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Wind power design for high capacity factors

A techno-economic analysis of specific power reduction and wind-solar hybrid plants

Master's thesis in Sustainable Energy Systems

EMMA ALBINSSON

DEPARTMENT OF ELECTRICAL ENGINEERING

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Supervisor: Anders Wickström, Rise Research Institutes of Sweden
Examiner: Ola Carlson, Department of Electrical Engineering

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Department of Electrical Engineering
Division of Electric Power Engineering
Chalmers University of Technology
SE-412 96 Gothenburg
Telephone +46 31 772 1000

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Abstract

Wind power production is the fastest growing electricity producing technology in Sweden today. However, its intermittent nature and relatively low capacity factor present significant challenges. Therefore, the aim of this thesis was to investigate the feasibility of increasing the capacity factor of a wind turbine situated in southern Sweden.

Two studies were conducted, implementing two different design changes on a wind turbine, for an increased capacity factor. The consequences of these design changes have been evaluated, and the results were continuous functions of levelized cost of electricity, value factor, and profit with respect to an increased capacity factor. Costs were evaluated through a combination of a bottom-up procedure, literature reviews, and discussions with industry actors, to ensure that the estimates were representative of the current Swedish market. Alternative ways of modelling hourly production of a single wind turbine, based on regional production data, have been analysed and validated against wind speed measurements from 2016 and 2017 in price area SE3 in Sweden.

The first study involved decreasing specific power by reducing rated power, which resulted in a higher capacity factor and reduced costs. However, a simultaneous decrease in energy production ultimately resulted in a higher levelized cost of electricity. Additionally, Study 1 indicated a potential decrease in profitability through this design change, although the results were shown to be heavily influenced by the wind speed distribution. Despite this, the results also illustrated that the value of the produced power did increase, highlighting how a higher capacity factor can benefit the power system.

For the second study, the wind turbine was complemented with solar power while keeping the grid connection constant. Similarly, it resulted in an increased levelized cost of electricity, but demonstrated a higher potential of increasing profitability. Moreover, just as Study 1 the value of produced electricity was consistently increased with the capacity factor. Overall, the second study highlighted how infrastructure such as grid connection can be utilized more effectively by combining wind and solar production, providing potential benefits on both a project and system level.

Keywords: wind power, capacity factor, specific power, levelized cost of electricity, value factor, profitability, wind speeds, solar power, hybrid power plant, techno-economic analysis, co-located power plants.

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Emma Albinsson, Gothenburg, May 2024

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

AEP	Annual Energy Production
CapEx	Capital Expenditures
CF	Capacity Factor
CRF	Capital Recovery Factor
CSM	Cost Scaling Model
DEA	Danish Energy Agency
GHI	Global Horizontal Irradiance
LCOE	Levelized Cost Of Electricity
OpEx	Operational Expenditures
PR	Performance Ratio
PV	Photovoltaics
RWT	Reference Wind Turbine
SP	Specific Power
SVK	Svenska Kraftnät
TF	Transposition Factor
WISDEM	Wind-Plant Integrated System Design and Engineering Model

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1
Introduction

The topic of wind power production is one of great interest. Our society is today facing the huge task of transitioning away from fossil to renewable based systems, which means that power production must come from fossil free sources at the same time as several major sectors are undergoing electrification. These trends point towards a future where we have to meet a much higher electricity demand, with a more limited set of power producing technologies. Therefore it is of utmost importance to continue the development of our renewable power technologies, and make sure that they are ready to take on a continuously growing load.

Wind power is often presented as one of the main renewable energy sources, and is together with solar the fastest increasing renewable power technology in the world today [1]. For Sweden, Figure 1.1 shows how wind power alone has been rapidly growing in the last years, steadily increasing its penetration level.

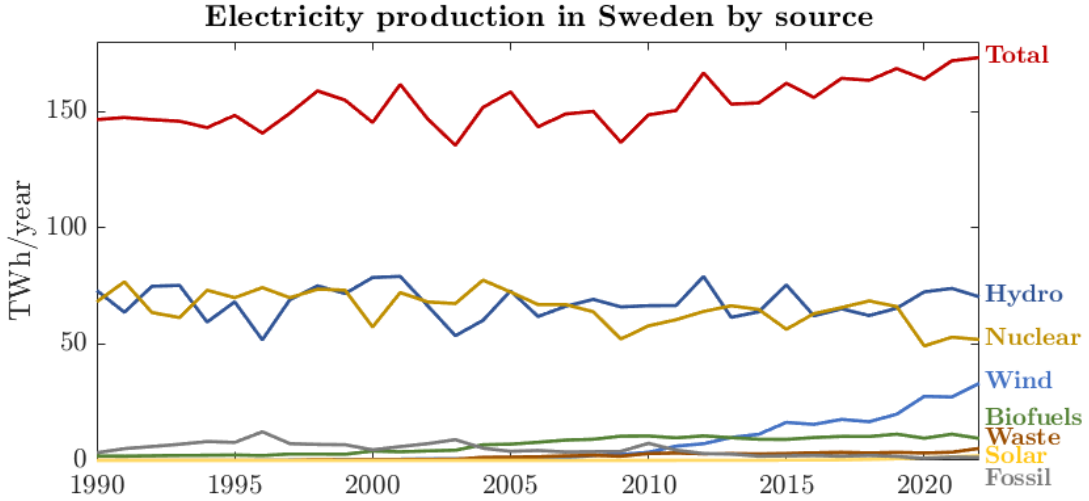


Figure 1.1: Historical trends of the electricity generation in Sweden by source [1].

However, utilizing more and more wind power comes with its own challenges. One major issue is the intermittency of wind power production, a natural consequence of the variable nature of wind. It adds complexity to the power system, and with an increasing share of wind power in the electricity production mix, this complexity will continue to add difficulty to for example balancing load and production, reactive power compensation, and need of reserve capacity [2], [3]. In extension, it can therefore pose as a limit to the expansion of wind power production [3], [4].

There are however several proposed options for mitigating these issues, such as demand side management, a more decentralized power system, or energy storage technologies [2], [4]. The focus of this work is the option of addressing the problem on the production side by increasing the wind turbine Capacity Factor (CF).

Over the years, there has in fact been a shift towards higher CF wind turbines [5], [6]. The main reason is the trend of increasing the hub height and decreasing the so called Specific Power (SP) through larger rotors [6]. The latter trend has been especially prominent on the American market, where they historically have had bigger limitations on transmission capacity. They have therefore desired to maximize produced energy per installed capacity, i.e. increase the CF [7]. But with the future large increase of electricity demand in Sweden [8], [9], limitations on the grid could be an increasing issue here as well, raising the question of low SP design.

That low SP design is an area of interest is further confirmed by the several research articles that are published on the topic [7], [10]–[15]. In many of these works, it is concluded that a lower SP can add benefits to the system, such as higher value of the electricity produced [11], [12], [14], [15]. Furthermore, it is often highlighted that these benefits are especially prominent in systems with a high wind power penetration level, suggesting that by lowering the SP the difficulty of introducing more wind power is reduced [7], [10]–[14].

In both recent trends and research, the prominent measure for achieving a reduced SP is an increase in rotor diameter. However, due to regulations and logistical issues there are limits posed on rotor size [7], [16]. Therefore, another option for reducing the SP could be to decrease the generator capacity. This has not been covered in previous research to the same extent, perhaps because it can seem contra intuitive to reduce capacity and thereby the potential to maximize power production. However, since it does contribute to an increased CF it is still an option of much interest, and therefore the feasibility of this design change needs to be further investigated.

Another topic of emerging interest is the addition of solar power production to complement the wind turbine output, i.e. creating a so called hybrid plant. Wind-solar hybrid plants are not common on the current Swedish market, but it is an up-and-coming topic with great potential [17]–[20]. Previous research within this topic has so far shown that there can be potential benefits to a hybrid configuration. It especially highlights that wind and solar production often anti-correlate and thereby complement each other well, as well as the fact that when co-located they have the potential to share infrastructural costs such as grid connection [21]–[25].

In this way, the CF is able to increase compared to the stand-alone wind turbine, by assuming the rated power to be the grid connection capacity. However, existing literature is fairly limited compared to the stand-alone technologies, especially for a utility scale [19]. There is therefore a need for extending existing research with respect to the potential for complementing wind turbines with solar capacity.

By focusing this work on the consequences and feasibility of these two design changes for a higher capacity factor, the hope is that the results will serve as a well-fitting complement to existing research.

1.1 Aim

The aim of this thesis is to investigate the feasibility of increasing the capacity factor of a wind turbine design, with respect to costs and profitability.

The analysis is conducted through two studies implementing two different design changes. The first is a decrease in specific power through a reduced generator capacity and rated power, while the second study consists of complementing the wind turbine with solar power production, making the system into a so called hybrid plant.

The intended outcome is a quantitative assessment of these two studies, with the original wind turbine as a reference system. This will form the basis of a discussion regarding the optimal design for wind power production, and the future potential of increasing wind turbine capacity factors through the studied design changes.

1.2 Problem Statement

- For each study, how are the costs of the system impacted by the implemented design changes, i.e. what is the relationship between the change in capacity factor and costs?
- What effects will this have on the cost of electricity, if also considering impacts on power production?
- What is the relationship between a varied capacity factor, and the value and profit from the power produced?
- Based on these established quantitative relationships, can the costs or profitability be improved by a higher capacity factor?
- Do these results motivate a design which increases the capacity factor compared to the reference system?

1.3 Scope and Limiations

The studies included are limited to two different design changes for increasing the capacity factor, with respect to the grid connection rated power. These are a decrease in specific power through decreasing the rated power, as well as with an introduction of solar power production while keeping the rated power constant.

There are however other similar ways of achieving an increased capacity factor. Regarding the choice of the first study, a decrease in rated power or an increase in rotor diameter will both result in a decreased specific power and have a similar effect on the capacity factor, so either could fulfill the purpose of the study. However, a focus on decreasing the rated power is the chosen approach with the hope to better complement existing research.

The second study is chosen since the concept of co-locating wind and solar power production is an emerging topic of interest on the Swedish market, with need for additional research. An alternative might be the introduction of battery storage, which could still be an interesting expansion of this work in the future, even as a further complement to the wind-solar hybrid plant.

In these two studies, the focus will be on a single wind turbine, where the reference system is a wind turbine design representative for the technology being installed today, at a typical wind speed site. Therefore, effects introduced in a wind farm or entire region will not be considered, nor different types of sites.

The geographic area of interest will be the electricity price area SE3 in southern Sweden. Both inputs and results could vary much with location, due to differently configured electricity markets as well as the intermittent nature of wind and solar production. In this way, it is possible to make the data more coherent and easier isolate the effects from the implemented design changes. By placing it in southern Sweden it also improves the feasibility of the second study which requires a certain level of available solar production data.

The effects of increasing the capacity factor will be focused mainly on the levelized cost of electricity, value factor, and profit. These complement each other well, and together cover the major financial measures that need to be considered when optimizing the design of a power producing unit. The evaluation will be performed on a yearly basis, based on data with an hourly resolution.

Implementation of ancillary services such as frequency control and its potential effects on the results will not be covered quantitatively. It is an area of interest since an increased capacity factor could make it easier to utilize the wind turbine for this purpose. However, to also consider these effects would require more time than is available within the scope of this thesis.

Another potential area of interest is production forecasting. It could be that an increased capacity factor reduces the times at which the resulting production does not match the predicted bid made to the spot market, thereby reducing the risk of added costs connected to this. However, with the same reasoning as for ancillary services, it will not be considered here.

1.4 Thesis Outline

Now that the background, aim, and scope has been presented, the following Chapter 2 will include all relevant theory needed for the understanding of this work. Then, the methodology is presented in Chapter 3, covering the steps from obtaining a reference system, to acquiring the final results of the two studies. These results will then be presented and discussed in Chapter 4, and then finally in Chapter 5 the main conclusions and takeaways are presented.

2
Theory

The following chapter provides the theory needed to perform and understand this work. It starts with the fundamentals of wind power production, and then expands upon the theory motivating the two studies. Finally, the measures used to evaluate the consequences of an increased capacity factor are defined.

2.1 Introduction to Wind Power Production

The fundamental idea behind wind power production is the extraction of kinetic power from the wind, and its transformation from rotational power of the rotor to mechanical shaft power and then finally electric power via a generator. This path is further described in this section.

2.1.1 Wind Energy

From Equation 2.1 the kinetic power of wind is obtained.

$$P_{wind} = \frac{1}{2}\rho A V^3 \tag{2.1}$$

Here, ρ represents the density of air, A is the rotor swept area, and V is the wind speed [26]. As seen, the available power in wind largely depends on the wind speed. Therefore, when performing wind power calculations it is of importance to correctly estimate the wind speeds, which by nature are constantly fluctuating and highly site-dependent [27].

The most common practice for handling the wind speed distribution of a site is to use the Weibull distribution function, described in Equation 2.2.

$$f(V) = (\frac{k}{c})(\frac{V}{c})^{k-1} e^{-(\frac{V}{c})^k} \tag{2.2}$$

Here, k is the shape factor, which is a site-specific parameter that needs to be fitted to wind speed measurement data [26]. Together with a determined mean wind speed, V_m, the scale factor, c, can then be calculated with the Gamma function, as in Equation 2.3 [26].

$$c = \frac{V_m}{\Gamma(1 + \frac{1}{k})} \tag{2.3}$$

However, for certain studies such as those of this work, it is necessary to depict the wind speeds on an hourly basis. This adds complexity since the wind speed distribution is very site-dependent due to large dependencies on factors such as surroundings and surface roughness. Without a very comprehensive assembly of accurate long term measurements at the desired height, there will always be uncertainties and errors present in hourly wind speeds estimates [28].

For example, one possible method is to use reanalysis data provided by tools such as ERA5 or MERRA2 [29], [30]. Their wind speed time series have been assembled with a certain spatial resolution through a combination of historical measurements and forecasting models, and can therefore be used to obtain wind speeds for any desired region or site [31]. These tools have proved to well capture long term trends on a system level [29], [30]. They are however less suitable for capturing short term fluctuations at a local site since the models have issues with capturing these high resolution effects [28], [30]. Furthermore, reanalysis data is also prone to systematic biases occurring from errors in their models [28].

To provide an alternative to this option, the wind speed data in this work will be obtained through the development of an iterative process utilizing production data from Svenska Kraftnät [32]. The methodology is described in detail in Section 3.2.3.

2.1.2 Power Curve of Turbine

A power curve is turbine specific and shows how much power that is extracted at each wind speed. There are several ways of modelling the power curve, but one widely used due to its simplicity is the approximate cubic function in Equation 2.4 [33].

It takes the available power in the wind, P_{wind}, and converts it into produced electrical output, P_{el}, through a set of efficiencies. Note that in this work, the rated power, P_{rated}, is defined as the maximum capacity of the grid connection. However, this will in all cases be set to the the same value as the maximum capacity of the wind turbine generator, and therefore rated power will also be used to denote the generator capacity to avoid overly complicated nomenclature.

$$P_{el}(V) = \begin{cases} 0 & V < V_{in} \\ \eta_m \eta_g \eta_c C_{P,max} P_{wind} & V_{in} \leq V \leq V_{rated} \\ P_{rated} & V_{rated} \leq V \leq V_{out} \\ 0 & V > V_{out} \end{cases} \tag{2.4}$$

The parameter $C_{P,max}$ is the maximum coefficient of performance. With the approximate cubic function it is assumed to be constant between the cut-in and rated wind speed, while in reality, it has a wind speed dependency. Another approximation of Equation 2.4 is the abrupt break it gives around the region of rated wind speed, where the real curve would be more continuous [26]. The same is true at the cut-out speed, where today's wind turbines can have an extended soft cut-out after 25 m/s [34]. Nevertheless, the approximate cubic is still a widely used method that for many applications gives a sufficient accuracy [33], [35].

2.1.3 Wind Turbine Technology

A wind turbine is made up of many components, and to design the entire system is a complex process that have to take several parameters into account, such as applied loads, efficiencies and costs. A simple schematic of a typical wind turbine design is shown in Figure 2.1, and as seen most main components are placed in the so called nacelle, at the top of the tower.

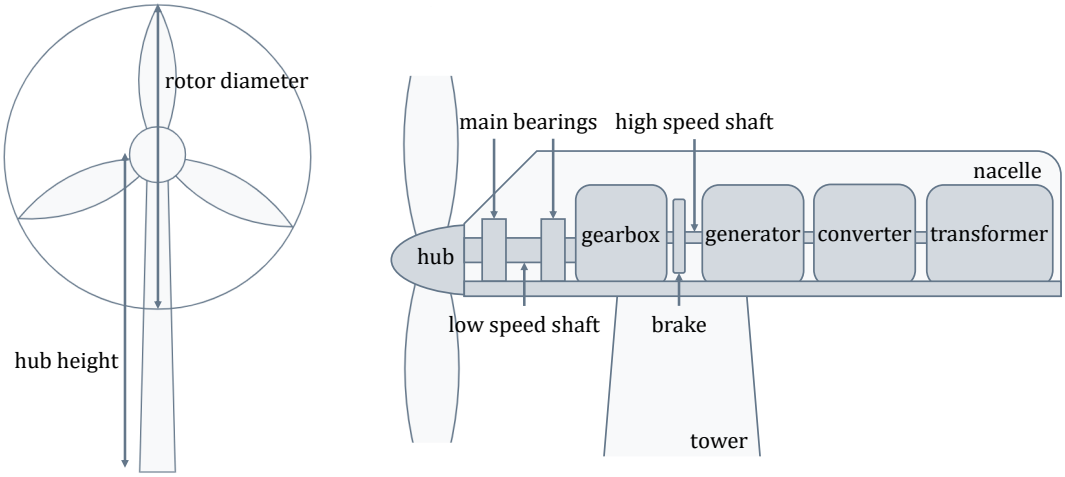


Figure 2.1: Schematic design of a wind turbine and its main components. Inspired by figure in IEA Wind Task 37 [36].

These different components are of interest for Study 1 in particular, as a change in rated power and generator capacity will have an effect on their loads, potentially impacting sizing and costs.

2.2 Capacity Factor

Once the wind speed distribution and power curve of a wind turbine are established, these can be used to obtain the Capacity Factor (CF). It is a measure of how much power that is generated in comparison to the maximum capacity of the plant, and can be applied to all types of power producing units [37]. It is therefore often used to compare different types of power generation, and is defined as

$$CF = \frac{AEP}{P_{rated}\ h} \tag{2.5}$$

Where h is the number of hours in a year, and AEP is the Annual Energy Production [26]. It in turn is for a wind turbine calculated as

$$AEP = \sum_{h=1}^{8760} P_{el,h}(V) \tag{2.6}$$

The aim of this work is to increase the CF of a wind turbine, and examine its effects on several measures to evaluate the feasibility of these actions. The theory behind the two chosen design changes to be studied is therefore described in the two upcoming sections. Again, in this work the rated power will be defined as the capacity of the grid connection, such that the addition of solar power capacity does not increase the rated power when the grid connection capacity is kept constant.

2.3 Theory Behind Study 1

The first study consists of increasing the CF of a wind turbine by decreasing its Specific Power (SP), defined as

$$SP = \frac{P_{rated}}{A} \tag{2.7}$$

A decrease in SP can thus be achieved either by decreasing the rated power, P_{rated}, or by increasing the rotor swept area, A, where both of these measures also will increase the CF [7]. An increase in rotor swept area will result in more energy captured, as seen from Equation 2.1.1, and therefore increase the AEP. A decrease in rated power will instead directly affect to an increase in CF from Equation 2.5. However, this effect is somewhat opposed by the resulting decrease of AEP due to less power produced at higher wind speeds [7].

In fact, both increasing the rotor swept area and decreasing the rated power will push the power production more towards the lower wind speeds, making it suitable for lower wind speed sites [13]. However, since a lower SP design as explained increases the CF, there can be benefits to employing this type of wind turbine design at higher wind speed sites as well. This is something already observed in some markets, and could be of increasing relevance in other regions as well [11].

2.4 Theory Behind Study 2

In this second study, the reference system consisting of a wind turbine will be complemented by solar power. By co-locating these two technologies, forming a so-called hybrid plant, a shared grid connection can be utilized at a more consistent rate. This will then increase the AEP, and with the rated power set constant as the grid capacity, the CF will thereby increase.

The motivation behind this is that wind and solar power production has potential to complement each other well. Figure 2.2 visualizes for example how there was a certain anti-correlation between wind and solar production, in SE3, 2023. It shows that over the year, wind power is generally lower at the time period where solar power has its highest production rates, i.e. during the summer.

Note that solar of course has many zero-production hours during night each day of the year, even though it might be difficult to read from this plot due to the resolution.

Furthermore, when the moving average is applied, these hours are averaged together with its neighbouring values, and thereby the moving average graph depicts a very low number of zero-hours.

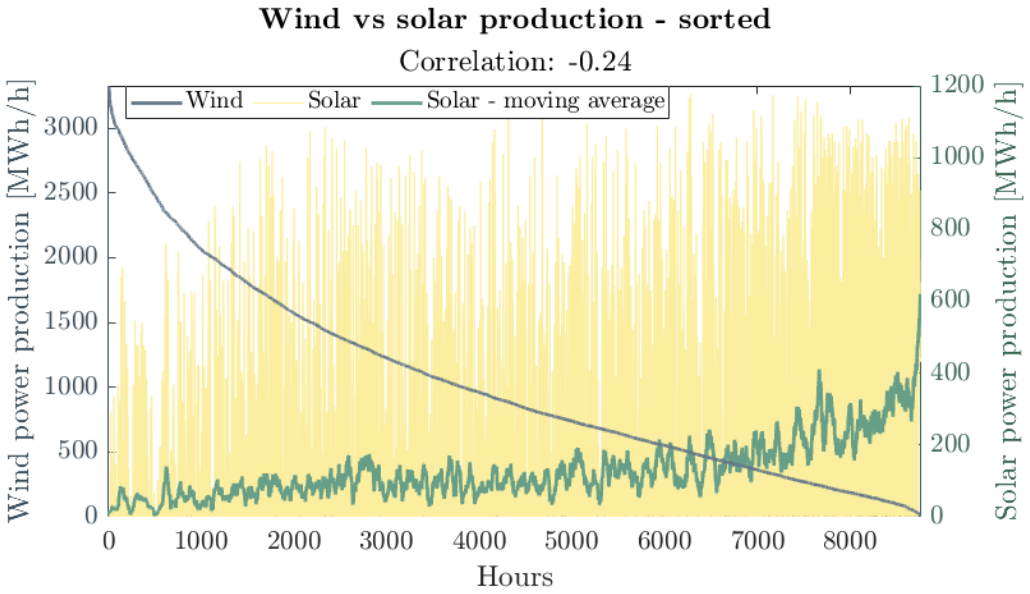


Figure 2.2: Power production in SE3, 2023. The hourly wind and solar production has been paired, and sorted according to descending amount of wind power production. For better visualization, a moving average with a window size 50 has been applied to the solar production.

This means that there is potential to co-locate wind and solar production on the same grid connection, without the need for much curtailment. As mentioned earlier, this is something that is of emerging interest and has been covered to some extent in existing research [21]–[25], but with need for further evaluation.

2.4.1 Solar Module Technology

The most common solar power producing technology today is silicon based photovoltaic (PV) modules [6]. Due to their modular property, they can be utilized both in residential and utility scale applications, where the latter is expected to become increasingly common on the Swedish market [6], [38].

The annual electricity production of a PV module can be calculated as

$$AEP_{mod} = GHI * TF * PR * P_{mod} \tag{2.8}$$

Where GHI is the annual global horizontal irradiance, TF is the transposition factor accounting for the change in irradiation due to tilt, and PR is the performance ratio accounting for all combined losses in the real system compared to the peak power, P_{mod} [6].

2.5 Measures of Performance

To evaluate the performance of a wind turbine and make comparisons between different configurations, there are several measures that can be calculated. A certain CF is not an end goal in itself, instead the main drivers behind turbine design choices are often of financial nature. Therefore, this work will focus on the main financial measures of interest, which are the Levelized Cost of Electricity (LCOE), value factor, and profit. Together, these measures form a comprehensive basis on which to optimize a wind turbine design, and will be able to represent several of the consequences of an increased CF.

2.5.1 Levelized Cost of Electricity

The LCOE is a commonly used measure of the cost of electricity production, and is a simple way of comparing different generating technologies. It is generally calculated as

$$LCOE = \frac{CapEx * CRF + OpEx}{AEP} \tag{2.9}$$

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1} \tag{2.10}$$

Where $CapEx$ is the Capital Expenditures, $OpEx$ the Operational Expenditures, and CRF the so called Capital Recovery Factor [39]. It is obtained from the discount rate, r, and the technology lifetime, N, according to Equation 2.10, and annualizes the CapEx over the entire lifetime.

2.5.2 Value Factor

A measure sometimes used is the so called value factor. It tells the value of the electricity produced by a certain technology, compared to the average value of electricity. Hirth et al. defines this factor as

$$value\ factor\ = \frac{wind\ market\ value}{base\ price} = \frac{\sum_{h=1}^{8760}(p_h P_{el,h})}{\sum_{h=1}^{8760} P_{el,h}} \frac{8760}{\sum_{h=1}^{8760} p_h} \tag{2.11}$$

Where p_h is the electricity spot price at hour h, and $P_{el,h}$ is the hourly power production from the technology of interest [11]. So for wind power for example, the value factor compares the wind-weighted average spot price, to the average hourly spot price.

Based on production data from Svenska Kraftnät, and spot prices from Nord Pool, the value factor for wind and solar power were calculated in SE3 for the years 2018-2023, and are presented in Table 2.1. As seen, the wind value factor is consistently below 1, meaning that the electricity produced by wind power is generally worth less than the average spot price. Compare that to solar power, whose value factors show that solar often produces at higher spot price hours.

Table 2.1: Value factor and penetration level for wind and solar power in the years 2018 to 2023.

	Value factor [-]		Penetration level [%]	
Year	Wind	Solar	Wind	Solar
2018	0.95	1.08	6.5	0.11
2019	0.97	0.96	7.9	0.19
2020	0.79	1.15	12.0	0.42
2021	0.88	0.90	10.5	0.55
2022	0.68	1.19	12.0	0.96
2023	0.80	0.78	12.5	1.55

From Table 2.1, it also seems as though the wind value factor has decreased over the years, while the penetration level has increased. The reason for this could be what is sometimes called the self-cannibalization effect, which means that an increased production of wind power pushes the electricity price down, thereby leading to lower spot prices when wind speeds are high [12]. This is further highlighted in Figure 2.3, which plots the hourly wind power production in descending order of magnitude. The corresponding spot prices are plotted on the right y-axis, and the very low spot prices do occur more often at the hours of highest wind power production.

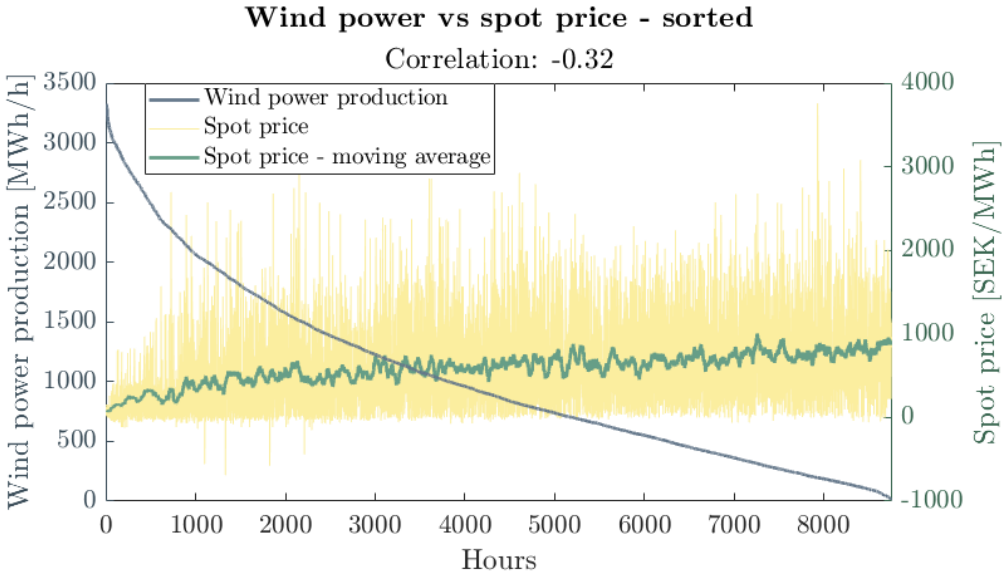


Figure 2.3: Power production and electricity spot price in SE3, 2023. These two data sets have been paired on an hourly basis, and sorted according to descending amount of wind power production. For better visualization, a moving average with window size 50 was applied to the spot price.

The trend seen in Figure 2.3 highlights the potential of the reduced SP of Study 1. It will make a larger share of the wind turbine production occur at the lower wind speeds, where the spot prices seem to be generally higher. Regarding Study 2, the value factors presented in Table 2.1 suggest that complementing wind power with solar also will increase the value of the produced electricity, since the solar value factor often is higher.

2.5.3 Profit of Electricity Production

The final financial measure is the profit of electricity production. In this work, the model for profit is defined according to Equation 2.12, taking the annual revenue from selling the produced electricity at spot prices, and subtracting it by the annual CapEx and OpEx.

$$profit = \sum_{h=1}^{8760} (p_h P_{el,h}) - (CapEx * CRF + OpEx) \tag{2.12}$$

In this way, this measure will be able to complement the LCOE and value factor, as it combines the effects on both costs and revenues.

In reality, there can be several other factors affecting the profit, such as taxes, potential subsidies, providing ancillary services, and forecasting errors. This model is also only valid for power producing units operating on the spot market. Today in Sweden it is common with so called power purchase agreements for wind turbines. It means that the price of selling the electricity has been fixed long term, and the incomes are therefore not affected by the fluctuations of the spot market prices [40].

3
Methodology

In this chapter each step of the process is explained and motivated. It starts in Section 3.1 with describing the process of choosing a suitable reference system, and then goes on to explaining how the two studies were conducted, in Section 3.2 and 3.3 respectively.

3.1 Obtaining a Reference System

A reference system in the form of a Reference Wind Turbine (RWT) was needed so that a baseline existed on which the design changes in the subsequent studies could be implemented. This reference system would also be the basis to which the performance of the two design changes could be compared. Therefore it had to represent the current market, both regarding technology and costs.

3.1.1 Technology Choices for the Reference Turbine

The technological choices for this RWT are presented in Table 3.1. These values were chosen after reviewing literature and in discussion with industry actors. In this way, a reference system representative of the current Swedish wind turbine market was achieved.

Table 3.1: Technology parameters for the reference wind turbine system. The capacity factor is obtained for a Weibull wind distribution of k=2, V_m=7.5 m/s.

Parameter	Symbol	Value	Unit
Rated power	P_{rated}	6.2	MW
Rotor diameter	d	162	m
Specific power	SP	300	W/m^2
Hub height	h	110	m
Maximum C_P	$C_{P,max}$	0.48	-
Cut in speed	V_{in}	3	m/s
Cut out speed	V_{out}	25	m/s
Drivetrain efficiency	η_m	0.96	-
Generator efficiency	η_g	0.98	-
Converter efficiency	η_c	0.98	-
Capacity factor	CF	0.44	-

In this work, all properties other than rated power will be kept fixed for all cases. This is a simplification, since in reality the efficiencies would vary depending on if the turbine is running at part-load or at rated power.

With the values in Table 3.1, the power curve of the RWT in Figure 3.1 was obtained.

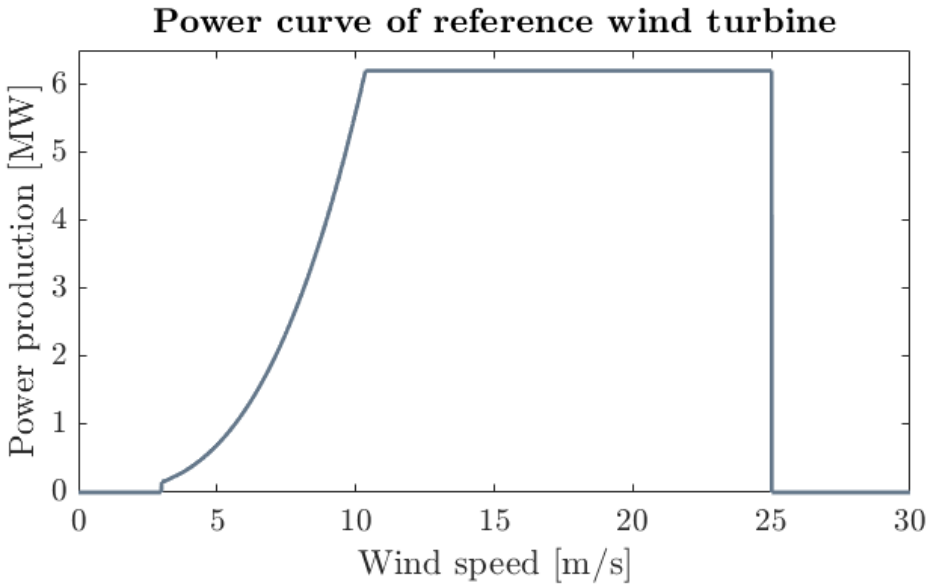


Figure 3.1: Power curve for the reference wind turbine. Note that the abrupt breaks come from using the approximate cubic function, whereas the actual power curve would be more continuous.

3.1.2 Costs of the Reference Wind Turbine

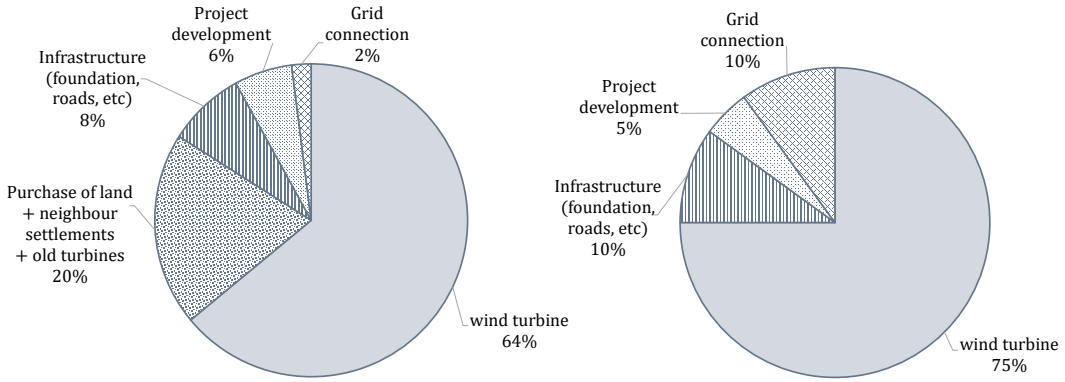
The next step was to establish the costs of the RWT. There are many ways to approach this, as the pricing of wind turbines depends on many parts and can be very project specific. In this work, the RWT cost was established by using estimates presented by the Danish Energy Agency (DEA) as a basis [6]. These were then adapted to the current Swedish market through discussions with industry actors, to accommodate for the differences between Denmark and Sweden, as well as the sharp increase in costs in the last few years.

This resulted in a total Capital Expenditures (CapEx) estimate of 100 MSEK, together with the other parameters presented in Table 3.2. In this way, the cost estimates are assumed to represent the Swedish market at the 2024 price level.

Table 3.2: Cost parameter estimates for the 6.2 MW reference wind turbine.

Parameter	Value	Unit
Total CapEx	100	MSEK
OpEx	2	% of CapEx
Lifetime	35	years
Discount rate	5	%

The total CapEx can be broken down into different areas. The resulting cost breakdown used in this work, seen in Figure 3.2(b), is an adaption of the CapEx breakdown presented by the DEA [6], seen in Figure 3.2(a). The main alteration was removing the costs for purchase of land and old wind turbines. On the Swedish market it is more common to rent the land, moving the purchase of land expenses to the Operational Expenditures (OpEx) instead. The cost of purchasing old wind turbines is more relevant for the Danish market, whose sites are more saturated with wind turbines. The final major adaption was to increase the grid connection share.



(a) DEA CapEx breakdown.

(b) Adjusted CapEx breakdown.

Figure 3.2: Breakdown of capital expenditures into the major components. Note the differences between the breakdown presented by the DEA (a), and the one applied in this work (b), which has been adapted to better reflect the Swedish market.

To further validate the resulting RWT costs, a comparison was made with existing literature. This is presented in Table 3.3, and asserts that the estimates are in line with other research. If several estimates existed in an article, the values presented in Table 3.3 are for the option closest to SP 300 W/m^2, year 2024.

Table 3.3: A comparison between the established reference wind turbine costs and a sample of cost estimates presented in literature. The values presented have been converted to SEK but kept at its respective price year. For conversion rates, see Appendix B.

Source	Price year	CapEx [MSEK/MW]	OpEx [SEK/kW/yr]
This work	2024	16.1	323
Bolinger et al. [7]	2018	14.1	357
Energiforsk [38]	2020	10.9	322
Hodel et al. [10]	2015	9.0	158
IRENA [41]	2021	10.3	386
NREL [39]	2022	17.7	415
Ryberg et al. [42]	2018	11.3	226
Swisher et al. [12]	2020	13.1	203

3.2 Study 1 - Reducing Specific Power

In this first study, the aim was to establish how an increase in CF through a decrease in Specific Power (SP) would affect the Levelized Cost of Electricity (LCOE), value factor, and profit. This was done by letting the SP decrease from 300 W/m^2 while keeping the rotor diameter fixed, thereby obtaining a reduction in rated power according to Equation 2.7. Note that this change in rated power was applied both to the grid connection and generator capacity.

Then, the RWT power curve seen in Figure 3.1 was used to form the corresponding power curve for each rated power, assuming all other properties remained constant. The resulting power curves for a sample of SPs are shown in Figure 3.3.

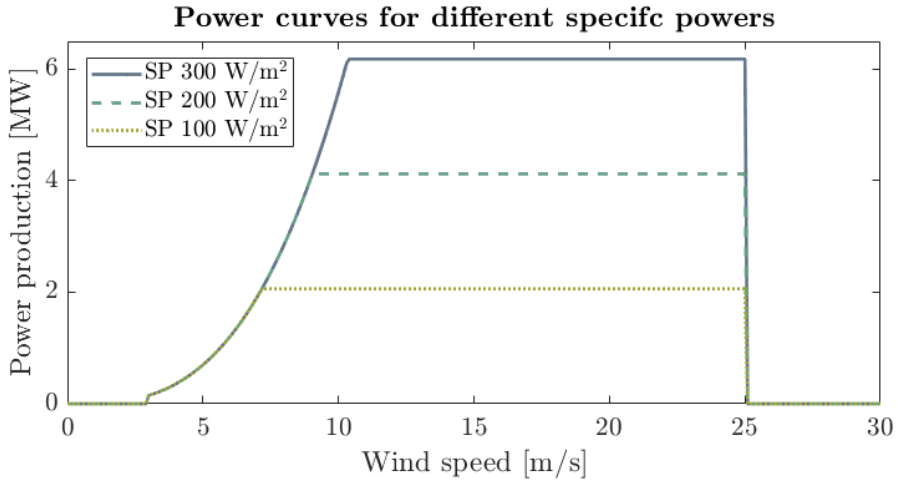


Figure 3.3: Power curves for a sample of specific powers, where SP=300 W/m^2 is the reference wind turbine.

It was then possible through Equation 2.5 and 2.6 to obtain the CF for an entire range of SP, and Figure 3.4 shows how an increase in CF is in fact achieved.

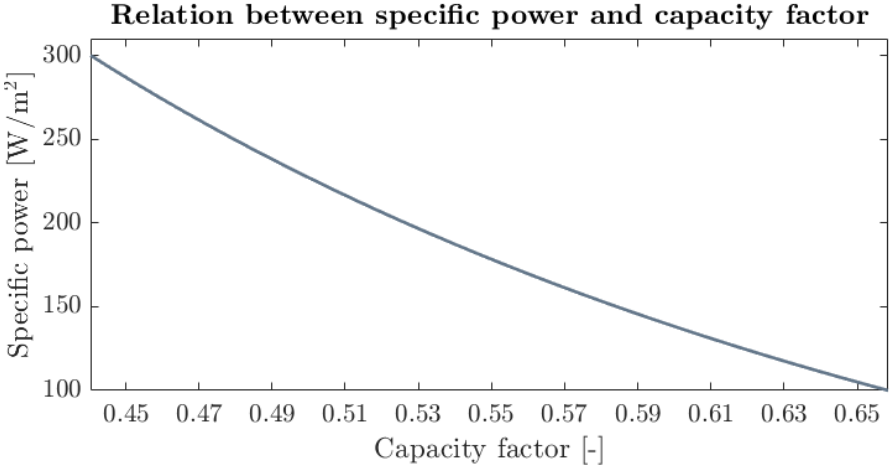


Figure 3.4: Capacity factor as a function of specific power, using Weibull k=2, V_m=7.5 m/s for production calculations.

3.2.1 Cost Assessment

With the power curves and the power production established for the range of CFs, the next step was to establish how the costs would be affected by the decrease in SP.

In previous research, this has been approached in various ways, such as obtaining regressions from a set of turbine designs with different SPs [14], [43], or by estimating a reasonable percentage effect on the pricing from altering the SP [7]. The main methodology applied to this work was more of a bottom-up procedure similar to that of other works [12], [42], where the cost was obtained by evaluating components individually. Each step of this is visualized in the flow chart in Figure 3.5.

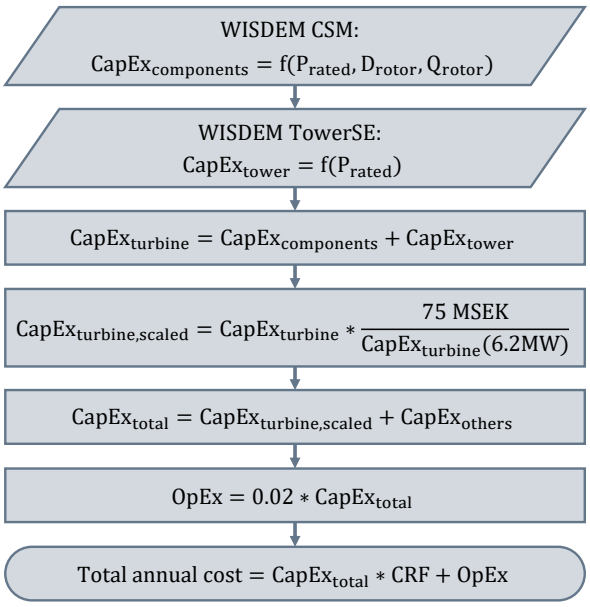


Figure 3.5: Flow chart describing the process of establishing the relationship between the range of investigated specific powers, and the corresponding costs.

As seen in the flow chart above, the first step was to utilize the Wind-Plant Integrated System Design and Engineering Model (WISDEM) developed by NREL [44]. It is an open-source software that can be used to analyse an entire wind turbine or plant system through a set of integrated modules. For more information, the reader is referred to the WISDEM documentation [44].

In this work, the module NREL CSM in WISDEM was used for the majority of the turbine CapEx calculations. It consists of a set of mass and cost correlations for all the main wind turbine components, based on the NREL Cost and Scaling Model (CSM) developed in 2006 but with updated values from 2015 [45]. It makes it possible to obtain the CapEx for each component of the wind turbine, as a continuous function of rotor diameter, rated power, and rotor torque. For detailed component breakdown and the included equations, see Appendix A.

For the wind turbine tower the correlation in the WISDEM CSM simply scales the tower mass and cost with respect to its hub height [45]. However, since a reduction in rated power would reduce the loads applied at the tower top, it was expected to

affect the mass needed for the tower, and thereby its costs. To account for this, the WISDEM module TowerSE was utilized, which models the tower as an elastic beam and optimizes its design [46].

It was first necessary to determine how its needed inputs would vary with the rated power. An initial non-optimizing WISDEM simulation was therefore performed with not only TowerSE but also the modules RotorSE and DrivetrainSE [47], [48]. A preexisting geometry file for a generic wind turbine was used with an altered rated power and rotor diameter, to obtain the rotor-nacelle mass, center of mass, forces on the tower top, and the first natural frequency. These values were then added as inputs to the TowerSE module, and a second simulation was performed with default constraints and tolerances, where the tower wall thickness and outer diameter was optimized to obtain a minimum tower cost. This was then repeated for the entire range of rated powers, and through a second order polynomial regression the following expression was obtained.

$$m_{tower} = 463.3 * P_{rated}^{2.44} + 3883 * P_{rated} + 279912 \tag{3.1}$$

$$c_{tower} = 2.9 * m_{tower} \tag{3.2}$$

Where m_{tower} is the mass of the tower in kg, P_{rated} is the rated power in MW, and c_{tower} is the tower cost in USD(2015). Equation 3.2 was then used together with the ones in Appendix A obtained from the CSM, to achieve the concluding function of turbine CapEx with respect to rated power.

Moving on, the next step was to adjust the obtained CapEx to the current Swedish market. The WISDEM cost estimates were lastly updated in 2015, and with the American market in mind. Therefore the turbine CapEx function was scaled so that for a rated power of 6.2 MW its value matched that of the RWT, i.e. 75 MSEK.

Finally, the rest of the costs were obtained by utilizing the established cost breakdowns described in Section 3.1.2. For infrastructure and project development their costs were assumed to follow the same trend as the turbine CapEx with respect to rated power, and were therefore kept as 10 and 5 % respectively of total CapEx. The same logic was applied to the OpEx which was fixed at 2 % of total CapEx. On the other hand, the grid connection CapEx was assumed to have a more linear relationship with respect to rated power, and was therefore set to 1.6 MSEK/MW, corresponding to 10 % of the RWT total CapEx. This was done to better match estimates presented in current literature as well as input received from industry actors.

3.2.2 Establishing Reference Weibull Parameters

With the above cost relations, it was possible to compute LCOE as a function of CF according to Equation 2.9, using the Weibull distribution. Measured hourly wind speeds available from 2016 and 2017 were analyzed to obtain suitable values of the shape factor, k, and the yearly mean wind speed, V_m. This is presented in Table 3.4, and from this k=2, V_m=7.5 m/s was deemed representative, and therefore used as the reference wind speed distribution.

Table 3.4: Calculated Weibull parameters for specific sites in SE3, where measured hourly wind speeds were available for years 2016 and 2017.

Location	Coordinates	k (2016/2017)	V_m (2016/2017)
Bäckhammar, Kristinehamn	59.1473, 14.2073	1.76/1.99	7.38/7.49
Målarberget, Norberg	60.0919, 16.0819	1.91/2.02	7.29/7.33
Norra vedbo, Jönköping-Aneby	57.844, 14.5902	1.90/2.11	7.80/8.00

3.2.3 Hourly Wind Power Production

Part of the objective was to evaluate value factor and profit, so power production with an hourly resolution was needed to be matched against spot price data, available for years 2018-2023. This work utilized hourly wind power production data from Svenska Kraftnät (SVK) [32] as a basis for modelling the hourly wind speed distribution.

The basic idea was to scale the total wind power production in an entire price area with a certain number of the RWT. This number was established through the iterative procedure depicted in Figure 3.6.

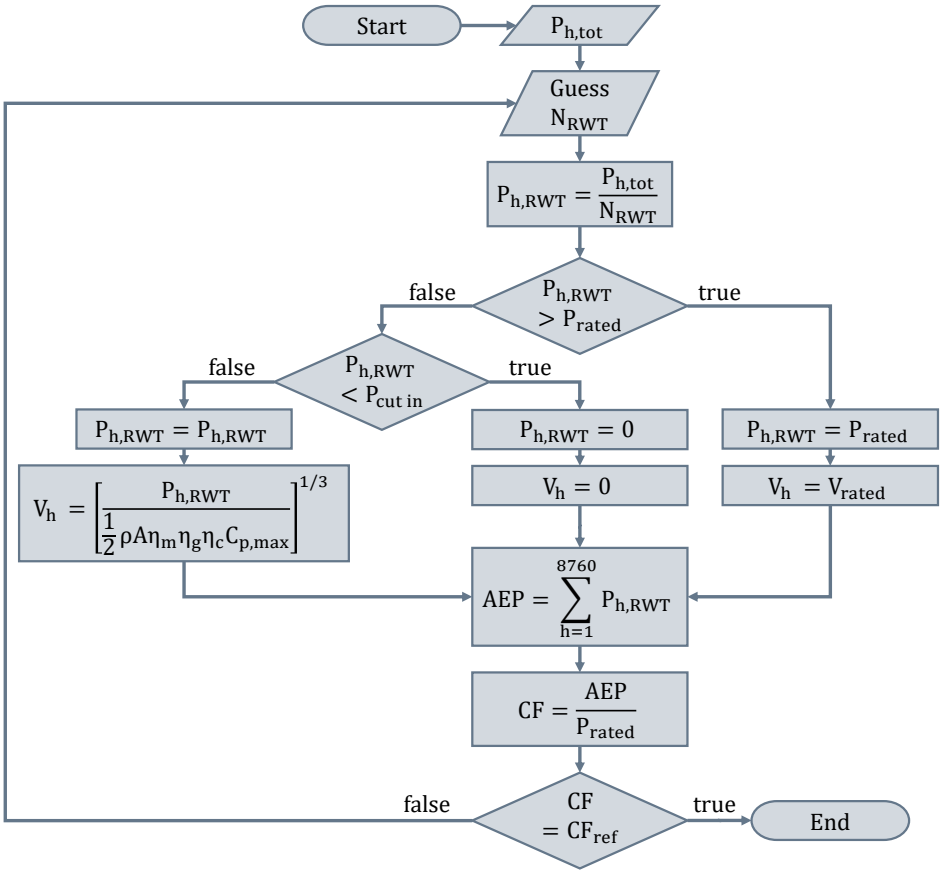


Figure 3.6: Iterative algorithm established for obtaining estimate of hourly wind speeds based on price area production data from Svenska Kraftnät [32].

A number of RWTs was guessed, and then used to scale down the price area wind production to an hourly production from one single turbine. Then, the hours with a production above the RWT rated power was set to produce at rated power, with the wind speed set to rated as well. In a similar way, all hourly production that did not reach the power at cut-in speed, was set to zero together with the corresponding wind speed. For the remaining hours, the wind speeds were obtained through the RWT power curve.

By then adding the hourly production over an entire year, the annual energy production and in extension CF was obtained. The iteration was then repeated until the CF matched the reference CF of 0.44, obtained from the RWT with the reference Weibull distribution (k=2, V_m=7.5 m/s).

However, when reviewing the resulting wind speed distribution, it was clear that this way of modelling the wind speeds gave very few hours with high and low wind speeds. This is explained in Section 4.1.2, but in short, there was thereby a risk of overestimating the benefits of the design changes. Therefore, the transformation in Equation 3.3 was applied to the original modelled wind speeds, in an attempt to avoid this issue.

$$V_{h,transformed} = \frac{V_{h,original}^2}{X} \tag{3.3}$$

This amplifies all wind speeds above the scaling parameter, X, while all wind speeds below instead are reduced in magnitude. The result is a wind speeds time series with a larger share of high and low wind speeds. Depending on the value of X, alternative distribution can be obtained, which is expanded upon in Appendix C. For the scope of this work, the final results are limited to the option of matching the reference Weibull distribution, by using an X-value of 8 m/s.

Both the original and transformed modelled wind speeds are shown and further discussed in Section 4.1.2.

3.2.4 Final Calculations for Study 1

Finally, Nord Pool spot market prices available for years 2018-2023 were matched against the hourly production to obtain the value factor and profit from Equation 2.11 and 2.12.

3.3 Study 2 - Introducing Solar Power Production

For the second study, the capacity of the RWT was fixed at 6.2 MW, together with the rated power of the grid connection. Then solar power capacity was added in the range of 0-10 MW, to add additional energy production and thereby achieve an increased CF.

The technological choices for the added photovoltaic (PV) modules are presented in Table 3.5, mainly based on technology-specific data from the Danish Energy Agency (DEA) for utility scale, ground mounted PV [6].

Table 3.5: Technology parameters used for PV modules.

Parameter	Symbol	Value	Unit
Peak power capacity	$P_{mod,max}$	500	W
Global horizontal irradiance	GHI	981.9	kWh/m^2/yr
Transposition factor	TF	1.17	-
Performance ratio	PR	0.91	-
Capacity factor	CF_{mod}	0.12	-

The value of the performance ratio, PR, was kept fixed for all cases. This is a simplification, since in reality it depends on factors such as module surface temperature and loading. The global horizontal irradiance comes from the long-term estimation of the Global Solar Atlas [49].

The resulting relationship between the added PV capacity and the CF is shown in Figure 3.7, based on modelled hourly power production as explained later in Section 3.3.2.

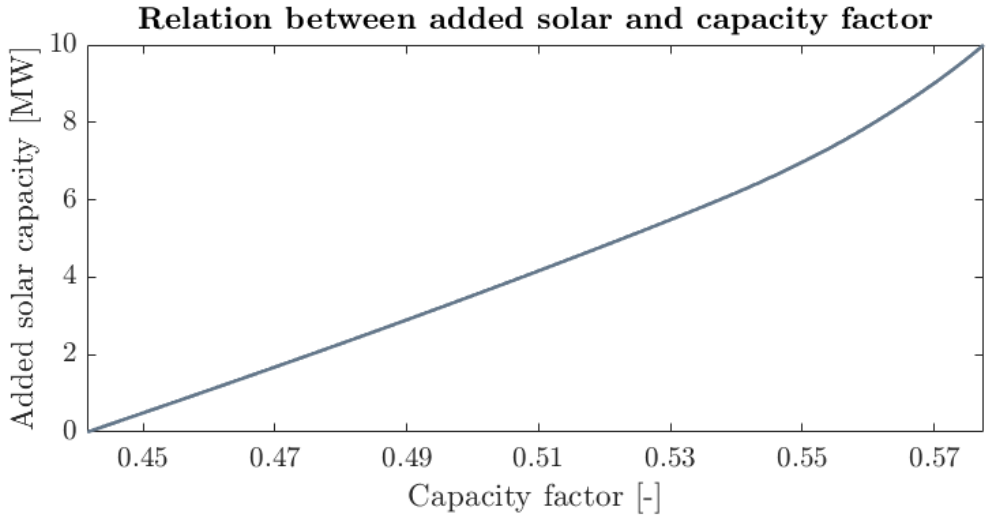


Figure 3.7: Capacity factor of the hybrid power plant, as a function of added solar capacity. Energy production estimated by modelled wind and solar production, as described later in Section 3.3.2.

3.3.1 Costs of Hybrid Plant

To determine the costs of the wind-solar hybrid plant, it was first necessary to establish what costs could be shared between the wind and solar technologies, and then what the additional costs for the PV modules would be.

Regarding the shared costs, some argue that quite a lot of the cost components could be shared, such as project development and land rent. However, after reviewing literature and discussing the topic with industry actors, it was decided that the wind turbine and PV modules only would share their grid connection costs. This is a more conservative approach, to not overestimate the advantages of the hybrid plant.

Therefore, the remaining solar components that needed CapEx estimates were the module itself, as well as the inverter, installation, soft costs and other expenses. For this, values from DEA were again used [6], and converted to SEK at the 2024 price level. The resulting costs parameters are presented in Table 3.6. The OpEx is set to a lower percentage than for wind power, since solar parks do not have any moving parts, and their wear and tear is generally much lower [6].

Table 3.6: Cost parameter estimates for the used PV modules. Note that the total CapEx is excluding the grid connection cost, as it is shared with the wind turbine.

Parameter	Value	Unit
Total CapEx	2722.7	SEK/module
OpEx	1	% of CapEx
Lifetime	35	years
Discount rate	5	%

To further validate the PV module costs, a comparison was made with existing literature. This is presented in Table 3.7, and asserts that the estimates are in line with other research. Note that for this analysis the grid connection cost has been included, to better facilitate a comparison with literature on stand-alone PV systems. If several estimates were provided in an article, the values presented in Table 3.7 are for the option closest to year 2024 on a utility-scale level.

Table 3.7: Comparison between the established PV module costs and a sample of estimates presented in literature. The values presented have been converted to SEK but kept at its respective price year. For conversion rates, see Appendix B.

Source	Price year	CapEx [SEK/module]	OpEx [SEK/module/yr]
This work	2024	3530	35.3
Energiforsk [38]	2020	3500	39
ETIP PV [50]	2024	3700	68
IEA [51]	2022	4300	-
IRENA [41]	2022	4800	41
Lindahl et al. [52]	2020	3400	51

3.3.2 Hourly Hybrid Plant Production

Since wind and solar share grid connection in the hybrid plant, it was necessary to match their individual production on an hourly basis. Hourly wind speeds and in extension production had already been established in Study 1, as described in Section 3.2.3. For all wind power calculations performed in Study 2, the transformed modelled wind speeds were used. The hourly PV module production was modelled in a similar way as the wind speeds, and the algorithm is depicted in Figure 3.8.

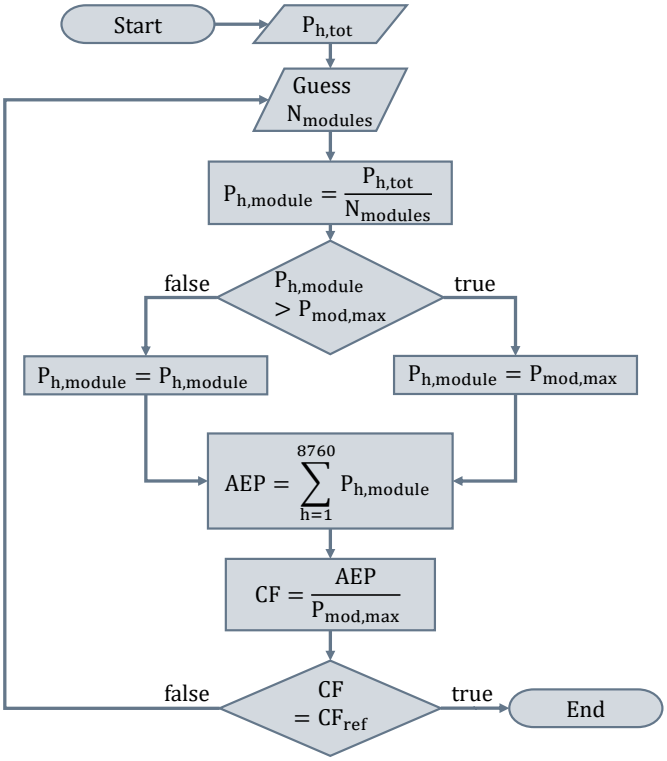


Figure 3.8: Iterative algorithm established for estimating hourly solar reference module production based on SE3 production data from Svenska Kraftnät [32].

A number of PV reference modules were guessed, and then used to scale down the SVK production data, to that of a single module. All production hours exceeding the module peak power capacity were capped, before calculating the annual energy production and CF. This iteration was repeated until the reference CF of 0.12 was met.

With both solar and wind production established at an hourly basis, the hybrid plant production could be determined. The hourly PV production was summed with the wind production, for the range of added PV capacities. For those hours where their sum exceeded the rated power of the grid connection, the excess was curtailed.

3.3.3 Final Calculations for Study 2

The hourly production, together with the Nord Pool spot prices, could then be used to obtain the LCOE, value factor and profit, just as for Study 1.

4
Results and Discussion

In this chapter, all relevant results are shown and simultaneously discussed. The two studies are presented separately, but with a short comparison in the final section.

4.1 Study 1 - Effects of Reducing Specific Power

This section begins by introducing the established costs and hourly wind speeds, accompanied by discussions on their validity. Based on these, the final results are thereafter presented and the underlying factors for the resulting trends are analyzed.

4.1.1 Final Cost Estimates

The resulting relationship between Capacity Factor (CF) and the annualized Capital Expenditures (CapEx) as well as the Operational Expenditures (OpEx) is shown in Figure 4.1. Note that this an estimation of a general trend. In reality, a continuous range of design options are not available, and the exact correlation between design and costs can vary between cases.

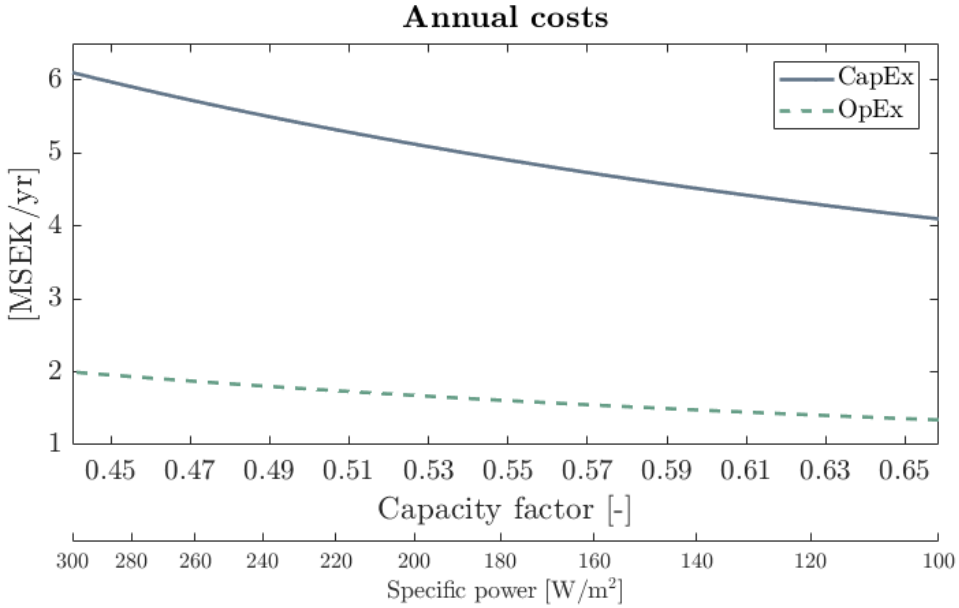


Figure 4.1: Annual costs as a function of capacity factor. Specific power values corresponding to the increase in capacity factor on the bottom x-axis. Based on Weibull with k=2, V_m=7.5 m/s.

A factor to consider is that the tower optimization approach added some uncertainty to the results, since the input geometry file did not fully represent the Reference Wind Turbine (RWT) used in this work. It is therefore reasonable to assume that obtained inputs such as tower top forces and natural frequencies are deviant to some extent. However, the cost scaling model is itself based on simple correlations, and it is therefore difficult to say which is more or less representative of a real case.

Another uncertainty factor is the cost breakdown, as it was assumed that costs of project development and infrastructure followed the same trend as the costs of the turbine. This is an approximation, since there are other factors other than turbine size affecting these costs. Furthermore, the grid connection cost was estimated as 1.6 MSEK/MW, which was deemed a representative value after discussion with industry actors. It is important however to note that this figure is very project specific, and depends on additional factors such as the required length of grid connection.

Nevertheless, the objective was to obtain a continuous function for the costs that highlighted the trends rather than exact values. For this purpose WISDEM was deemed suitable, as a conceptual lower fidelity design tool focusing on preliminary design [44], [53]. Furthermore, despite the approximations in the cost breakdowns it is overall likely to well represent the current Swedish market, by allowing input from both recently published research and actors within the wind power industry. It was therefore assumed that this approach provided sufficiently accurate estimates within the correct order of magnitude, and as seen it shows how there is a clear reduction in costs when reducing the Specific Power (SP).

4.1.2 Established Wind Speed Model

In this section, the modelled wind speeds will be analyzed and validated, by comparing those based on production data from SE3, 2017, to wind speed measurements from the same price area and year. First, an example of the original modelled wind speeds is depicted in Figure 4.2, showing the hourly fluctuations during a week in April.

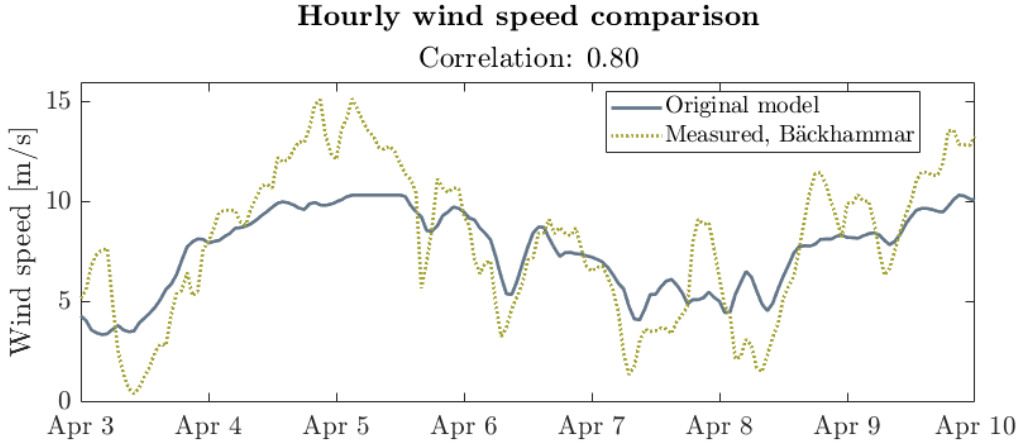


Figure 4.2: Original modelled wind speeds for a week in April 2017, in price area SE3. Corresponding measurements for site Bäckhammar provided for comparison.

As seen, there is a relatively strong correlation between the modelled and measured wind speeds. However, when looking at the wind speed duration curves in Figure 4.3, it is apparent that there is a discrepancy regarding the yearly distribution. For better visualization all wind speeds above the RWT rated level has been capped, and all below cut-in has been set to zero.

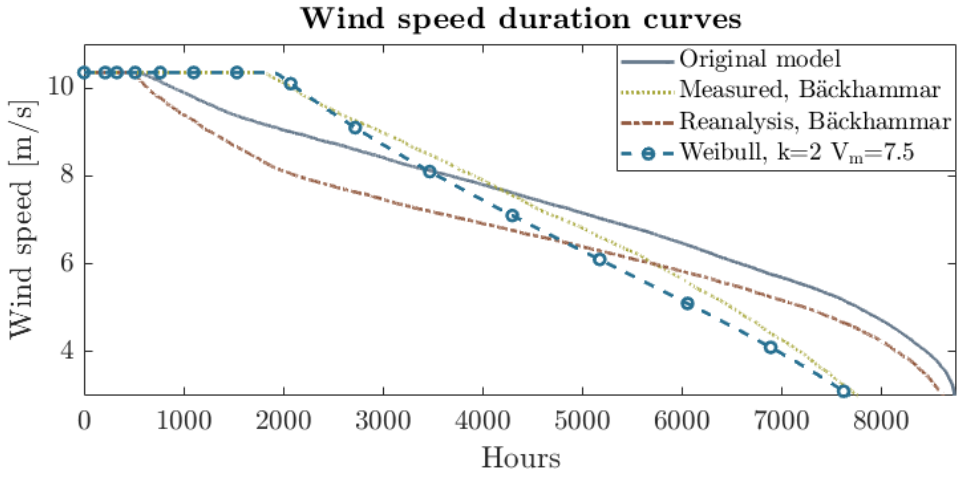


Figure 4.3: Wind speed duration curve of the original modelled wind speed distribution in 2017, SE3. Corresponding measurements and reanalysis data [54], [55] for site Bäckhammar provided for comparison, and the reference Weibull distribution.

The measured distribution is similar to the Weibull with k=2, V_m=7.5 m/s, while the modelled distribution instead resembles the reanalysis data with less hours of higher and lower wind speeds. As explained in Section 2.1.1, reanalysis data has difficulties with capturing high resolution effects, and it seems as though these modelled wind speeds have the same issues. The reason is that they are based on production data aggregated over an entire price area, consisting of different turbines and sites. Therefore, the modelled wind speeds were transformed according to Equation 3.3, giving the new wind speed duration curve shown in Figure 4.4.

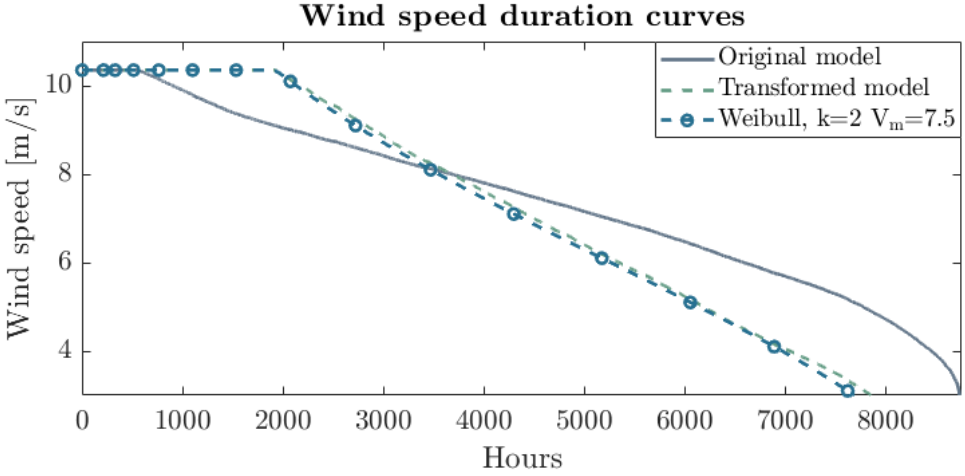


Figure 4.4: Wind speed duration curves of the transformed and original modelled wind speeds in 2017, SE3, compared to the reference Weibull distribution.

By applying this transformation the modelled wind speed distribution thus follows the reference Weibull distribution more closely, giving more full-load and shut-down hours. In Appendix C, additional wind speed measurements and transformation alternatives are presented. It highlights how wind speed distributions are both site and year dependent, and how different modelled distributions can be achieved by the selection of the scaling parameter, X. For this the work, the choice was to fit the data to the established reference Weibull distribution, but it could be further expanded to include other alternatives in the future.

The effect on an hourly basis can be seen in Figure 4.5, where the same week in April has been plotted again.

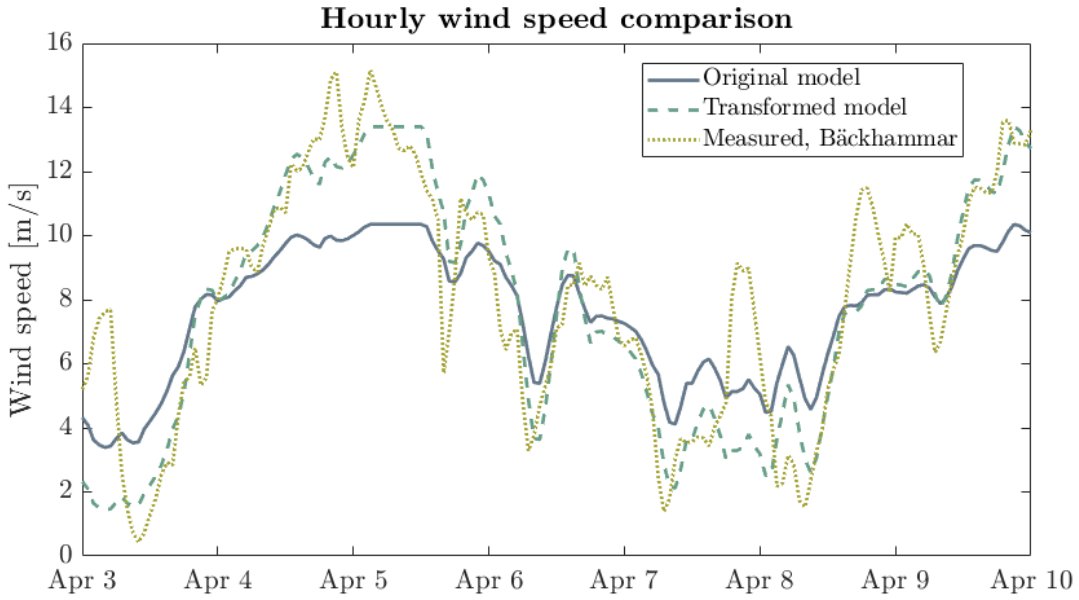


Figure 4.5: Original modelled wind speeds together with the transformed version for a week in April 2017, in price area SE3. Corresponding wind speed measurements for site Bäckhammar kept for comparison.

From Figure 4.5 it is clear that the transformation amplifies the wind speed fluctuations, and as a final visualization of this the relevant probability density functions are plotted in Figure 4.6. It shows how the original modelled wind speeds have a much higher concentration around the mid range of wind speeds, probably due to the regional aggregation of the input production data. With the applied transformation, the distribution is more spread out and much more simulates the shape of both the measured and the Weibull distribution.

Figure 4.6 also shows how neither of the models manage to fully capture the distribution of wind speeds above rated and below cut-in. However, this is not an issue for this work as the power curve is not wind speed dependent in those regions, and when reducing the SP the rated wind speed is moved towards even lower values.

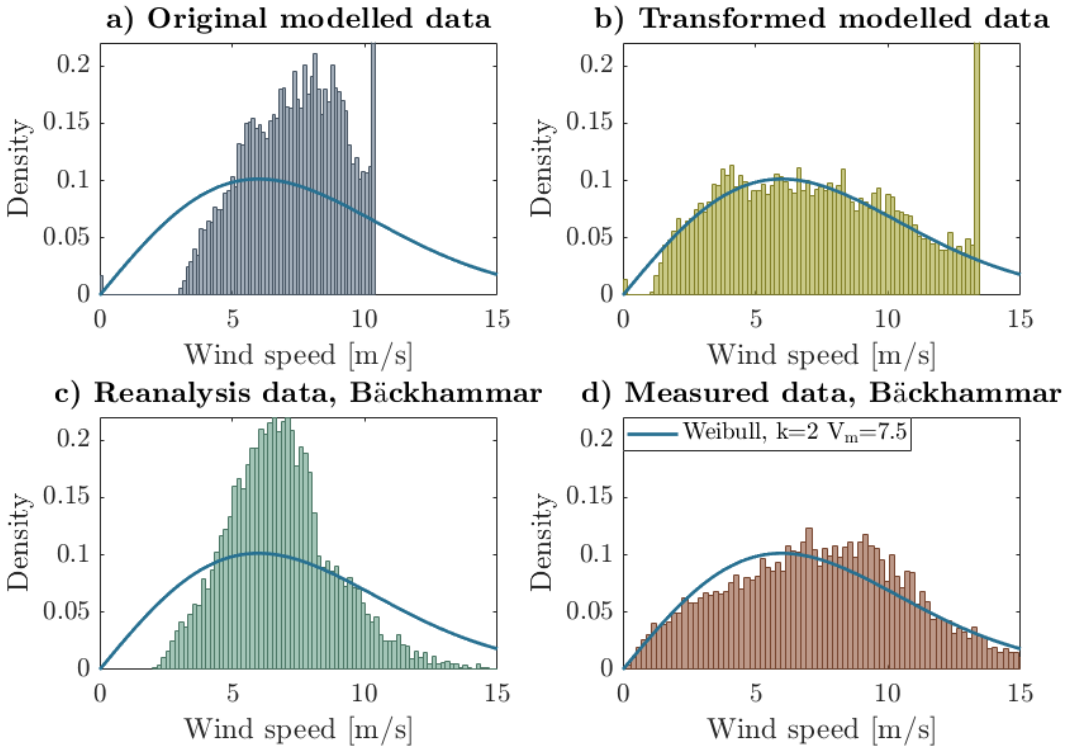


Figure 4.6: Probability density functions for price area SE3, 2017, compared to the reference Weibull. a) Original modelled wind speeds based on Svenska Kraftnät data. b) Transformed modelled wind speeds based on Svenska Kraftnät data. c) Reanalysis data at site Bäckhammar [54], [55]. d) Measured wind speeds at site Bäckhammar.

From the analysis above, it was concluded that the transformed modelled data probably is more suitable for a single-site analysis than the original model. It is however important to remember that wind power production is heavily site-dependent, so there is no single data set that holds the one correct answer. This is further shown in Appendix C. In Section 4.1.3, the main results are therefore presented both for the original and transformed model, to represent a range in which a plausible representation of reality lies.

In Section 4.2.3, the results of Study 2 are presented based on one model exclusively. This choice was made to facilitate a clearer examination of the isolated effects of adding solar capacity. Therefore the transformed model, which ultimately was deemed more plausible than the original, was used.

4.1.3 Main Results of Study 1

In this upcoming section, the main resulting trends from increasing the CF in Study 1 are presented and discussed. Comparisons will be made between the original and transformed modelled wind speeds. Further, the case of keeping CapEx and OpEx constant instead of letting them decrease with SP is also presented for comparison.

All figures are based on data from 2023, but corresponding plots for all years 2018-2023 can be found in Appendix D. In general all years depict similar trends as shown here for 2023, but with profit and value factor at different magnitudes due to varying spot price levels. Especially the years 2020 and 2022 saw an unusual spot market, and therefore those results stand out.

Firstly, Figure 4.7 has the resulting relationship between LCOE and CF, for the two different modelled wind speed distributions. This clearly shows how much influence the choice of wind speed distribution has, and highlights the concern of the original modelled wind speeds. Due to their high concentration of mid range values, and very few hours of high and low wind speeds, the original model overestimates the production levels in comparison to the reference Weibull distribution with k=2 and V_m=7.5 m/s. This gives a much faster increase in CF with respect to SP reduction, which is highlighted by the marked points at a CF of 0.64.

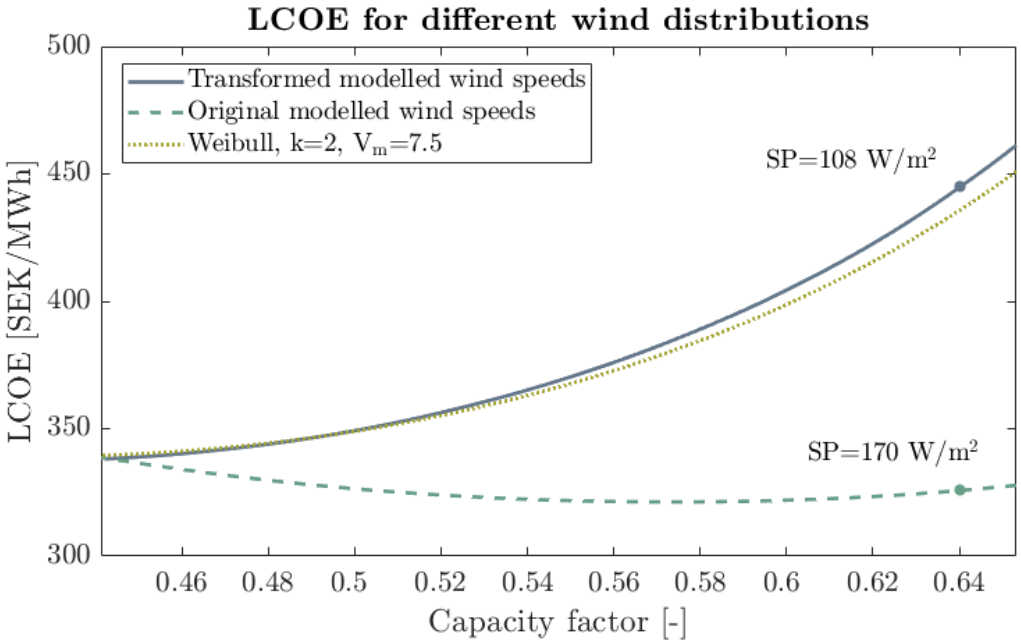


Figure 4.7: LCOE as a function of capacity factor for 2023, based on both the transformed modelled wind speeds, and the original version. A comparison is made with the results of using the Weibull distribution with k=2, V_m=7.5 m/s.

If looking at the original model only, it seems as though it could even be beneficial to raise the CF with respect to the LCOE. However, when instead reviewing the trend based on the Weibull distribution or the transformed wind speeds, there is an

LCOE penalty to raising the CF, which is considered more reasonable. As discussed in Section 4.1.2, neither of these two models can be said to represent the exact truth. They should instead be interpreted as a range in which the truth is plausible to exist.

Another comparison is to the resulting LCOE when not considering the established cost savings from reducing the SP. As expected, this gives a faster increasing LCOE, as depicted in Figure 4.8. It shows the difference of designing for a lower SP turbine from start, compared to reducing the rating of an existing turbine.

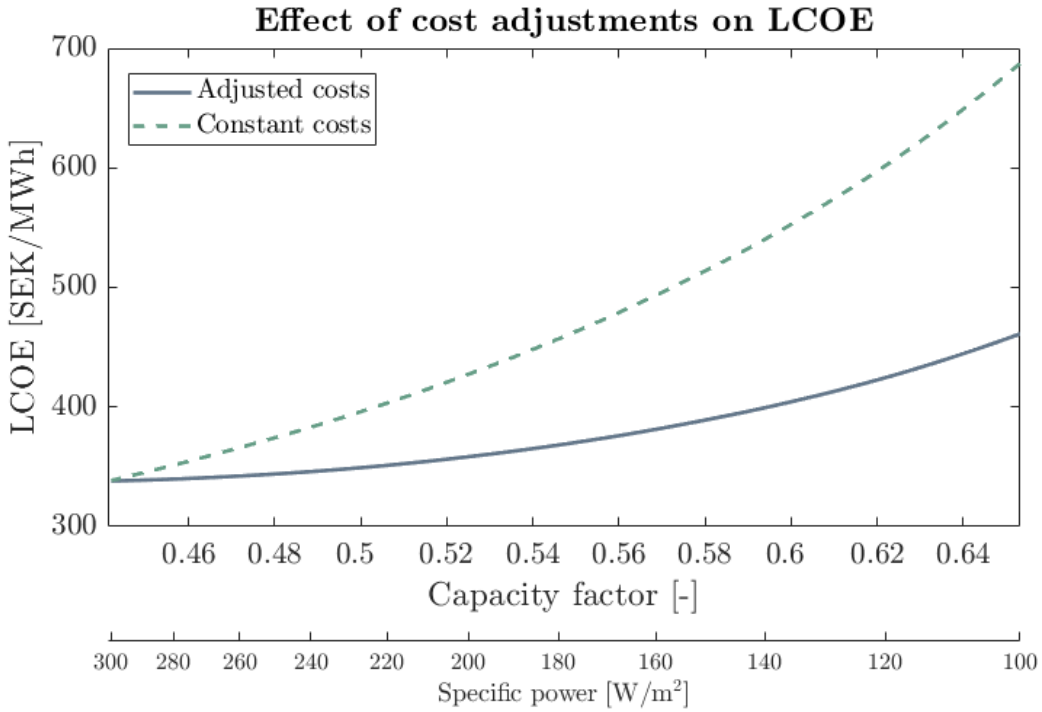


Figure 4.8: Comparing the resulting LCOE, to the case of not considering any change in costs when reducing the specific power. Based on transformed wind speeds.

The central message of the LCOE results is that even though it is likely that the increased CF will come with a higher LCOE, it does not have to be large. In fact, a raise in CF from 0.44 to 0.54 only gives a 27.3 SEK/MWh increase of LCOE, when considering the potential cost savings and using the transformed data set.

The next main evaluated measure was the value factor. Figure 4.9 shows how both models give an increase in value factor, meaning that the average price of the electricity produced goes up when the CF increases. This is in line with previous research, that have shown similar trends when reducing the SP.

The overall value factor for wind power in SE3, 2023 was 0.80, which correlates well with the starting point for both models in Figure 4.9. The reason that the original model starts at a slightly higher value factor, is likely that with the transformed model there are more hours of zero production at relatively high spot prices.

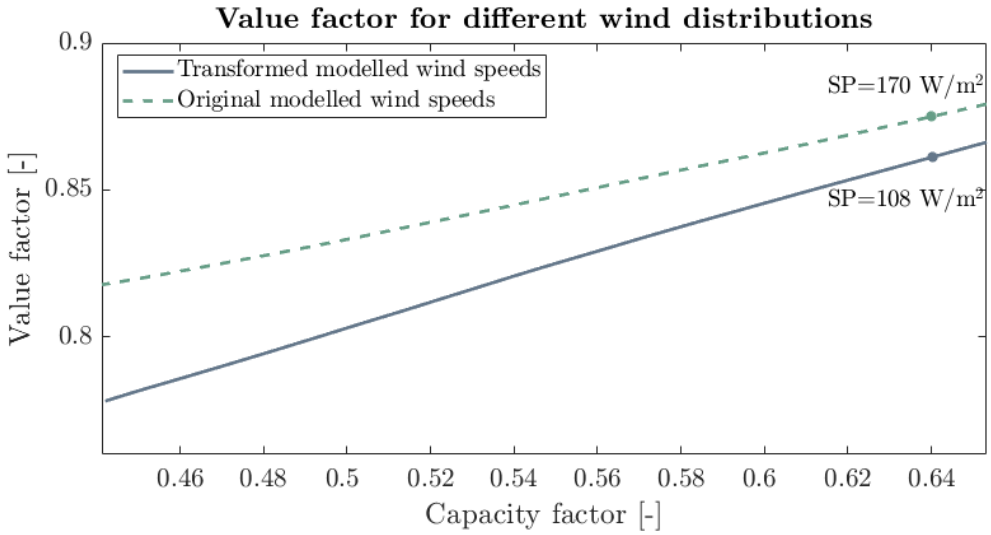


Figure 4.9: Value factor of produced wind power as a function of capacity factor for 2023, based on both the transformed modelled wind speeds, and the original version.

So, with respect to the value of the produced electricity, there is a benefit of increasing the CF. This is further explained by Figure 4.10, which shows that the production lost when reducing the SP is consistently worth less than the produced electricity. This is likely connected to the somewhat opposite trend of wind production and spot prices discussed in Section 2.5.2, which suggests that the hours of low spot prices are more likely to occur when wind power production is high. By reducing the SP the production of the investigated wind turbine has been shifted away from those hours, explaining why the lost production has a much lower value than the produced.

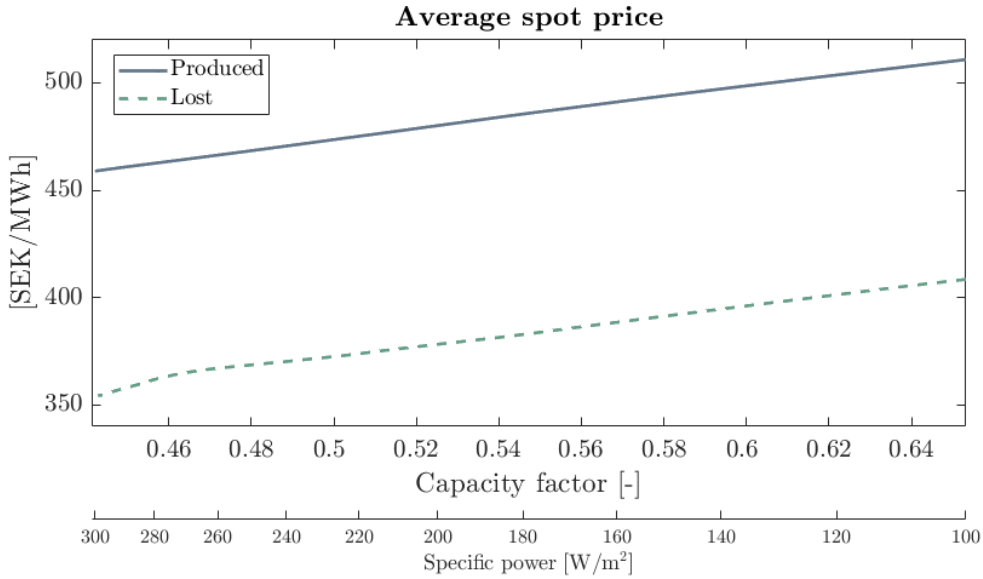


Figure 4.10: Average spot price of the wind power production lost when reducing the specific power, compared to the average spot price of the produced wind power. For reference, the average electricity spot price in 2023 was 589.8 SEK/MWh. Based on transformed wind speeds.

Finally, the last evaluated measure was the profit of electricity production, based on estimated costs and revenues from the spot market. Starting with Figure 4.11, the difference between the original and transformed model is again depicted.

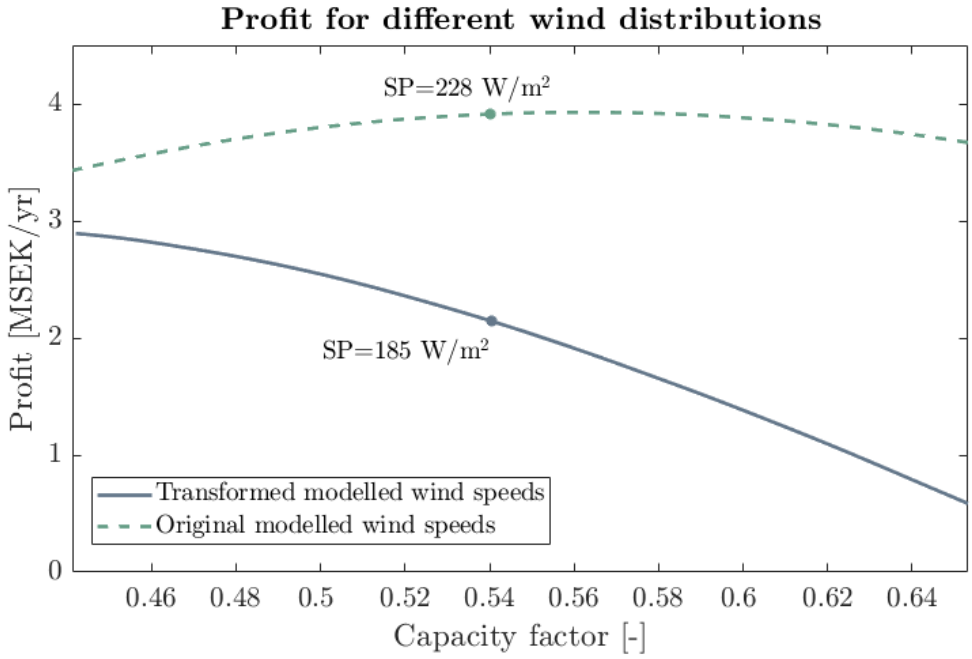


Figure 4.11: Profit of wind power production as a function of capacity factor for 2023, based on both the transformed modelled wind speeds, and the original version.

Just as for the LCOE, the original model estimates the increase in CF to be more beneficial than the transformed model does. One reason is likely that the transformed model has more hours of low wind speeds below cut-in. As was seen in Section 2.5.2, Figure 2.3, there is somewhat of an anti-correlation between wind power production and spot market price, which means that it is more likely that spot prices are high when wind speeds are low. More of these high spot price hours are therefore lost with the transformed model.

Another contributing factor is that with the original model, the CF increase depicted is reached faster. To reach a CF of 0.54 for example, the SP has been reduced to 185 W/m^2 for the transformed model, while with the original model the same CF is reached already at an SP of 228 W/m^2. Therefore the rated power is consistently higher with the original model compared to the transformed, for the same CFs. This leads to a higher production level, and thereby higher revenues.

Again, in reality the true answer might lay somewhere in between these two, since wind speed distributions are very site-dependent. As concluded earlier though, the transformed data is more similar to the reference Weibull distribution representative of measurements from 2016-2017 in SE3, and it is therefore likely that the transformed model is a somewhat better representation of a single site.

Figure 4.12 below, shows the comparison with not considering cost savings from lowering the SP. Once more, it is clear that the negative effect that the increased CF might have on profit, is much counteracted by the cost decrease.

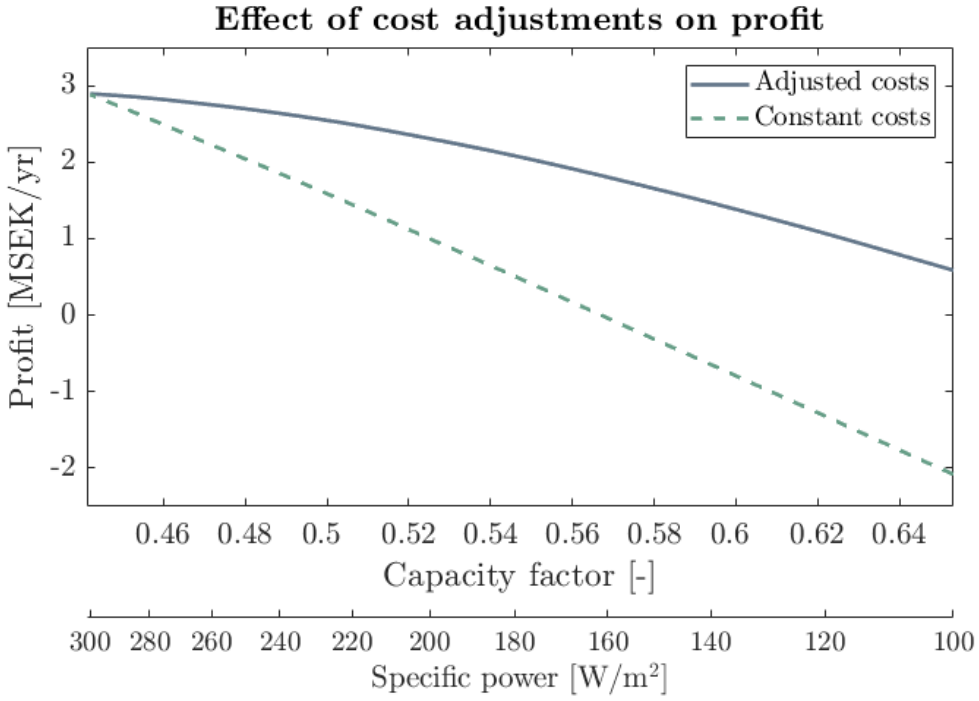


Figure 4.12: Comparison of the resulting profit from electricity, with the case of not considering any effect on CapEx and OpEx when reducing the specific power. Based on transformed wind speeds.

From these resulting profit trends, it seems as though there might not be much financial benefits to an increased CF. It lowers the feasibility of this design change, since profitability of course is a major driver for investors.

However, the model for profit used in this work is a simplification of reality, and there are some potential benefits to the increased CF that it does not capture. For example, a higher CF could make it easier to utilize the wind turbine for ancillary services, which then could be a potential revenue stream. Another example is that the higher CF could make it easier to accurately forecast and bid for production. Therefore the results presented here are mainly applicable to wind turbines that are operating purely on the spot market.

In summary, the first study indicates the potential to reduce actual costs, but with a decreased production which counteracts this benefit, and results in a LCOE that is likely increasing. Moreover, increasing the CF in this way is likely to reduce the profitability, although this outcome is highly dependent on the input wind speed data. Despite these potential drawbacks, the value of the produced electricity is shown to increase. Ultimately, the results suggest that while this design change might not be the most appealing option for wind turbine investors, the increased CF can yield benefits for the overall system.

4.2 Study 2 - Effects of Introducing Solar Power

In this section, the hybrid model is first described, showing how the co-located wind and solar production interact with each other. Then, the estimated costs are shortly discussed, before the main results are presented and studied.

For this second study, the transformed modelled wind speeds were used since they likely lie closer to a realistic wind distribution of a single site. For PV production the original model is kept as is, in part because there in this work was no measured data available to validate the model against. Additionally, even though solar irradiation is intermittent it follows a more predictable pattern than wind, with less hourly fluctuations. Therefore, by scaling the SVK data to match the production levels for the long term average GHI, the validity of the resulting model is deemed sufficient.

4.2.1 Established Hybrid Model

An example of how the added PV capacity complements the wind power production can be seen in Figure 4.13, for a week in July as well as the entire year of 2023. This figure depicts the hourly wind production, with the corresponding solar production added on top to fill out the production up to the rated power limit. Here it is clear that the wind and solar production do complement to some extent. When looking over the entire year, wind production is seen to be lower in summer, which of course is when solar production is at its highest.

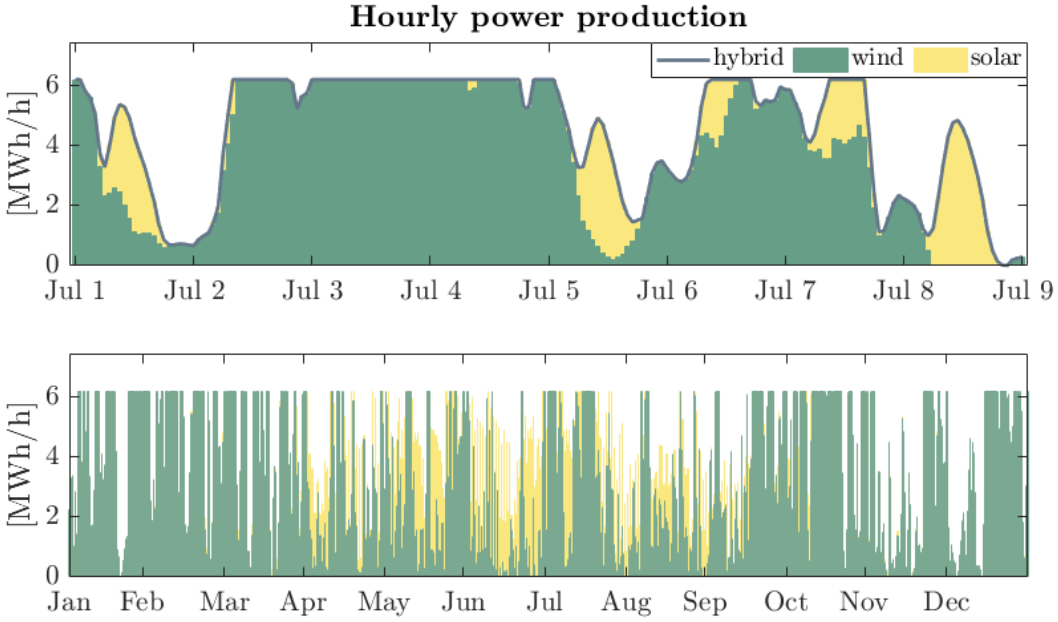


Figure 4.13: Hourly power production for the hybrid power plant with a solar capacity of 5 MW, corresponding to a hybrid plant capacity factor of 0.52. The solar production has been stacked on top of the wind production, so that the resulting magnitude represents the hybrid plant output for each hour.

Due to this complementary production pattern, it was possible to increase the CF quite substantially with added PV capacity, without loosing much production. Figure 4.14 shows that a CF raise to 0.54, corresponding to 6.2 MW added PV capacity, means that only 3.6 % of the production is lost even though the installed capacity then is twice the size of the rated power.

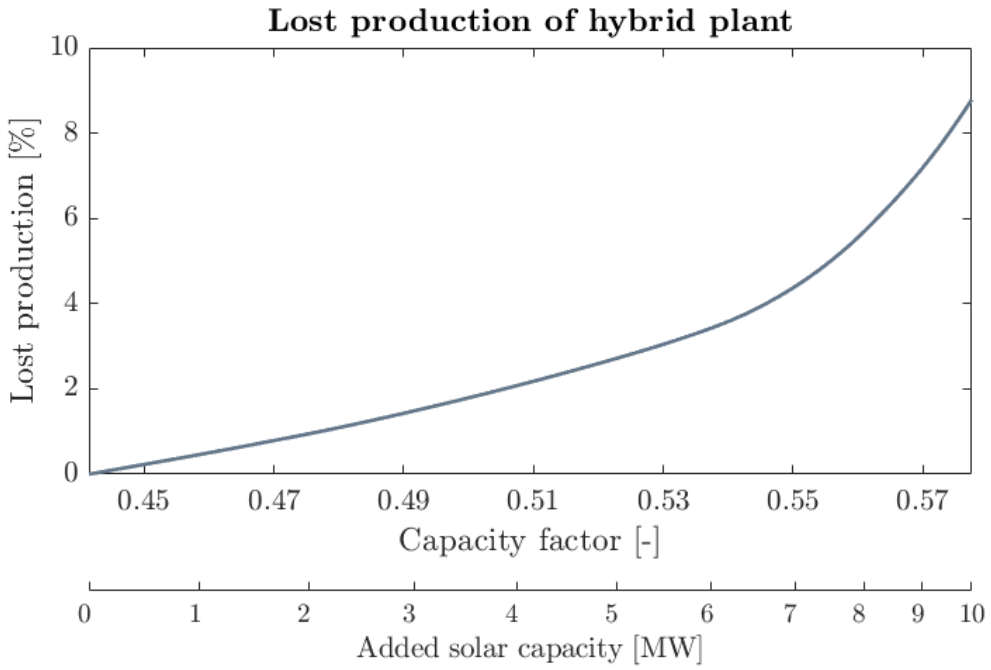


Figure 4.14: Percentage of annual energy production lost due to co-locating wind and PV production on the same grid connection, for added PV capacities up to 10 MW. For price area SE3 in Sweden.

These calculations are based on price area SE3 in Sweden. Other geographical locations with different wind speed distributions or solar irradiation are likely to affect the trend shown in Figure 4.14. Furthermore, in a real-case scenario, land availability limitations could affect the amount of installable solar power at certain sites.

Finally, Figure 4.15 visualizes how the increased CF is achieved. For the hybrid plant, additional PV leads to a shift of the power duration curve to the right, meaning a higher energy production for a constant rated power.

For comparison, the power duration curves when having two stand-alone plants, i.e. a separate wind turbine and solar farm, are also depicted in Figure 4.15. Even though having two stand-alone plants gives a slightly higher energy production as there would not be the production losses shown in Figure 4.14, the resulting CF would be substantially lower since they no longer share the same grid connection and rated power.

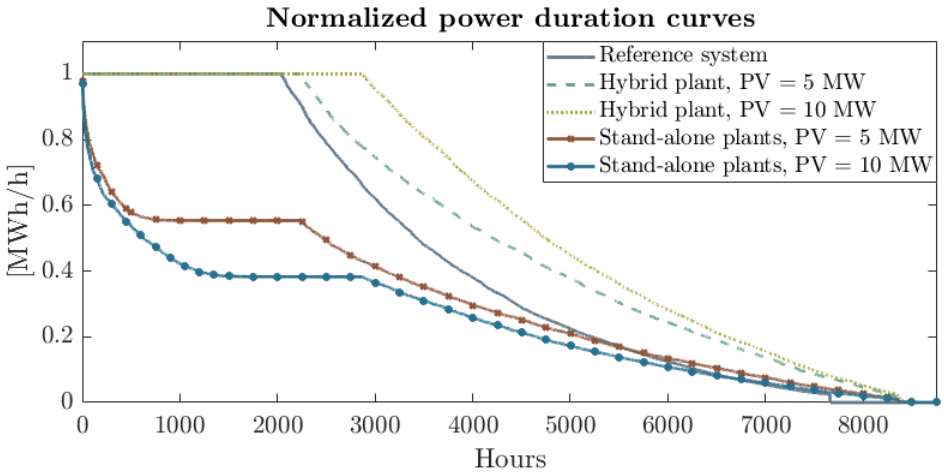


Figure 4.15: Power duration curves for the hybrid plant with added solar capacities 5 and 10 MW, compared to the corresponding curves of two stand-alone plants. They have been normalized to each respective plant rated power, so that the area underneath each curve corresponds to its respective capacity factor.

4.2.2 Final Hybrid Cost Estimates

For the hybrid plant, the wind turbine capacity and its costs were fixed at that of the RWT, and then an increasing share of PV modules was added, with a shared grid connection cost. This resulted in the relationship shown in Figure 4.16, for the combined annual CapEx and OpEx. The corresponding cost of instead having two stand-alone plants is also shown, highlighting how there is a clear cost reduction due to the shared grid connection costs. Note that the plot for the stand-alone plants does not match the CF range on the top x-axis, but still corresponds to the same PV capacities as the hybrid plant, shown on the bottom x-axis.

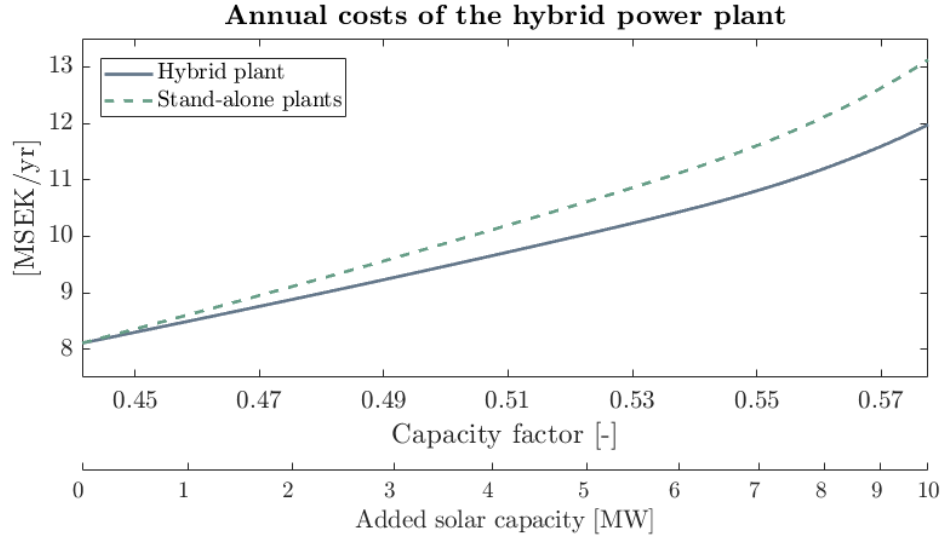


Figure 4.16: Annual costs as a function of capacity factor, with corresponding installed solar capacity shown on the bottom x-axis. For comparison the cost of stand-alone wind and PV plants with the corresponding installed capacity is shown.

Since a fixed modular cost was assumed for the PV, the cost increase is linear with respect to the added PV capacity. In reality, the PV market is very volatile and there could also be project specific differences, for example that the price per module could be reduced for a larger order of modules.

4.2.3 Main Results of Study 2

In this section, the resulting LCOE, value factor, and profit from Study 2 are shown. Just as with the first study, the year 2023 is represented here, while all years 2018-2023 are in Appendix E. All results will also be compared to the corresponding trends for stand-alone wind and solar plants with the same 6.2 MW wind turbine and the same range of PV capacities. Again, these do not reach the same CFs shown on the top x-axis, but matches instead against the corresponding added solar capacity on the bottom x-axis.

Firstly, in Figure 4.17 the LCOE is presented. Both the hybrid plant and the stand-alone plants obtain an increase in LCOE when more PV is added. The reason is that the estimated PV costs are high in comparison to its output production.

There is however a clear advantage to the hybrid plant, especially for PV capacities up to ~7 MW. This corresponds well with the trend seen in Figure 4.14, where the production losses start to accelerate around this point. The reason is that if too much PV capacity is added, the reduced production compared to the stand-alone plants starts to overweight the cost savings of the shared grid connection, thereby accelerating the LCOE increase.

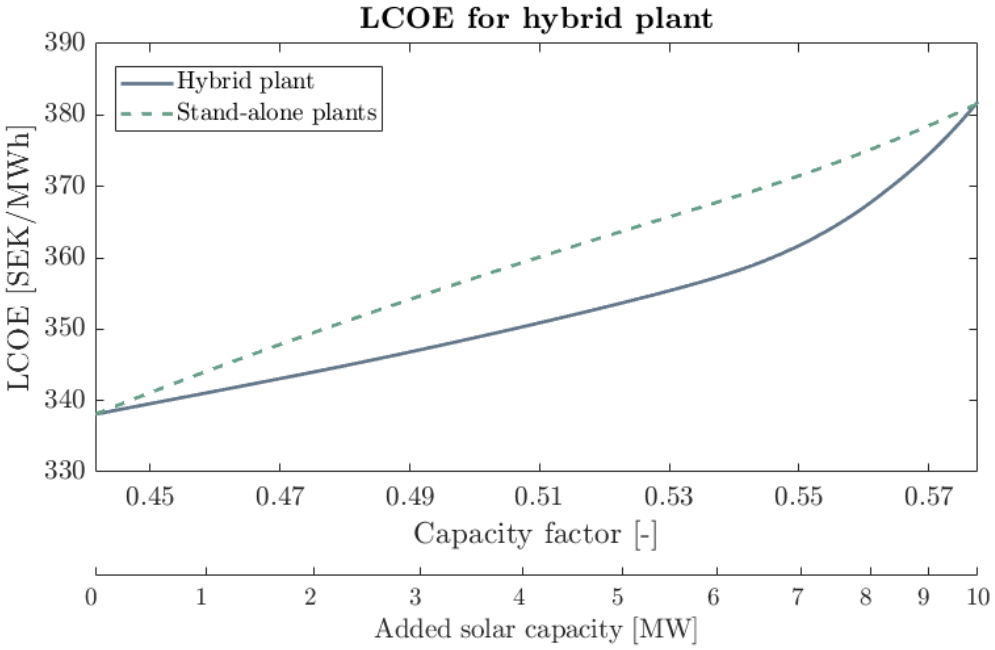


Figure 4.17: LCOE as a function of capacity factor for 2023, based on modelled wind speeds and PV module production. The LCOE of stand-alone wind and PV plants with corresponding installed capacity is shown for comparison.

Moving on, Figure 4.18 shows how the value factor of the hybrid plant electricity increases with the addition of PV capacity. The stand-alone plants on the other hand have a fairly constant value factor. The reason is the similar value factors of wind and PV in 2023, and this differs between the examined years as seen in Appendix E, Figure E.2.

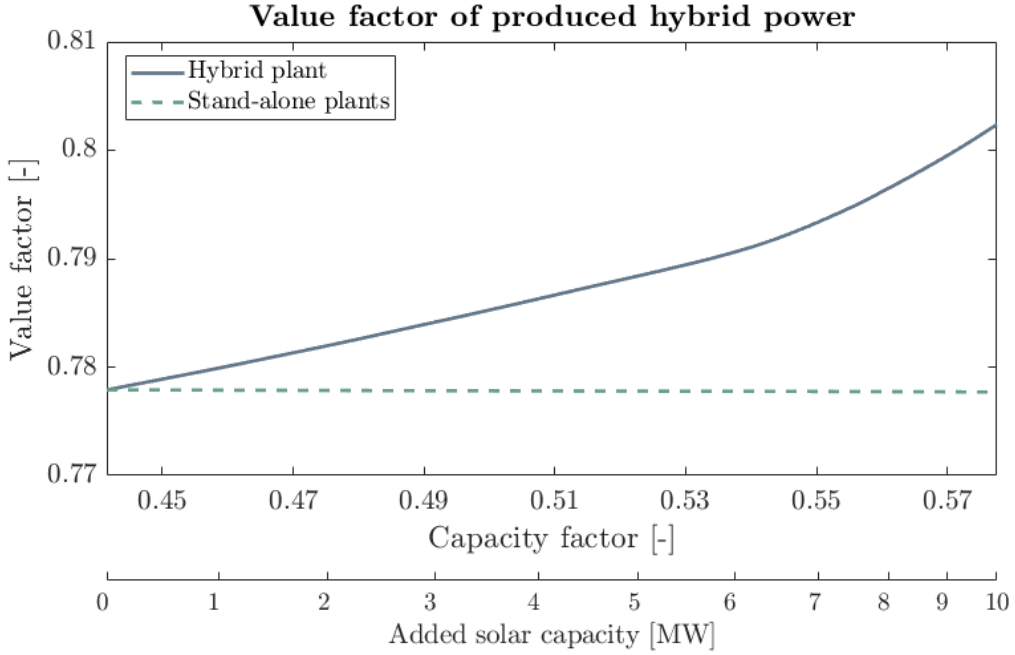


Figure 4.18: Value factor of produced hybrid power as a function of capacity factor for 2023, compared to stand-alone wind and PV plants with corresponding installed capacity.

The difference between the value of the hybrid plant and the stand-alone plants connects to how the solar power production often manages to fill out the hours where wind production is low, and as discussed those hours are more likely to have higher spot prices. Vice versa, the hours where much production is lost due to the capped grid capacity have a tendency to have lower spot prices due to the high wind power production.

This reasoning is further confirmed by Figure 4.19. It shows that there is a large difference in the average price between the power produced by the hybrid plant, and the price of the production that is curtailed. This is recurring for all examined years, as seen in Appendix E, Figure E.3. The one exception is 2018, where the lost production seems to be more valuable than the produced. It is not clear why this year is an outlier, but one explanation could be that in 2018 the solar penetration was very low, and therefore there might be issues with modelling the production based on SVK production data.

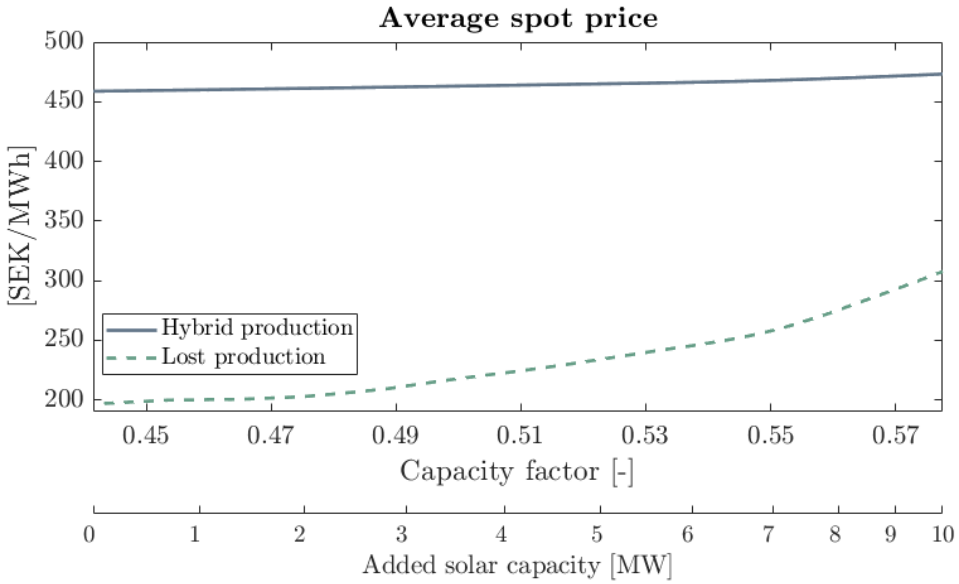


Figure 4.19: Average spot price of the power production lost when combining PV and wind into a hybrid plant with a shared grid connection. The average spot price of the produced power is shown for comparison. For reference, the average electricity spot price in 2023 was 589.8 SEK/MWh.

Finally, Figure 4.20 shows how the profit of electricity production varies with CF. Again there is a clear difference between stand-alone plants and the hybrid alternative. One reason is of course the reduced costs from co-locating the plants, and it is also likely that the anti-correlation between wind power production and spot market price plays a part. As was seen in Figure 4.19, the value of the electricity that is produced when both wind and solar production is high, and power therefore has to be curtailed, is substantially lower than the overall value of the delivered electricity.

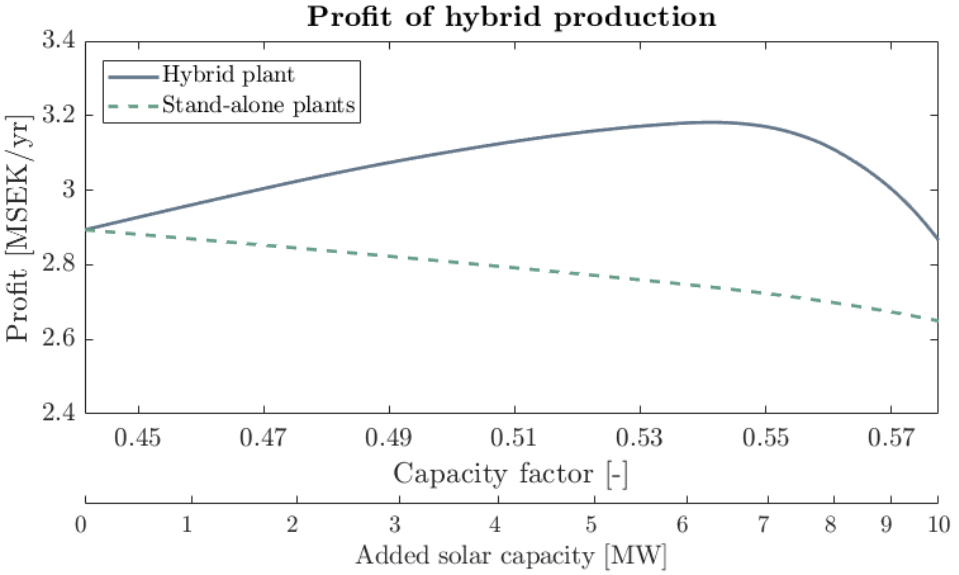


Figure 4.20: Profit of hybrid production as a function of capacity factor for 2023, compared to stand-alone wind and PV plants with corresponding installed solar.

The magnitude of the profit varies between the examined years due to the different spot prices, which can be seen in Figure E.4, Appendix E. Nevertheless, the overall trend is that the hybrid plant is more profitable than two stand-alone plants. Furthermore, for several of the investigated years the results show that there is potential of increasing the profitability through the addition of solar capacity.

In summary, this second study shows that even though the added PV capacity probably comes with additional actual costs and an increased LCOE, it has the potential to increase the profitability as well as the value factor. The reason is that the solar production to a high extent complements the wind production, which results in relatively low energy curtailment, and produced electricity of a higher value.

4.3 Comparison of the Two Studies

To finalize this chapter, a summarizing comparison is made between the two studies. The main resulting measures are presented in Table 4.1, for a sample of CFs. The key point to make is that both studies give an increasing LCOE when the CF is increased, but that they also give higher value factors. Study 1 is able to reach higher CFs than study 2, and thereby higher value factors. Cost and revenue effects counteract each other in the resulting profit, where it seems as though Study 2 results in a system that is more likely to increase profitability for a CF increased beyond 0.5.

Table 4.1: Comparison of the main results from both studies. Based on the transformed modelled wind speeds and the modelled solar production, for SE3, 2023. The first row represents the unaltered reference wind turbine.

	LCOE [SEK/MWh]		Profit [MSEK/yr]		Value factor [-]	
CF	Study 1	Study 2	Study 1	Study 2	Study 1	Study 2
0.44	338	338	2.9	2.9	0.78	0.78
0.46	340	341	2.8	3.0	0.79	0.78
0.48	344	345	2.7	3.0	0.79	0.78
0.50	349	349	2.5	3.1	0.80	0.79
0.52	356	353	2.4	3.2	0.81	0.79
0.54	365	358	2.1	3.2	0.82	0.79
0.56	376	367	1.9	3.1	0.83	0.80
0.58	389	-	1.7	-	0.84	-
0.60	405	-	1.4	-	0.85	-
0.62	423	-	1.1	-	0.85	-
0.64	445	-	0.8	-	0.86	-

Note however that these two studies consisted of two very different changes to the reference system. The above comparison is still relevant for the sake of concluding this work, but the main results are best reviewed for each study separately.

5
Conclusions

In this work, two different studies have shown how costs, Levelized Cost of Electricity (LCOE), value factors and profit are affected by two alternative ways of increasing the Capacity Factor (CF). The resulting trends have formed the basis of a discussion about the feasibility of the investigated design changes.

A first conclusion, is that the results were shown to be heavily dependent on the approach of obtaining input wind speeds. This is not unreasonable since wind power production is directly linked to wind speed magnitude, which makes all of the investigated measures very site-dependent. In this work, two different distributions were used, as well as compared to actual wind speed measurements, and the conclusion is that a result representative of reality likely lies somewhere in between these. For a single wind speed site with the characteristic Weibull distribution that was the focus of this work, it is likely that the transformed model is the most representative of the two. It is however important to remember that it does not represent a general truth, and that it likely exists more refined models that achieve alternative results.

With that said, Study 1 showed that the costs of a wind turbine are reduced when the Specific Power (SP) is lowered by a reduction in rated power. It is therefore possible to achieve a higher CF at lower costs. However, the resulting LCOE shows that the lost production likely counteracts these savings, giving a system that is more expensive per MWh produced. Furthermore, the first study also concludes that it might be difficult to achieve a more profitable wind turbine when the CF is increased in this way. Both these measures combined suggests that this design change is perhaps not the most attractive for the price area SE3 market, unless other unexplored consequences of the increased CF are more important.

Nevertheless, the value of the power produced consistently proved to increase, since a larger share of the production was shifted towards lower wind speeds. Therefore a lower SP could potentially help mitigate the issue of the self-cannibalization effect, and thereby make it easier to increase the wind power penetration level. So in conclusion, this design change has potential to be beneficial on a system level, but for it to be implemented there also need to be further project level financial incentives, other than those included in the profit model of this work.

Moving on to Study 2, it instead showed an increase in actual costs with a raised CF, which is reasonable since the raised CF is achieved by adding solar capacity. This is reflected in the LCOE, which just as for Study 1 likely increases with the CF.

With respect to profit of electricity production though, this second study shows a higher potential to increase the profitability for higher CFs, even though the trends vary somewhat between the investigated years. Furthermore, just as for the first study the value of produced electricity is consistently higher when more solar power is introduced in the hybrid park.

Overall, this second study highlights that the concept of co-locating wind and solar power could prove to be beneficial in southern Sweden, both on a project and system level. Its potential is emphasized by the relatively low percentage of energy curtailment, and the increased CF shows prospects of potentially mitigating some of the issues related to the intermittency of wind and solar.

5.1 Future Work

Firstly, to further improve this work the established algorithms for determining hourly production from wind and solar might benefit from further refinement. As seen in this work, it can have major effects on the results. Therefore, the robustness of the obtained trends would benefit from investigating further tuning of the conversion from production data to wind speeds, with respect to for example local variations and biases.

Furthermore, additional effort can be done with respect to the cost estimations. Especially, more focus could be made to tune the WISDEM cost scaling model to the market of today, and higher fidelity simulations could be performed to better validate the established tower cost correlation.

As a final suggested improvement, the applied profit model could be expanded with additional factors, to better capture the actual market. One is the possible revenue stream of providing ancillary services, and how it is affected by a higher CF. Another is production forecasting, and how the increased CF could influence the risk of prediction errors.

There are also several ways of expanding beyond this work. One is to complement the hybrid park of the second study with the option of battery storage. Through a suitable charging and discharging model, this addition has the potential to further increase the CF as well as introduce dispatchability.

Another way is to expand the study to include a larger system. This work has focused on examining one type of wind turbine at a site with one specific Weibull distribution. A next step could therefore be to investigate different types of wind speed sites, or an entire system consisting of several designs and configurations. Even the time horizon could be expanded, by simulating future prices and forecasting weather for input data.

With these points in mind, this thesis has fulfilled its aim of investigating the feasibility of wind power design for high capacity factors, and can be seen as an initial step with the potential to expand further.

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A

Cost Correlations

Table A.1: Components evaluated with the WISDEM cost scaling model, and their scaling variables. Note that rotor torque depends on both rotor diameter and rated power.

Component	Function of
Blades	Rotor diameter
Brake system	Rotor torque
Cabling and electrical connections	Rated power
Control system	Rated power
Generator	Rated power
Gearbox	Rotor torque
High speed shaft	Rated power
Hub	Rotor diameter
Hydraulic cooling systems	Rated power
Low speed shaft	Rotor diameter, Rated power
Main bearings	Rotor diameter
Other nacelle equipment	Rotor diameter, Rated power
Pitch system	Rotor diameter
Spinner	Rotor diameter
Transformer	Rated power
Yaw system	Rotor diameter

Below follows the WISDEM correlations used for component cost calculations. Here m denotes mass in kg, c denotes cost in USD(2015). Rotor diameter, D_{rotor}, is 130 m. Rated power, P_{rated}, is in MW if nothing else is stated. Rotor torque, Q_{rotor}, is defined as

$$Q_{rotor} = \frac{0.5 P_{rated} D_{rotor}}{\eta_{drivetrain} V_{tip}} \tag{A.1}$$

Where P_{rated} is in kW.

Blades:

$$m_{blade} = 0.5 \left(0.5 D_{rotor}\right)^{2.44} \tag{A.2}$$

$$c_{blade} = 14.6 m_{blade} \tag{A.3}$$

Brake System:

$$m_{brake} = 1.22 Q_{rotor} \tag{A.4}$$

$$c_{brake} = 3.6254 m_{brake} \tag{A.5}$$

Cabling and Electrical Connections:

$$c_{el} = 41850 P_{rated} \tag{A.6}$$

Control System:

$$c_{control} = 21150 P_{rated} \tag{A.7}$$

Generator:

$$m_{gen} = 2.3 P_{rated} + 3400 \tag{A.8}$$

$$c_{gen} = 12.4 m_{gen} \tag{A.9}$$

Where P_{rated} is in kW.

Gearbox:

$$m_{gear} = 113 Q_{rotor}^{0.71} \tag{A.10}$$

$$c_{gear} = 12.9 m_{gear} \tag{A.11}$$

High-Speed Shaft:

$$m_{hss} = 198.94 P_{rated} \tag{A.12}$$

$$c_{hss} = 6.8 m_{hss} \tag{A.13}$$

Hub:

$$m_{hub} = 2.3 m_{blade} + 1320 \tag{A.14}$$

$$c_{hub} = 3.9 m_{hub} \tag{A.15}$$

Hydraulic Cooling Systems:

$$m_{hydraulic} = 80 P_{rated} \tag{A.16}$$

$$c_{hydraulic} = 124 m_{hydraulic} \tag{A.17}$$

Low-Speed Shaft:

$$m_{lss} = 13 \left(m_{blade} P_{rated} \right)^{0.65} + 775 \tag{A.18}$$

$$c_{lss} = 11.9 m_{lss} \tag{A.19}$$

Main Bearings:

$$m_{bearings} = 0.0001 n_{bearings} D_{rotor}^{3.5} \tag{A.20}$$

$$c_{bearings} = 4.5 m_{bearings} \tag{A.21}$$

Where $n_{bearings}$ is the number of main bearings, i.e. 2.

Nacelle Bedplate:

$$m_{bedplate} = D_{rotor}^{2.2} \tag{A.22}$$

$$c_{bedplate} = 2.9 m_{bedplate} \tag{A.23}$$

Nacelle Platform:

$$m_{platform} = 0.125 m_{bedplate} \tag{A.24}$$

$$c_{platform} = 17.1 m_{platform} \tag{A.25}$$

Nacelle Cover:

$$m_{cover} = 1.2817 P_{rated} + 428.19 \tag{A.26}$$

$$c_{cover} = 5.7 m_{cover} \tag{A.27}$$

Where P_{rated} is in kW.

Pitch System:

$$m_{pitch} = (1 + 0.328)\,(0.1295 n_{blade} m_{blade} + 491.31) + 555 \tag{A.28}$$

$$c_{pitch} = 22.1 m_{pitch} \tag{A.29}$$

Where n_{blade} is the number of blades, i.e. 3.

Spinner:

$$m_{spinner} = 15.5 D_{rotor} - 980 \tag{A.30}$$

$$c_{spinner} = 11.1 m_{spinner} \tag{A.31}$$

Transformer:

$$m_{trans} = 1.915 P_{rated} + 1910 \tag{A.32}$$

$$c_{trans} = 18.8 m_{trans} \tag{A.33}$$

Where P_{rated} is in kW.

Yaw System:

$$m_{yaw} = 0.0009 D_{rotor}^{3.314} \tag{A.34}$$

$$c_{yaw} = 8.3 m_{yaw} \tag{A.35}$$

B

Currency Unit Conversion

Table B.1: Exchange rates for converting literature values from Euro to SEK [56].

Year	Exchange rate
2015	9.358689
2018	10.262964
2020	10.490595
2024	11.363945

Table B.2: Exchange rates for converting literature values from USD to SEK [56].

Year	Exchange rate
2018	8.701154
2021	8.58396
2022	10.122161

C

Additional Wind Speed Distribution Plots

The purpose of this appendix is to provide additional insight into the differences between alternative wind speed distributions and data transformations. The first section motivates the choice of transformation scaling parameter, while the second complements the measured wind speeds shown in Section 4.1.2, with additional sites and year.

C.1 Choice of Transformation Scaling Parameter

As explained in Section 3.2.3, the transformation in Equation C.1 below was applied to the original modelled wind speeds to make their distribution better fit the desired Weibull distribution (k=2, V_m=7.5 m/s).

$$V_{h,transformed} = \frac{V_{h,original}^2}{X} \tag{C.1}$$

The value of X was decided as 8 m/s, since it proved to give the best fit, as seen in Figures C.1 and C.2.

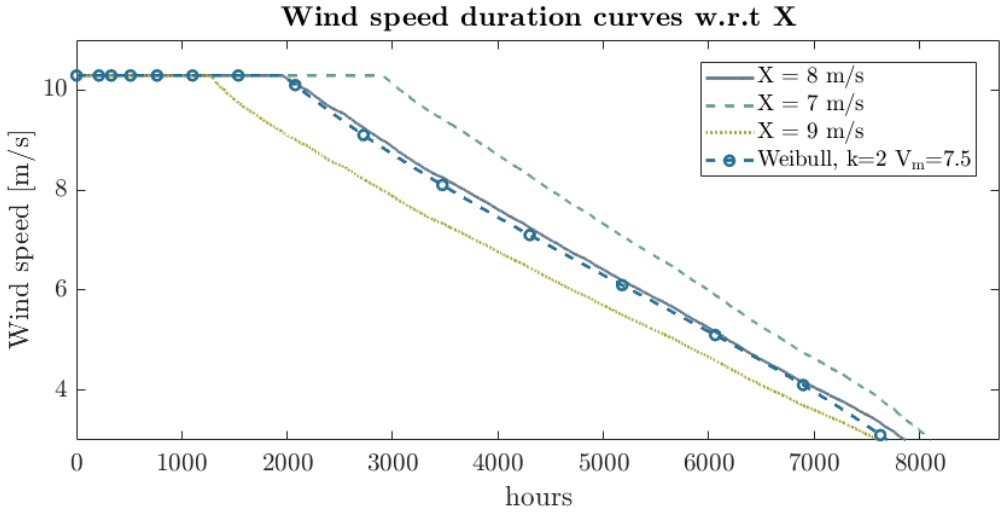

Figure C.1: Wind speed duration curves of the transformed modelled data with different values of scaling parameter X, compared to the reference Weibull distribution. SE3, 2023.

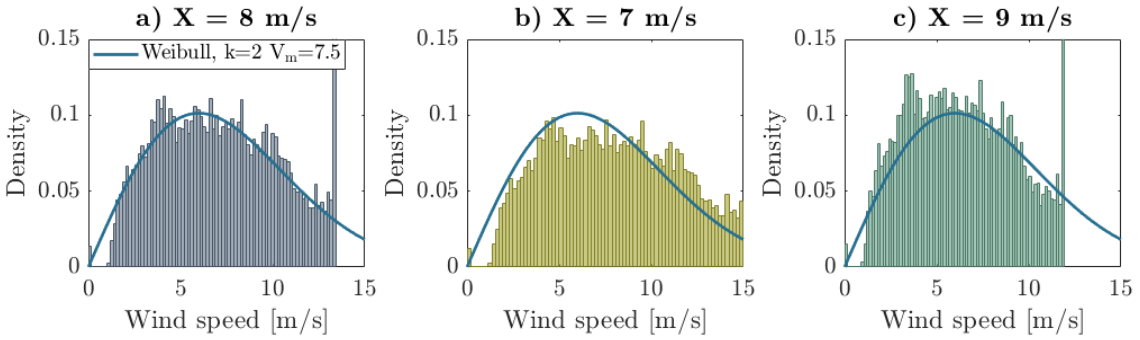

Figure C.2: Probability density function of transformed modelled wind speeds for different values of scaling parameter X, compared to the reference Weibull distribution. SE3, 2023.

As seen from the probability density functions above, a higher value of X pushes the distribution towards the lower wind speeds, and vice versa. This is also seen in Figure C.3.

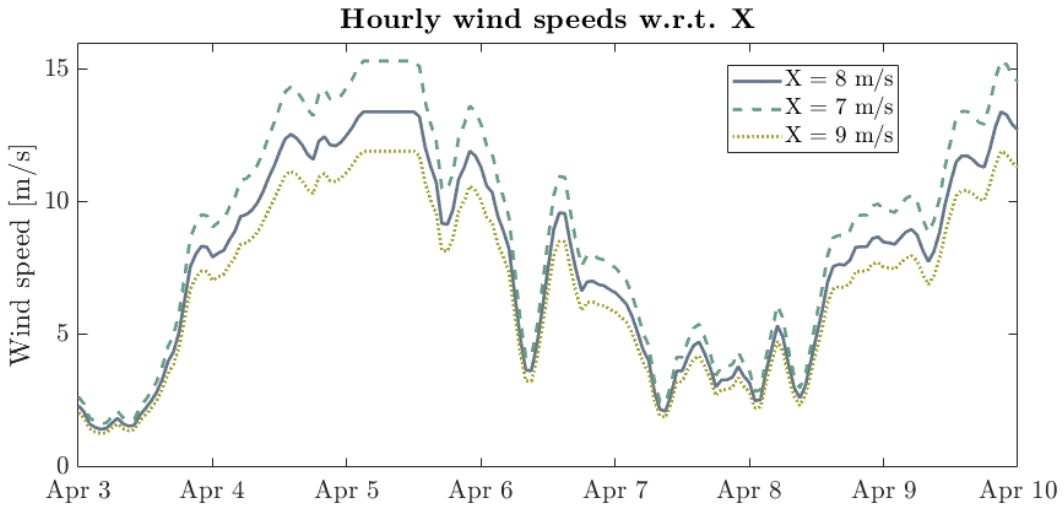

Figure C.3: Transformed modelled wind speeds with different scaling parameters for a week in April. SE3, 2023.

C.2 Additional Wind Speed Measurements

Wind speed duration curves for measurements available at three sites in SE3, during the years 2016-2017 are shown in Figure C.4.

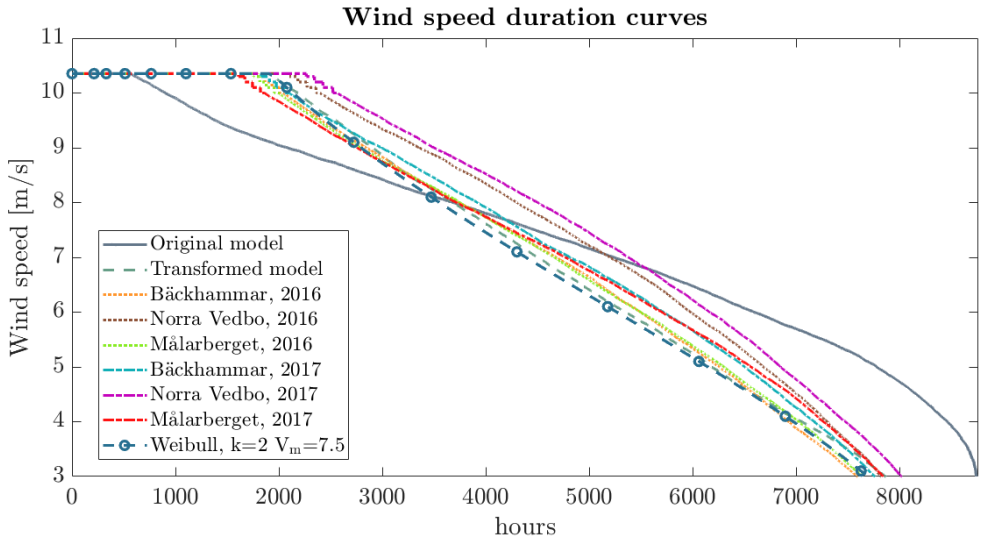

Figure C.4: Wind speed duration curves for all available wind speed measurements. The original and transformed modelled wind speeds for 2017, as well as the reference Weibull distribution, are plotted for comparison.

The comparison to the modelled wind speeds show that the original model underestimates the hours of full-load and shut-down. The transformed model matches well with the Weibull distribution, and lies in the same range as the measurements. The measured wind speeds have some differences between them, where 2017 shows to be a higher wind speed year than 2016. This highlights that there is no one answer to what wind speed data is correct, since it is both site- and year-dependent.

D

Main results Study 1: 2018-2023

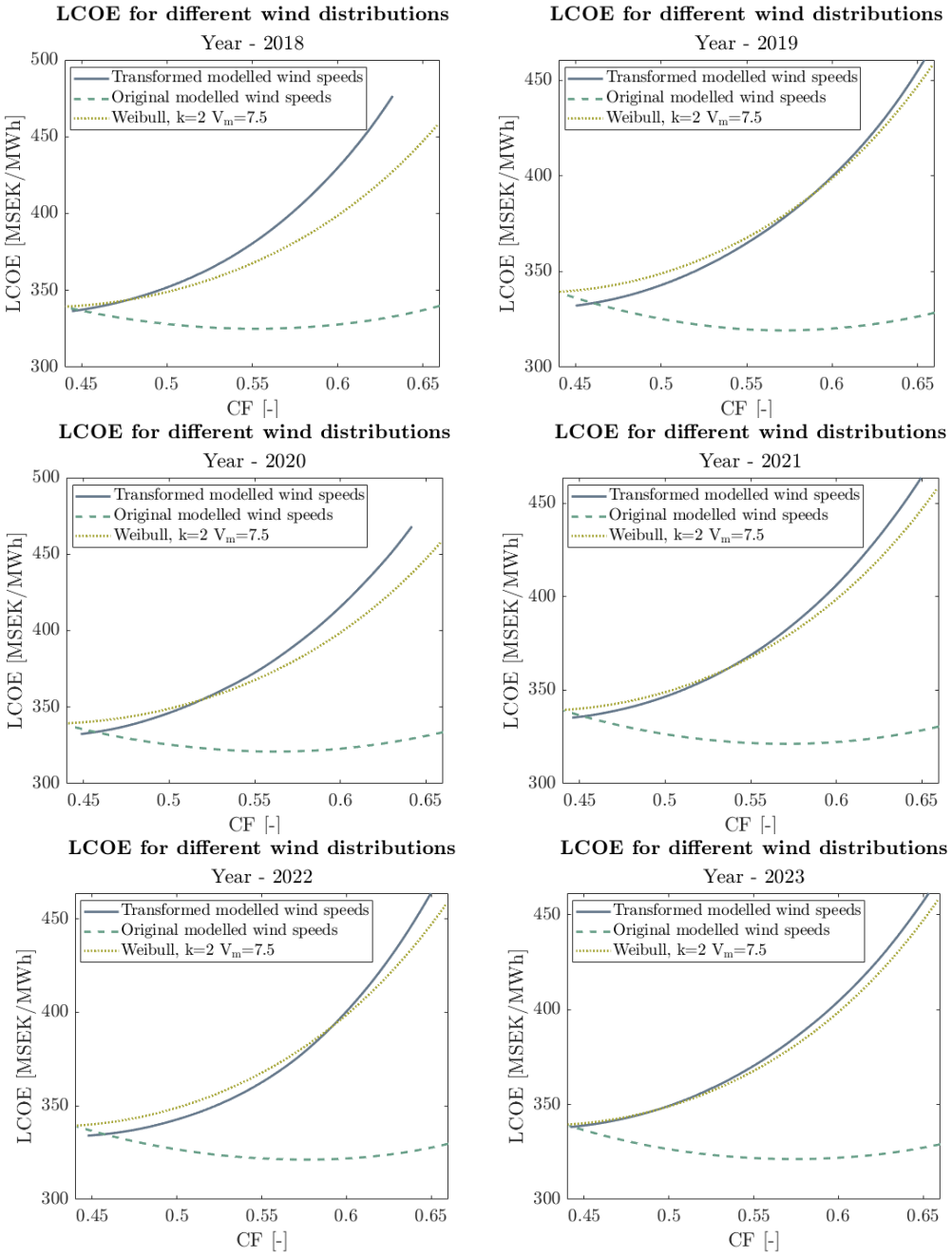

Figure D.1: LCOE as a function of capacity factor, for years 2018-2023. Comparison between original and transformed modelled wind speeds, and the Weibull distribution.

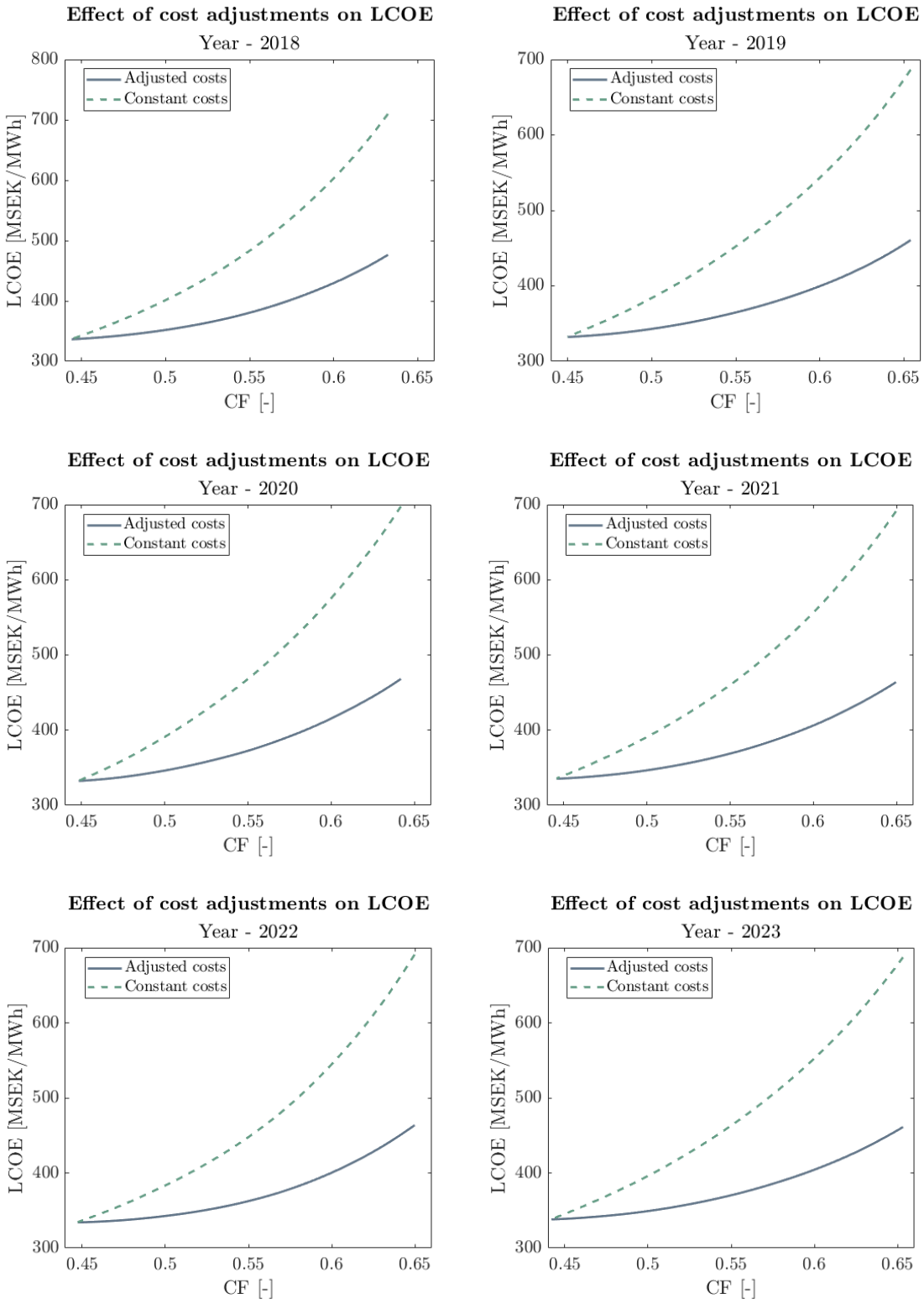

Figure D.2: LCOE as a function of capacity factor, for years 2018-2023. Comparison with the case of not assuming any change in costs. Based on transformed modelled wind speeds.

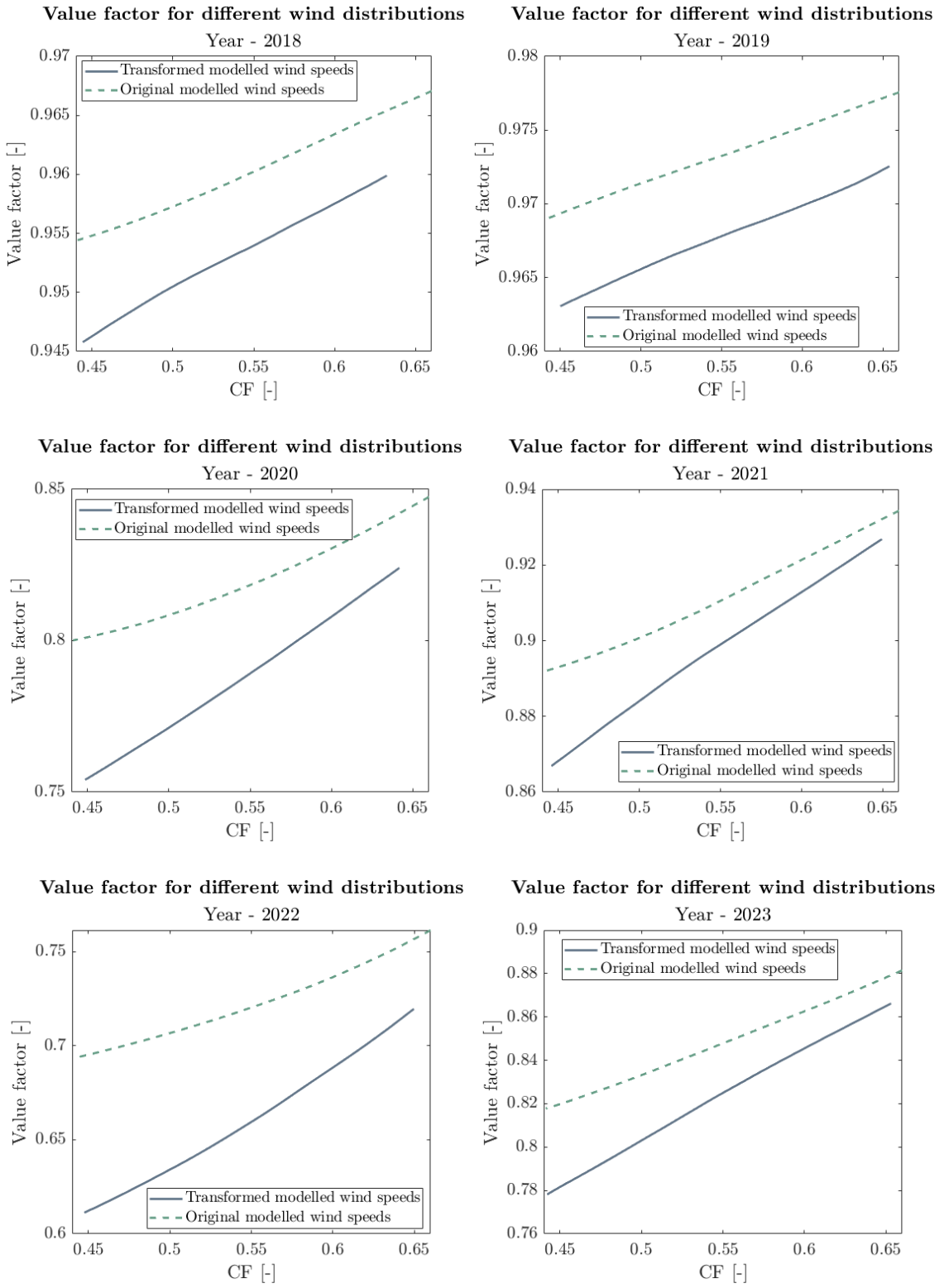

Figure D.3: Value factor as a function of capacity factor, for years 2018-2023. Comparison between original and transformed modelled wind speeds.

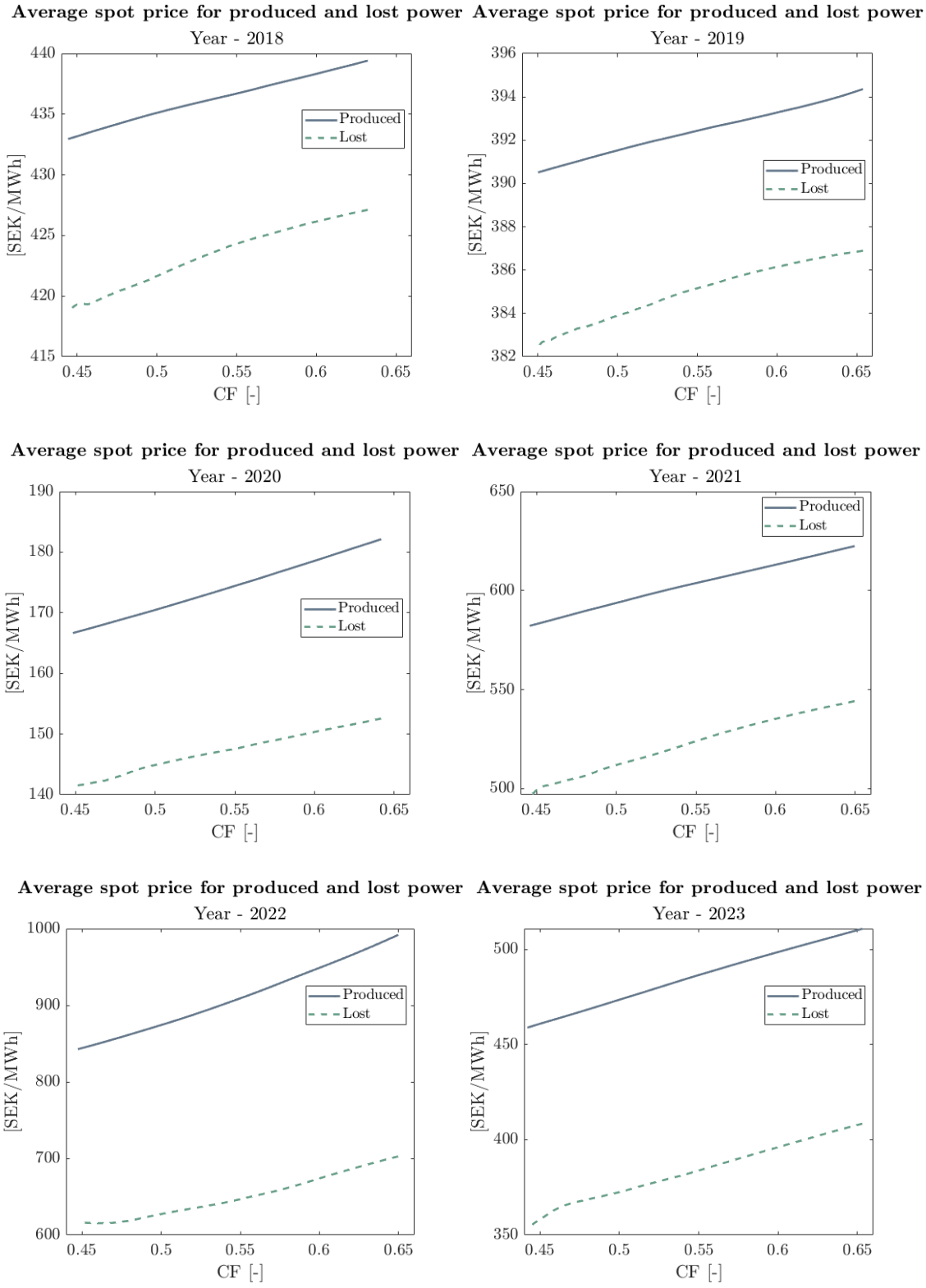

Figure D.4: Average spot price of lost and produced power as a function of capacity factor, for years 2018-2023. Based on transformed modelled wind speeds.

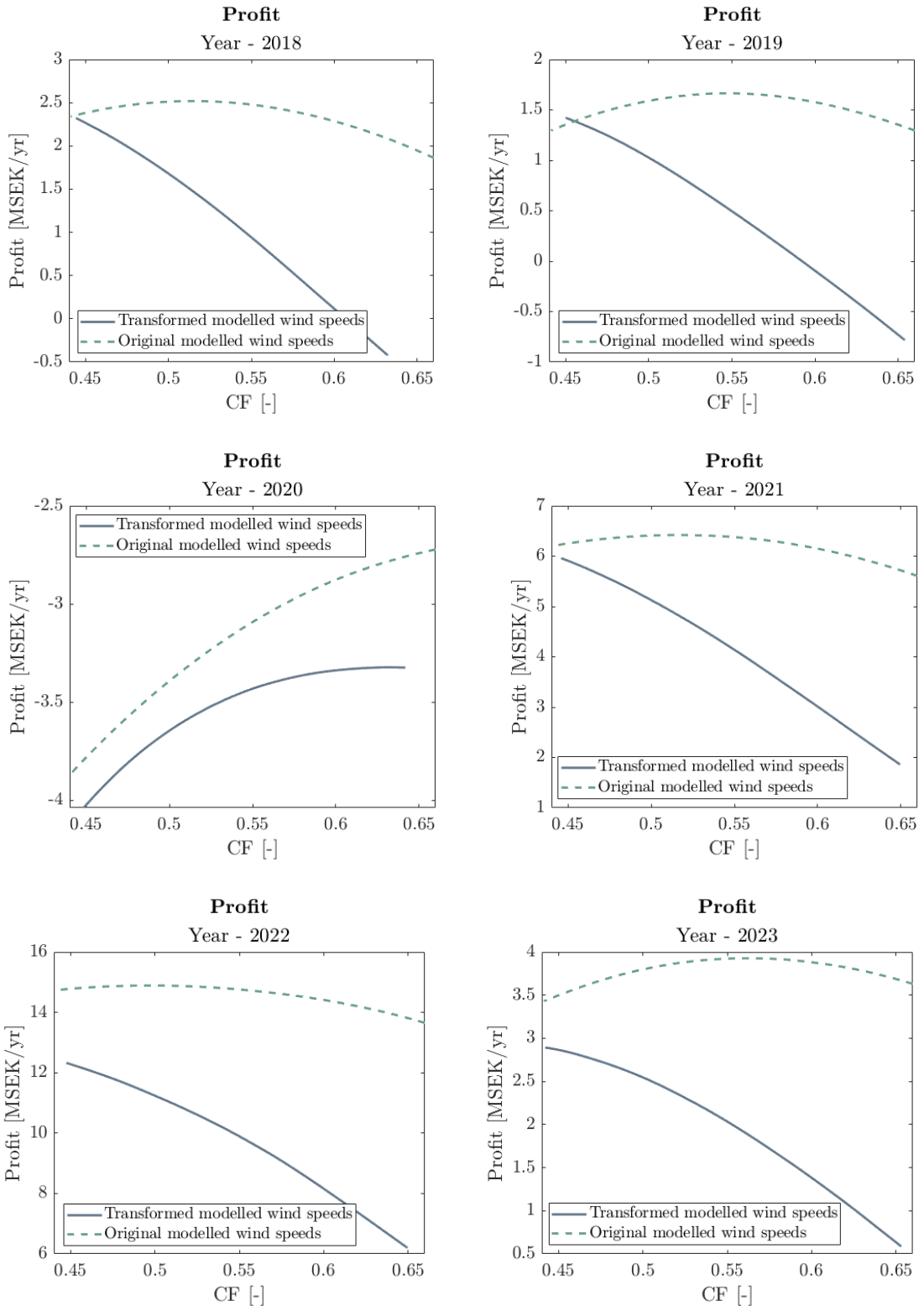

Figure D.5: Profit of electricity production as a function of capacity factor, for years 2018-2023. Comparison between original and transformed modelled wind speeds.

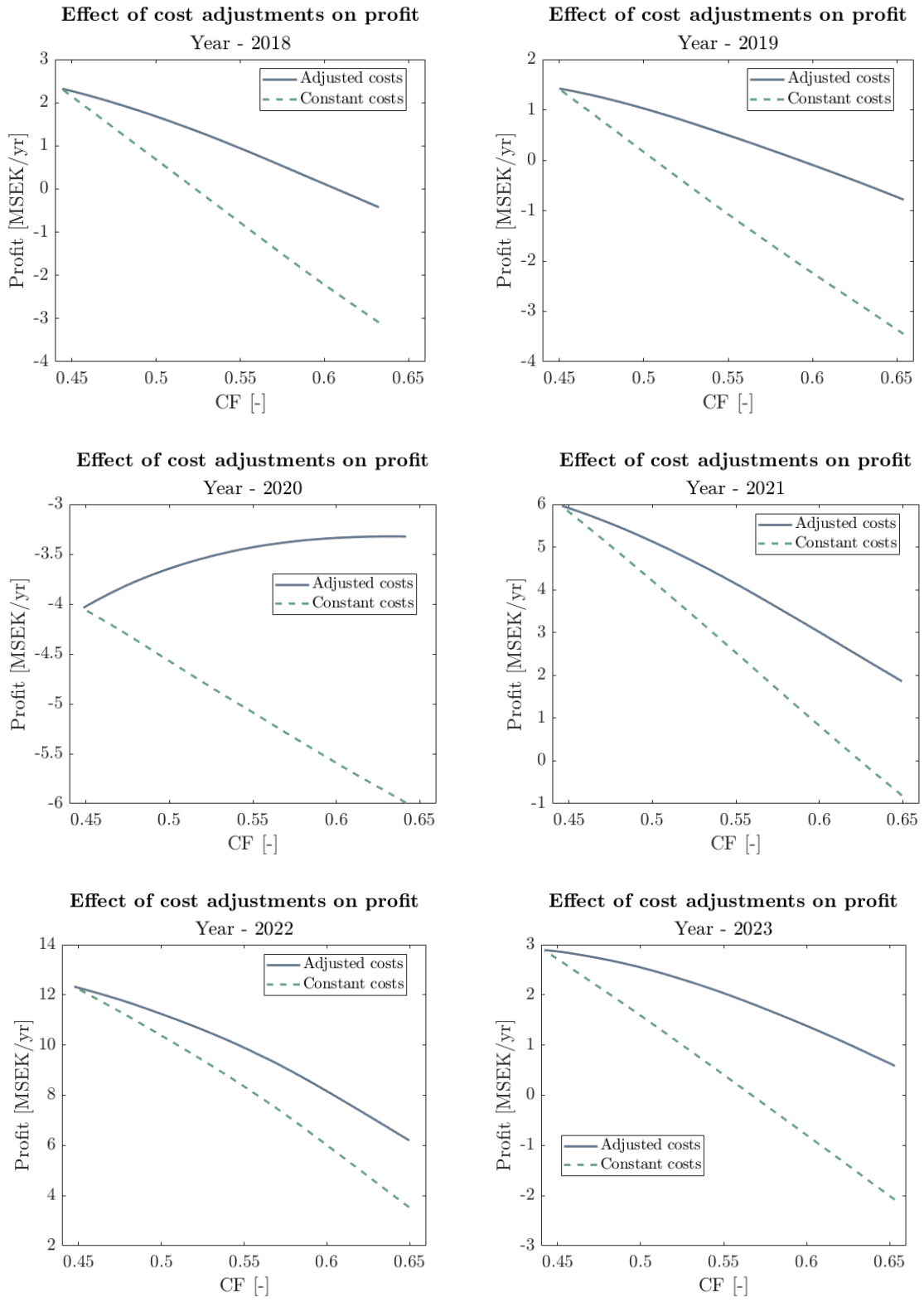

Figure D.6: Profit of electricity production as a function of capacity factor, for years 2018-2023. Comparison with the case of not assuming any change in costs. Based on transformed modelled wind speeds.

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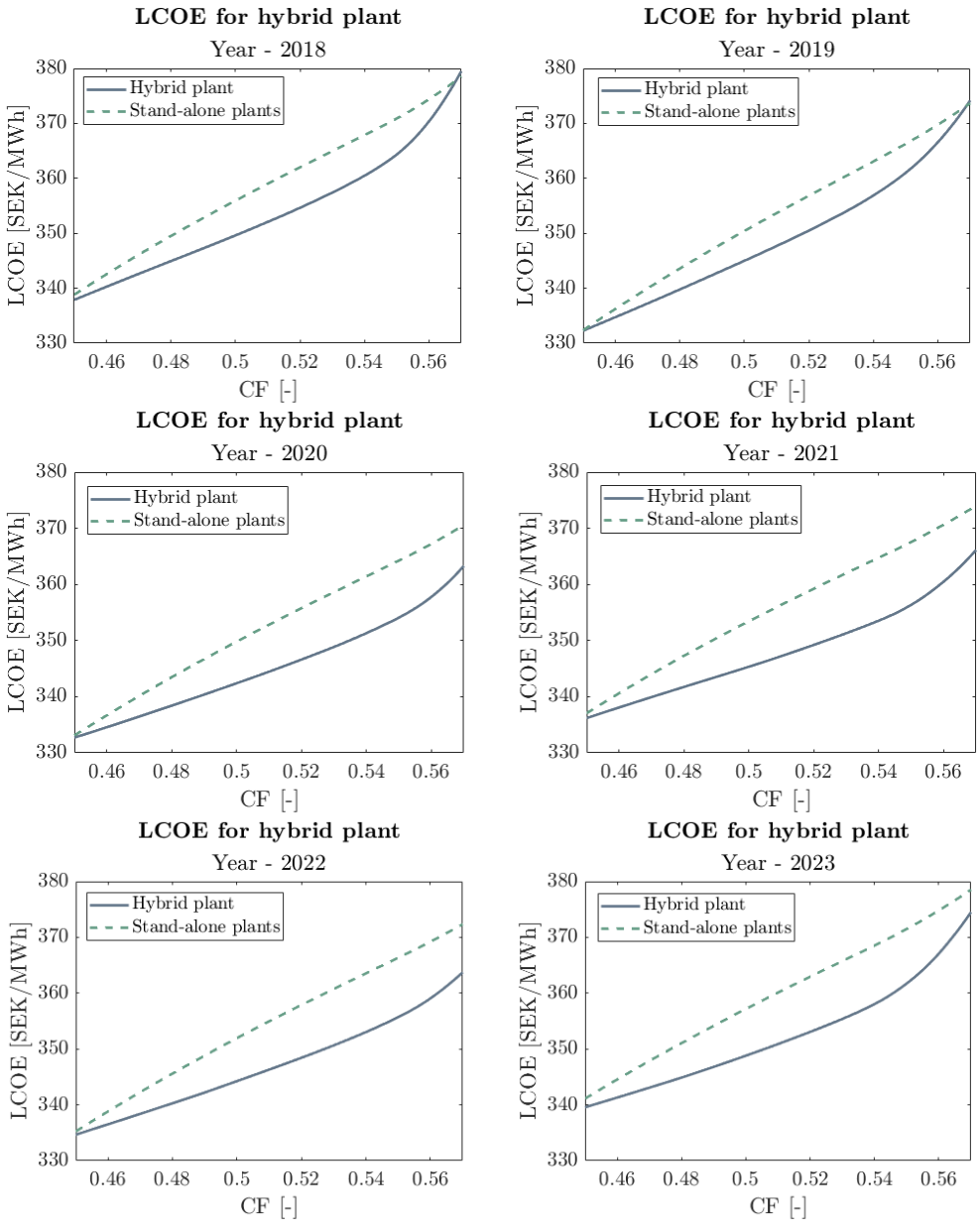

Figure E.1: LCOE as a function of capacity factor, for years 2018-2023. Based on transformed modelled wind speeds, and modelled PV production.

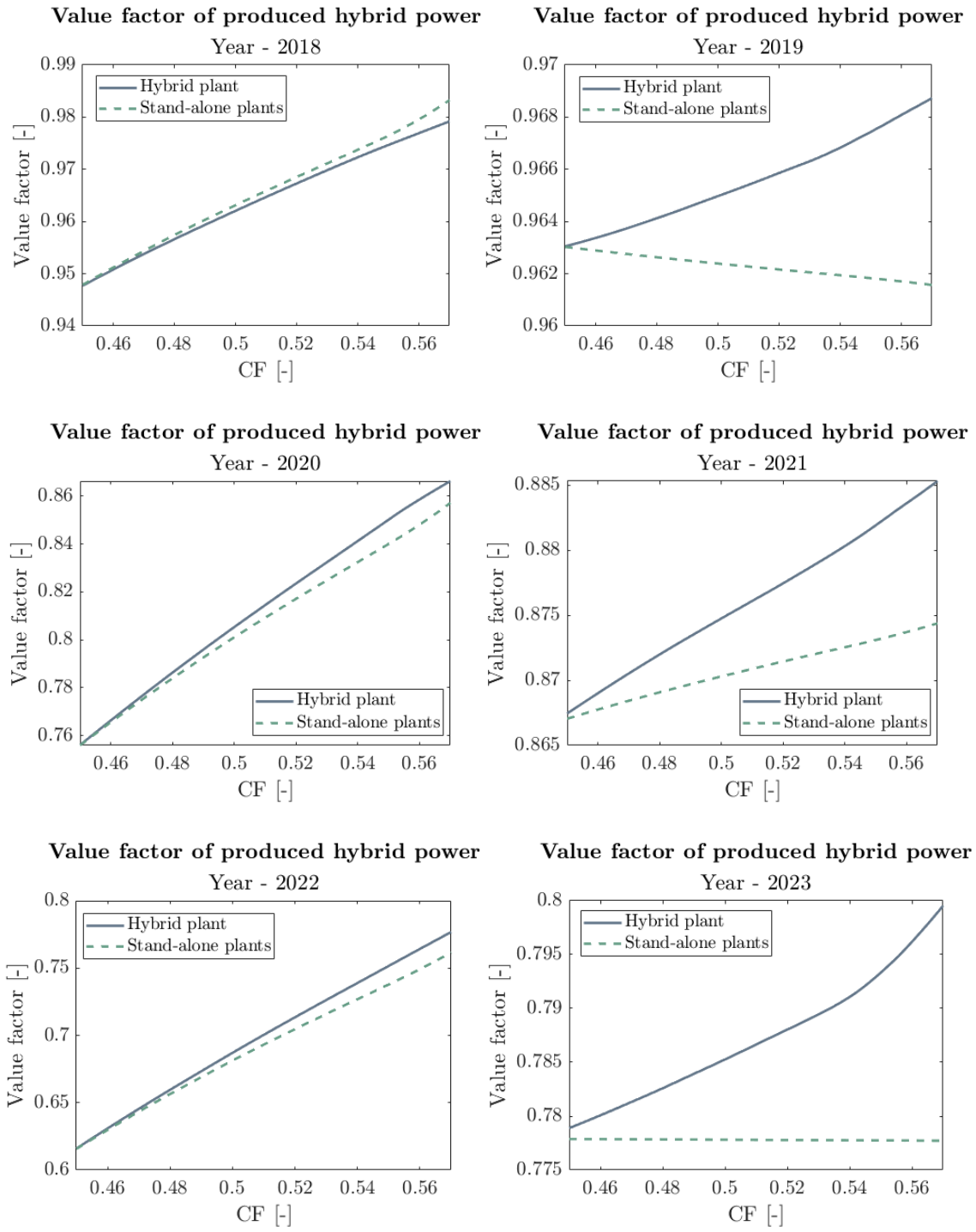

Figure E.2: Value factor as a function of capacity factor, for years 2018-2023. Based on transformed modelled wind speeds, and modelled PV production.

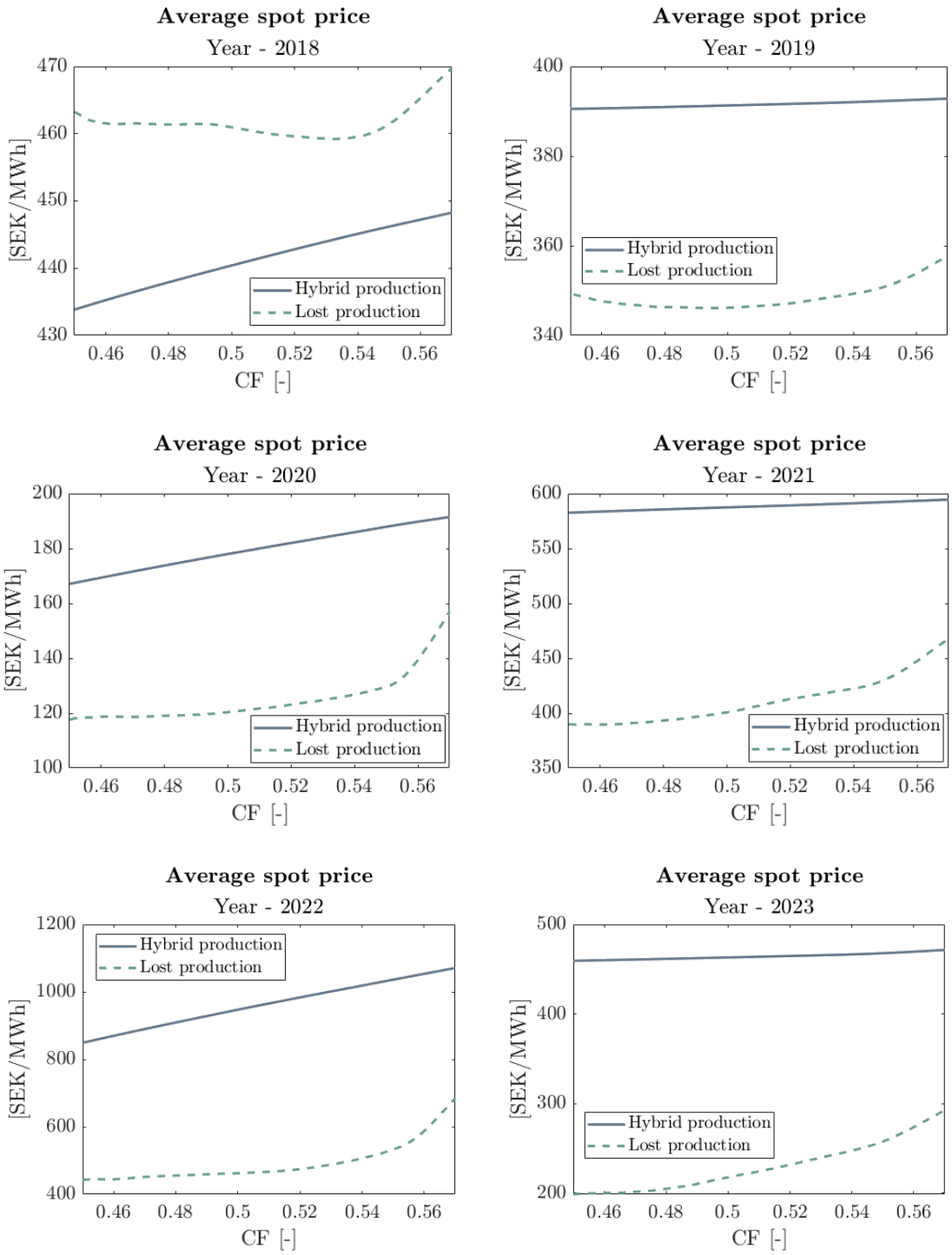

Figure E.3: Average price of lost and produced power as a function of capacity factor, for years 2018-2023. Based on transformed modelled wind speeds, and modelled PV production.

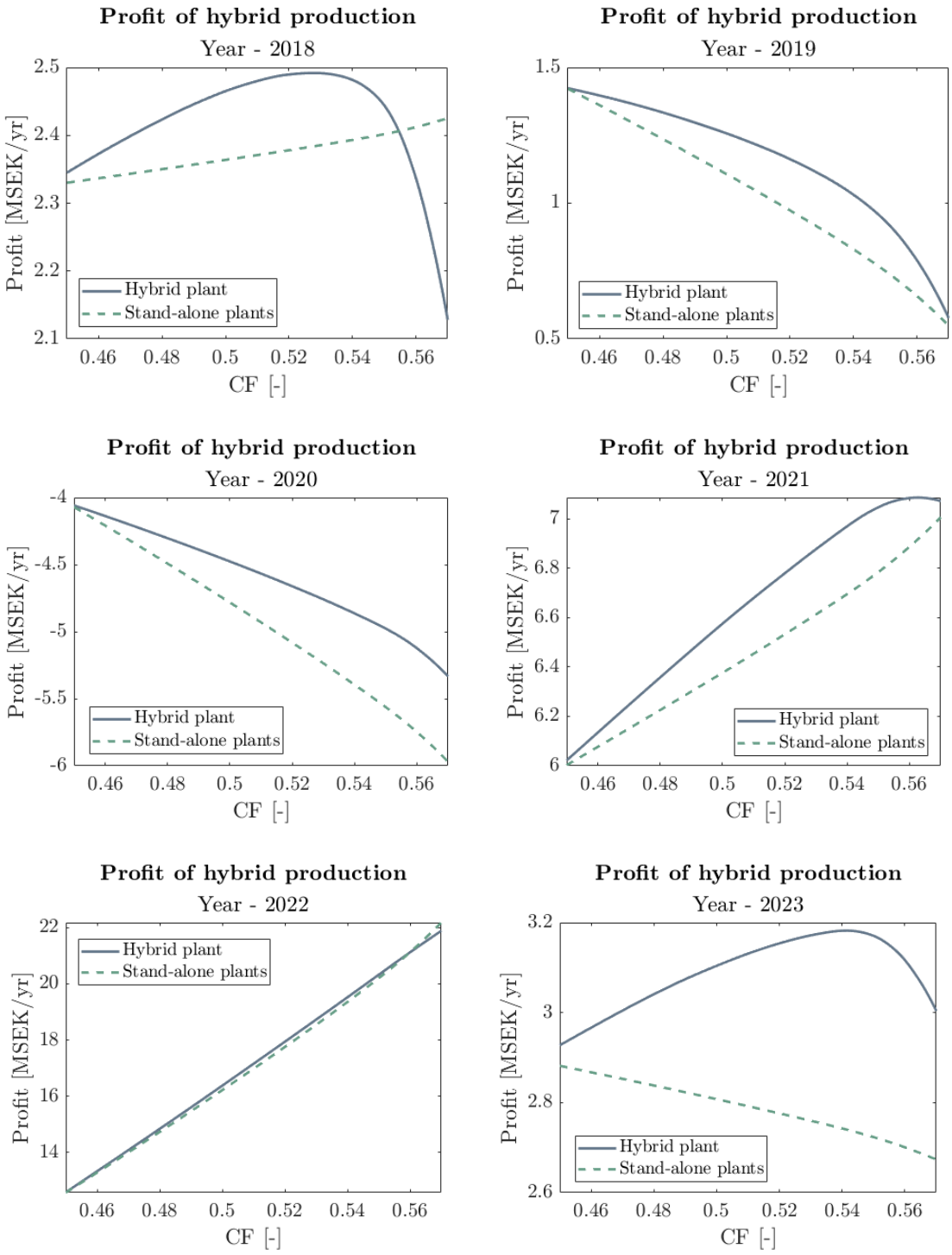

Figure E.4: Profit of electricity production as a function of capacity factor, for years 2018-2023. Based on transformed modelled wind speeds, and modelled PV production.

DEPARTMENT OF ELECTRICAL ENGINEERING
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden
www.chalmers.se

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