%**	**46%**

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