Ida Nilsen Aure

Feasibility of Establishing a Solar PV Power Plant in the Existing Wind Farm at Smøla

Master's thesis in Energy and the Environment
Supervisor: Trygve M. Eikevik
June 2023

Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Engineering
Department of Energy and Process Engineering

NTNU
Norwegian University of
Science and Technology

Ida Nilsen Aure

Feasibility of Establishing a Solar PV Power Plant in the Existing Wind Farm at Smøla

Master's thesis in Energy and the Environment
Supervisor: Trygve M. Eikevik
June 2023

Norwegian University of Science and Technology
Faculty of Engineering
Department of Energy and Process Engineering

NTNU
Norwegian University of
Science and Technology

Preface

This master's thesis represents the work performed for completing the master's degree in Energy and the Environment at the Norwegian University of Science and Technology (NTNU) under the Faculty of Engineering, Department of Energy and Process Engineering. The thesis is written by one student during the spring semester of 2023 and counts 30 credits.

The thesis has been elaborated in collaboration with Møre and Romsdal County Council, where the main focus has been to investigate the possibilities of implementing photovoltaic panels in the existing wind farm at Smøla to form a hybrid power park.

With a background from the bachelor's degree program Renewable Energy at NTNU and with roots from Møre and Romsdal, this project interested me at instant. The work has been challenging as neither hybrid power parks combining wind and solar, nor PV parks of great scale, exist in Norway today. Consequently, there has been no similar projects to gain experience from. Nevertheless, the work has been giving in the way of working independently and experiencing how to make assumptions based on a scarce data availability. Learning how to use PVSyst and discussing the theme with several of the greatest actors in the Norwegian market have also been valuable.

I am grateful for assistance provided by the internal supervisor Trygve Magne Eikevik, Associate Professor at the Department of Energy and Process Engineering at NTNU, for his constructive feedback and valuable discussions. In addition, I offer gratitude to Statkraft, for providing essential information and data, and to COWI for sharing results and the 3D file to PVSyst.

Trondheim, 30.05.2023

Ida Aure

Ida Nilsen Aure

Abstract

One of the greatest challenges of this century is the environmental and social issues associated with energy demand and production. The global energy demand is constantly increasing and the need for green and reliable technologies are acute. Today, energy based on renewable sources represent 26% of the global power output, but to reach the ambitious energy and climate targets, a share of 85% in the power sector is needed. This increase is expected to mostly be through wind and solar generation. As renewables in the power grid increases, hybrid power plants have gained interest.

Møre and Romsdal County Council are now looking into the possibilities of combining wind power and PV panels to form a hybrid power park in the existing wind farm at Smøla, Møre and Romsdal. In the case of excess energy, storage is an additional element of interest. By investigating three PV capacity scenarios, this thesis intends to discover the potential of forming a hybrid at Smøla. The first scenario takes repowering of the wind farm into consideration, and utilizes empty installation spaces for cranes in front of old wind turbine fundaments. Scenario 2 and 3 are of greater scale, where the former has a capacity corresponding to the optimal use of the cable to the mainland, whereas the latter includes hydrogen production for handling excess energy. The production potential for each scenario was simulated in PVSyst followed by an economical profitability analysis.

The results showed an annual production of 4.45 GWh with an installed capacity of 4.76 MW_p for scenario 1. With an installed capacity of 190 MW_p, scenario 2 had an annual production of 172 GWh, followed by 186 GWh for scenario 3 with a capacity of 205 MW_p. Furthermore, the economical analysis resulted in a negative NPV for scenario 2 and 3, with values of -424 MNOK and -458 MNOK, respectively. Scenario 1 had a positive NPV of 3.31 MNOK, and is therefore the only alternative giving profitability to the project. The calculations further showed that results are highly dependent on the power price. Consequently, the LCOE was calculated. For scenario 1 to break even at the end of the project's lifetime, a power price of 39.8 øre/kWh is needed, while the price is 58.2 øre/kWh for scenario 2 and 3.

Based on production potential, scenario 3 therefore appears to be the best alternative, followed by scenario 2 and then 1. However, the ranking is reversed when focusing on the economical aspect. A third factor should therefore be evaluated and included when determining which scenario to be chosen. This factor is the socio-economic factors, and include security of supply, environmental impacts, sustainability and local repercussions. In addition, the potential for research and development work should be considered along with the possibilities of getting concession for the project.

The greatest sources of uncertainty are attributed to the financial costs of the project. As there currently are no PV-wind HPPs or PV farms of great scale in Norway today, determining investment and operational costs are challenging as there are no empirical figures. Small changes have also shown to have a great influence on the final result.

Sammendrag

De sosiale og miljømessige utfordringene knyttet til produksjon og etterspørsel av energi er en av de største utfordringene i dagens samfunn. På globalt nivå øker etterspørselen stadig, og behovet for grønne og pålitelige teknologier har aldri vært større. Idag utgjør fornybar energi rundt 26% av den totale produksjonen, men for å nå de ambisiøse energi- og klimamålene kreves en andel på 85% i energisektoren. Denne økningen forventes hovedsakelig å komme fra vind- og solenergi. Etter hvert som andelen av fornybar energi har økt i nettet, har også interessen rundt hybride kraftverk vokst.

Møre og Romsdal fylkeskommune ser nå på mulighetene til kombinere vind- og solkraft i et hybrid system i den eksisterende vindparken på Smøla i Møre og Romsdal. Dersom det er et kraftoverskudd, er lagringsmuligheter også av interesse. Ved å undersøke tre ulike scenario av installert solkraft, håper denne oppgaven å kunne finne potenisalet for en hybrid park på Smøla. Det første scenarioet baserer seg på den planlagte repoweringen av vindparken, og utnytter de tomme kranoppstillingsplassene foran de gamle turbinfundamentene. Scenario 2 og 3 er av større skala, der solkapasiteten til førstnevnte tilsvarer den kapasiteten som gjør at kabelen inn til fastlandet blir fullt utnyttet, mens scenario 3 inkluderer hydrogenproduksjon som en løsning for overskuddsenergi. Produksjonspotentsialet for hvert scenario ble simulert i PVSyst, etterfulgt av en økonomisk lønnsomhetsanalyse.

Resultatene viste en årlig produksjon på 4.45 GWh med en installert effekt på 4.76 MW_p for scenario 1. Med en installert effekt på 190 MW_p hadde scenario 2 en årlig produksjon på 172 GWh, etterfulgt av 186 GWh for scenario 3 med en installert effekt på 205 MW_p. Videre viste den økonomiske analysen en negativ NPV for scenario 2 og 3 med verdier på henholdsvis -424 MNOK og -458 MNOK. Scenario 1 hadde en positiv NPV på 3.31 MNOK, og er derfor det eneste alternativet som kan gi lønnsomhet til prosjektet. De økonomiske resultatene viste videre en sterk avgengighet til kraftprisen. Derfor ble LCOE også beregnet. For at scenario 1 skal gå i null ved slutten av prosjektets levetid, kreves en kraftpris på 39.8 øre/kWh, mens 58.2 øre/kWh kreves for scenario 2 of 3.

Basert på produksjonspotensial, fremstår scenario 3 dermed som det beste alternativet, etterfulgt av scenario 2 og til slutt 1. Rettes fokuset mot det økonomiske aspektet derimot, er rekkefølgen snudd om. En tredje faktor burde derfor evalueres og inkluderes før valget mellom de tre scenarioene blir tatt. Denne faktoren er den samfunnsøkonomiske faktoren og inkluderer forsyningssikkerhet, miljøkonsekvenser, bærekraft og lokale ringvirkninger. Videre burde potensialet for forskning og utviklingsarbeid samt forskningsfasciliteter tas i betraktning, i tillegg til mulighetene for å få godkjent konsesjonssøknad.

Den største usikkerheten ligger i de økonomiske kostnadene tilhørende prosjektet. Siden det idag ikke finnes noen hybride kraftverk som kombinerer sol og vind, og heller ingen storskala solkraftanlegg i Norge, er det utfordrende å prissette investerings- og operasjonelle kostnader. Små endringer har også vist seg å kunne ha store påvirkninger på resultatet.

List of Terms

Term	Description
Albedo	Fraction of light reflected by a body or surface.
Azimuth angle	The compass direction from which the sunlight is coming.
Cut-in speed	Wind speed at which the wind turbine starts generating power.
Cut-off speed	Wind speed at which the turbine stops automatically to prevent defects and damages.
Electrolyser	Apparatus using electricity to break water into hydrogen and oxygen.
Green hydrogen	Hydrogen generated by renewable energy through electrolysis.
Hybrid Power Plant	A power-generating facility that consists of more than one power-generating module.
NO3	Power pricing area consisting of Møre and Romsdal and Trøndelag.
NPV	Method to assess profitability and investment ranking.
PV panel	A device converting solar energy to electricity.
Rated output speed	Wind speed at which the turbine reaches its rated power.
Tilt angle	Number of degrees from the horizontal plane.

List of Abbreviations

AEP	Annual Energy Production
AWE	Alkaline Water Electrolysis
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenses
DEVEX	Development Expenses
EPC	Engineering, Procurement and Construction
GoO	Guarantees of Origin
HPP	Hybrid Power Plant
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOE	Levelized Cost of Energy
NPV	Net Present Value
NVE	The Norwegian Water Resources and Energy Directorate
OEM	Original Equipment Manufacturers
OPEX	Operation Expenses
PEM	Proton Exchange Membrane
PV	Photovoltaic
RES	Renewable Energy Sources
RFC	Regenerative Fuel Cell
SOEC	Solid Oxide Electrolysis Cell
WEO	World Energy Outlook

List of Figures

List of Tables

Contents

1 Introduction

Reducing the environmental and social issues associated with energy are among the greatest challenges of the 21st century, and the demand for green and reliable technologies are acute. Today, most of the energy is produced by fossil fuels led by coal, natural gas and oil. However, the share of renewable based energy is increasing, and alternatives combining several technologies in one system have gained interest recent time.[1, 2] Møre and Romsdal County Council is now looking at the possibilities of combining power generation by wind and solar into one hybrid power park in the existing wind farm at Smøla, and this thesis intends to investigate this issue. This chapter will focus on the motivation behind the thesis, its purpose as well as the problems to be addressed.

1.1 Motivation

The global energy and electricity demand is constantly increasing, and in 2018 the global primary energy demand rose by 2.3% and electricity demand by 3.9%. According to the International Energy Agency (IEA), this is the fastest pace of the decade. Moreover, the focus on climate change is greater than ever, at the same time as there is a global energy crisis sparked by Russia's invasion of Ukraine. As a result, the focus on reducing the risk of future disruptions and promote energy security, which also is renewable, have become one of the greatest issues of today.[1, 3]

Globally, energy sources based on renewables represent approximately 26% of the global power output. According to IEA's World Energy Outlook (WEO), the share is expected to increase more than 40% by 2040. This increase is considered highly necessary to be able to meet the ambitious climate-related goals laid out in the European Green Deal. In order to meet these energy and climate targets within the context of a successful energy transition, the International Renewable Energy Agency (IRENA) states that renewable energy would need to provide two thirds of the global energy supply by 2050. In the power sector, as seen in figure 1.1, the share of renewables should increase to 85% by 2050, mostly through growth in wind and solar PV energy generation.[3]

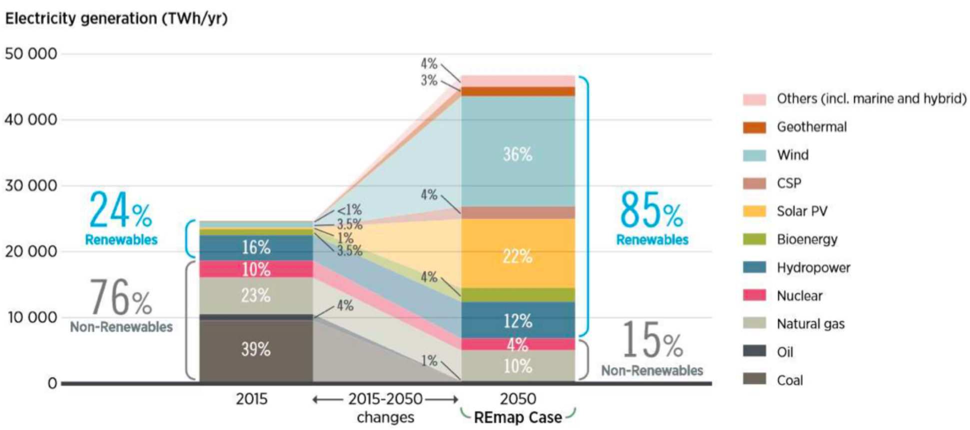


Figure 1.1: *Breakdown of electricity generation by source [3].*

As renewables in the power grid increases, the discussion of potential advantages of hybrid power plants (HPP) has been evolving. A hybrid power plant refers to a power-generating facility that consists of more than one power-generating module that converts primary energy into electrical energy. These systems often consist of a renewable source combined with fossil fuels, but this thesis will mainly refer to HPP as renewable based systems.[2] Unless otherwise is stated, HPP means a combination of wind and solar, with or without storage.

Compared to pure wind or solar plants, HPPs provides several benefits. First of all, wind and solar are often negatively correlated, providing a firmer capacity alternative. Over time, this gives a greater annual capacity factor, and a more stable power output with less ramping issues and instantaneous peaks as each technology makes up for the intermittency of the other. Consequently, the opportunity of a partially scheduled power dispatch is possible, which in turn can ease the fulfilment of power production requirements.[2, 4]

Secondly, the HPP provides the opportunity of optimizing the network use as more capacity than what is authorized in the connection agreement can be installed. In this way, the installed capacity at the connection point increases at the same time as the maximum evacuation capacity remains the same. Consequently, the impact on the network is limited, there are savings in the grid development, the existing network will be maximally used, and in countries where new grid deployments are not allowed, HPPs can solve a bottleneck problem. HPPs can also reduce the infrastructure investment costs as only one single grid connection point is needed in most cases. This fact reduces the overall project and grid investment costs and subsequent grid tariffs paid by grid end-users. Reductions in development, capital and operation expenses (DEVEX, CAPEX, OPEX) are also possible since developers can harvest synergies within the development and permitting processes, in addition to deploying joint operation and maintenance strategies of the plants.[2, 4]

Furthermore, due to the co-existence of generation units and digital technologies with several capabilities, HPPs make a good partner to the grid when it comes to flexibility and resilience when storage is included. The latter provides the possibility of reduced balancing costs and less curtailment of renewable energy sources (RES).[2, 4]

Another advantage is that land is more efficiently utilized as installed capacity as well as energy output per square meter of land increases. In addition, HPPs can accelerate rural electrification if they partially can provide scheduled power dispatch to satisfy load demand in areas where the power grid is too weak to provide reliable power supply.[2, 4]

1.2 Objectives and Problems to be Addressed

This thesis intends to investigate the opportunity of implementing PV panels in the existing wind farm at Smøla, Møre and Romsdal. In addition, alternatives for handling excess energy from the HPP will be evaluated. Increased power production at Smøla will contribute to improve power security in the region, reduce CO_2 emissions and contribute to the green transition by increasing access to renewable energy. By simulating the PV power production and obtaining essential meteorological data and production from the existing wind farm, the thesis's author and Møre and Romsdal County Council will receive an understanding of the potential for a HPP at Smøla.

The main problems to be addressed in this thesis are:

- Literature review of integrated energy systems based on wind power and PV panels.
- Develop a simulation tool for energy production depending on meteorological data.
- Definition of three scenarios for energy production.
- Evaluation of the results from the three scenarios.
- Economic evaluation of the three scenarios.
- Make a draft of a scientific paper of the thesis.
- Make proposals for further work.

1.3 Structure of Thesis

To get an overview of the technology status and where the research front is in area of work, the reports starts with a literature review in chapter 2. Furthermore, chapter 3 provides general information about the wind farm at Smøla, before chapter 4 describes the essentials of wind power generation. Theory regarding PV panels is then presented in chapter 5. This includes descriptions of essential factors relevant for the simulation, such as orientation and shading. Thereafter, a description of the two most common system configuration types are given in chapter 6, followed by storage alternatives in chapter 7. The theoretical part of the thesis finishes of with factors relevant for the economical analysis in chapter 8. This chapter covers themes as economical analysis methods, prices for power and PV as well as reference projects.

The most relevant findings from the preliminary project work are then presented in chapter 9. Furthermore, the definition of the three scenarios as well as a thorough description on how the simulations were performed in PVSyst are provided in chapter 10. In addition, the chapter contains methods to other calculations performed and assumptions made. The results are then presented in chapter 11, followed by a discussion in chapter 12. The reports finishes of with proposals for further work and a conclusion in chapter 13 and 14, respectively.

1.4 Special Notes

When implementing shadings to the PV simulation, a 3D file was imported to PVSyst. Conversations with several actors in the Norwegian PV market revealed that AutoCAD with a PVCase plug-in seemed to be the most common way of making this file. The author of this thesis intended to produce such a file, but this was not possible as PVCase do not provide their software for personal or scientific use. Consequently, a 3D file provided by COWI was imported and was later modified in the simulation. The method described under *Creating 3D Scene* in section 10.2.6 therefore describes the work performed by COWI. Nevertheless, the method and assumptions made were evaluated as essential information and was therefore included in this thesis.

Other solutions were also considered, such as implementing height data and then manually draw each module. However, this alternative entails two challenges in particular. First of all, distinguishing e.g. rock, marsh and internal roads from each other would not have been possible. This is crucial when placing PV modules at this location. Secondly, this alternative would have been time consuming - the imported file has a total of 216311 modules. In addition, manually placing modules in PVSyst is convoluted and increases the possibilities of inaccuracies.

The last alternative was to not implement a 3D file, meaning not simulating near shadings from the terrain, wind turbines or other PV modules. However, this increases the uncertainty of the simulation significantly. Consequently, using a provided 3D file was evaluated to be a better option than not having, or having a unsatisfactory, shading scene. Finally, it should be noted that the 3D file is used for shading simulations only, and does not determine any other variables in the simulation.

2 Literature Review

The topic of hybrid power plants has already been investigated by several studies and commercial actors. However, what they choose to highlight and put their focus on are varied. This chapter will give an insight to the market size value and leaders of PV-wind HPPs today, in addition to some pioneer developments. Moreover, the focus areas of some studies are presented, as well as the greatest challenges of the PV-wind HPPs today.

2.1 Market Size and Trends

In 2019, the global solar wind systems market size was valued at USD 925.2 million. This number is predicted to grow at a 7.2% compound annual growth rate (CAGR) from 2020 to 2027, meaning USD 1.61 billion by 2027. The trend can be observed in figure 2.1. An increasing demand for clean energy alternatives in combination with favorable government initiatives and declining costs of solar panels are expected to drive the market during the forecast period.[5, 6]

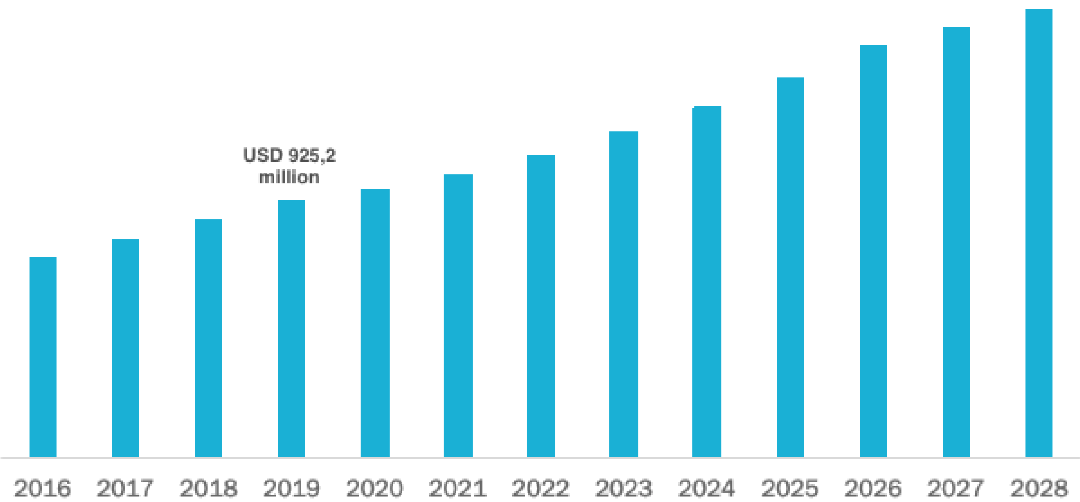


Figure 2.1: *Hybrid solar wind systems market, 2016–2028 (USD Million) [7]. The figure has been modified.*

Furthermore, market research indicates that Asia Pacific, holding for more than 37%, are the PV-wind hybrid leaders, followed by North America with 21.7% of the overall share. The primary driving factors have been original equipment manufacturers (OEM), engineering, procurement and construction (EPC) and a developed electricity transmission infrastructure.[5] Comparing these market research insights with Google trends, specific countries involved in the PV-wind hybrid market and research can be further identified. As seen in figure 2.2, the interest in PV-wind hybrid energy compared to solar and wind energy is minute.[6, 8]

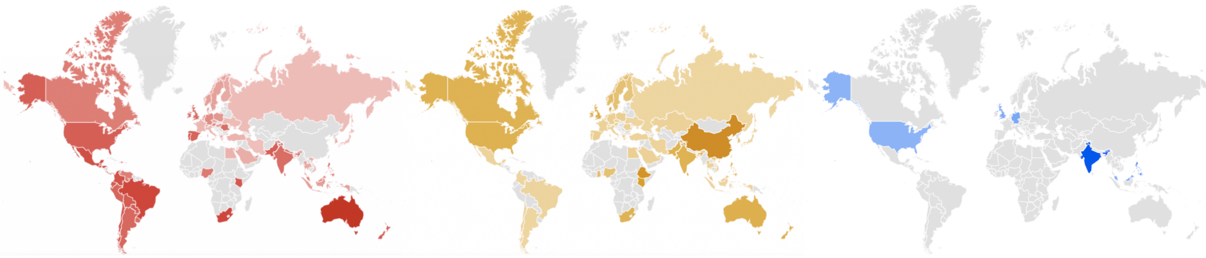


Figure 2.2: *Google trends on solar (red), wind (yellow) and solar-wind hybrid (blue). Darker color indicates greater interest.[8]*

2.2 Existing Developments

Although the concept of using PV and wind in a hybrid system may seem new, the concept was initiated a long time ago. However, there has been relatively little innovation on the fundamentals to date, and there is a limited number of companies providing these kinds of hybrids. Today, the top OEMs and trademarks include: Blue Pacific Solar, Windmills, ReGen Powertech, Siemens Gamesa, UNITRON Energy System Pvt. Ltd., Supernova Technologies Pvt. Ltd., Alternate Energy Company, Grupo Dragon and Polar Power, Inc.[5, 6]

As of today, there is a limited number of HPPs operating or that is under development. Consequently, the availability of reliable data is scarce since most developments are in their early ages. In addition, operators and developers are reluctant to share crucial information in order to secure competitive advantage.[4] An overview of existing hybrid plants is provided in figure 2.3. Here orange and blue dots represent hybrid PV-wind power plants with and without storage, respectively.[9]

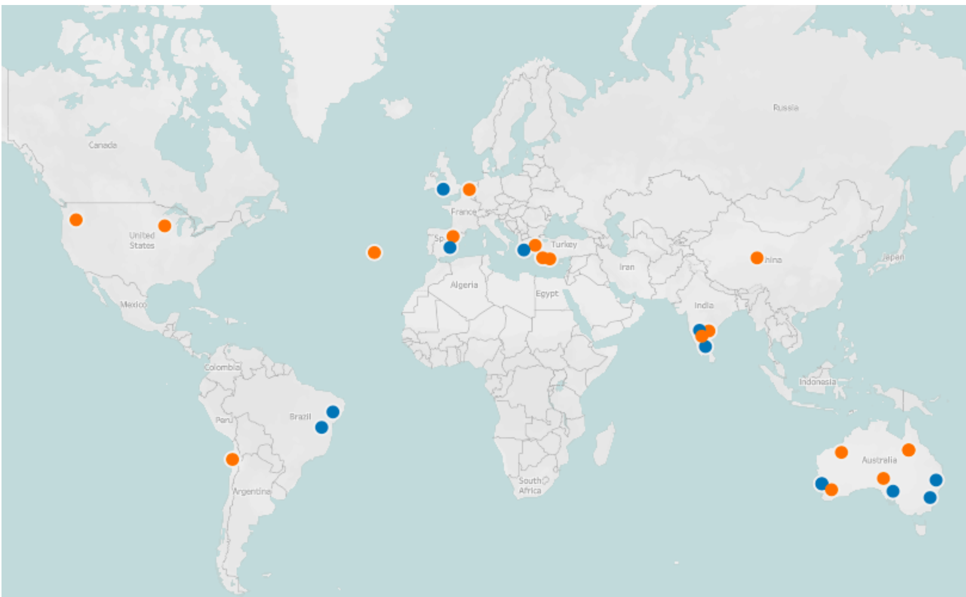


Figure 2.3: *Existing PV-wind hybrid power plants globally. Orange and blue dots are developments with and without storage systems, respectively.[9]*

Minnesota Community Site, United States of America

The first integrated PV-wind HPP in the USA was developed by Juhl Energy for a local municipality. The installed system of the *Minnesota Community Site* has an installed wind capacity of 2.0 MW, supported by 500 kW_p of PV solar. The project utilizes GE's Wind Integrated Solar Energy (WiSE) technology platform. According to GE, by directly integrating the PV panels through the converter of the wind turbine, the net capacity can increase by 3 - 4% and annual production by 10%. The project was installed in December 2018 and is still operational.[4, 10]

As for the challenges during development and operation, power curtailment has been estimated to not be an issue. However, one of the challenges has been related to the grid connection compliance. This issue is not attributed to technical reasons, but mainly to the innovative character of the project. The project has been used by both local authorities and developers to gain experience.[4]

Cynog Park, United Kingdom

In the United Kingdom, Vattenfall developed and built the first hybrid park in Europe, seen in figure 2.4. In 2016 a solar park was co-located next to the existing onshore Cynog wind farm, built in South West Wales in 2001. This pilot project, developed as a strategic project for gaining experience, has a PV capacity of 4.95 MW_p and 3.6 MW of wind. The hybrid power plant has a grid connection capacity of 4.1 MW in total.[4, 11]

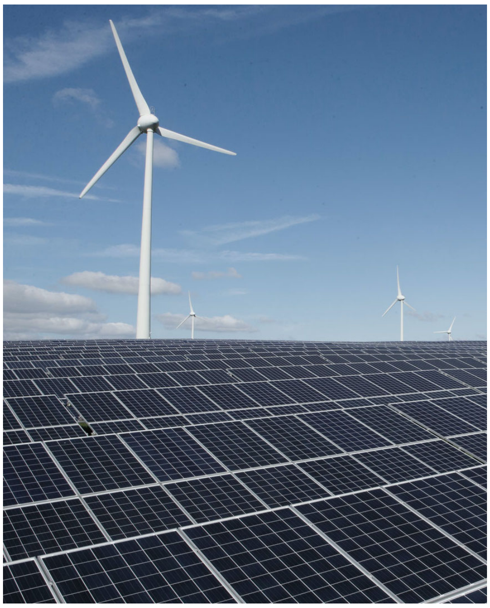


Figure 2.4: *Cynog PV-wind hybrid park in the United Kingdom [11].*

Vattenfall stated that negative correlation of solar irradiation and wind has been observed at site, both on a monthly, daily and ten minute basis. This has been positive for firming the output capacity of the plant, which in turn maximizes the utilization of the grid capacity. Vattenfall also emphasized that a battery could smooth the production profile further.[4]

The park, like many other initial farms, suffered from a massive curtailment higher than anticipated. For that reason, the developer emphasized the importance of performing curtailment simulations on a 10 or 15 minute basis. Furthermore, some of the losses have been monitored due to conflicting settings of controllers for active and reactive power. In the times when there is an over-supply of power, it is primordial with a fast reaction of the controllers.[4]

Haringvliet, Netherlands

In 2022 Vattenfall opened *Haringvliet*, the company's largest and first hybrid energy park combining wind, PV and battery storage. The park consists of six wind turbines of 26 MW in total, 41 MW_p from 115 000 solar panels and 12 battery sea containers of 12 MW. The grid connection capacity is of 50 MW. At an annual basis, Haringvliet is expected to produce 140 GWh, an amount corresponding to the consumption of 40 000 Dutch households. The battery facility has the opportunity of operating frequency and store excess electricity, maintaining a balance on the system.[4, 12]

Since the early development, the developer's objective has been to combine the three technologies to stay competitive in the future. The permitting and the Dutch Renewable Energy Grant Scheme have been secured for the plant since 2017. The income of the park is expected through participation in the wholesale electricity market and Guaranties of Origin (GoO), Frequency Containment Reserve services and time shifting services.[4]

La Plana, Spain

The *La Plana* facility located i La Muela in Spain was commissioned in 2015 to explore the potential of hybrid power. In March 2021, the development had been in operation for over three years. The site is used by Siemens Gamesa for the following purposes: as a test branch, for research development and as a commercial tool.[13–15]

The facility combines 245 kW_p of PV panels, 850 kW of wind power, three optional diesel generators in addition to storage technologies. Today the storage system is including a lithium battery and a vanadium redox flow battery. The entire system is controlled by a novel hybrid controller that can manage the mix of generating technologies in real time. In addition, the plant can work both in an off-grid and on-grid operation mode. The hybrid tests can be performed with any combination of the aforementioned devices, which also is provided in figure 2.5. Additionally to what is already installed, other devices can be commissioned to integrate several energy systems. This may be stacks of hydrogen or new technologies of PV systems.[13–15]

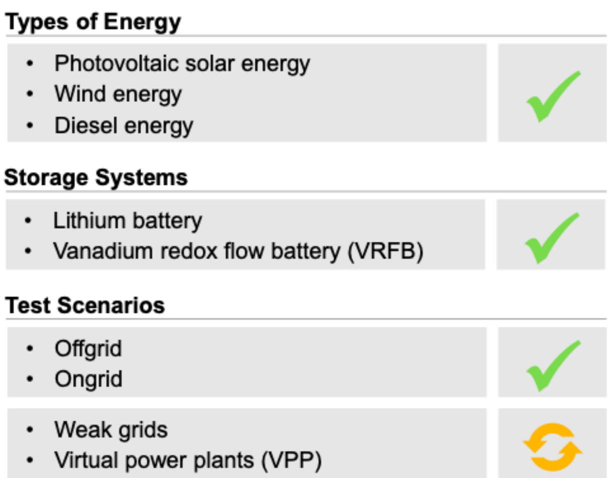


Figure 2.5: *Energy types, storage systems and test scenarios in the La Plana facility [13].*

2.3 Focus Areas

There are several studies that have been conducted on the theme of PV-wind hybrids. However, a majority seem to be simulations and computational analyses that have not been put to life for commercial applications. Many of these focus on system level aspects related to complementarity, such as improving matching to the local demand or finding the optimal mix of wind and solar. Nevertheless, the goal was usually the same; to prove that implementation of PV-wind hybrid systems are possible for a given location.[6, 16]

Agrawal et al. studied the feasibility of establishing PV at an 25 MW existing wind farm in India. The solar energy potential were simulated by using PVSyst for six cases with different levels of PV module coverage ranging from 5 - 30%, and four configurations of wind turbine location. Their result showed an annual specific production of 1704 kWh/kW_p and that the contribution from PV power in the HPP was greater than 50% in most cases. The maximum share from solar in the PV-wind farm was 82,1%.[17]

Other studies were of grid hybrids or grid optimization studies, such as Kim et al. who analyzed a power control strategy to extract the maximum energy available from wind and solar irradiance fluctuations while maintaining power quality at a satisfactory level [18]. Studies have also examined the economics of PV-wind hybrids. Hocaoğlu et al. found a procedure for optimum battery capacity, together with the optimum number of PV modules and wind turbines to minimum cost.[19] Furthermore, Ludwig et al. studied the PV yield loss caused by the wind turbine shading effect. They found that this shading was negligible both for the smallest and largest plant layout. Their result showed a 3.1% self-shading of the PV array, whereas the additional shading from turbines in the larger plant layout was only 0.7%. Consequently, even at the worst case scenario, the loss were lower than the regular inter-array shading loss.[16]

Some studies were not only computational or based on simulations. One of these were by Sopian et al. which explored the opportunity of using PV-wind hybrids to produce hydrogen. Their system was composed of a photovoltaic array, wind turbine, proton exchange membrane (PEM) electrolyser, battery bank, hydrogen storage tank, and an automatic control system for battery charging and discharging conditions. They were able to produce 130 - 140 ml/min of hydrogen with an average global radiation and wind speed ranging between 200 - 800 W/m^2 and 2.0 - 5.0 m/s, respectively. Their study confirmed that there was no insurmountable technical problems associated with producing hydrogen by a PV-wind hybrid electrolyser, and field observations showed that hybrid systems are feasible and reliable enough and requires less maintenance. They concluded that the electrolyser technology appeared to be mature enough for hybrid system application.[20]

2.4 Challenges

Presently, the principal challenges of PV–wind hybrids are overproduction, enabling policies and electricity storage. These challenges have been addressed and identified by several studies, and some of them will be described below.

2.4.1 Policy

Currently, hybrid power plants are still a relatively new development. As a result, there are few policy schemes specifically directed at hybrids. India is expanding their wind and solar shares in addition to targeting an efficient utilization of the transmission grid. Consequently, they have taken the lead and introduced hybrid-specific auctions.[2]

In comparison, in several countries, predominantly in Europe, PV-wind HPPs are generally not treated differently than other generation technologies when it comes to legal requirements. These HPPs are often treated as pure wind or solar developments or as co-located RES or storage projects. This means that HPPs will not fully be rewarded for their particular societal and system integration benefits. However, fully complementary solar-wind resources may have significant advantages.[2]

The challenges related to policy have been highlighted by several studies. Two of these are conducted by Klonari et al. and WindEurope. The latter identified a number of common challenges and presented a set of policy recommendations. These are provided in figure 2.6.[2, 4]

- A **clear regulatory framework**, starting with the **definition of the HPPs** needs to be established. WindEurope identifies 2 types of wind-solar HPPS in function of the common integration and operation of the different generating modules; (A) Wind and solar sharing the same substation and coupling point to the grid and (B) PV panels integrated with the wind turbines;
- To **facilitate the deployment** of HPPs, policy makers should initially **create a level playing field for them**, **by standardising grid connection requirements, metering and renewable energy traceability procedures** in such projects;
- **HPP developers must be able to install total renewable power capacity higher than the existing or agreed grid connection capacity**, even though a part of the produced energy might be curtailed when instantaneous generation exceeds the grid connection capacity. This is the only way to take full advantage of HPPs;
- In case storage is integrated in HPPs**,** the regulatory framework should set **clear criteria on the monitoring practices for tracing energy flows between the storage device and the grid.** Moreover, **double taxation and double grid charges must be avoided**; and
- In existing power plants under hybridisation, **developers should not have to re-apply for grid connection compliance as long as the power that the HPP exports to the grid does not exceed the approved capacity of the grid connection.**
- **European Research and Innovation (R&I) funding should address technical challenges** to the development and scaling-up of HPPs

Figure 2.6: *PV-wind HPP political challenges and recommendations [2].*

2.4.2 Overproduction

The second challenge related to PV-wind HPPs is overproduction. This phenomena has been reported in almost all developments.[6] The use of these hybrids, and solar in general, continues to suffer since PV panels in particular overproduce energy that only can be consumed in a given time frame. Government bodies and developers have typically utilized curtailment law to reduce this problem. However, curtailing also reduce the benefits both in an environmental and economical manner. Coupling storage systems to the HPP may alleviate, and possibly eliminate, the risk of over-generation.[6, 21]

There are several studies that focus on optimization techniques that can determine the generation systems optimum size to secure that the equipment are fully utilized at the lowest costs. This has proven to have a significant impact on generation capacities. The techniques cover probabilistic approach, iterative technique, meteorological data, intelligence methods, graphic construction method, algorithms, energy flow and management controls and multi-objective design. Examples of these studies are by Malysz et al., Bae et al. and Siddique et al.[6]

Other utilities, grid operators and plant owners utilize solar power predictions and forecasts to better understand generation patterns and to avoid overproduction. By using a machine-learning technology, IBM was able to improve the prediction accuracy by 30%. Several researchers are positive, but they also emphasize that further improvements in predictive accuracy will be needed as the amount of energy generation connected to the grid continues to grow at a rapid rate.[6, 21]

2.4.3 Storage

Even though storage is the most prominent solution to overproduction, reports often characterizes this as a challenge of its own. There are several advantages of combining storage with HPPs. It can ensure reliability and close the energy gap between load demand and generation. It can provide ample time for maintenance activities and eliminate the need for curtailment. Moreover, it can reduce the need to run PV-wind systems continuously since customers can draw energy from the storage system during downtime.[6]

A variety of studies have been conducted on the topic of storage. Xu et al., Xie et al. and Makarom et al. focused on optimizing the storage units to enhance the power generation's reliability, and proposed methods for achieving this [22–24]. Xu et al. also examined optimization of the charge/discharge states of the storage systems, in addition to minimizing the total cost of the system [22].

Today, there are a variety of energy storage systems available. These include electrochemical batteries, flywheels, pump storage and hydrogen. Recent time, the interest in the latter has increased significantly.[6] Maclay et al. presented a model for a solar-hydrogen powered residence in both stand-alone and grid connections. The model was developed using Matlab Simulink. Their model examined the possibility of using a regenerative fuel cell (RFC) as a device for energy storage for PV. The authors also discussed challenges such as RFC and battery sizing, charge/discharge rates and charge limitations. They found that a dynamic load demand was challenging and the size of the RFC and battery had to be larger than those required to meet an average power demand.[25]

3 Smøla Wind Farm

Smøla wind farm is located in the municipality Smøla in Møre og Romsdal. The park covers an area of 18 km^2, and consist of 68 turbines with a total installed capacity of 150 MW. The annual average production is of 356 GWh, corresponding to the average use of 17 800 Norwegian households. The first construction stage with 20 wind turbines was put into operation in September 2002, while the second stage with 48 wind turbines was put into operation in September 2005. Smøla was Europe's largest onshore wind farm when it was built, and was Norway's largest until 2017. The rotors have a diameter of 76 m and 82.4 m, depending on the construction stage, whereas the height of the towers are 70 m.[26–29] The capacity of the electricity transmission cable to the mainland is limited, and is of 160 MVA [30].

Smøla is an island located at the north-west coast of Norway, and has no mainland connection aside car ferries and high-speed passenger ferries. As can be seen in figure 3.1, the wind farm is located in a relatively flat and open terrain, with heights ranging from 10 - 40 m above sea level.[26–28] The wind at Smøla is mainly coming from the south-west direction. In the winter, there is normally a light snow coverage, that usually disappears after a short amount of time. The wind farm is open during the entire year, as there are no registration of ice throw from the turbines.[30, 31]

Figure 3.1: *Smøla wind farm [26].*

Moreover, the Norwegian National Wind Energy Centre is located at Smøla and in recent years, several reports have been published from research projects on birds and wind turbines from the wind farm. Researchers at NINA have been researching the topic at Smøla for a long time, and have been able to demonstrate a clear connection. The researchers demonstrated a 48% reduction in the recorded number of dead ptarmigans around turbine towers that were painted black at the bottom, compared to white control turbines. Another study showed that the annual bird strike rate was reduced by 70% for turbines with one rotor blade painted black compared to white control turbines.[32]

Unlike other local communities, the population at Smøla supports the wind farm. According to a survey conducted by Synovate NMI, 72% of the 2121 inhabitants have a positive view of the wind farm - they are even proud of it. In addition, 31% state that they are more positive about the wind farm today than before it was built. The park is opened to non-motorized traffic all year around, and has become a popular hiking area for both local residents and tourists. The road network of 28 km is particularly suitable for cycling, and there are both swimming and fishing opportunities in the wind farm.[26]

The building of the wind farm led to several new and stable jobs and has contributed to development of Smøla's local businesses. Aquaculture has become an important industry for Smøla, and Smøla continuously sees great synergies in business development that spring from these activities.[26, 28]

3.1 Repowering of Wind Farm

The wind farm at Smøla is currently under the preliminary project planning stage for repowering, and the construction of the new wind farm is schemed to be completed around 2030. As of today, Statkraft states that the number of turbines presumably will be reduced whereas the rated power of the new turbines will be greater. Here turbines with power ratings of 5.0 MW and 10 MW are considered. By e.g. utilizing the former, the number of turbines will be reduced from 68 to 30. The two turbine types have tower heights of 90 - 120 m and rotor diameters of 110 - 130 m, respectively.[33]

However, the existing turbine fundaments cannot be employed by the new turbines of greater size. Consequently, new fundaments must be built, which in turn mean that the new turbines presumably will get new locations. In addition, the installation spaces for cranes in front of each turbine will only be re-usable to a little or no extent. The same applies for the existing cabling. However, the Norwegian Water Resources and Energy Directorate (NVE) sets strict requirements for removal, covering or revegetation of infrastructure that is no longer used. Statkraft is therefore looking into alternative usages of these spaces as part of the repowering.[33]

NVE further makes strict demands for impact assessments before a new license is granted for a project. Renewal projects must go through the same thorough processes as new projects, meaning that all conditions that were assessed for the impact of today's wind farm must be re-examined. This include impacts on nature, environment and society and covers themes like landscape, cultural heritage, biological diversity, noise, shadow casting, pollution and waste management, outdoor life, business and municipal finances.[33]

4 Wind Power

Wind power is energy obtained from the wind. It is considered one of the earliest sources of energy utilized by humans, and is today one of the most established and efficient renewable energy sources. Wind power is generated by converting energy in the moving wind turbine blades, driven by the wind, into electrical energy.[34]

4.1 Main Components

As illustrated in figure 4.1, the main components of a wind turbine are the tower, rotor, main shaft, gear, generator and necessary auxiliary units and control system. Most of the components are built into a machine house mounted on top of a tall steel tower. The rotor usually consists of three blades mounted on a hub. Here, the wind energy is converted into rotational energy, which is fed into a generator through a main shaft and gear. This converts the rotational energy into electrical energy. The machine housing rotates with the direction of the wind so that the rotor plane is always across the direction of the wind.[35]

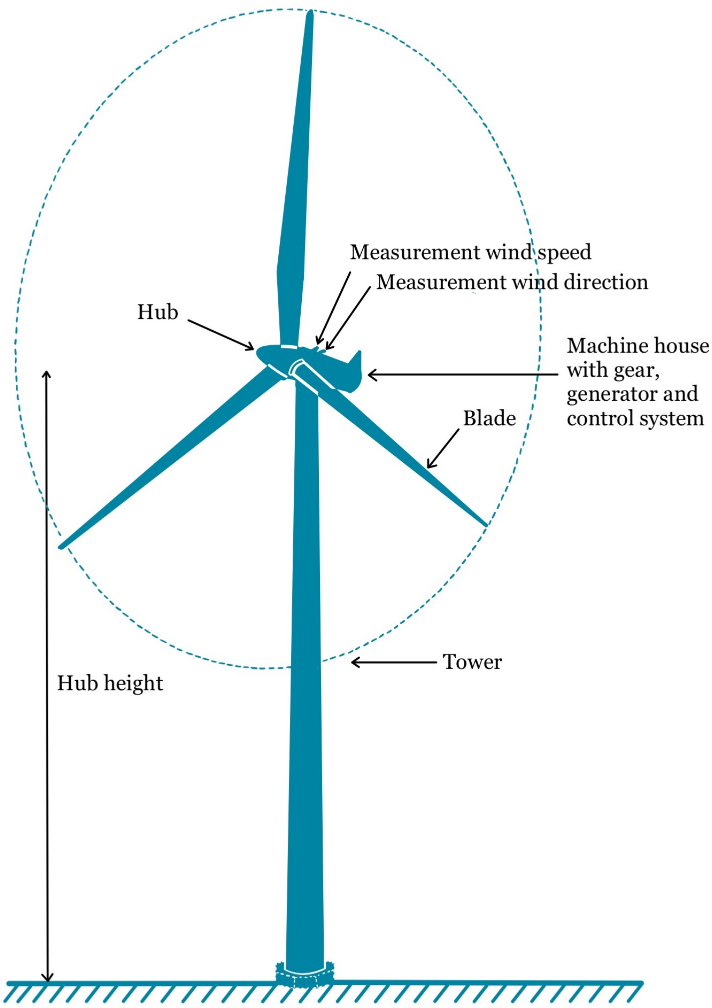


Figure 4.1: *Wind turbine and its main components.*

4.2 Power Output

The theoretical maximum efficiency of a wind turbine is given by Betz limit and is of 59%. Nevertheless, a turbine typically utilizes 30 - 40% of the wind energy that passes through the rotor area. Furthermore, the rated wind turbine power is defined as the maximum amount of power by which a wind turbine can produce, that is the rated output or the peak production, at a specific wind velocity. When the wind turbine produces at a higher or lower wind level than the rated power, the efficiency drops due to aerodynamic conditions. The rated power is also known as the *nominal effect*. A wind turbine can normally utilize wind velocities ranging from 3 to 25 m/s, but is only in full production at approximately 14 m/s.[35]

The electrical power output ratings at different wind velocities for a wind turbine, are often presented as the wind power curve. As seen in figure 4.2, the power curve has three main characteristic velocities: cut-in speed, rated output speed and cut-out speed. When the velocity reaches the cut-in speed, the wind turbine starts generating power. The power output continues to rise with increasing wind velocity until it reaches the rated output speed, which is the wind speed at which the turbine reaches its rated power. When the velocity reaches the cut-out speed, the turbine stops automatically to prevent defects and damages caused by excessive mechanical loads. Manufacturers provide theoretical power curves based on ideal meteorological and topographical conditions. However, wind turbines are rarely used under these ideal conditions.[35, 36]

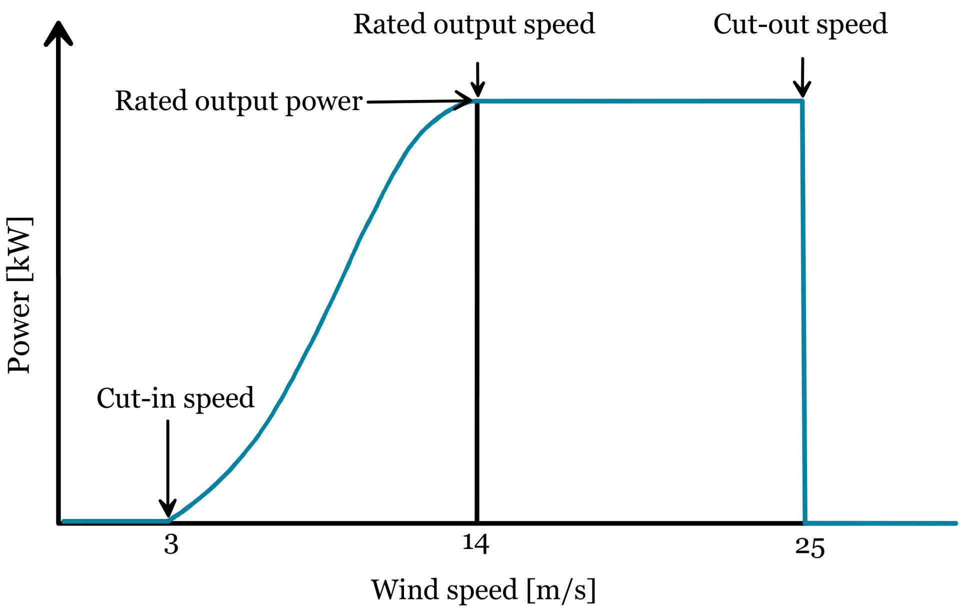


Figure 4.2: *Wind power curve.*

4.3 Wake Effect in Wind Farms

As wind turbines extract energy from the wind to produce electricity, the wind leaving the turbine has a lower energy content than the wind upstream of the turbine, and consequently has reduced speed and is turbulent. This downstream wind is the wake of the turbine. If a wake intersects with the swept area of a downwind turbine, this turbine extracts less power and is said to be shadowed by the turbine creating the wake. As the number of wind turbines in a wind farm increases, the average power output per wind turbine decreases due to the presence of wake effects. It is reported that power losses caused by wind turbine wakes are in the order of 10 – 20% of the total power output in large wind farms. Another consequence is the potentially increasing dynamic mechanical loading on the the downwind turbines due to the turbulence. [37–39]

Consequently, it is crucial to consider wake affects when designing wind farms to find the optimal placement of turbines that maximizes energy production and lifetime of the machines. A large number of numerical models, of varying complexity, have therefore been developed to describe both wake and optimal turbine placement.[37, 38] As seen in figure 4.3, the Patel rule of thumb states that that the optimal placement for wind turbines is found in rows of 8 - 12 rotor diameters apart in the windward direction. For the crosswind direction, they should be 3 - 5 rotor diameters apart. However, this method may lead to inefficient positioning due to the fact that terrain characteristics, turbine size and wind speed and direction are not considered.[38]

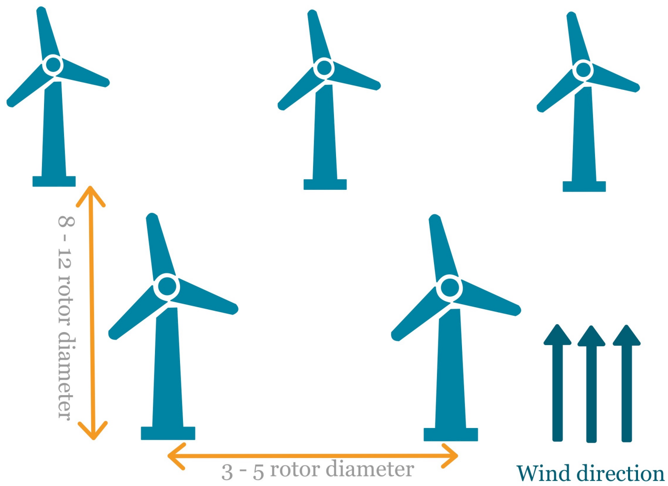


Figure 4.3: *Optimal turbine placement according to the Patel rule of thumb.*

5 Photovoltaic Panels

A photovoltaic panel is a device converting solar energy directly to electricity. The panel consist of several individual cells connected to produce electricity of a desired voltage. PV panels produce DC in proportion to the solar radiation level, thus to produce AC, an inverter is needed.[40] A typical PV panel in Norway produces approximately 650 - 1000 kWh per installed kW_p annually, and has an expected life time of 25 - 30 years. The efficiency is of approximately 15 - 20%, and is the ratio between the power delivered and the power supplied. In other words; energy from solar rays in, versus what is produced. The amount which is produced varies both throughout the day and year, where factors such as location, radiation, meteorological conditions and temperature play important roles.[41–43]

5.1 Orientation

The PV panel output is affected by a variety of factors. One of the greatest factors are the orientation of the panels, meaning how much of the solar rays that hit the surface of the panels. Here, there are specially two crucial factors: tilt angle and azimuth angle. In figure 5.1, the azimuth is denoted by γ. The azimuth angle is the compass direction from which the sunlight is coming and varies throughout the day. In general, the azimuth angle varies with the latitude and time of year. When installing PV panels in the northern hemisphere, the optimum orientation is towards south.[44]

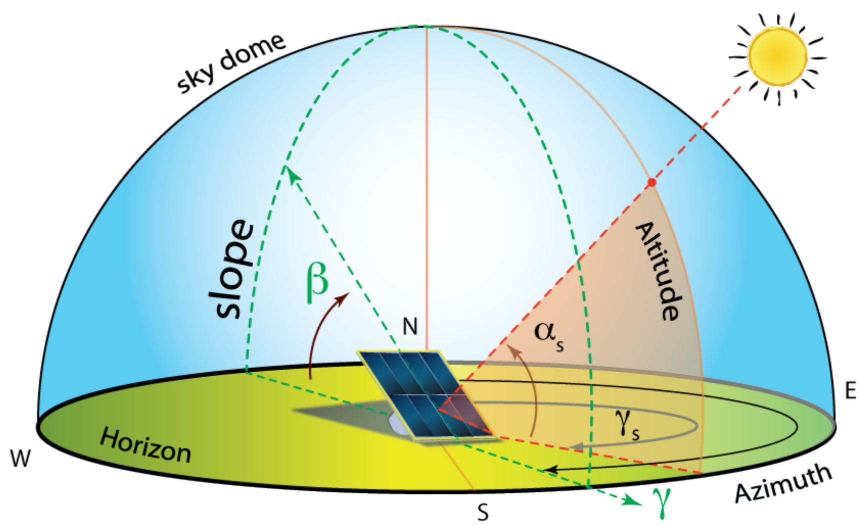


Figure 5.1: *Angular factors defining orientation of a PV panel [45].*

The other crucial factor is the tilt angle of the panels, denoted by β in figure 5.1. The tilt angle is defined as the number of degrees from the horizontal plane, or the slope angle at which solar panels are mounted to face the sun. The optimum angle is location specific and depends on the daily, monthly and yearly location of the sun.[44, 46] For that reason, the ideal angle is never fixed. Both single and dual-axis tracking systems exists today, but if the panels are going to be fixed, there are two factors that should be taken into consideration: the location and at what time of year the production should be optimized for. There are several simplified methods for calculating an approximated optimum tilt angle for fixed systems, and one method is given by equation 5.1. This method finds the optimum angle for summer production.[47]

$$\beta = (latitude \cdot 0.9) - 23.5^\circ \tag{5.1}$$

5.2 Global Radiation

Solar radiation incident on a surface consists of three components. As can be seen in figure 5.2, these are direct solar radiation, diffuse solar radiation and ground albedo solar radiation. Direct radiation, or beam radiation, is the radiation that is not reflected nor scattered, and reaches the surface directly in line from the solar disc. Furthermore, diffuse radiation is the result of scattering of the sunbeam due to atmospheric constituents, and is incident from all directions in the sky. The solar radiation may be scattered by clouds, gases and particulate matter.[44, 49] Finally, albedo is the radiation that reaches the receiver after reflection from the ground. It is defined as the fraction of the solar radiation which is reflected, and has a value between zero and one, zero being no reflection and one being maximal reflection.[44] Table 5.1 gives an overview of some common albedo values.

Table 5.1: *Approximated ranges of albedo for different surfaces [48].*

Surface Type	**Albedo**
Asphalt	0.10 - 0.15
Green forest	0.10 - 0.20
Wet ground	0.10 - 0.20
Dry ground	0.15 - 0.30
Grass	0.20 - 0.30
Concrete	0.20 - 0.35
Sand	0.30 - 0.40
Old snow	0.50 - 0.75
Fresh snow	0.75 - 0.90

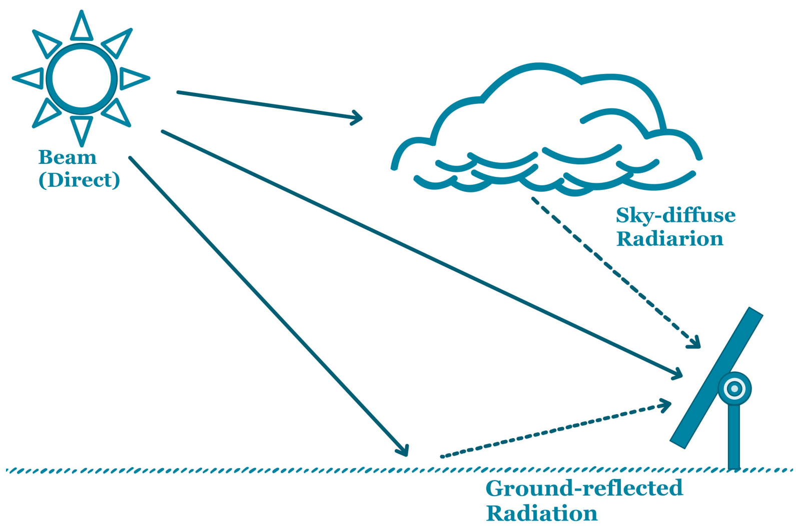


Figure 5.2: *Global radiation consisting of direct, diffuse and reflected radiation on an inclined surface [50]. The figure has been modified.*

5.2.1 Bifacial PV Panels

The effect of albedo is specially utilized in bifacial PV modules. Bifacial modules are modules designed to accept light from either the front or the rear of the solar cell. Consequently, the cell and module construction becomes more expensive. However, the price premium is decreasing and is offset by the increased energy yield from the incident sunlight.[44, 51]

The bifacial increase compared to the single sided panel can be determined by the relative strength of albedo and the ability of a PV bifacial panel to capture the light. Bench flash testing suggest that several panels theoretically can absorb 90% of the albedo incident on it. However, due to the variety of variables involved in positioning, field testing of bifacial panels indicates levels of absorption in the range of 10 - 15%.[51]

5.3 Shading

Shading is a great concern for PV modules as shading just one cell in the module may reduce the total power output to zero. The shading may be caused by a tree branch, building and snow, and the output declines proportionally to the amount of shading. The decrease in current output of a cell is proportional to the amount of the cell that is obscured. The phenomenon can be observed in figure 5.3, which shows the output when the cell is not shaded and when the cell is party covered by 1/3 and 2/3.[52]

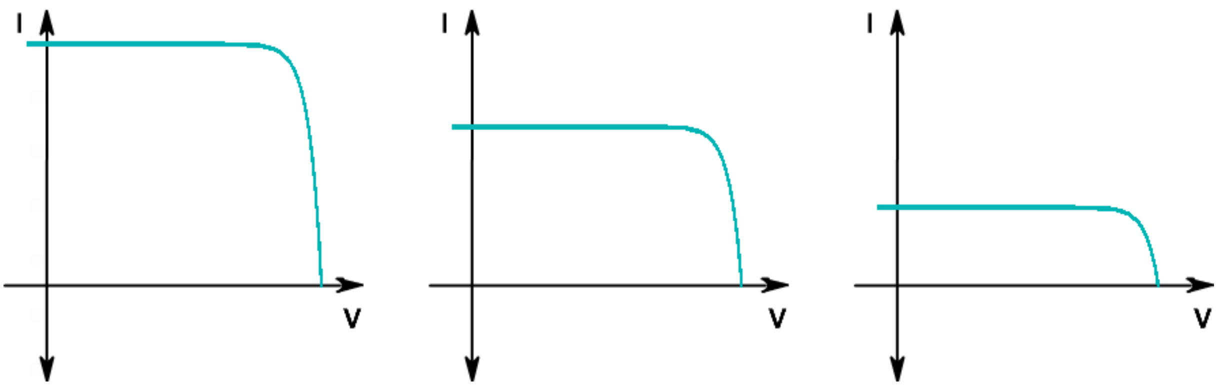


Figure 5.3: *Current output for a solar cell with no shading, 1/3 shading and 2/3 shading.*

In general, solar cells act as generators and cells are connected in series in a module to increase the voltage. Since the cells are series connected, the current is equal in each cell. Consequently, the current in the string is limited to the current of the weakest cell. Partly or completely shading just one cell in a module causes the power output of the whole module to fall to half or zero, no matter how many cells there are in the string. If multiple modules are series connected, the shaded cell will have a great influence on a system level as well.[44, 52]

Another possible consequence of shading, is hot-spot formation. Hot-spot formation occurs when a large number of series connected cells cause a large reverse bias across the shaded cell, leading to large dissipation of power in the shaded cell. Essentially, the entire generating capacity of the unshaded cells is dissipated in the shaded cell. The enormous power dissipation occurring in a small area results in local overheating, or *hot-spots*, which in turn leads to destructive effects such as cell or glass cracking, melting or degradation of the cell.[44, 53] Fortunately, the formation of hot-spots can be avoided by the use of bypass diodes. As illustrated in figure 5.4, these diodes are connected in parallel with the opposite polarity. Since the bypass diodes are generally expensive, the diodes are usually placed across groups of solar cells.[54]

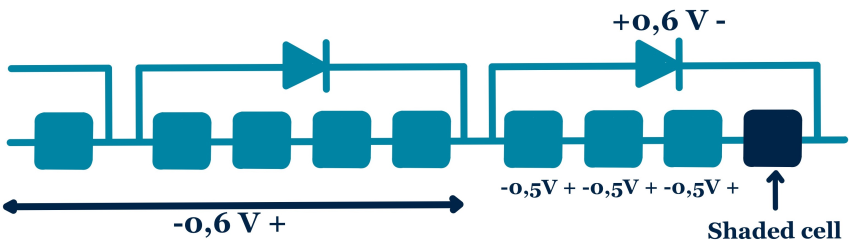


Figure 5.4: *Bypass diodes across groups of solar cells. The figure is inspired by [54].*

5.4 Temperature

Due to less solar hours in Nordic countries like Norway, several people have an opinion that PV is not worth pursuing. However, the PV panel efficiency improves in colder climates as the power produced increases when the temperature decreases. This can be seen in the power curve in figure 5.5. The rated performance of PV panels are given at standard conditions at 25 °C. For higher temperatures, the efficiency is negatively affected, and the solar cell performance is lowered. Consequently, manufacturers often present a temperature coefficient.[56] The temperature coefficient of a solar cell is the amount by which its output voltage, current, or power changes due to a physical change in the ambient temperature. The coefficient is dependent by the module type, but a number of -0.25 – -0.30 %/°C is common. Thus for every 1 °C temperature change above 25 °C, the PV panel loses 0.25% of its e.g. voltage. But equally, for every 1 °C below 25 °C, the PV panel's voltage increases by 0.25%.[56, 57]

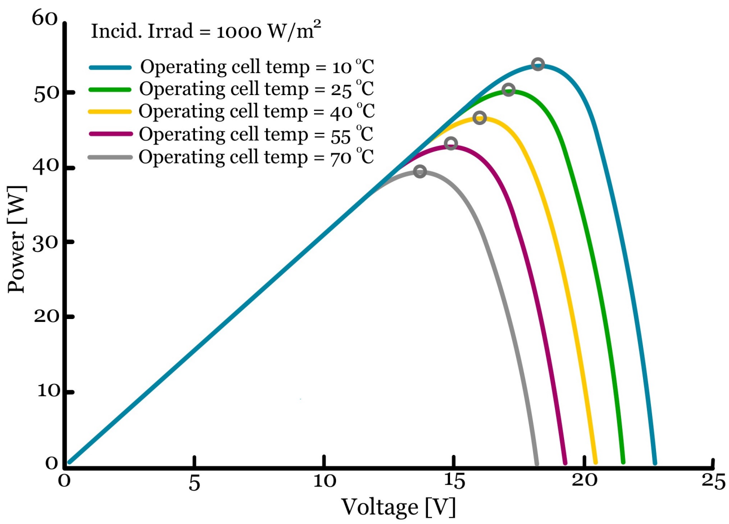


Figure 5.5: *Temperature influence on PV power and voltage. The figure is inspired by [55].*

5.5 PV in Norway Today

The scope of solar power in Norway has historically been modest, and for a long time the Norwegian solar market consisted of small cottage complexes and smaller PV systems on homes built by enthusiasts [58]. The rate of PV in the total power production has therefore been minute. Nevertheless, PV power is currently at a rapid growth, and in 2021 the total capacity rose by more than 30%.[59] This trend continued in 2022, and by the end of the year, 149 MW_p was installed. This corresponds to a doubling of the total installed capacity during the year.[43]

To this date, PV panels have almost exclusively been seen on roofs of private individuals and industry, and have primarily been used to cover own consumption. Approximately 5% of the systems in Norway are larger systems of more than 50 kW_p, where the biggest (as of 19.08.2022) is ASKO Øst in Vestby of 4241 kW_p. There are currently no dedicated solar power plants, but this is predicted to change. These parks must have a license from NVE.[43, 58]

Even though the capacity is increasing, the potential in Norway is far from reached. In 2022, Multiconsult published a paper reviewing the potential in Norway. By utilizing the full PV potential on buildings and grey areas (seized land, such as agricultural land out of operation, parking lots and closed landfills), 199 TWh can be produced annually. This production potential is greater than today's production of hydro and wind power combined.[60] The potential was also calculated for Møre and Romsdal, and as seen in figure 5.6, the value is of 14 TWh. NO3 represents the power pricing area consisting of Møre and Romsdal and Trøndelag, respectively.[61]

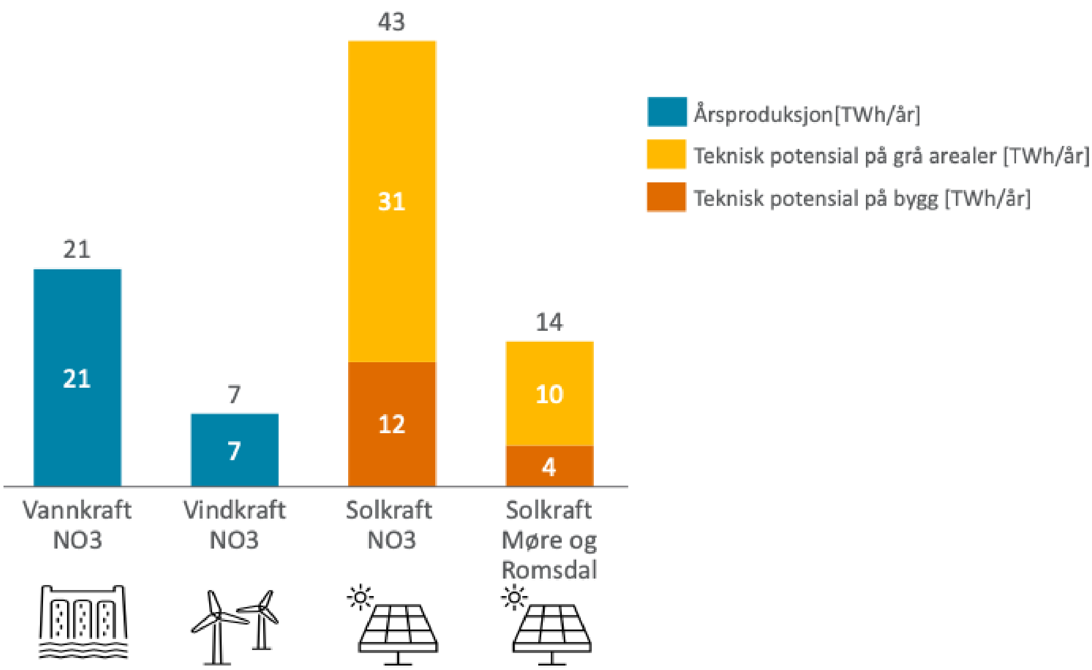


Figure 5.6: *PV production potential in NO3 and Møre and Romsdal [61].*

6 Configuration Types

PV-wind HPPs are mainly classified in two categories: stand-alone or grid connected. Currently, the former leads the PV-wind hybrid systems with 60% of the global share, and is expected to retain its dominant position throughout the upcoming years due to numerous off-grid industries. However, grid connected systems are anticipated to increase with the fastest CAGR of 7.6% from 2020 to 2027.[5]

Furthermore, HPPs can be identified by their configuration. As illustrated in figure 6.1, the first type is a system where wind and solar share substation and grid coupling point, whereas the PV panels are integrated with the wind turbines in the other system. Currently, the former is the most developed, while the latter is an alternative that may eliminate the solar converter in certain cases. In general, both can maximize use of the grid connection point by increasing the capacity factor of the installation, reducing CAPEX and permitting timing, and thus to defer investments for grid reinforcement.[2, 6]

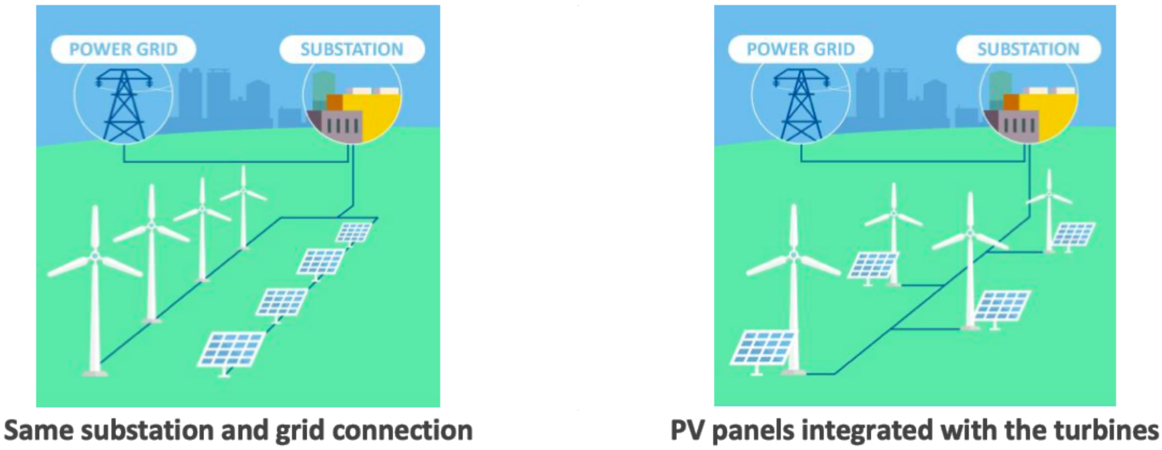


Figure 6.1: *Configuration types of PV-wind hybrid power plants [2].*

Same Substation and Grid Connection

Compared to developing separate wind and solar plants, HPPs sharing the same substation and grid connection are known for savings in CAPEX and permitting times. In addition, the overall development, covering site conditioning, resource assessment and regular operation and maintenance costs are lower. Sometimes the PV capacity is located outside the limits of the wind farm to optimize the PV output. Nevertheless, as they still share the grid interconnection point, the HPP controller ensures network code compliance for the entire plant and simplifies operation and maintenance. When existing assets are becoming hybrids, only the new modules have to comply with the new network codes, not the ones that are existing. Consequently, coordinated control is necessary, fulfilling the several requirements per module.[2]

PV Panels Integrated With the Turbines

Plants with PV panels integrated with the turbines have the advantage of eliminating the solar inverters in cases of full-scale conversion in the wind turbines, resulting in a more efficient use of the converter. Since converters usually are more efficient during high full-load operation compared to partial load, the generation from the PV panels will ensure a more efficient use of the converter during partial wind generation. All of the above gives potentially important cost savings. In addition, this configuration also cover the advantages of the first category and increases the Annual Energy Production (AEP) per square meter.[2]

Nevertheless, a significant disadvantage is that the blades and the tower can cast shade over the PV panels, which may neutralize the AEP increase over time. The PV panels can be installed in less shadowed areas around the turbines or further apart from the turbines, increasing cabling and creating line losses. It is also worthwhile to mention that this configuration is not suitable when implementing PV to an existing wind farm. This is due to the space constraints for PV integration and capacity limitation given the existing power export capacity of the wind turbine. In addition, the ancillary services provision may be limited as solar inverters are not interfaced with the grid.[2]

7 Storage

As of today, electricity can be stored in a variety of methods. This includes pumped hydroelectric, flywheels and compressed air. Nevertheless, battery storage is the method most commonly used. As seen in figure 7.1, batteries have the ability of storing the energy produced in periods of low demand in order to stabilize the output when the demand is high. Batteries are consequently well suited for storing energy for short periods of time. For seasonal mismatching problems, other methods such as storing electricity in the form of hydrogen is beneficial as it is capable of storing in longer periods of time.[20]

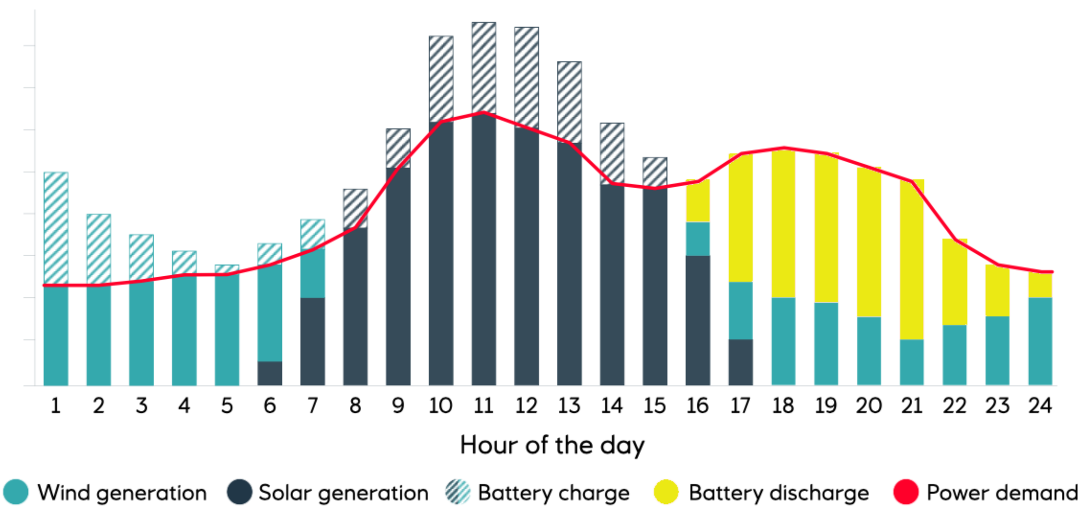


Figure 7.1: *Example of how batteries can store energy produced by renewables in periods of low demand in order to stabilize the output when the demand is high [62]. The figure has been modified.*

7.1 Hydrogen

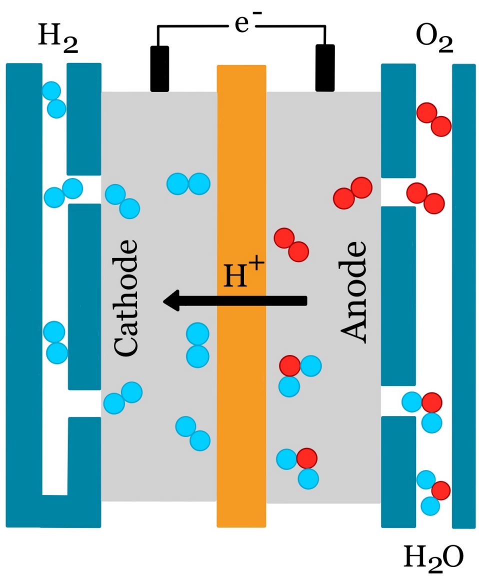
Over the last decade, hydrogen as an energy storage medium has drawn the attention of research institutions and industry. The EU even sees pure hydrogen as one of the pillars of its future energy system. This is partly motivated by renewable energy developments, which have led to surplus wind and PV power that is being unused. In several terms, hydrogen is a more suited energy storage medium, compared to other fuels, owing to the high heat value. The energy density of hydrogen is more than twice as high as that of typical solid fuels with 140 MJ/kg compared to 50 MJ/kg. Furthermore, hydrogen burns to produce water, making hydrogen an environmental friendly energy store.[63, 64]

Hydrogen is normally stored as either gas or liquid. The former requires the use of high pressure tanks (350 - 700 bar or 5000 - 10 000 psi), while the latter alternative requires cryogenic temperatures to prevent the hydrogen boiling back into a gaseous form. This occurs at -252.8 °C. Hydrogen storage is a challenge as it typically requires large-volume systems.[65]

Today there are several technologies available for hydrogen production, including reforming, decomposition and hydrolysis of fossil fuels. However, as of today the major part of hydrogen production is covered by fossil fuels by e.g. steam reforming of natural gas. This production is denoted as grey or blue hydrogen, depending on whether carbon capture is included or not. Green hydrogen on the other hand, produces hydrogen from water electrolysis powered by renewable energy sources. This technique shows great promise and is expected to enable the scale-up of hydrogen production.[63]

7.1.1 Water Electrolysis

In the water electrolysis process, water is electrochemically split into hydrogen and oxygen at their respective electrodes. The electrode and overall reaction, as well as a principle sketch of the PEM electrolyser, are provided in figure 7.2. At the anode, water is split into oxygen, protons and electrons. The protons are then transferred to the cathode side via a conducting membrane, whereas the electrons travels through an external power circuit which provides the driving force for the reaction. The protons and electrons are then re-combined at the cathode side and forms hydrogen.[66]



Anode: $H_2O \longrightarrow 1/2\,O_2 + 2H^+ + 2e^-$

Cathode: $2H^+ + 2e^- \longrightarrow H_2$

Total: $H_2O \longrightarrow H_2 + 1/2\,O_2$

Figure 7.2: *PEM electrolysis cell and chemical reaction.*

For the reaction to take place, a total energy input of 285.8 kJ/mol is required for an optimal process. This number equals the energy amount released when combustion of hydrogen to liquid water takes place. Of this 285.8 kJ/mol, 237.2 kJ/mol is the electricity that goes into the work of splitting the water - the Gibbs free energy. The remaining 48.6 kJ/mol is the entropy change and corresponds to the heat released by the combustion reaction. The total energy required for a real process can be calculated by equation 7.1, which is a function of the heating value of the produced hydrogen (E_{out}) - the energy amount released during combustion, the energy input (E_{in}) and efficiency of the system (η).[67, 68]

$$E_{in} = \frac{E_{out}}{\eta} \tag{7.1}$$

However, PEM is not the only system developed for water electrolysis. Other technologies include alkaline water electrolysis (AWE), alkaline anion exchange membranes (AEMs) and solid oxide water electrolysis cell (SOEC). Different materials and operating conditions characterizes these systems, however, the operating principles are equal. The PEM electrolysis is seen as a promising hydrogen production technology as it has fast response, high efficiencies of 65 - 82%, compact design and high output pressure. In addition, balancing PEM plants are simpler, making it more attractive for industrial applications. The downside, however, is the costs of the metals used as electrocatalysts. AWE is a relatively stable and mature technology, but cannot start up quickly and have a slow loading response. Consequently, AWEs are normally utilized with steady power inputs. Moreover, if it is operated with current densities being too high, excessive gas bubble formation will block the electrode surface. AWEs therefore have a specific maximum current density where it can operate. High temperature SOEC has elevated efficiencies, and when heat utilization is included, the efficiency is more than 90%. However, high temperatures present challenges in terms of material degradation, and the start-up and shut-down procedures have to be conducted slowly for this technology. In addition, to obtain high purity hydrogen, the generated hydrogen mixture needs additional treatment due to the water vapor from the SOEC. For that reason, the SOEC technology currently is still under development.[63, 69]

7.1.2 Hydrogen Production at Smøla

The possibilities of hydrogen production at Smøla has already been presented in a business case by Møre and Romsdal County Council, Smøla Business and culture center and the National wind energy center. In addition, several other reports covering the similar theme have been conducted. Even though there are several aspects to be fulfilled before such a production could be realized, the reports show that it is possible to make hydrogen production profitable at Smøla.[28]

To achieve this profit, the business case states several essential prerequisites that have to be fulfilled. According to the study, some of them are already fulfilled while others are partly fulfilled. The former includes that there is an available area for the production site and access to green energy. The plan is to use green energy produced in the wind farm and an existing area at Vikan planned for industry. This requires an upgrading of the power grid to Vikan, located on the southeast side of the island. Furthermore, the business case calculated that production is profitable if the production plant produces and sell at least 1000 kg hydrogen per day, in addition to make profit of the by-products. However, this claims that there are potential users of both hydrogen and by-products. Some of the suggested users are included in the hydrogen value chain shown in figure 7.3.[28]

Figure 7.3: *A possible hydrogen value chain at Smøla [28].*

One challenge, however, is the maturity of the technology. Today it is already technically possible for ships, boats and busses to use hydrogen, but due to financing and uncertainties regarding regulations and technical solutions, there is a limited amount that are built. Consequently, there are no certain hydrogen users for the near future at Smøla. However, the maritime activity at Vikan port is foreseen to increase once the infrastructure of e.g. power and water is present. In addition, Smøla has a comprehensive aquaculture industry that will continue to grow in the coming years. This industry requires both heat and significant amounts of oxygen. Hydrogen production could therefore contribute to enhance this industry by the use of by-products from the production itself and adapting it to Smøla's local aquaculture companies.[28]

8 Economical Analysis

An economic analysis is typically conducted to ascertain the feasibility and profitability of a given project or investment opportunity. This process entails a comprehensive evaluation of the costs and benefits associated with the project under consideration. Essentially, it involves the identification, evaluation, and comparison of cost and benefit factors. It is best initiated during the early stages of the project cycle, which enables decision-makers to make well-informed decisions regarding the most viable investment option among various alternatives and their corresponding costs. The utilization of economic analysis tools can aid in addressing several inquiries concerning the project's societal impact, fiscal aspects, sustainability, and its effect on various stakeholders/beneficiaries. Despite distinct sectors having their own set of issues that must be addressed, the fundamental principles of economic analysis can still be employed. However, the analytical approach and data requirements would necessitate adjustments to suit the specific project. The key is to determine the appropriate level of analysis to inform project decision making.[70] This chapter will describe two methods associated with profitability analysis, as well as factors included in it. This includes prices for PV systems, power prices and costs of reference projects.

8.1 Profitability Analysis

Calculating the economics of a PV system is key to understanding whether the investment is worth pursuing or not. The net present value (NPV) is an essential method to assess profitability and investment ranking. In addition to its intrinsic value, this method is used as a starting point for most other economic considerations. The method is based on the present value, which is a method of representing the current value of future cash flows, based on the principle that money in the present is worth more than money in the future. The project is profitable at a particular rate of interest if the NPV is positive. The NPV can be calculated by equation 8.1, where B is the net annual savings, r is discount rate, n is the economic life time and I is the investment costs.[71, 72] In Norway, the calculated interest rate for all public projects with a 40-year discounting period is 4% [73].

$$NPV = B \cdot \frac{1-(1+r)^{-n}}{r} - I \tag{8.1}$$

Equation 8.1 can further be used to calculate the levelized cost of energy (LCOE). LCOE is defined as the minimum price at which the generated energy must be sold for the project to break even at the end of its lifetime.[74] At this price, revenues equal costs, including making a return on the capital invested equal to the discount rate. If the generated energy is sold for a price above the LCOE, this would yield a greater return on capital, whereas the opposite case would yield lower returns or even loss. LCOE is seen as a useful metric as it enables comparisons between several different projects and energy sources to determine which is the most competitive.[75]

8.2 PV Module Prices

PV continues to improve its competitiveness and an important driver has been the downward trend in PV module prices. Of all renewable energy technologies, PV has shown the greatest learning rates.[76] The global and national trends for a selection of countries based on several sources, in addition to the IEA forecasts in 2010 and 2014, can be observed in figure 8.1 [77]. In the time period of December 2009 to December 2021, the module prices on crystalline silicon modules decreased by 88% and 95% for modules sold in Europe. At an individual country level, the decrease of the weighted average LCOE of utility-scale PV was of 75 - 95% between 2010 and 2021.[76]

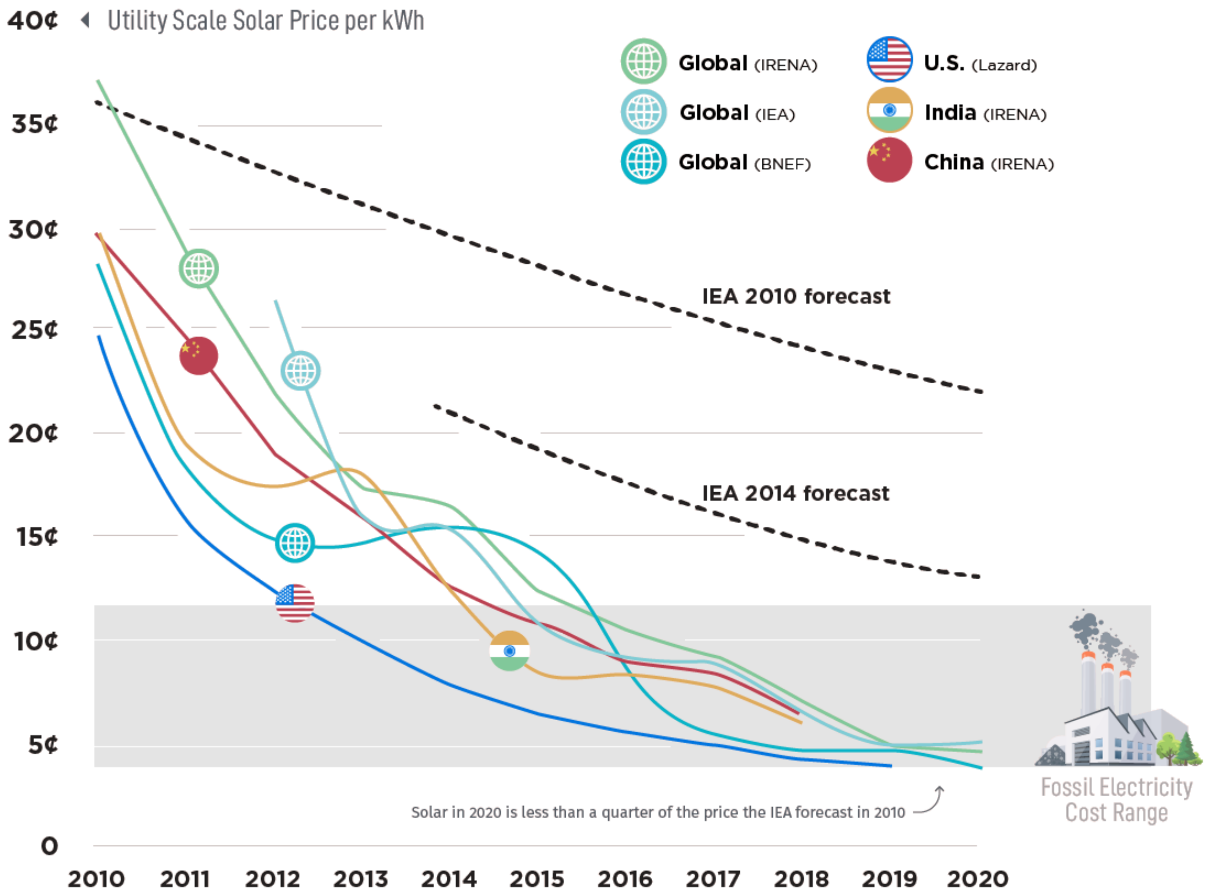


Figure 8.1: *Solar PV energy costs from 2010 to 2020 [77].*

However, after several years of downward price trends, the yearly average price between 2020 and 2021 increased by 4 - 7%. The main cause was chain disruptions during 2021 that resulted in higher material costs and lower availability, pushing up the prices. Nevertheless, an analysis from 2022 by IRENA states that the prices have now stabilised and have started to decline for low cost offerings, though they remain at 2019 levels for mainstream products.[76]

Furthermore, bifacial crystalline modules continues to improve their market share. Driven by the narrowing cost gap and the potential for increased yield per watt when compared to monofacial technologies, the market share grew from 8% in 2019 to 27% during 2020.[76]

The future predicted cost of PV can be seen in figure 8.2, showing all PV projections found in the IEA's World Energy Outlooks. Reports are shown in colors varying from purple through light green and denote the base year of projection.[78] IEA states that continuous innovation to further improve material and energy efficiency is expected to drive the cost reduction [1].

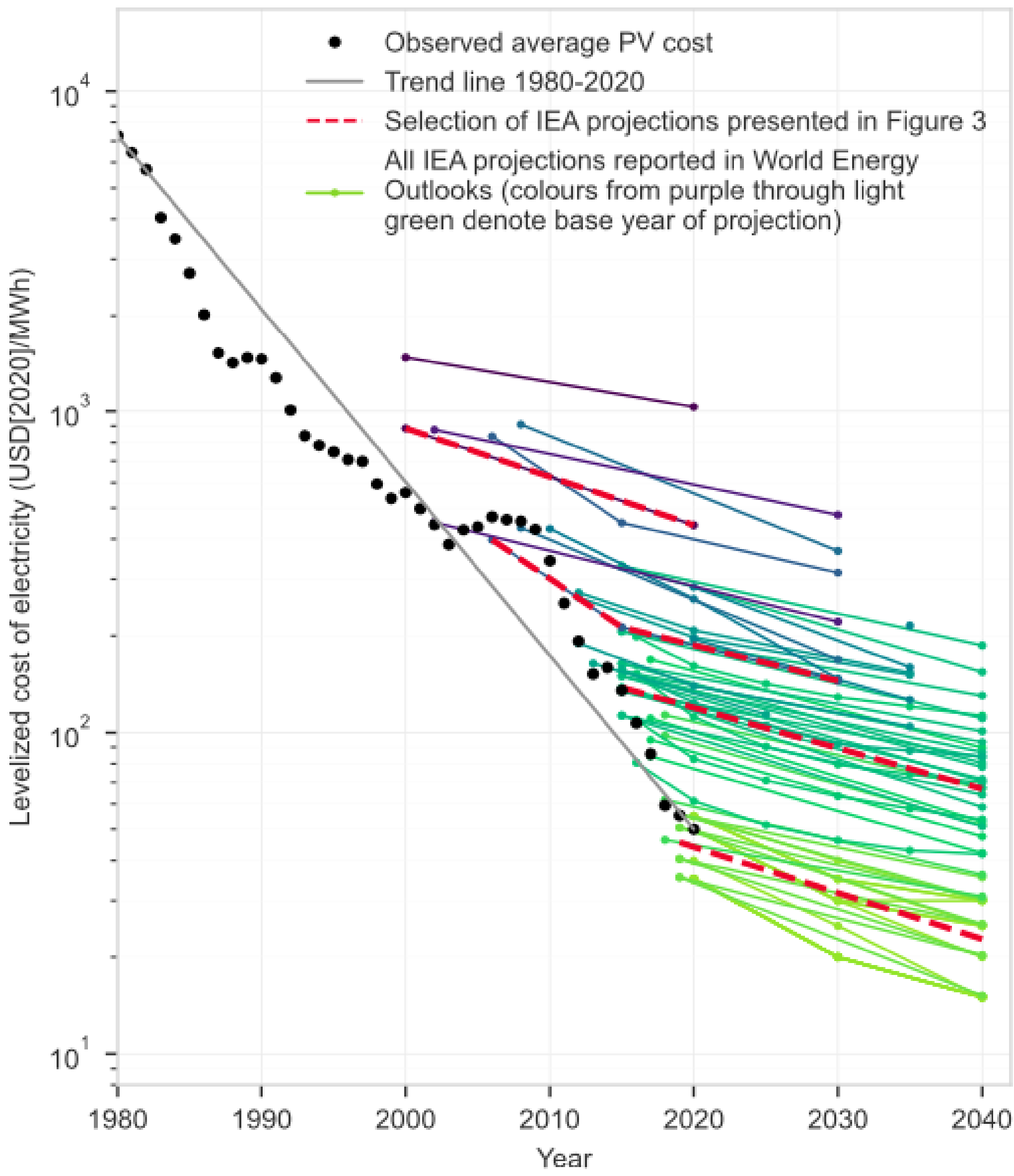


Figure 8.2: *Observed average PV cost and predicted future cost based on IEA projections [78].*

8.3 Energy Prices

The energy system in Europe is currently in a time of major changes. In the last year alone, there have been changes that presumably will impact the power system and prices in long term. The EU has decided to adjust the emission targets for 2030 and proposed several changes to the regulations to achieve this. Consequently, the CO_2 prices have been raised significantly, which in turn had a clear impact on power prices in Norway recent years.[79]

The power prices have been varying even further in short term, both throughout the year and from year to year. 2020 was a year with a lot of rainfall and record low power prices. The opposite was true for the following year.[79] In 2022, NO3 once again experienced greater amounts of rainfall until November. When the snow also melted towards the summer, the magazine filling increased and became close to the historical maximum. However, towards the end of November, the prices in the area increased significantly. According to NVE, this was mainly due to low magazine filling, little wind and high energy prices in the northern part of Sweden. Rapid weather changes combined with high costs on thermal production, have clearly shown how prices can fluctuate in a weather based system.[80] Historical power prices from 2016 - 2023 for NO3 can be observed in figure 8.3 [81].

Midt-Norge - Trondheim (NO3)
Prisene er oppgitt inkludert mva.

Måned/År	2023	2022	2021	2020	2019	2018	2017	2016
Januar	87,01	32,98	56,87	29,12	64,12	38,97	33,97	33,98
Februar	60,82	22,59	55,10	17,43	55,17	47,54	36,32	23,23
Mars		21,60	31,75	12,53	49,97	53,80	35,38	25,48
April		56,34	34,70	6,61	49,70	47,12	34,24	26,11
Mai		19,70	46,11	12,00	47,15	40,65	34,73	27,37
Juni		14,80	44,60	4,22	31,66	53,57	29,39	35,88
Juli		2,38	59,26	3,40	41,57	62,02	29,42	34,50
August		23,61	74,49	8,49	45,63	61,80	32,25	34,52
September		94,12	67,39	13,38	41,38	58,77	38,54	32,56
Oktober		44,97	30,88	16,36	46,25	50,88	33,64	40,76
November		79,72	52,15	7,04	52,22	56,97	38,39	47,85
Desember		226,91	75,96	18,88	44,69	62,70	37,11	36,44

Figure 8.3: *Historical energy prices for NO3 from 2016 - 2023 [81].*

Each year NVE also develops a long-term power market analysis. Based on the long-term drivers seen today, NVE analyses how the power system in Norway and Europe develops towards 2040. The foreseen prices for NO3 are provided in figure 8.4. NVE states that the developments of the power market in Europe towards 2040 largely will be driven by climate policy and technological development. However, it is highly uncertain when and to what extent the changes will take place, which means of action that will be used, and how this overall affects the energy and power markets.[79]

The climate transition is driving the development in the direction of higher CO_2 prices and growth in power consumption. This is also true for Norway. As a result, the power prices increases. Development of more power generation, on the other hand, contribute to a reduction in power prices. At the same time, the development of power production is often controversial and entails natural encroachment and other social impacts. Political trade-offs will be of great importance for the development towards 2040. The desire for more, affordable renewable power production that facilitates increased electrification and industry must be balanced against the desire to minimize the negative effects of more development. All this points to the fact that the development in the coming decades is uncertain. What assumptions are made regarding the development are decisive for the analysis results.[79]

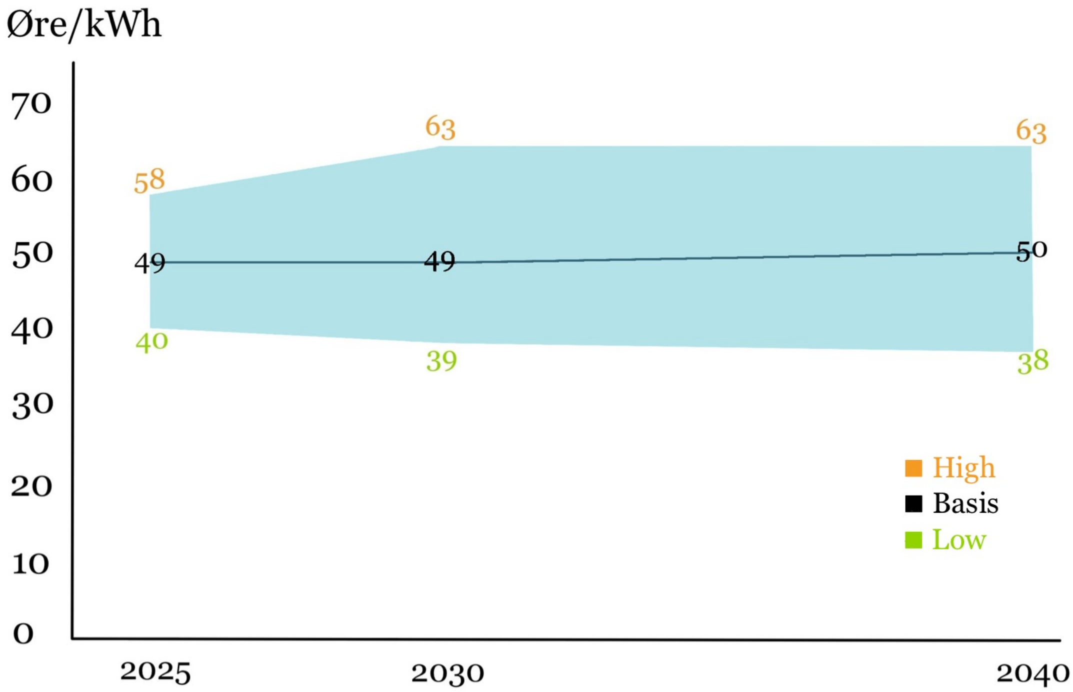


Figure 8.4: *Predicted energy prices towards 2040. The figure is based on numbers from NVE [79].*

8.4 Reference Projects

The need to define a measure of the profitability of PV facilities is highly relevant, and the topic has been addressed by several authors and companies. Multiconsult and THEMA proposed estimates for various Norwegian construction types and the composition of the total cost. As can be seen in figure 8.5, the CAPEX, and its composition, for a PV farm is estimated to be 5.5 NOK/W_p. Furthermore, it is stated that the module constitutes the largest cost across the segments at between 30 - 40% of the total project costs, followed by installation work.[82]

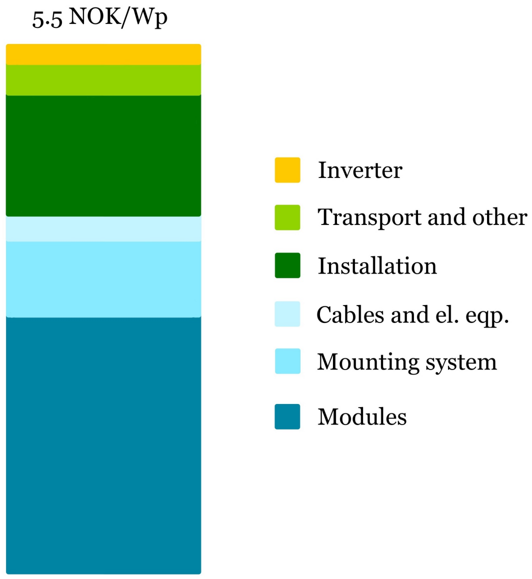


Figure 8.5: *CAPEX and its composition for Norwegian PV power farms. The figure is reconstructed from [82].*

However, other studies show that the CAPEX may vary significantly between projects both within and between countries. Despite the fact that PV system hardware is generally priced the same worldwide and are globally traded, this is true. The main reason for the observed variations, according to the ETRI report by the European Commission, are *soft costs*. Soft costs consist of financing and permitting costs, as well as labour requirements and installer/system integrator margins. In addition, the CAPEX depends on the maturity of the market, i.e. market size and competition between installers, regulatory framework and permitting rules. The ETRI report takes these variations into account. For commercial solar PV above 2 MW_p without tracking systems for 2020, they suggests a CAPEX ranging from 650 - 900 EUR/kW_p with 800 EUR/kW_p as reference. These numbers are expected to decrease to 520 - 720 and 640 EUR/kW_p by 2030, respectively.[83]

The variance in CAPEX is also observed in the Scandinavian countries. A study performed by IRENA mapped the renewable power generation costs in 2020, and proposed a CAPEX of 861 USD/kW_p and 772 USD/kW_p in Sweden and Denmark, respectively [84]. However, another study by IEA suggested a value of 700 EUR/kW_p in Denmark [85]. Furthermore, variations between projects within the same country was enlightened by Lindahl et al.. The authors found that the CAPEX for six PV park projects in Sweden ranged between 603 250 - 776 091 EUR/kW_p.[86] With an exchange rate of 10 NOK/EUR and 10 NOK/USD, the CAPEX prices for the aforementioned reports are given in table 8.1. All of the studies emphasized the strong dependence construction costs have on the CAPEX of the project. The authors further presumed that the PV park size and choice of site were the factors having the greatest impact as these impacted costs for ground preparation and access to infrastructure such as roads and grid.[84–86]

Table 8.1: *CAPEX for European and Scandinavian PV projects listed in different reports.*

Report	**CAPEX [NOK/$\mathbf{W_p}$]**		
	High	**Low**	**Ref.**
THEMA/Multiconsult	-	-	5.50
ETRI	9.00	6.50	8.00
IRENA	8.61	7.72	-
IEA	-	-	7.00
Lindahl et al.	7.76	6.03	-

As for the CAPEX, OPEX also varies greatly between projects and countries. Lugo-Laguna et al. performed an economic comparative analysis of PV energy production for a specific set of countries. In their work, the OPEX for a fixed plate corresponded to 1% of the initial costs of the PV park.[87]

9 Preliminary Project Work

In advance of the master thesis, a project report concerning a HPP at Smøla was conducted. The project mainly mapped the meteorological conditions on Smøla as well as the power production from the wind farm. In addition, a simplified simulation on PV production was performed. This section will present the most essential findings and results of the preliminary work.

9.1 Meteorological Data

Meteorological data related to wind are measured in the wind farm and was provided by Statkraft, whereas there are no measurements of solar irradiation at site. Several sources were therefore evaluated for the latter. One of them was satellite values by Solargis, while the other was actual measurements at Tingvoll, approximately 50 km in air from Smøla. Even though Solargis states that locations at latitudes above 50° can expect greater uncertainties, the two profiles showed no significant deviations from each other. As the data from Solargis also included several types of meteorological data, this option was considered the best alternative.

9.1.1 Wind Velocity and Direction

In general, the findings indicated stronger winds during the winter months, which weaken towards the summer. In addition, high wind velocities appear both during the day and night in the winter, whereas the wind seem highest during noon and decreases towards midnight i the summer.

Wind velocity and direction are measured on a turbine level in the wind farm, and the findings show that both wind velocity and direction varies greatly on the island. This is true for both two turbines placed next to each other and for turbines located at different locations in the wind farm. The variations in the beginning of January 2021 can be observed in figure 9.1 and 9.2. As can be seen in appendix A, turbine 1 and 2 are located next to each other on the northern side of the park, whereas turbine 57 is located in the southern part.

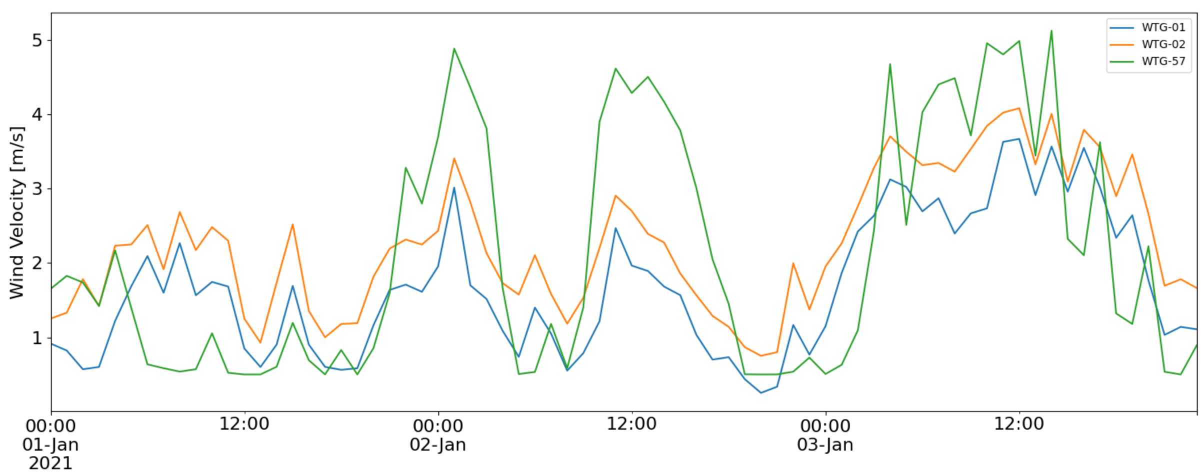


Figure 9.1: *Hourly wind velocity data for a time period of five days in January 2021.*

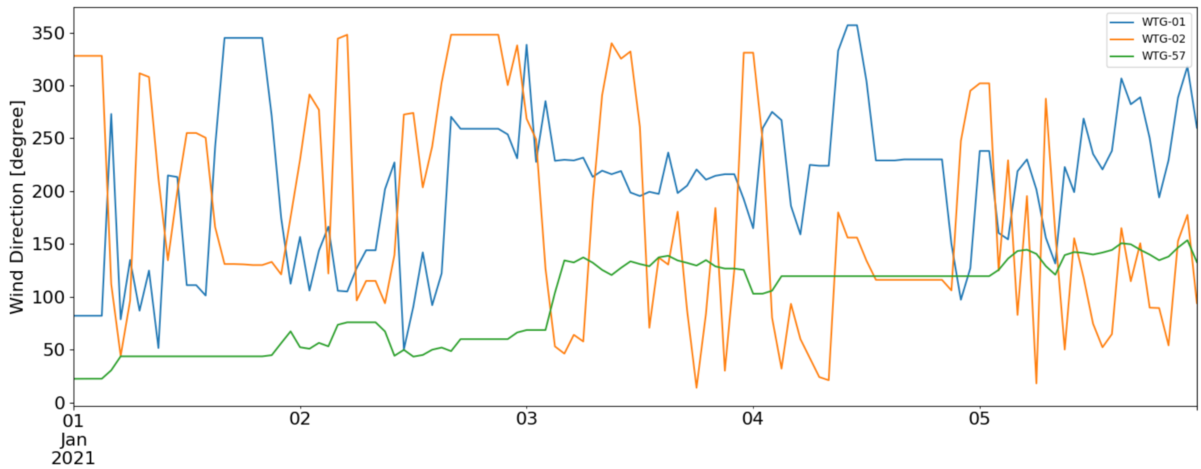


Figure 9.2: *Hourly wind direction for a time period of five days in January 2021.*

9.1.2 Wind vs. Solar Irradiation

As opposed to wind strength, solar irradiance is greater in the summer. This is shown in figure 9.3. Negative correlation was also observed on a daily basis during the entire year, and figure 9.4 presents the correlation in August 2021. When solar irradiance is stronger, the wind is weaker and vice versa. Wind and solar therefore seem to complement each other both on an annual and daily basis.

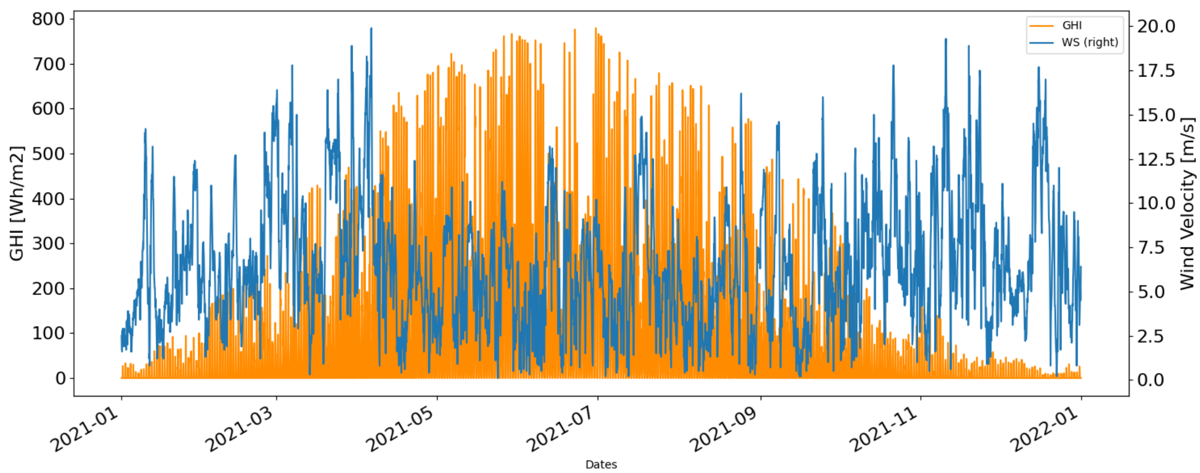


Figure 9.3: *Annual correlation of hourly global solar irradiation and wind velocity.*

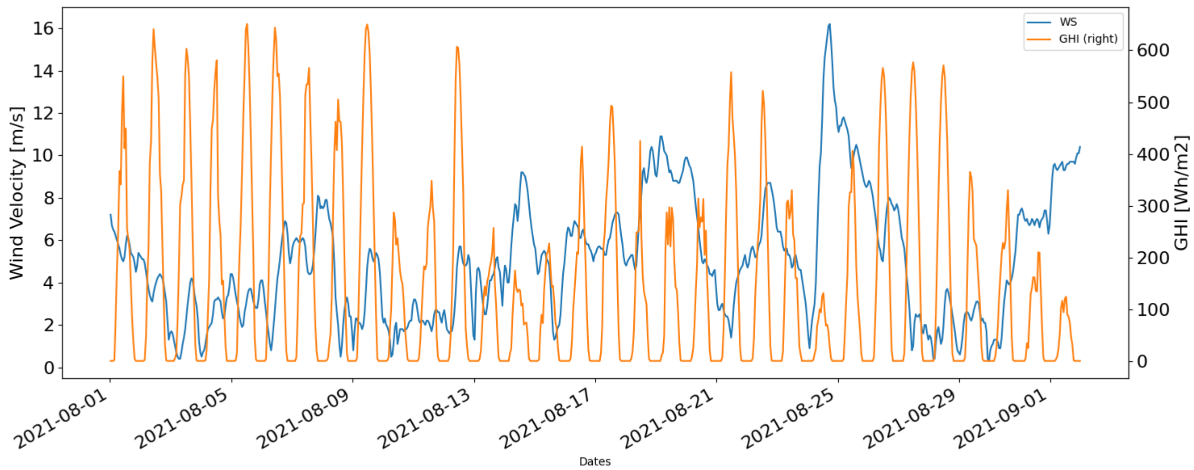


Figure 9.4: *Correlation of global solar irradiation and wind velocity in August 2021.*

9.2 Power Production

In 2021 Smøla wind farm produced a total of 330 GWh, 7.3% lower than Statkraft's expected value of 356 GWh. PV production was simulated in PVSyst where the pre-sizing tool was utilized to calculate the power production possible per 1000 m^2. The simulation kept all other settings at default and did not take near shadings into account. The system then had a specific production of 891 kWh/($kW_p \cdot$ year) and a total annual production of 130 MWh. By utilizing bifacial PV modules, the annual production rose to 173 MWh. As for the meteorological profiles, the production profiles from wind and solar also complement each other. For August 2021, this can be observed in figure 9.5

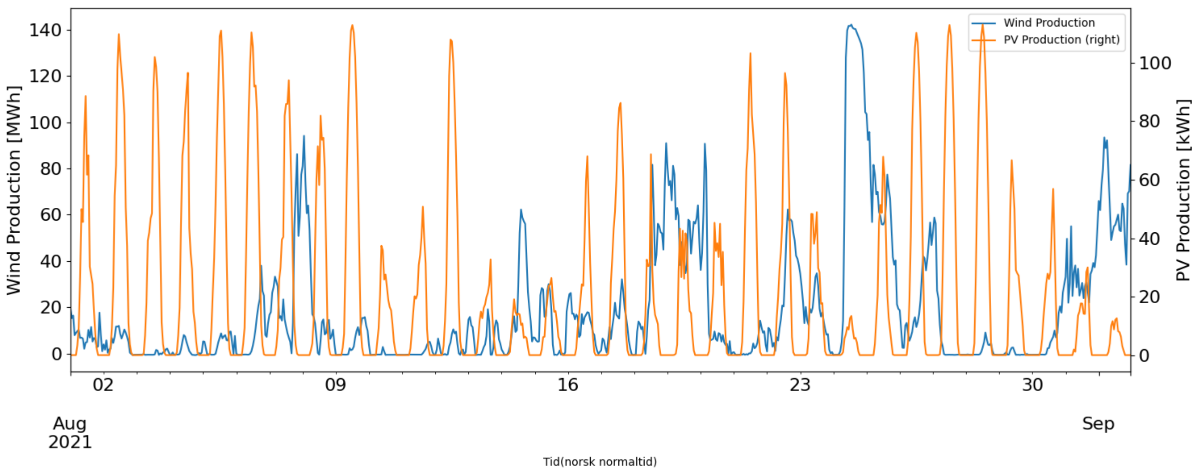


Figure 9.5: *Hourly production profiles for the wind farm and PV panels in August 2021.*

10 Methodology

This chapter outlines the methodology employed to address the research questions posed in this thesis, including the underlying assumptions and choices. Firstly, the three PV capacity scenarios are defined, and a thorough simulation procedure using PVSyst is subsequently undertaken. The utilization of the simulation results for each scenario are then elaborated upon. Finally, the chapter concludes by outlining the procedure for conducting the economical analysis.

10.1 Defining PV Capacity Scenarios

To evaluate the potential for a PV-wind HPP at Smøla, the following three scenarios were defined:

.

1. PV is installed in empty installation spaces for cranes in front of old wind turbine fundaments and roof of the operation building.
2. PV capacity installed corresponds to optimum use of cable to mainland.
3. PV capacity installed corresponds to capacity needed to produce 1000 kg hydrogen per day from excess energy.

The first scenario takes repowering of the wind farm into account. As described in section 3.1, Statkraft has indicated plans for the replacement of existing wind turbines, with the likelihood of these being relocated. This means that the installation area in front of each turbine and the existing cabling can be utilized. In addition, this scenario will utilize the roof on the operation building in the wind farm. A simple system schematic can be seen in figure 10.1.

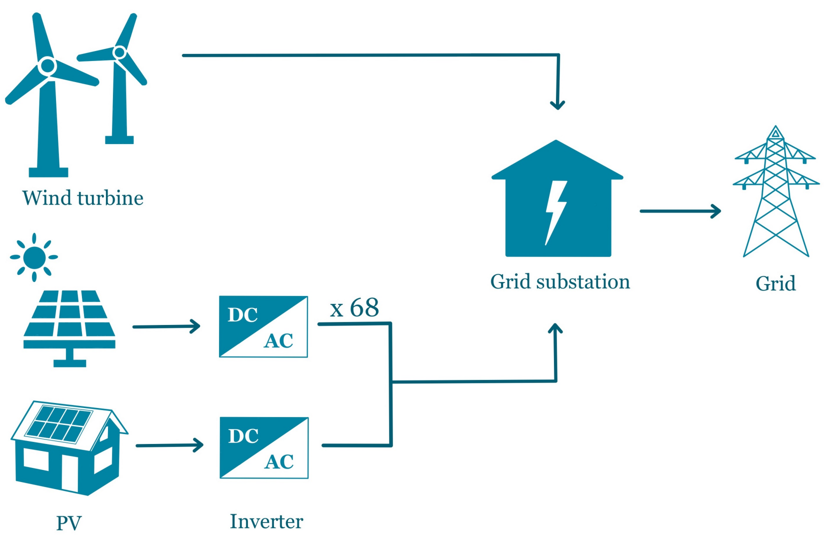


Figure 10.1: *System design of scenario 1.*

The second scenario focus on optimizing use of the existing cable to the mainland. At most times, the capacity of the cable is not fully utilized, and this scenario will therefore find the

PV capacity to do so. Consequently, both resources will be fully utilized without causing the curtailment losses to be dominating. A sketch of scenario 2 is provided in figure 10.2.

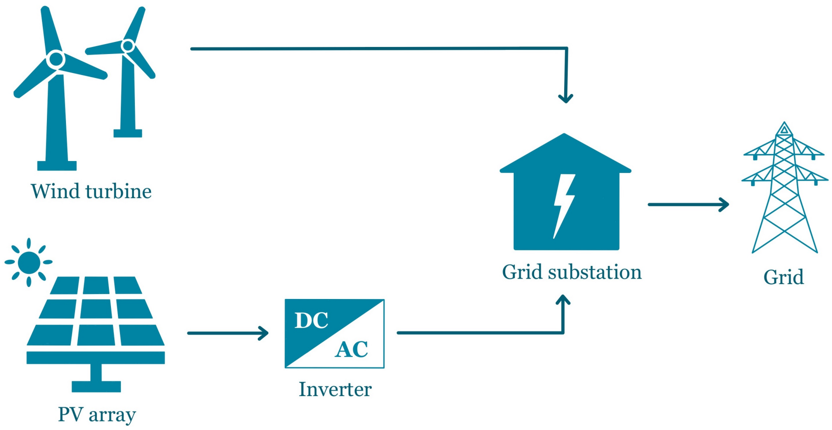


Figure 10.2: *System design of scenario 2.*

The third solution is based on the hydrogen business case described in section 7.1.2, which states that 1000 kg of hydrogen is necessary to make the project profitable. In this case, the excess energy from the HPP therefore needs to cover the energy required to produce 1000 kg hydrogen per day. Consequently, the installed capacity needed in this case will correspond to the capacity producing this amount of excess energy. As presented in figure 10.3, the excess power will produce hydrogen through the electrolysis process.

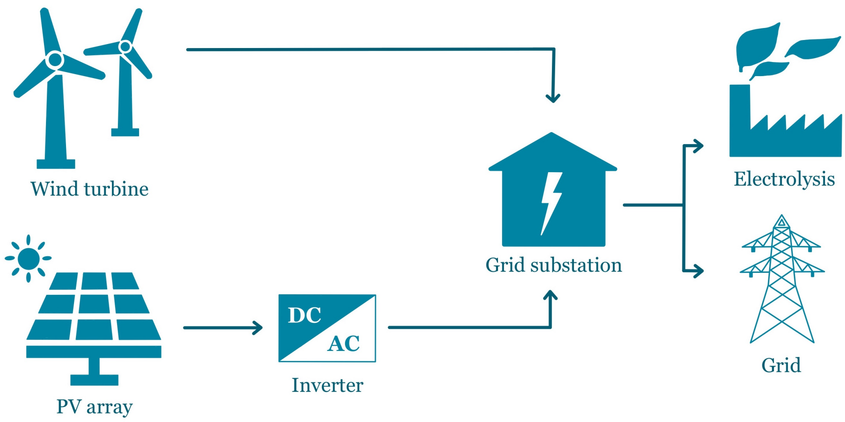


Figure 10.3: *System design of scenario 3.*

10.2 Simulation

The annual PV power production calculations in this thesis were performed as simulations in PVSyst. Even though the three scenarios are unalike, the technical solution and build-up of the PVSyst simulation are similar. This section will provide a thorough description of how the simulation was conducted for a reference area utilized for scenario 2 and 3, before the differences to scenario 1 are explained. The simulations were performed two times; in a reference year and for a year with less solar irradiation to get the worst case scenario, weather-wise.

10.2.1 Importing Data

To be able to simulate, PVSyst first requires a location and meteorological data. As Smøla wind farm and recent weather files do not exist in the software, these had to be imported. The location of Smøla was added by using the coordinates of the wind farm. Furthermore, meteorological data were imported by making a custom file in the *Databases* section. Based on solar irradiation the past ten years, 2014 was suited as a reference year whereas 2013 was used as a low estimate year. All available data were imported from Solargis and included the following: global horizontal radiation, diffuse horizontal radiation, ambient air temperature, wind velocity and relative humidity.

10.2.2 Albedo

PVSyst applies a default albedo value of 0.2 for each month, unless otherwise is specified. Since there is a light snow coverage parts of the winter, the monthly values were changed in the project settings tab. Based on historical snow conditions at Smøla provided by the Norwegian Climate Service Centre and table 5.1, the values in table 10.1 were selected.

Table 10.1: *Albedo values used in PVSyst simulation.*

Month	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Albedo	0.7	0.6	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.7

10.2.3 Orientation

The next step was defining information regarding orientation of the panels. Møre and Romsdal county council has stated that there will most likely not be seasonal adjustments, nor the use of trackers [88]. For that reason, a fixed tilted plane was chosen as field type. Furthermore, a plane tilt of 33° was first chosen based on equation 5.1. To optimize the production, the panels were orientated towards south, corresponding to an azimuth angle of 0°.

10.2.4 System Design

For the system design, the AE Solar 665 W_p bifacial modules and Sungrow 3437 kW inverter were utilized as both brands have been observed in other projects and reports. The number of modules in series and strings were set to 29 and 7459, respectively, and were determined by the total desired module area. The resulting power conditions decided the number of inverters, which was set to 36. An overview of all system settings are shown in figure 10.4.

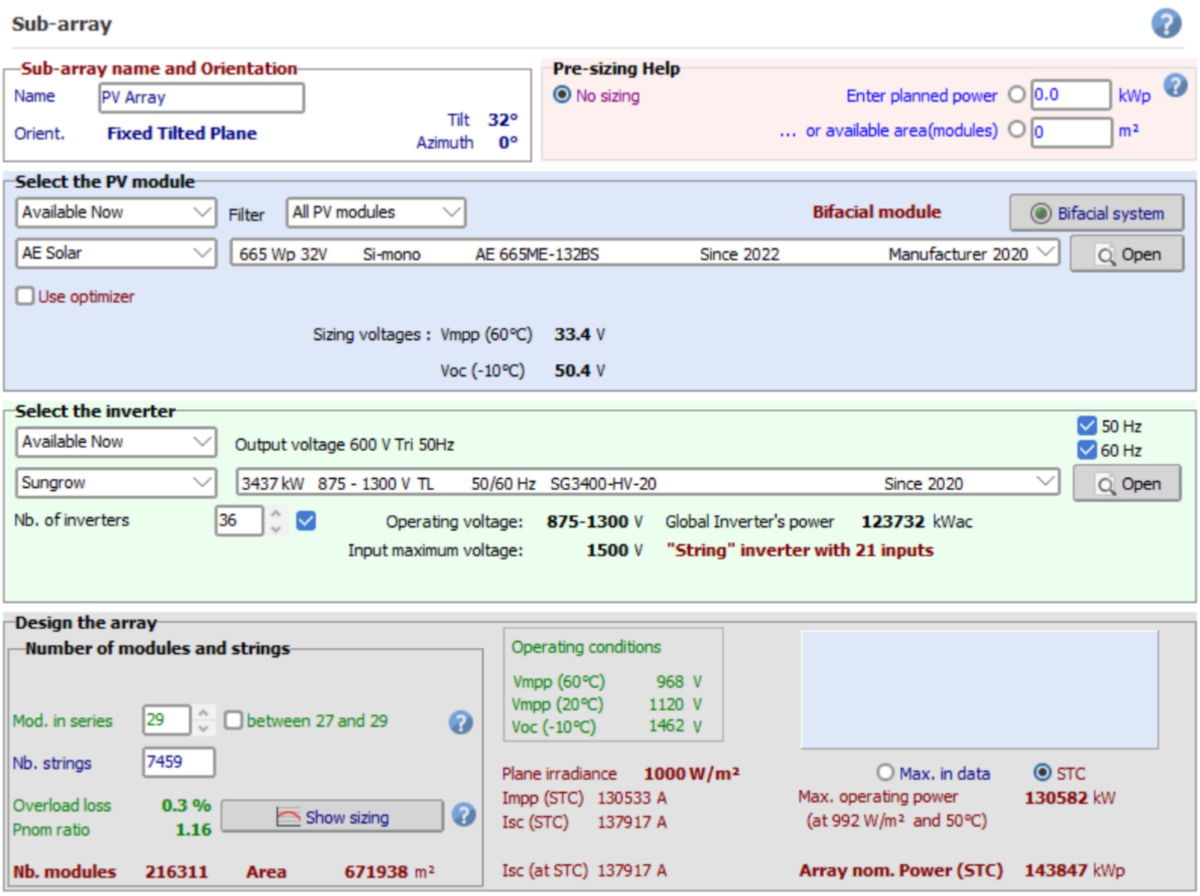


Figure 10.4: *System design settings in PVSyst simulation.*

10.2.5 Detailed Losses

Then the detailed losses were defined. In the thermal parameter tab, the constant loss factor was set to 40 W/(m^{2}K) according to table P.4 in the Norwegian standard SN-NSPEK 3031, shown in figure 10.5. Furthermore, table P.3 in SN-NSPEK 3031 describes monthly soiling losses for several Norwegian cities. These numbers are presented in figure 10.6.[89] A value of two in the summer usually stems from pollen settling on the panels, while the elevated numbers in the winter are caused by snow coverage [90]. However, since Smøla is not one of the locations listed in the table, some adjustments were made. Smøla is highly wind exposed and there are generally little vegetation causing pollen. In addition, there is just a small

Tabell P.4 – Veiledende varmetapsfaktor for solcellemoduler

Forhold	Varmetapsfaktor, U_L W/(m^2·K)	
	Vindeksponert	Lite vindeksponert
Bygningsintegrert, dårlig ventilerte	20	15
Bygningsintegrert, middels ventilerte	25	20
Bygningsintegrert, godt ventilerte	30	25
Bygningsintegrert, meget godt ventilerte	35	30
Frittstående solcellemoduler	45	35

Figure 10.5: *Guiding thermal factor for PV modules [89].*

amount of snow in the winter. Most of the pollen and snow, if any, are therefore assumed to be blown off the panels. However, as Smøla is an island, there may be salt in the air that may settle on the panels. All of these factors causes the soiling losses to be lower than the numbers in the table, and the assumed percentages are presented in table 10.2.

Tabell P.3 – Veiledende verdier for soiling-faktoren, φ_{soil}, for solmoduler som har helning i området 25–40 ° (ref. horisontal flate)

Sted	Måned											
	J	F	M	A	M	J	J	A	S	O	N	D
Stavanger	5	5	2	2	2	2	2	2	2	2	2	5
Oslo	20	25	20	2	2	2	2	2	2	2	5	15
Trondheim	20	25	15	3	2	2	2	2	2	2	5	18
Tromsø	25	25	25	25	2	2	2	2	2	10	15	20
Bergen	5	10	5	2	2	2	2	2	2	2	2	8
Kristiansand	15	25	15	2	2	2	2	2	2	2	2	13
Lillehammer	25	25	25	10	2	2	2	2	2	2	10	25
Drammen	25	25	20	3	2	2	2	2	2	2	5	18
Skien	25	25	20	3	2	2	2	2	2	2	5	18
Tønsberg	15	25	20	2	2	2	2	2	2	2	3	13
Fredrikstad	13	25	20	2	2	2	2	2	2	2	2	8
Ålesund	5	10	5	2	2	2	2	2	2	2	2	3

MERKNAD 1 For solcellemoduler montert med 40 graders helning eller mer kan soiling-faktoren settes til 0.

MERKNAD 2 For vertikalt monterte solcellemoduler kan soiling-faktoren som en første tilnærmelse settes til null. For mellomliggende helning på mellom 40 ° og vertikal (90 °) kan man bruke lineær interpolasjon.

Figure 10.6: *Guiding soiling factor values for PV modules with an incline of 25 - 40° [89].*

Table 10.2: *Monthly soiling losses used in PVSyst simulation.*

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Soiling loss [%]	1.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0

10.2.6 Shading

Shadings are added in two main steps in PVSyst: far shadings and near shadings. Far shadings are typically caused by the horizon and were added from the *PVGIS Horizon from web* as this alternative seemed to be closest to reality. Near shadings were added by creating a 3D scene which was imported to the near shading scene in PVSyst.

Creating 3D Scene

The 3D file was imported from PVCase/AutoCAD, and was provided by COWI. This software makes it possible to import terrain and place PV modules efficiently. The area inside the blue lines in figure 10.7 was used as reference area and is of 2.4 km^2. The variations of marsh, rock, wind turbines and roads in the reference area were assumed to be representative for the entire wind farm.[91]

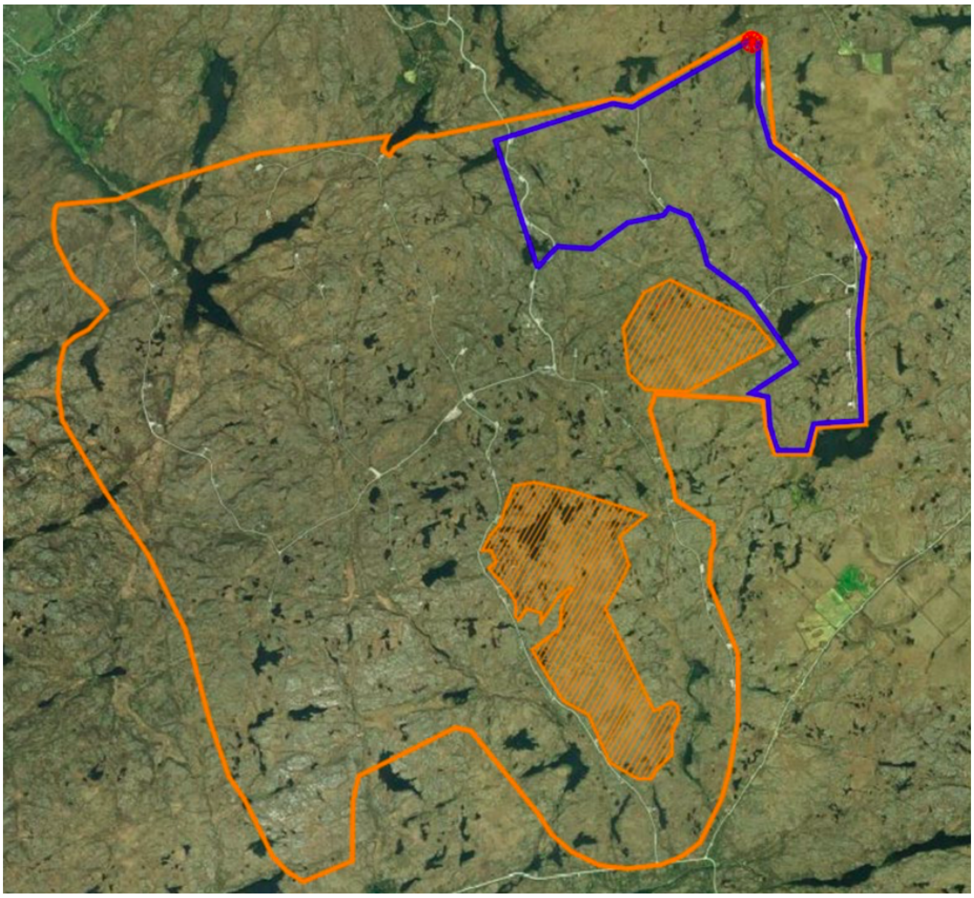


Figure 10.7: *Reference area (blue) used in simulation. Orange line marks the area of the wind farm, while the outlined area in orange are greater areas of marsh.[91]*

PV module groups of 2x12 were placed in the reference area with a minimum of 40 cm above ground. Furthermore, the modules have a tilt angle of 32° and an azimuth angle of 0° for optimizing production. The pitch between the rows was set to 10 m. The modules were placed on rock with spacing for service roads between greater groups of modules, while areas of marsh, water and existing roads were avoided. Marsh was not considered available as it has a high uptake and storage of carbon. In addition, the modules were placed in a sufficient distance from the wind turbines to avoid shading. If the terrain caused the modules to be orientated too much east or west, they were removed.[91]

Near Shading Scene

The 3D file was then imported to PVSyst. Since the turbines appears as *spikes* in the terrain data, these were removed and substituted with wind turbines. The turbines were then modified to match the turbines used at Smøla. A snapshot of a part of the near shading scene is shown in figure 10.8. Furthermore, it was chosen to use linear shading and the shading table was created. The system settings were finally fined-tuned to match the area in the near shading scene, and the tilt angle was changed to 32° for optimal production.

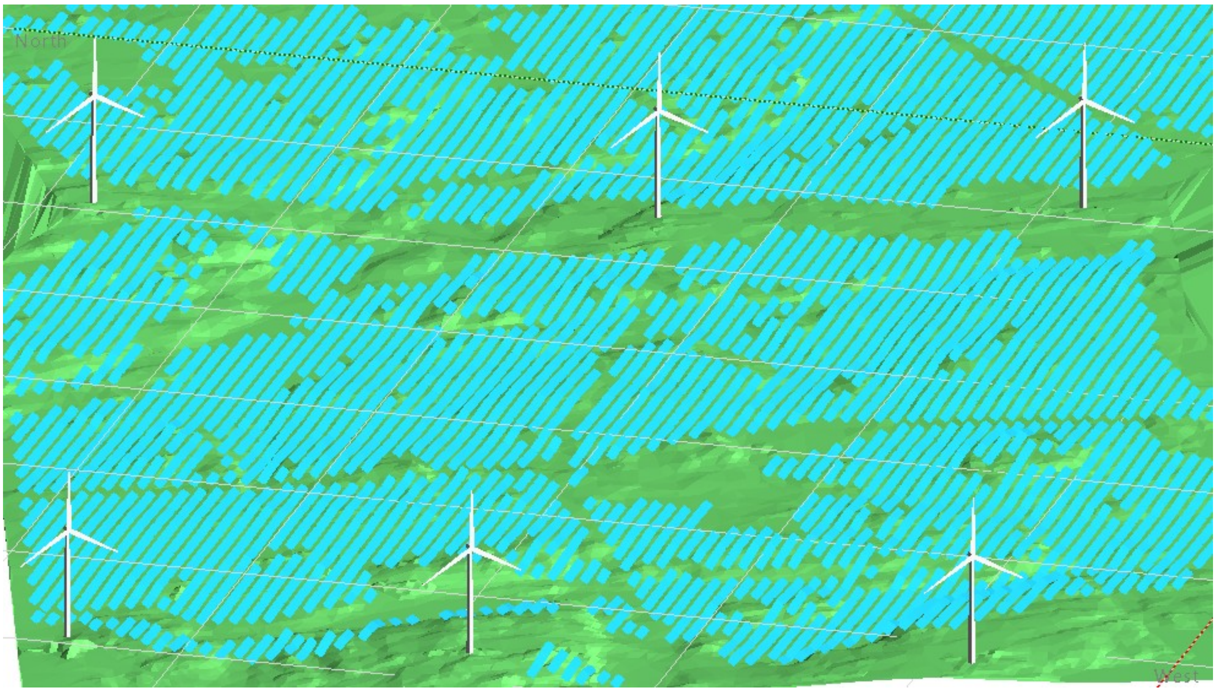


Figure 10.8: *Near shading scene for reference area in PVSyst. Blue areas represent PV modules.*

10.2.7 Specifications to Scenario 1

As scenario 1 makes use of flat and smaller areas, some adjustments were made to the reference simulation. The changes were mainly made to the system settings as well as the near shading scene. In this case, the simulated reference area was the installation space in front of turbine 49. Moreover, as this scenario also utilizes the roof of the operation building, two separate simulations were necessary as it is not possible to set several orientation data in one simulation. Unless otherwise is specified, the procedure is equal as for the reference area and will not be repeated.

System Design

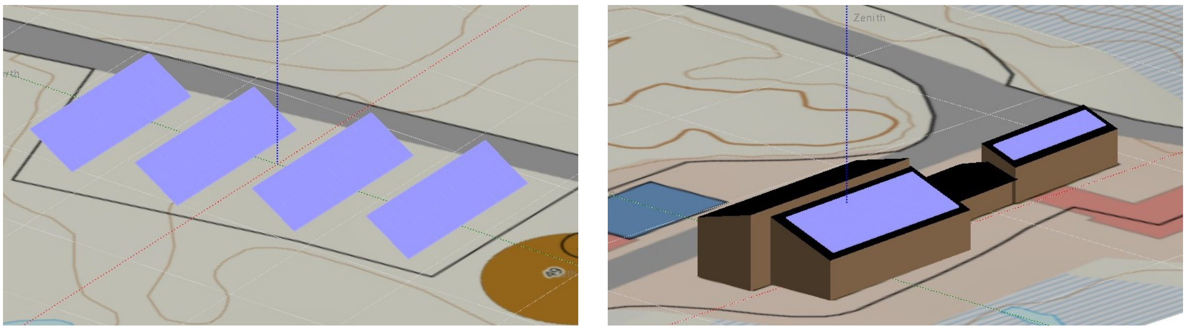
For the empty installation spaces, the same orientation and module type were utilized. However, since this is a smaller system, another inverter was selected. With 19 modules in series and 5 strings, the Sungrow 55 kW inverter suited.

For the operation building, the AE 370 W_p twin 120 half-cells was chosen as modules after conversations with an expert on the theme [90]. Since this case handles two separate roofs of different sizes, two sub-arrays were created. The first sub-array utilizes the Generic 30 kW inverter and has 17 modules in series and 5 strings, whereas the other uses the Generic 7.5 kW inverter, has 6 modules in series and 4 strings.

Near Shading Scene

As this scenario includes panels placed on flat terrain or at a roof with no terrain casting shade, a ground image was imported in both cases. A zone was created for the installation space area and then the same pitch, spacing and distance from ground as for the reference simulation were specified. PVSyst was then able to fill the zone with modules.

For the building roof case, the building was created by using several elementary shading objects. To obtain approximate measurements of the building, *kartdata.no* were used to find lengths and widths, whereas *høydedata.no* were utilized to find the height measures. Furthermore, the nearest wind turbine was added, followed by the function *Transform to PV faces* to fill the two roofs with PV. Snapshots of the near shading scene for both cases are provided in figure 10.9a and 10.9b, respectively.



(a) *Crane installation space.*　　**(b)** *Operation building roof.*

Figure 10.9: *Near shading scenes for scenario 1.*

As the roof is not tilted at 32° and the azimuth is not 0° towards south, the orientation of these panels had to be adjusted in the orientation settings tab. These angles are now at 20° and -2.7°, respectively.

10.3 Scenarios Calculation

After conducting the simulation, the results were analyzed to fit the various scenarios and were then further processed. This work is presented in the following sections.

10.3.1 Scenario 1

As the simulation in 10.2.7 only applies to one of the 68 installation places, the installed capacity and production result had to be scaled up. This was performed by dividing the two by the area of the simulated installation space and then multiply the numbers with the total available area from the 68 spaces. To find this area, *kartdata.no* were utilized. Here the measuring tool was used to measure the area of each space.

10.3.2 Scenario 2

The installed PV capacity in scenario 2 is based on optimizing the existing cable to the mainland. To find this optimal capacity, a code was written in Python. The code summarizes the hourly production from wind and PV for several PV capacities installed, with basis in the production from the reference area. If the hourly sum exceeded the size of the cable to the mainland, the sum was added to the previous sum for that capacity. According to Statkraft, 160 MVA corresponds to 150 MW, and was therefore set as limit [92].

10.3.3 Scenario 3

The capacity in the third scenario must produce enough excess energy to operate the electrolysis process and produce 1000 kg hydrogen per day. After conversations with a PhD student and a professor at NTNU in Trondheim, there seem to be no clear method or standard when performing this calculation. Nevertheless, based on the conversations and other scientific reports, this thesis assumes that the total energy input required for the electrolysis process can be calculated by equation 7.1.[93]

As AWE requires steady power inputs and SOEC has slow start-up and shut-down, the PEM electrolysis cell was selected as basis in the calculation. As described in section 7.1.1, the PEM electrolysis has fast response, efficiency of 65 - 82% and high output pressure. In the calculations, an efficiency of 70% was therefore chosen.

After calculating the daily power needed for the electrolysis, several PV capacities were tested to find the capacity fulfilling the power need. Then it became clear that even by filling the entire available area in the wind farm with PV, several days do not fulfill the energy surplus needed to produce 1000 kg hydrogen daily due to little or no sun. The surplus was then summarized monthly for the same PV capacity, with the assumption that production exceeding 1000 kg one day, covers the remaining required production on a day with less production. Nevertheless, there were still some months that did not have sufficient production. It was therefore assumed that

PV production during the sunny months must cover for the winter days. This means that the minimum energy required corresponds to the daily need multiplied with 365 days. Then the same code as described in section 10.3.2 was utilized to find the corresponding installed capacity of PV.

10.4 Economical Analysis

Reports of other projects in Europe and Scandinavia clarifies that the CAPEX may vary greatly. Based on the reference projects presented in section 8.4, the range is from 5.5 - 9.0 NOK/W_p. Since the PV modules in scenario 1 can be placed on flat surfaces with roads right up to them, in addition to the opportunity of taking advantage of the existing cabling from the old wind turbines, the costs were assumed to be in the lower part of the range. As these factors reduces the installation costs significantly, the CAPEX was set to 5.5 NOK/W_p, following the number for Norwegian PV power parks presented in the report by THEMA and Multiconsult. For scenario 2 and 3, installation is more complicated due to the terrain. The CAPEX was therefore assumed to be higher, and was set to 8.0 NOK/W_p according to the reference value in the ETRI report. In addition, this number seem to match the more expensive projects in Sweden and Denmark.

The same argumentation applies for the chosen OPEX. In accordance with the paper by Lugo-Laguna et al. presented in section 8.4, the OPEX was assumed to be 1% of the initial costs. The OPEX was therefore set to 0.055 NOK/W_p for scenario 1. Due to the extra complications caused by the terrain, the number was assumed to be higher for scenario 2 and 3, and was consequently set to 0.065 NOK/W_p.

The net present value was calculated by equation 8.1. It was assumed that operation of the wind farm is a base scenario, meaning that the extra costs and economical gains are from PV. As other actors have shown interest in hydrogen production, these costs were kept out of the calculation. The net annual savings were therefore calculated to be the difference between annual gains from power sales and OPEX. The former was calculated by multiplying the monthly production with the historical power prices for NO3 shown in figure 8.4, for the respective month. As the prices are fluctuating between years, the annual gains, and therefore the NPV, was calculated for two years. 2019 was considered a representative *normal* year, while 2022 was considered more extreme, compared to previous years. Furthermore, the discount rate was in accordance to the Norwegian standard presented in section 8.1 set to 4%, whereas the lifetime was set to 30 years based on the expected lifetime of PV modules described in chapter 5. All factors utilized in the calculation are provided in table 10.3.

Table 10.3: *Factors utilized in economical calculations.*

	Scenario 1	Scenario 2 and 3
CAPEX [NOK/W_p]	5.5	8.0
OPEX [NOK/W_p]	0.055	0.065
Discount rate [%]	4.0	
Lifetime [years]	30	

To find the power price needed for the project to break even at the end of its lifetime, the LCOE was calculated. This was done by using equation 8.1 and setting the NPV to zero. The remaining factors, apart from the power price, were equal as for the NPV calculation.

11 Results

This section will present the results obtained from the simulation in PVSyst as well as the calculations associated with the economical analysis. This includes annual production values, influence of shading and temperature, and total capacity installed for each scenario. In addition, the NPV and LCOE for each scenario are presented. Unless otherwise is stated, the results apply for the reference year.

11.1 Energy Production

The simulations showed that the reference installation space chosen produced 58.7 MWh annually for the reference year and 56.5 MWh in the lower estimate year. The 68 crane installation spaces corresponded to approximately 62472 m^2, resulting in a total annual production of 4.42 GWh and 4.28 GWh, respectively. Furthermore, the PV modules placed on the roof of the operation building produced 0.0351 GWh in the reference year and 0.0338 GWh in the low estimate year. The annual production for both cases, as well as the specific production, are provided in table 11.1, whereas the total simulation reports for the reference year are provided in appendix B and C.

Table 11.1: *PV power production for scenario 1.*

	Production [GWh/year]		**Specific Production [kWh/($kW_p \cdot$ year)]**	
	Ref. estimate	Low estimate	Ref. estimate	Low estimate
Ground	4.42	4.28	929	900
Roof	0.0351	0.0338	871	839

Furthermore, the simulated reference area had a capacity of 143.8 MW_p and an annual production of 130 GWh and 126 GWh in the reference year and lower estimate year, respectively. The monthly distribution for the former is provided in figure 11.1. May and June were the months with the greatest production, whereas January and December had the least. The total simulation report are given in appendix D.

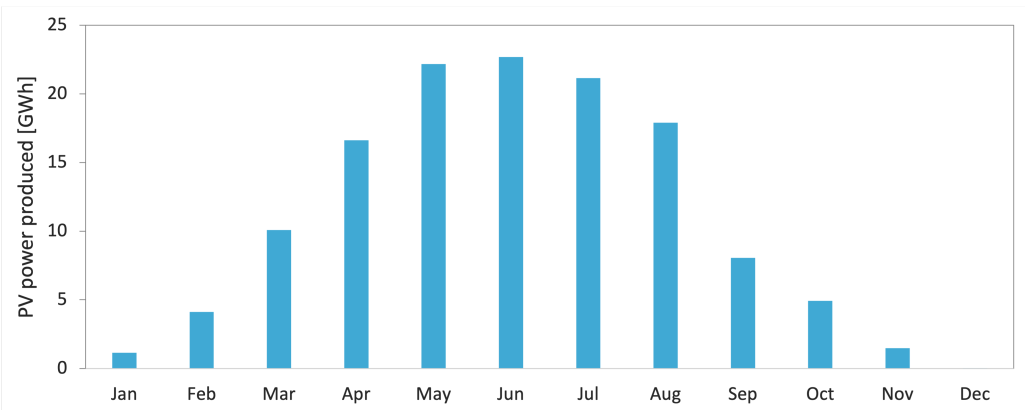


Figure 11.1: *Monthly PV power production for reference area simulation.*

Based on the reference area simulation, figure 11.2 was created. The figure provides a graph of energy curtailed as a function of PV capacity installed. Energy curtailed is relatively constant until it reaches a value of 150 - 200 MW_p. For capacities over these values, the curtailed energy increases significantly. For that reason, 190 MW_p was chosen as the optimal capacity in terms of cable optimization. The resulting annual production for the reference year was then 172 GWh and 167 GWh for the low estimate year. For the former, this capacity results in an energy loss of approximately 3.4% of the HPP's total production of 473 GWh.

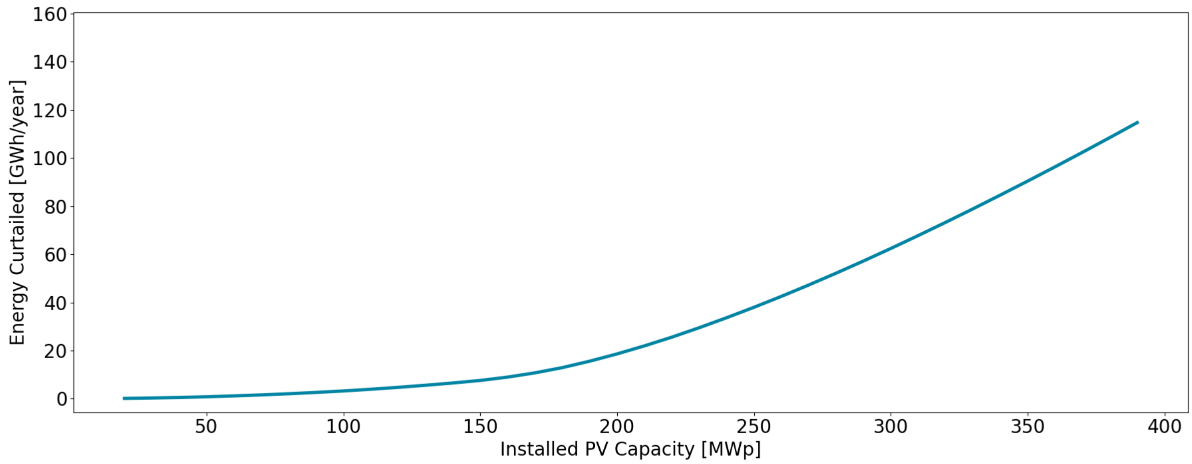


Figure 11.2: *Total energy curtailed at different capacities of PV installed.*

The reference area simulation was also performed without wind turbines in the near shading scene to observe the shading effect from turbines. As presented in table 11.2, the near shading loss was 7.23% without turbines, whereas the number increased to 7.37% when turbines were present. Furthermore, the near shading loss for scenario 1 is just over the half of the reference area. The table also shows PV loss due to temperature, which has a positive value.

Table 11.2: *Near shading loss and PV loss due to temperature.*

	Scenario 1	**Reference area**	**Ref. area without turbines**
Near shadings	- 3.77%	- 7.37%	- 7.23%
Temperature	+ 2.15%	+ 2.13%	+ 2.13%

The electrolysis process has a daily consumption of 56.2 MWh when producing 1000 kg per day. On an annual basis, this equals to 20.5 GWh. As can be seen in figure 11.2, this approximately corresponds to an installed PV capacity of 205 MWh. This gives an annual production of 186 GWh and 180 GWh for the reference and low estimate year, respectively. The annual production as well as the specific production for all three scenarios are presented in table 11.3. The annual production increases with increasing PV capacity, while scenario 1 has the greatest specific production.

Table 11.3: *PV power production for three capacity scenarios.*

Scenario	**Production [GWh/year]**		**Specific Production [kWh/(kWh · year)]**	
	Ref. estimate	Low estimate	Ref. estimate	Low estimate
1	4.45	4.31	929	900
2	172	167	907	878
3	186	180	907	878

Furthermore, the total PV capacity installed for all scenarios, and the area it requires, can be observed in table 11.4. While scenario 1 does not take up any significant fraction of the wind farm, scenario 2 and 3 covers just below 20%.

Table 11.4: *PV capacity installed and required area for the scenarios.*

Scenario		**PV Capacity Installed [MW_p]**	**Area required [km^2]**
1	Ground	4.76	0.0625
	Roof	0.0403	0.000204
2		190	3.17
3		205	3.42

11.2 Economical Analysis

The resulting economical factors utilized in the calculation of the net present value, are provided in table 11.5. This includes CAPEX, OPEX and annual earnings for each scenario. The former has a range of 26.2 - 1641 MNOK, whereas the OPEX ranges from 0.262 - 13.3 MNOK. Furthermore, the economical annual earnings from power sales was significantly higher in 2019 compared to 2022.

Table 11.5: *Total CAPEX, OPEX and annual earnings for the scenarios.*

		Scenario 1	Scenario 2	Scenario 3
Installed PV capacity [MW_p]		4.80	190	205
Annual production [MWh]		4.45	172	186
CAPEX [MNOK]		26.2	1520	1641
OPEX [MNOK]		0.262	12.4	13.3
Annual earnings [MNOK]	**2019**	1.97	75.7	81.8
	2022	1.26	48.3	52.1

The resulting net present value and the LCOE for all scenarios are provided in table 11.6. For 2019, The NPV is positive for scenario 1, whereas the numbers are negative for scenario 2 and 3. In 2022, all numbers are negative. Furthermore, the power price needed for the project to break even are 40 øre/kwh for scenario 1 and 58.2 øre/kWh for scenario 2 and 3.

Table 11.6: *NPV and LCOE for the scenarios.*

		Scenario 1	Scenario 2	Scenario 3
NPV [MNOK]	**2019**	3.31	-424	-458
	2022	-8.86	-899	-970
LCOE [øre/kWh]		39.8	58.2	58.2

12 Discussion

The preliminary project work showed that the production profiles of wind and solar are negatively correlated. Consequently, one of the main prerequisites for hybridizing the wind farm is fulfilled. However, are the PV production potential sufficient for the project to be worth pursuing? Is the project financially sound, and are there other factors to consider? These include some of the questions that will be evaluated in this chapter.

12.1 Production Potential

By simulating the PV production for three different PV capacity scenarios, the annual production was, as expected, greater with increasing capacity. Consequently, scenario 3 had the greatest annual production of 186 GWh, whereas scenario 1 had the least with 4.80 GWh. In comparison, this is in the range of approximately 50% and 1% of the expected annual production from the wind farm alone. All three scenarios indicate production potential at Smøla, even though there is a great gap between the production for scenario 1 and up to the two others.

By observing the specific production of the three scenarios, the range is between 878 - 929 $kWh/(kW_p \cdot year)$ including both the reference and low estimate year. Compared to the expected range of 650 - 1000 $kWh/(kW_p \cdot year)$ described in chapter 5, the simulated numbers are well within the expectations, and lies in the higher range of the scale. This strengthens the reliability of the results. However, when comparing the numbers to the results of the report by Agrawal et al. in section 2.3, the numbers are lower. 45% lower when comparing the best result in this thesis, respectively. Nevertheless, this was an expected outcome. Agrawal et al. simulated PV production in an existing wind farm in India, meaning that the meteorological conditions are completely different than Smøla. India is closer to equator and has generally more hours with sun each year. It is therefore challenging to compare the two directly. Nevertheless, both simulations show potential for hybridizing an existing wind farm despite the fact that the conditions are different.

This was also the conclusion of the preliminary project of the master thesis. As described in section 9.2, the preliminary project simulation showed a specific production of 891 $kWh/(kW_p \cdot year)$. This means that the systems in the master thesis generally have a greater performance even though the simulations are significantly more complex. However, one major reason is attributed to the meteorological data utilized. The year used as reference in this master thesis had more hours of sun during the year compared to the year utilized in the preliminary project, and as will be further discussed in section 12.4, this has a great influence on the result. Nevertheless, comparing the preliminary project result to the specific production of scenario 2 and 3, the number is in the middle of the reference and low estimate year. First of all, this is plausible as the reference year was a better year in terms of sunny days whereas the low estimate year was the opposite. Secondly, this indicates that it is possible to obtain a satisfactory result in PVSyst without making the simulation complex. However, it should be noted that this may be a coincidence for this case only.

Furthermore, scenario 1 had the greatest specific production of 929 kWh/($kW_p \cdot$ year), compared to 907 kWh/($kW_p \cdot$ year) for scenario 2 and 3. This was an expected difference as the PV modules in scenario 1 are placed on flat ground far from wind turbines, whereas the opposite is true for the other two scenarios. In addition, the complexity and accuracy of the shading scene in PVSyst can be considered different. Scenario 2 and 3 utilizes the reference area simulation which has an imported 3D file and an accurate placement of wind turbines. The shading scene for scenario 1 includes neither, only a ground image. As a result, near shadings are significantly reduced. As shown in table 11.2, the near shading loss are 3.77% and 7.37% for scenario 1 and for the reference area, respectively. Furthermore, the importance of optimal tilt and azimuth angle on the specific production can be observed in table 11.1. The modules on the operation building follows the angle and orientation of the roof, and not the optimal tilt angle for the area. This gives a reduction of 6.2% in specific production compared to the installation spaces. This causes less solar rays to hit the module surface, which in turn results in lower production.

Lower production can also be caused by temperature, but in this case, the temperature leads to a production gain. As presented in table 11.2, production increases by 2.13% for the reference area simulation. This gain is mainly due to the wind being able to cool the PV modules from both the front and rare side, in addition to the colder climate at site. This result also confirms the theory regarding increased power performance with decreased temperatures described in section 5.4, and shows that PV modules works better in colder countries like Norway. Furthermore, the energy loss diagram shows a loss of 7.37% due to near shadings. Performing the simulations once again without the presence of wind turbines, the number decreases to 7.23%. This is a decrease of 1.9% and indicates that near shadings mainly stems from the terrain and self-shading by other modules. Like the report by Ludwig et al., presented in section 2.3, the turbine shading can therefore be accounted as nearly negligible. Of the remaining 7.23%, just over the half is most likely caused by self-shading. As seen in table 11.2, near shadings for scenario 1 are estimated to be 3.77%, and since the module parameters are equal for the two simulations, the self-shading loss is assumed to be approximately equal. This value also relatively matches the self-shading loss calculated by Ludwig et al., which was of 3.1%. By designing and placing the modules even more thoroughly in the terrain, the near shading losses could be decreased.

To improve the production even further, there are several possible measures. One alternative is to utilize single or dual-axis tracking systems instead of a fixed system. Such systems increase production as the mounting system ensures that the modules faces the sun throughout the entire day and year. Consequently, the tilt and azimuth angle are always optimal. As a result, more solar rays hit the module surface and power production increases. However, these systems include moving parts, which in turn means higher prices due to the maintenance required. In addition, moving parts significantly increase the risk of damage and faults. This is especially true for a wind exposed island like Smøla. Repairs constitute an unforeseen and unnecessary cost, and relative to the economical gain that would come with increased solar power production, it may not be profitable. The investment costs would also increase as tracking systems are more expensive than the solution chosen.

Regarding storage opportunities, this thesis has assumed that hydrogen is the most relevant method for handling excess energy at Smøla. This is mainly due to the interest shown and to the several reports and planning previously conducted. If production during the sunnier months can cover for that missing in the winter, this thesis also shows that hydrogen storage is possible when installing at least 205 MW_p of PV capacity. However, battery storage still dominates as the most used storage method today and should not be ruled out entirely. As described in chapter 7, the battery provides the opportunity of reducing curtailment loss as it can shift power peaks to periods where there are no capacity challenges. Depending on the battery size, this also means that a greater PV capacity than 190 MW_p can be installed for scenario 2, as the curtailment will be reduced. Nevertheless, it is not certain that curtailment will be fully eliminated as the battery also has charge and discharging times and will reach its capacity several times in a row at hours with high production. Another option is to add a battery to the 190 MW_p and not increase the PV capacity further. However, due to the complementary production profiles of PV and wind, the economical gain may not cover the extra costs of such a system as the curtailment loss only is 3.4% of the HPP's total production. In addition, the amount of excess energy is low in the winter and higher during the summer. This is caused by a greater PV production, but it is also due to a lower power demand in the summer. Consequently, the battery will be most utilized during the summer while the use during winter will be significantly lower. This leads to a suboptimal use of the battery.

It is here hydrogen has one of its greatest advantages. While the battery often is used to shift power peaks in short time periods, hydrogen can be stored in longer periods of time. If necessary for operational reasons, the hydrogen plant also has the opportunity of purchasing the necessary power needed to operate the plant in winter. A major challenge as of today, however, is that there only are potential users of the products and no certain customers. This makes investing and start-up challenging as income cannot be guaranteed. The positive, however, is that hydrogen constantly is increasing its interest and, as described in section 7.1, is by many seen as one of the pillars of the future energy system. The study by Sopian et al. described in section 2.3 also showed that combining PV-wind hybrids and hydrogen production is a reliable technology which appears to be mature enough for application. Moreover, the fact that several prerequisites already are fulfilled for hydrogen production at Smøla is a great advantage.

12.2 Economical Aspect

Even though scenario 2 and 3 show greater annual yield and may appear the best options in an energy production point of view, the NPV speaks the opposite. While scenario 1 has a positive NPV in the reference year, scenario 2 and 3 show negative numbers. The former is therefore the only alternative giving profitability to the project, and the ranking is now reversed. Based on NPV, scenario 1 appears as the best alternative, followed by scenario 2 and finally 3. Nevertheless, when the Norwegian PV market becomes more mature, and if the PV module prices decrease as described in section 8.2, the NPV for scenario 2 and 3 may also turn positive. As seen in figure 8.5, PV module prices represent the greatest investment cost and therefore have a significant impact on the CAPEX and thus the NPV.

However, PV module price is not the only economical factor with a great impact on the NPV. Also annual earnings, more specifically power prices, are of great importance. Power prices represent one of the several uncertainties in the estimates for priced impacts, and there is a particularly high degree of uncertainty associated with power prices in the future. The market is today characterized by variable prices, and it is challenging to estimate the future development. As NVE states in their annual long-term market analysis: the development in the coming years is uncertain and what assumptions are made regarding the development are decisive for the analysis results. Consequently, the LCOE was calculated to find the minimum price at which the electricity must be sold for the project to break even at the end of its lifetime. For scenario 1 to break even, a power price of 39.8 øre/kWh is needed, while the number is 58.2 øre/kWh for scenario 2 and 3. Comparing these numbers with the average of today's power prices, 58.2 is higher. The average of 2019 and 2022 were 47.5 øre/kWh and 53.3 øre/kWh, respectively. This also shows that the required power price for scenario 1 is lower than the LCOE, and gives one explanation to why the NPV is positive and shows profitability.

Comparing the LCOE to NVE's predicted energy prices towards 2040 in figure 8.4, however, both prices are within the range by 2030. As stated in section 3.1, this is the year Statkraft expects to be finished with the repowering of the wind farm, which in turn means that all three scenarios have potential of becoming profitable. This is especially true if module prices also are lowered. On the other hand, the calculated LCOE shows the annual average power price and does not take seasonal variations into account. With 2022 power prices, scenario 1 had a negative NPV even though the annual average power price was above the calculated LCOE. As seen in figure 8.3, power prices were low in the summer and high in November and December compared to previous years. Comparing these monthly prices to the monthly power production in figure 11.1, the negative NPV for scenario 1 in 2022 is explained. The production was highest during the summer at the same time as the power prices were at their lowest, while the production was close to zero when the prices reached maximum. Consequently, the annual earnings became less compared to 2019 values even though the average power price was higher. If the coming years are like 2022, with unusually low prices in the summer when there is PV production, and higher prices in the winter when production is low, then the LCOE can be misleading. The annual earnings may then actually be lower and a positive NPV calculated by the average annual price may even turn negative.

12.3 Other Considerations

Even though production potential and economical costs are crucial in the process of deciding PV capacity scenario, there are several non-priced factors that also should be taken into consideration. These include socio-economical factors such as security of supply, environmental impacts, sustainability and local repercussions. Even though all scenarios increase the former, scenario 2 and 3 have a greater security of supply than scenario 1 due to the great gap in production. Regarding environmental impacts, greenhouse gas emissions should be compared to what reduced. When establishing a PV farm, there are several contributors to emissions, and these are linked to e.g. land encroachment in carbon-rich areas, increased or changed traffic and transport patterns, emissions from construction activities and material production. In this case, emissions will increase with increasing installed capacity, meaning that scenario 1 will have the least impact. On the other hand, a greater capacity means that a greater amount of the power generated by fossil fuels in Europe can be replaced with renewable energy, which in turn will reduce emissions. As scenario 3 also provides the opportunity of replacing fossil fuels in e.g. boats and busses with hydrogen, this alternative appears best in this case. Furthermore, local repercussions include impacts on tax revenues, number of jobs, and consequences for local businesses. All scenarios will have a positive impact on these factors, and the impact probably increases with increasing capacity.

Moreover, the potential for research and development work as well as research facilities are present as there currently are no PV farms in the scale of this project, nor any HPPs in Norway today. In addition, scenario 3 provides the opportunity of discovering the interaction between a HPP and hydrogen production. Scenario 3 therefore has the greatest potential in a research and development point of view, followed by scenario 2 and then 1. As described in section 3, Smøla wind farm is already used for research related to wind power production. By having such work on solar, the region, and Smøla specifically, will be put on the map.

Another factor of importance is related to the process of getting concession to the project. As described in section 3.1, NVE sets strict requirements and requires impact analysis' on nature, environment and society before a project is approved. As several birds such as eagles and ptarmigans have their nesting area within the limits of the wind farm, it is not certain that the area required by the modules for scenario 2 and 3 will be approved. If other biological species also are affected, both animals and vegetation, getting concession for these scenarios may be challenging. In addition, as the wind farm is a popular hiking area, the PV coverage of ground may be considered as a contamination of sight. Since NVE further sets strict requirements for removal, covering or revegetation of existing infrastructure that is no longer used, scenario 1 has an advantage in the application process as it can take advantage of what is already there. By doing this, the existing infrastructure does not need to be removed and unused areas are not damaged.

12.4 Sources of Uncertainty

One of the major causes of uncertainty for both production and economical values are related to the fact that there currently are no PV farms of great scale in Norway. In addition, PV in Norway is still in a relatively early stage. As a result, there are no empirical figures for expected production or financial costs. Lack of experience means that one has to estimate a great number of variables, typically based on numbers from projects in other countries. However, even this becomes challenging when meteorological conditions are different and prices are fluctuating both between countries and between projects within the same country. Nevertheless, the interest for projects of greater scale are increasing in Norway and once the experience is there, several of the following uncertainties may be reduced.

The first factors that would make estimates more accurate, are related to investment and operational costs. In this thesis, these two probably represent the greatest uncertainties. With no experience, numbers from neighbouring countries are as close as it can get, but when these numbers also deviates from project to project, the prices are highly challenging to predict. Even discussions with experts on the theme led to no clear answer as no one can say anything for sure. In addition, the fact that there are few reference projects in general that have modules placed in a terrain like Smøla, makes it difficult to assume the extra costs associated with this issue. The real value could therefore lay somewhere in the entire range of 5.5 - 9.0 NOK/W_p, proposed in section 10.4. However, due to the complexity, and thus extra costs related to the installation itself, it is more likely that the costs are somewhere in the middle to high part of the range.

Another economical uncertainty is related to the assumption that costs are linear with the size of the PV farm, for the sake of simplicity. However, this is probably not entirely true. One of the several factors included in the price are labour costs. It is not certain that the number of workers increases at the same rate as the size of the PV farm, and it is likely that there will be some economical advantages of both installing and operating a PV farm of great scale. If the PV farm also is co-operated with the wind farm, the costs would probably be even lower. These factors contribute to the fact that there is not necessarily a linear relationship between the size of the PV farm and the number of workers. It should also be noted that the advantages of big scale may have positive impacts on other elements in costs as well. When multiplying price per installed capacity, even small changes may have great influence on the final result.

However, some of the uncertainties are related to the simulation itself. First of all, the result is dependent on the meteorological file used in simulation. As seen in table 11.3, changing the meteorological file while keeping other factors constant led to a reduction in specific production from 907 kWh/($kW_p \cdot$ year) to 878 kWh/($kW_p \cdot$ year) for the reference area simulation. Even though the reduction is only 3.2%, this may have a significant effect on financial figures. This also means that the result easily can be manipulated to match the wish of the person or the company performing the simulations. The simulations should therefore either use a representative reference year, a typical meteorological year or a year that shows the worst case scenario to not give the client false hopes. Furthermore, there may be an uncertainty in using satellite measurements for meteorological data. As described in section 9.1, Solargis states that regions with latitudes above 50° can expect a greater uncertainty. Only by measuring meteorological data at site, and preferably over several years, this variable can be considered accurate. On the other hand, the preliminary project work showed indications that the difference to reality was not significantly deviating.

Furthermore, the simulations are based on hourly values. However, the weather and thus production may vary from minute to minute. In the west coast of Norway where Smøla is located, all four seasons may be represented within the same hour. This has an effect on the production and possibly the curtailment in particular. At a low resolution like one hour, the data present the average over the corresponding time step, meaning that power peaks occurring for shorter times will be leveled. As a result, the curtailment losses are underestimated. This issue has also been emphasized by several studies and by existing HPPs, and represents one of the main challenges of the technology today. One of them is described in section 2.2, and is the Cynog Park in the United Kingdom. The Cynog Park suffered from a massive curtailment higher than anticipated and emphasized the importance of performing simulations on a 10 or 15 minute basis. If the third scenario is to be chosen, this is not an issue as the excess energy can produce hydrogen. However, if scenario 2 is selected, this is a factor that needs to be considered.

Curtailment is also the topic of another uncertainty. When the total energy produced by the HPP was calculated, PV production was added to the production from wind turbines. However, the wind production data utilized were the energy ejected into the grid, not what is possible to produce. The numbers says nothing about the energy demand at time, nor if energy already is curtailed or if a turbine is stopped due to this reason. Consequently, the total production of the HPP is most likely greater in some periods compared to what is calculated in this thesis. If this leads to a greater amount of excess energy, the PV capacity needed for scenario 3 may be lower. If this is true, the investment costs of the system will decrease, and thus bring the NPV closer to a positive number. The scenario would then become more profitable.

Nevertheless, this may not be the case after all as there are some uncertainties related to the hydrogen calculation as well. As described in section 7.1.2, the hydrogen needed to be produced each day to make the project profitable implies that heat and oxygen from the process also are sold. In this thesis, it is assumed that hydrogen produced during the summer can cover for that missing in the winter. However, this means that the oxygen and heat also needs to be stored or sold when the production is occurring. Storing heat and oxygen adds complexity and costs, so the latter may be the most likely alternative. However, it is not certain that the oxygen demand is equal to what is produced at time, and since the main production takes place in the summer, it is not certain that heat is needed at all. The income from these sales may therefore be lower if the main production is occurring in summer. As a result, the production of hydrogen should probably be higher to make the project profitable. In addition, this thesis has assumed that all excess power can be utilized for hydrogen production, regardless of how great the excess is at a given time. In reality, there is most likely a minimum power needed to run the electrolysis, meaning that some power will be lost due to the energy being too low. This means that more excess energy is required, which in turn means that a greater capacity of PV needs to be installed.

Furthermore, there is an uncertainty related to the use of a reference area in the simulation. Scenario 2 and 3 are based on the production in a reference area which is then scaled. It is therefore assumed that the reference area is representative for the entire wind farm, and that PV module density and performance is equal regardless of the size of the PV farm. However, in reality these assumptions may not be true. If the remaining parts of the area is more hilly and have more areas of marsh and water, placing modules is more challenging and fewer modules would probably fit. The opposite is true if the areas are more flat and have less marsh and water. A reference area is adequate for estimates, but for a more accurate result, the PV production should be performed with all modules placed at their correct location.

Finally, there might be an uncertainty in the calculated PV capacity for scenario 1. For the sake of simplicity, the same module parameters as for the reference area were utilized. However, this may not be the case in reality as the spaces are smaller and have flat grounds. In reality, the modules would probably be designed to fill the spaces more efficiently, meaning that the module layout and spacing would be different. As the spaces themselves also have different layouts, the work would probably have been conducted for each space rather than for just one and then scaled up. Consequently, the installed capacity calculated in this thesis may be lower than what is possible to install.

13 Further Work

If the project of a hybrid power park at Smøla is to be proceeded, there are several topics suited for taking the work further. First of all, a specific location for the PV modules needs to be specified, unless scenario 1 is selected. This includes work on finding the most suited area in the wind farm considering ground composition and topography, influence on wildlife, and the trade-off between location versus the length of the cable to the grid connection point. The placement must therefore take varied disciplines into account, such as site planning, geotechnical engineering, natural diversity and environmental impact, as well as the practicality of installation. Furthermore, optimizing production by e.g. reducing near shadings while making full use of the area is essential. If a measuring device for solar irradiation also is installed at site, the 3D model and simulation becomes more accurate and the results will be closer to reality.

Accuracy can also be achieved by mapping the amount of energy curtailed within the wind farm and by performing simulations on a 10 or 15 minute basis. As discussed in section 12.4, this is essential in avoiding curtailments greater than calculated for. Doing so simplifies designing PV capacity and storage opportunities. Regarding hydrogen storage, a more thorough evaluation of the profitability potential by combining the power potential from the HPP and hydrogen production should be performed. In addition, a simulation combining the two is advantageous to discover the interaction between them. This thesis has assumed that all excess power can be utilized for hydrogen production, regardless of how great the excess is at a given time. In reality, there is most likely a minimum power needed to run the electrolysis, meaning that some power will be lost due to the energy being too low. A simulation could implement that factor. Furthermore, the use of battery storage should be further investigated as it has the opportunity of reducing curtailment loss by shifting power peaks to periods with no capacity challenges. It should also be noted that the battery can be utilized for other services, but these are not weighted in this thesis.

Furthermore, Møre and Romsdal County Council has stated that a socio-economic evaluation of hybridizing the wind farm is of desire. Such an analysis should be performed for each scenario and include security of supply, in addition to environmental impacts, sustainability and local repercussions. In addition, as the experience on PV farms of greater scale in Norway is scarce, the project may also have potential in research and development work. Consequently, this potential should be described and evaluated.

By performing the propositions suggested above, the work will give a more accurate result as well as a broader insight to the scenarios and their impact. Before a final decision is taken among the scenarios, this work should be performed. In addition, the work could further be utilized in an impact assessment used for a concession application.

14 Conclusion

By simulating three different PV capacity scenarios, this thesis has found that all three have potential. The results matches empirical values for Norwegian PV production, which in turn strengthens the reliability of the results. In an energy production manner, scenario 3 has the greatest potential of 186 GWh/year, followed by scenario 2 with 172 GWh/year and then 1 with a production of 4.45 GWh/year. Like other studies performed, near shadings are mainly caused by the terrain and self-shading of the PV array, whereas shading losses caused by turbines are nearly negligible. With basis in the hydrogen business case at Smøla, the thesis further show that the HPP is able to produce a sufficient amount of excess energy if 205 MW_p is installed.

The economical analysis show that the results are sensitive for smaller changes. Nevertheless, scenario 1 is the most profitable alternative, followed by scenario 2 and then 3. In the reference year, the former is also the only alternative with a positive NPV i.e. the only alternative that may give profit to the project. This year, scenario 1 had a NPV of 3.31 MNOK, whereas scenario 2 and 3 had values of -424 MNOK and -458 MNOK, respectively. Furthermore, the LCOE of 39.8 øre/kWh for scenario 1 is lower than the average power price in the reference year, whereas the LCOE is higher for scenario 2 and 3. The two latter had a LCOE of 58.2 øre/kWh. However, with the foreseen future power prices by NVE, all scenarios show potential of becoming profitable by 2030. This is especially true if PV module prices also are lowered.

In addition, non-priced factors should be evaluated before a final decision is taken among the scenarios. This includes socio-economical factors, research and development work and research facilities opportunities, and the possibility of getting concession for the project.

The greatest uncertainties are attributed to the CAPEX and OPEX as there are no Norwegian projects to get experience from. Lack of experience means that these numbers has to be estimated, which entails several challenges. In addition, the results would have a higher level of accuracy if energy already curtailed within the wind farm is mapped, and if simulations were performed on a 10 or 15 minute basis.

References

[1] International Energy Agency. *World Energy Outlook 2022*. Oct. 2022. URL: https://iea.blob.core.windows.net/assets/c282400e-00b0-4edf-9a8e-6f2ca6536ec8/WorldEnergyOutlook2022.pdf (visited on 10/22/2022).

[2] WindEurope. *Renewable Hybrid Power Plants*. July 2009. URL: https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-renewable-hybrid-power-plants-benefits-and-market-opportunities.pdf (visited on 10/22/2022).

[3] Samuel Carrara et al. *Raw materials demand for wind and solar PV technologies in the transition towards a decarbonised energy system*. Apr. 14, 2020. URL: https://data.europa.eu/doi/10.2760/160859 (visited on 11/02/2022).

[4] Vasiliki Klonari et al. *Exploring the Viability of Hybrid Wind-Solar Power Plants*. May 22, 2019. URL: https://hybridpowersystems.org/crete2019/wp-content/uploads/sites/13/2020/03/3A_1_HYB19_063_paper_Klonari_Vasiliki.pdf (visited on 10/22/2022).

[5] GrandView Research. *Hybrid Solar Wind Systems Market Size, Share Report 2020-2027*. 2020. URL: https://www.grandviewresearch.com/industry-analysis/hybrid-solar-wind-systems-market (visited on 10/07/2022).

[6] Kunle Babaremu et al. *Overview of Solar–Wind Hybrid Products: Prominent Challenges and Possible Solutions*. Aug. 19, 2022. URL: https://www.mdpi.com/1996-1073/15/16/6014 (visited on 10/07/2022).

[7] Grand View Research. *Hybrid Solar Wind Systems - Market Analysis, 2021*. 2022.

[8] Google Trends. *Solar Wind Hybrid, Solar, Wind Power—Explore—Google Trends*. Google Trends. URL: https://trends.google.com/trends/explore?date=today%205-y&q=Solar%20wind%20hybrid,Solar,Wind%20power (visited on 10/27/2022).

[9] WindEurope. *Database for wind + storage co-located projects*. URL: https://windeurope.org/about-wind/database-for-wind-and-storage-colocated-projects/ (visited on 10/27/2022).

[10] GE Renewable Energy. *Juhl Energy Partners With GE Renewable Energy to Build First of Its Kind Solar-Wind Hybrid Project*. Nov. 20, 2018. URL: https://www.ge.com/news/press-releases/juhl-energy-partners-ge-renewable-energy-build-first-its-kind-solar-wind-hybrid (visited on 10/27/2022).

[11] Diane Vrielman. *Hybrid parks – new opportunities with multi-technology facilities*. Vattenfall. May 6, 2021. URL: https://group.vattenfall.com/press-and-media/newsroom/2021/hybrid-parks--new-opportunities-with-multi-technology-facilities (visited on 10/27/2022).

[12] Vattenfall. *Vattenfall opens Energypark Haringvliet – a combination of wind, solar and batteries*. Mar. 22, 2022. URL: https://group.vattenfall.com/press-and-media/pressreleases/2022/vattenfall-opens-energypark-haringvliet--a-combination-of-wind-solar-and-batteries (visited on 10/27/2022).

[13] Alberto Alonso Cantalapiedra. *La Plana Hybrid Facility Test Plant*. Mar. 11, 2021. URL: https://higreew-project.eu/wp-content/uploads/2021/03/La-Plana-Overview-V3.0.pdf (visited on 10/07/2022).

[14] HIGREEW. *Official certification of the La Plana Facility*. Mar. 15, 2021. URL: https://higreew-project.eu/official-certification-of-the-la-plana-facility/ (visited on 10/27/2022).

[15] MuseGrids. *SIEMENS GAMESA RENEWABLE ENERGY – March 2021*. Mar. 30, 2021. URL: https://muse-grids.eu/siemens-gamesa-renewable-energy-innovation-technology-s-l-sgre-march-2021/ (visited on 10/27/2022).

[16] David Ludwig et al. *Evaluation of an onsite integrated hybrid PV-Wind power plant*. Oct. 13, 2020. URL: https://www.aimspress.com/article/id/5f859256ba35de64f8a67487 (visited on 10/27/2022).

[17] Monika Agrawal, Bharat Kumar Saxena, and K.V.S. Rao. *Feasibility of Establishing Solar Photovoltaic Power Plants at Existing Wind Farms*. July 18, 2019. URL: https://www.researchgate.net/publication/325521876_Feasibility_of_establishing_solar_photovoltaic_power_plants_at_existing_wind_farms (visited on 10/03/2022).

[18] Seul-Ki Kim, Eung-Sang Kim, and Jong-Bo Ahn. *Modeling and Control of a Grid-connected Wind/PV Hybrid Generation System*. Aug. 21, 2006. URL: https://ieeexplore.ieee.org/document/1668676 (visited on 10/27/2022).

[19] Fatih O. Hocaoğlu, Ömer N. Gerek, and Mehmet Kurban. *A novel hybrid (wind–photovoltaic) system sizing procedure*. Aug. 27, 2009. URL: https://www.sciencedirect.com/science/article/pii/S0038092X09001807 (visited on 10/27/2022).

[20] Kamaruzzaman Sopian et al. *Performance of a PV–wind hybrid system for hydrogen production*. Jan. 1, 2009. URL: https://www.sciencedirect.com/science/article/pii/S0960148108004588 (visited on 10/27/2022).

[21] U.S Department of Energy. *Confronting the Duck Curve: How to Address Over-Generation of Solar Energy*. Oct. 12, 2017. URL: https://www.energy.gov/eere/articles/confronting-duck-curve-how-address-over-generation-solar-energy (visited on 10/27/2022).

[22] Lin Xu et al. *An Improved Optimal Sizing Method for Wind-Solar-Battery Hybrid Power System*. July 3, 2013. URL: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6485020 (visited on 10/27/2022).

[23] Qing Xie et al. *Charge Allocation in Hybrid Electrical Energy Storage Systems*. July 7, 2013. URL: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6532424 (visited on 10/27/2022).

[24] Yuri V. Makarov et al. *Sizing Energy Storage to Accommodate High Penetration of Variable Energy Resources*. Jan. 1, 2012. URL: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6095383 (visited on 10/28/2022).

[25] James D. Maclay, Jacob Brouwer, and G. Scott Samuelsen. *Dynamic analyses of regenerative fuel cell power for potential use in renewable residential applications*. July 8, 2006.

URL: https://www.sciencedirect.com/science/article/pii/S0360319905003447 (visited on 10/28/2022).

[26] Statkraft. *SMØLA VINDPARK*. Sept. 2011. URL: https://www.statkraft.no/globalassets/1-statkraft-public/04-energy-sources/wind-power/faktaark-smola-vindpark_tcm10-17663.pdf (visited on 10/14/2022).

[27] Statkraft. *Smøla vindpark*. URL: https://www.statkraft.no/om-statkraft/hvor-vi-har-virksomhet/norge/smola-vindpark/ (visited on 11/02/2022).

[28] Møre & Romsdal County Council, Smøla Business & culture center, and National wind energy center (NVES). *Green hydrogen production at Vikan, Smøla, Norway*. 2021. URL: https://northsearegion.eu/media/19309/business-case-for-green-hydrogen-production-on-smoela.pdf (visited on 10/12/2022).

[29] Knut A. Rosvold. *Smøla vindpark*. Store norske leksikon. July 6, 2021. URL: http://snl.no/Sm\%C3\%B8la_vindpark (visited on 12/07/2022).

[30] Asbjørn Jonassen Dyrnes. *Smøla samtale*. Statkraft. Conversation. Nov. 9, 2022.

[31] Varsom SeNorge. *Snødybde*. 2022. URL: https://www.senorge.no/map (visited on 12/09/2022).

[32] Gunhild Haugnes. *Statkraft pålegges avbøtende tiltak på Smøla, skal redusere fuglekollisjoner*. Jan. 10, 2022. URL: https://www.europower-energi.no/vindkraft/statkraft-palegges-avbotende-tiltak-pa-smola-skal-redusere-fuglekollisjoner/2-1-1142136 (visited on 12/07/2022).

[33] Harald Kristoffersen and Nina Lindholm. "Møte om solenergi og forskningsprosjekt". Statkraft. Smøla, Mar. 2, 2023.

[34] Acciona. *Wind Energy*. URL: https://www.acciona.com/renewable-energy/wind-energy/ (visited on 12/09/2022).

[35] Håvard Karoliussen. *Compendium TFNE1001 - Vindkraft*. 2016.

[36] Huynh Dong Nguyen. *Wind power curve modeling*. 2020. URL: https://kaggle.com/code/winternguyen/wind-power-curve-modeling (visited on 12/09/2022).

[37] F. González-Longatt, P. Wall, and V. Terzija. *Wake effect in wind farm performance: Steady-state and dynamic behavior*. Sept. 16, 2012. URL: https://www.sciencedirect.com/science/article/pii/S0960148111005155 (visited on 04/03/2023).

[38] Sittichoke Pookpunt and Weerakorn Ongsakul. *Optimal placement of wind turbines within wind farm using binary particle swarm optimization with time-varying acceleration coefficients*. Jan. 24, 2013. URL: https://www.sciencedirect.com/science/article/pii/S0960148112007604 (visited on 04/03/2023).

[39] Xiaoxia Gao, Hongxing Yang, and Lin Lu. *Optimization of wind turbine layout position in a wind farm using a newly-developed two-dimensional wake model*. Apr. 28, 2016. URL: https://www.sciencedirect.com/science/article/pii/S0306261916305633 (visited on 04/03/2023).

[40] J. F. Manwell. *Hybrid Energy Systems*. Jan. 27, 2004. URL: http://resume.marcbrands.com/classfolder/45-859/https@blackboard.andrew.cmu.edu/courses/1/s04-45859/content/_185100_1/hybrid_systems_review.pdf (visited on 11/04/2022).

[41] Håvard Karoliussen. *Compendium TFNE1001 - Solenergi*. 2018.

[42] NTE. *Solcellepanel er lønnsomt!* Aug. 10, 2023. URL: https://nte.no/blogg/solcellepanel-er-lonnsomt/ (visited on 03/30/2023).

[43] Mikal-André Tvedt. *Solkraft*. NVE. Jan. 18, 2023. URL: https://www.nve.no/energi/energisystem/solkraft/ (visited on 02/10/2023).

[44] T. Markvart. *Solar Electricity*. 2nd ed. Chichester: John Wiley & Sons, 2000.

[45] Jeffrey Brownson. *Collector Orientation*. URL: https://www.e-education.psu.edu/eme810/node/576 (visited on 11/03/2022).

[46] Kerry A. Sado, Lokman H. Hassan, and Shivan Sado. *Photovoltaic panels tilt angle optimization*. Feb. 10, 2021. URL: https://www.e3s-conferences.org/10.1051/e3sconf/202123900019 (visited on 11/03/2022).

[47] DS New Energy. *Hvordan finne ut den rette vinkelen for solcellepaneler i solcelle PV-system*. July 19, 2019. URL: https://no.dsisolar.com/info/how-to-figure-the-correct-angle-for-solar-pane-37643825.html (visited on 05/12/2023).

[48] Kristin Rove Bentsen. *Sammenligning av reell energiproduksjon fra PV-anlegg og estimater fra PVsyst, samt lønnsomhetsvurdering av PV-anlegg i Norge*. May 15, 2014. URL: https://nmbu.brage.unit.no/nmbu-xmlui/bitstream/handle/11250/221671/Bentsen%2C%20Kristin%20Rove%202014.pdf?sequence=1&isAllowed=y (visited on 11/03/2022).

[49] Emanuele Calabrò and Salvatore magazù. *Correlation between Increases of the Annual Global Solar Radiation and the Ground Albedo Solar Radiation due to Desertification—A Possible Factor Contributing to Climatic Change*. Dec. 14, 2016. URL: https://www.researchgate.net/publication/311657426_Correlation_between_Increases_of_the_Annual_Global_Solar_Radiation_and_the_Ground_Albedo_Solar_Radiation_due_to_Desertification-A_Possible_Factor_Contributing_to_Climatic_Change (visited on 10/21/2022).

[50] Joseph H. McIntyre. *Community-scale assessment of rooftop-mounted solar energy potential with meteorological, atlas, and GIS data: a case study of Guelph, Ontario (Canada)*. Nov. 27, 2012. URL: https://doi.org/10.1186/2192-0567-2-23 (visited on 11/04/2022).

[51] Niclas D. Weimar. *Albedo*. URL: https://sinovoltaics.com/learning-center/basics/albedo/ (visited on 11/03/2022).

[52] PVEducation. *Shading*. URL: https://www.pveducation.org/pvcdrom/modules-and-arrays/shading (visited on 11/03/2022).

[53] PVEducation. *Hot Spot Heating*. URL: https://www.pveducation.org/pvcdrom/modules-and-arrays/hot-spot-heating (visited on 11/03/2022).

[54] PVEducation. *Bypass Diodes*. URL: https://www.pveducation.org/pvcdrom/modules-and-arrays/bypass-diodes (visited on 11/03/2022).

[55] Amelia Razak et al. *Investigation of the Effect Temperature on Photovoltaic (PV) Panel Output Performance*. Oct. 25, 2016. URL: https://www.researchgate.net/publication/309600416_Investigation_of_the_Effect_Temperature_on_Photovoltaic_PV_Panel_Output_Performance (visited on 04/27/2023).

[56] Andreas Bentzen. *Solcellepanel effekt - hva er virkningsgrad?* Otovo. Mar. 25, 2023. URL: https://www.otovo.no/blog/solcellepanel-solceller/solceller-norge-virkningsgrad/ (visited on 04/27/2023).

[57] Alternative Energy Tutorials. *Temperature Coefficient of a PV Cell.* 2022. URL: https://www.alternative-energy-tutorials.com/photovoltaics/temperature-coefficient.html (visited on 04/27/2023).

[58] Hege Njå Bjørkmann. *Lillebror på sol i Europa øker kraftig.* Norconsult. Aug. 19, 2022. URL: https://www.norconsult.no/aktuelt/nyheter/lillebror-pa-sol-i-europa-oker-kraftig/ (visited on 02/10/2023).

[59] Jarand Hole. *Kapasiteten på solkraftproduksjonen økte jevnt i 2021.* NVE. Apr. 7, 2022. URL: https://www.nve.no/nytt-fra-nve/nyheter-energi/kapasiteten-paa-solkraftproduksjonen-oekte-jevnt-i-2021/ (visited on 02/10/2023).

[60] Oda Andrea Hjelme et al. *Norsk solkraft 2022 – innenlands og eksport.* Aug. 15, 2022. URL: https://www.multiconsult.no/assets/220815-markedsrapport-solenergiklyngen-final-.pdf (visited on 02/10/2023).

[61] Oda Andrea Hjelme et al. *Teknisk potensial for solkraft i Møre og Romsdal.* Dec. 21, 2022.

[62] Equinor. *Battery storage.* URL: https://www.equinor.com/energy/battery-storage (visited on 04/27/2023).

[63] Jun Chi and Hongmei Yu. *Water electrolysis based on renewable energy for hydrogen production.* Mar. 16, 2018. URL: https://www.sciencedirect.com/science/article/pii/S1872206717629498 (visited on 03/15/2023).

[64] Stefania Osk Gardarsdottir and Kyrre Sundseth. *Hydrogen som energi for fremtiden.* SINTEF. Apr. 21, 2023. URL: https://www.sintef.no/fagomrader/hydrogen/ (visited on 04/27/2023).

[65] U.S Department of Energy. *Hydrogen Storage.* URL: https://www.energy.gov/eere/fuelcells/hydrogen-storage (visited on 12/11/2022).

[66] S. Shiva Kumar and V. Himabindu. *Hydrogen production by PEM water electrolysis – A review.* Mar. 29, 2019. URL: https://www.sciencedirect.com/science/article/pii/S2589299119300035 (visited on 03/15/2023).

[67] K. W. Harrison et al. *Hydrogen Production: Fundamentals and Case Study Summaries.* May 2010. URL: https://www.nrel.gov/docs/fy10osti/47302.pdf (visited on 03/23/2023).

[68] Mohit Kumar et al. *Recent trends in photoelectrochemical water splitting: the role of cocatalysts.* Nov. 11, 2022. URL: https://doi.org/10.1038/s41427-022-00436-x (visited on 03/23/2023).

[69] VTT Technical Research Centre of Finland Ltd. *Review of electrolysis technologies and their integration alternatives.* Grant agreement No: 763919, Deliverable No: 2.1. Aug. 31, 2018.

[70] Shruti B. Godbole and Geetha K. Jayaraj. *Project Economic Appraisal Techniques in Construction Industry - A Comparative Study.* Feb. 2019. URL: https://issuu.com/irjet/docs/irjet-v6i2492 (visited on 05/19/2023).

[71] S.J. Garrett. "Chapter 6 - Project Appraisal and Investment Performance". In: *Introduction to the Mathematics of Finance (Second Edition)*. Ed. by S.J. Garrett. Second Edition. San Diego: Butterworth-Heinemann, 2013, pp. 95–119. URL: https://www.sciencedirect.com/science/article/pii/B9780080982403000060 (visited on 02/24/2023).

[72] Vojislav Novakovic et al. *Compendium TEP4235 - Energy Management in Buildings*. 2019.

[73] Kåre P. Hagen et al. *Samfunnsøkonomiske analyser*. Oct. 3, 2012. URL: https://www.regjeringen.no/contentassets/5fce956d51364811b8547eebdbcde52c/no/pdfs/nou201220120016000dddpdfs.pdf (visited on 03/10/2023).

[74] Michael Papapetrou and George Kosmadakis. "Chapter 9 - Resource, environmental, and economic aspects of SGHE". In: *Salinity Gradient Heat Engines*. Ed. by Alessandro Tamburini, Andrea Cipollina, and Giorgio Micale. Woodhead Publishing Series in Energy. Woodhead Publishing, 2022, pp. 319–353. URL: https://www.sciencedirect.com/science/article/pii/B9780081028476000061 (visited on 03/24/2023).

[75] Laura Rodríguez. *What is LCOE and why is it important?* Aug. 18, 2022. URL: https://ratedpower.com/blog/lcoe/ (visited on 03/24/2023).

[76] IRENA. *Renewable Power Generation Costs in 2021*. 2022. URL: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Power_Generation_Costs_2021.pdf?rev=34c22a4b244d434da0accde7de7c73d8 (visited on 03/13/2023).

[77] Jeff Desjardins. *The Exponential View of Solar Energy*. June 25, 2021. URL: https://elements.visualcapitalist.com/the-exponential-view-of-solar-energy/ (visited on 03/14/2023).

[78] Rupert Way et al. *Empirically grounded technology forecasts and the energy transition*. Sept. 21, 2022. URL: https://www.cell.com/joule/abstract/S2542-4351(22)00410-X (visited on 03/14/2023).

[79] NVE. *LANGSIKTIG KRAFTMARKEDSANALYSE 2021 – 2040*. Oct. 2021. URL: https://publikasjoner.nve.no/rapport/2021/rapport2021_29.pdf (visited on 03/10/2023).

[80] NVE. *Kraftsituasjonen fjerde kvartal og året 2022*. Mar. 1, 2023. URL: https://www.nve.no/media/15154/kvartalsrapportq4_2022.pdf (visited on 03/29/2023).

[81] LOS. *Historiske strømpriser*. Mar. 2023. URL: https://aez-app-prd-web-los3.azurewebsites.net/dagens-strompris/historiske-strompriser/ (visited on 03/10/2023).

[82] Adrian Mekki et al. *Verdiskaping og ringvirkninger av solkraftutbygging i Norge mot 2040*. Aug. 2021. URL: https://www.solenergiklyngen.no/wp-content/uploads/2021/08/TE-21-07-Verdiskaping-og-ringvirkninger-av-solkraftutbygging-i-Norge-mot-2040.pdf (visited on 03/08/2023).

[83] Johan Carlsson et al. *ETRI 2014 Energy Technology Reference Indicator projections for 2010-2050*. Dec. 2014. URL: https://data.europa.eu/doi/10.2790/057687 (visited on 03/08/2023).

[84] IRENA. *Renewable Power Generation Costs 2020*. 2021. URL: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jun/IRENA_Power_Generation_Costs_2020.pdf (visited on 03/08/2023).

[85] Mauricio Richter et al. *Technical assumptions used in PV financial models Review of current practices and recommendations*. In collab. with International Energy Agency. May 2017. URL: https://iea-pvps.org/wp-content/uploads/2020/01/Report_IEA-PVPS_T13-08_2017_Technical_Assumptions_Used_in_PV_Financial_Models.pdf (visited on 03/08/2023).

[86] Johan Lindahl et al. *Economic analysis of the early market of centralized photovoltaic parks in Sweden*. Jan. 25, 2021. URL: https://www.sciencedirect.com/science/article/pii/S0960148121018012 (visited on 03/08/2023).

[87] Daniel Lugo-Laguna, Angel Arcos-Vargas, and Fernando Nuñez-Hernandez. *A European Assessment of the Solar Energy Cost: Key Factors and Optimal Technology*. Mar. 15, 2021. URL: https://www.mdpi.com/2071-1050/13/6/3238 (visited on 03/10/2023).

[88] Per Oterholm. *Smøla Samtale*. Møre & Romsdal County Council. Conversation. Nov. 4, 2022.

[89] Standard Norge. *SN-NSPEK 3031:2021 - Bygningers energiytelse - Beregning av energibehov og energiforsyning*. Dec. 3, 2021.

[90] Mari Lauglo. "Introduction to PVSyst". Trondheim, Jan. 30, 2023.

[91] Nils R. Ruud et al. *Utredning solenergi Smøla - V06*. COWI and IFE. Jan. 2023.

[92] Harald Kristoffersen and Nina Lindholm. *Solenergi Smøla*. Statkraft. Conversation. Feb. 14, 2023.

[93] Megan Heath. *Discussion on Hydrogen*. E-mail. Mar. 10, 2023.

A Wind Turbine Location

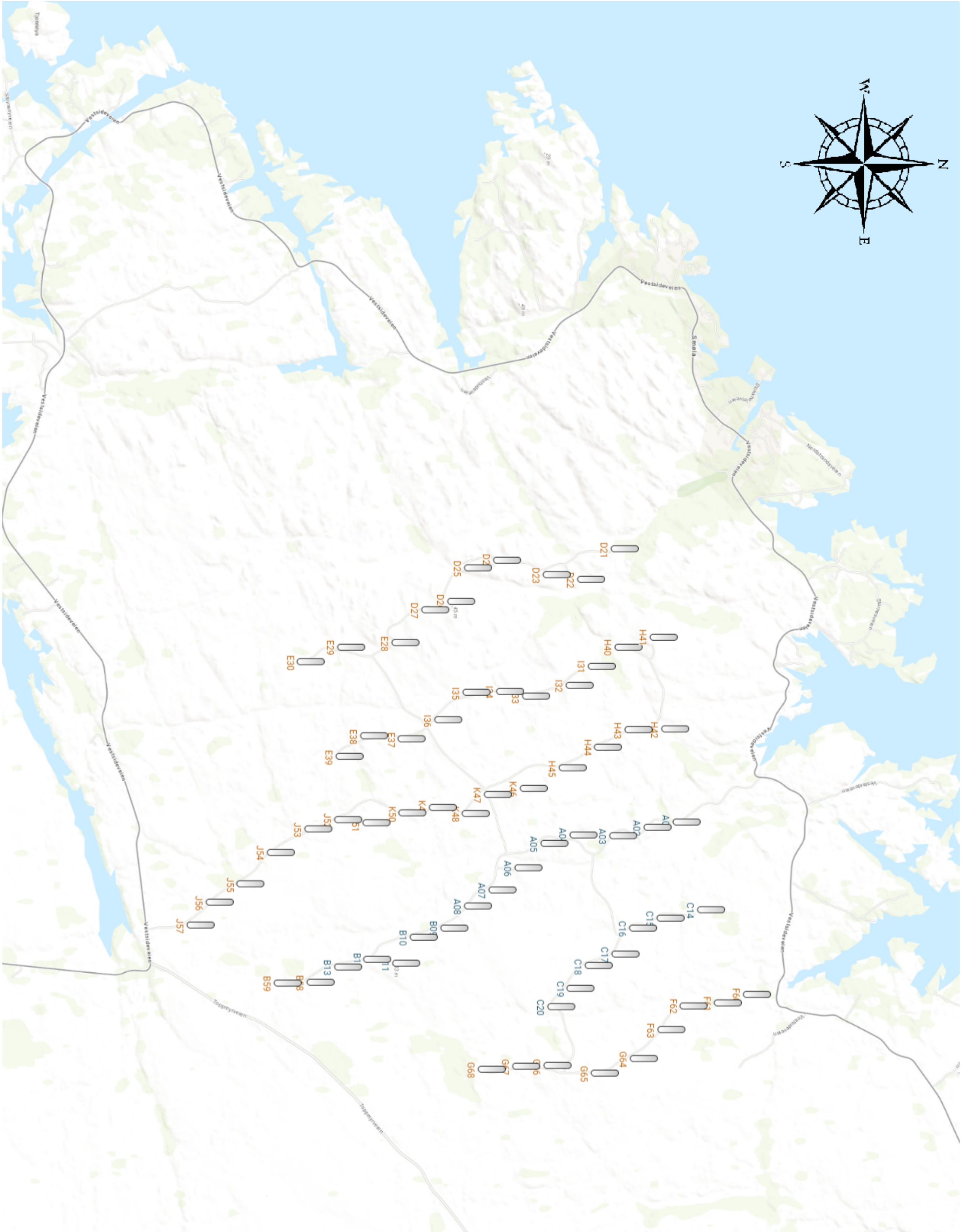


Figure A.1: *Location of each wind turbine at Smøla wind farm.*

B PVSyst Simulation Report: Crane Installation Space

Version 7.3.2

PVsyst - Simulation report

Grid-Connected System

Project: Smøla Hybrid Power Park

Variant: Parking Area

Sheds on ground

System power: 63.2 kWp

Smøla vindpark - Norway

Author

Ida Aure (Norway)

Project summary

Geographical Site
Smøla vindpark
Norway

Situation

Latitude	63.41 °N
Longitude	7.91 °E
Altitude	15 m
Time zone	UTC+1

Meteo data
Smøla vindpark
Custom file - Imported

Monthly albedo values

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Albedo	0.70	0.60	0.40	0.30	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.70

System summary

Grid-Connected System

Sheds on ground

PV Field Orientation
Fixed plane
Tilt/Azimuth 32 / 0 °

Near Shadings
Linear shadings

User's needs
Unlimited load (grid)

System information

PV Array

Nb. of modules	95 units
Pnom total	63.2 kWp

Inverters

Nb. of units	1 unit
Pnom total	55.0 kWac
Pnom ratio	1.149

Results summary

Produced Energy	58711 kWh/year	Specific production	929 kWh/kWp/year	Perf. Ratio PR	88.96 %

Table of contents

General parameters

Grid-Connected System — **Sheds on ground**

PV Field Orientation

Orientation		Sheds configuration		Models used	
Fixed plane		Nb. of sheds	4 units	Transposition	Perez
Tilt/Azimuth	32 / 0 °	**Sizes**		Diffuse	Imported
		Sheds spacing	10.0 m	Circumsolar	separate
		Collector width	4.79 m		
		Ground Cov. Ratio (GCR)	47.9 %		
		Shading limit angle			
		Limit profile angle	23.1 °		

Horizon
Free Horizon

Near Shadings
Linear shadings

User's needs
Unlimited load (grid)

PV Array Characteristics

PV module

Manufacturer	Generic
Model	AE 665ME-132BS
(Original PVsyst database)	
Unit Nom. Power	665 Wp
Number of PV modules	95 units
Nominal (STC)	63.2 kWp
Modules	5 Strings x 19 In series
At operating cond. (50°C)	
Pmpp	57.8 kWp
U mpp	660 V
I mpp	88 A

Inverter

Manufacturer	Generic
Model	SG50-CX
(Original PVsyst database)	
Unit Nom. Power	55.0 kWac
Number of inverters	1 unit
Total power	55.0 kWac
Operating voltage	200-850 V
Pnom ratio (DC:AC)	1.15
Power sharing within this inverter	

Total PV power

Nominal (STC)	63 kWp
Total	95 modules
Module area	295 m²
Cell area	277 m²

Total inverter power

Total power	55 kWac
Number of inverters	1 unit
Pnom ratio	1.15

Array losses

Array Soiling Losses
Average loss Fraction 0.6 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
1.0%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	1.0%

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 40.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

DC wiring losses
Global array res. 124 mΩ
Loss Fraction 1.5 % at STC

Module Quality Loss
Loss Fraction -0.8 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

Strings Mismatch loss
Loss Fraction 0.1 %

Array losses

IAM loss factor

Incidence effect (IAM): Fresnel, AR coating, n(glass)=1.526, n(AR)=1.290

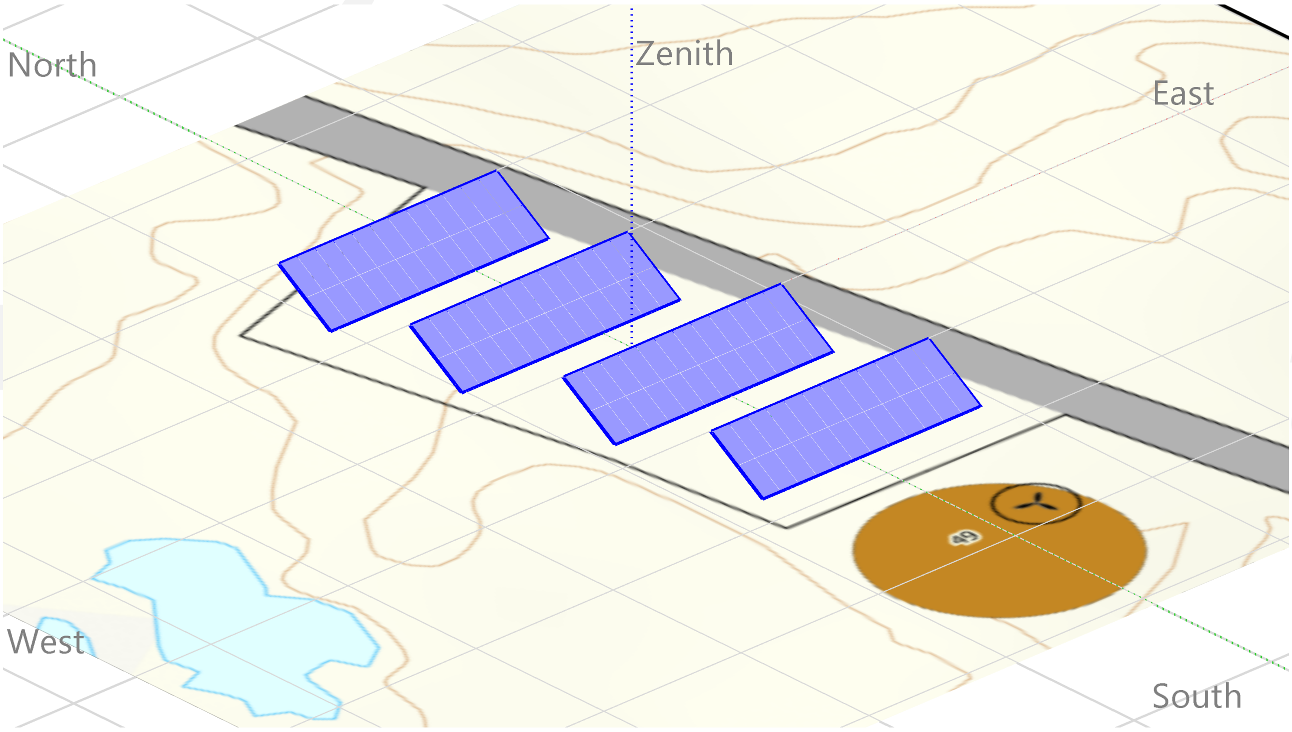
0°	30°	50°	60°	70°	75°	80°	85°	90°
1.000	0.999	0.987	0.962	0.892	0.816	0.681	0.440	0.000

PVsyst V7.3.2
VC1, Simulation date:
27/02/23 12:10
with v7.3.2

Ida Aure (Norway)

Near shadings parameter

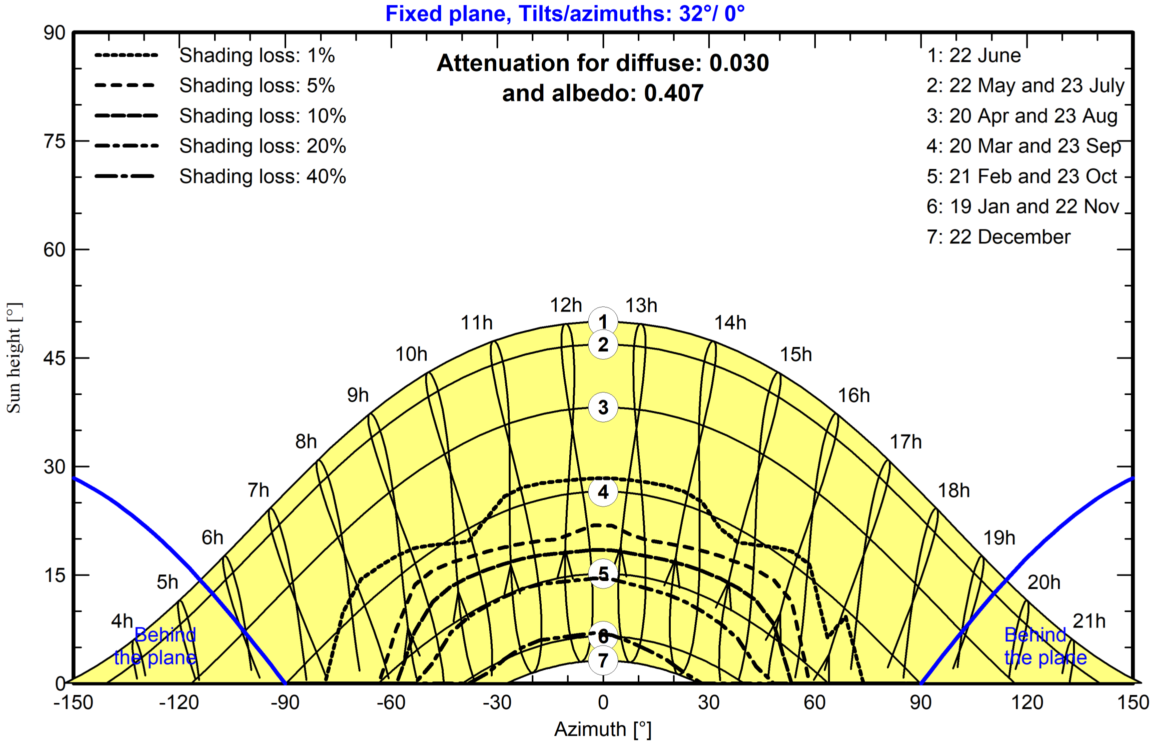
Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

Fixed plane, Tilts/azimuths: 32°/ 0°



Main results

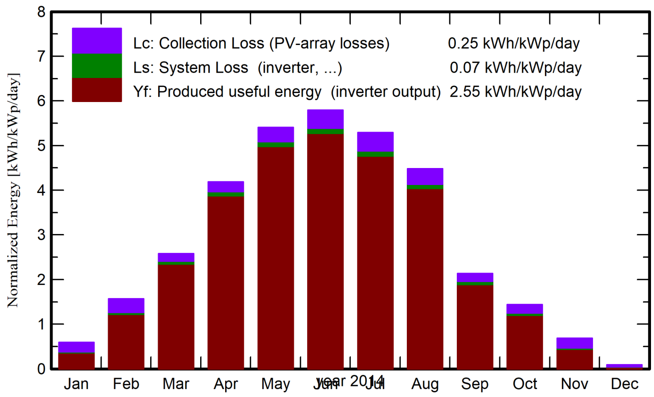
System Production

Produced Energy 58711 kWh/year

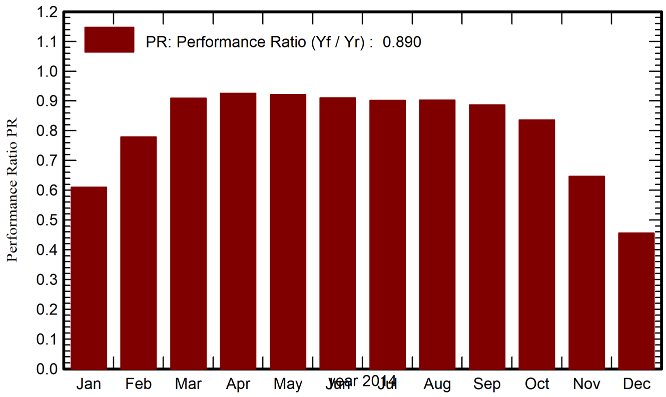
Specific production 929 kWh/kWp/year

Performance Ratio PR 88.96 %

Normalized productions (per installed kWp)



Performance Ratio PR



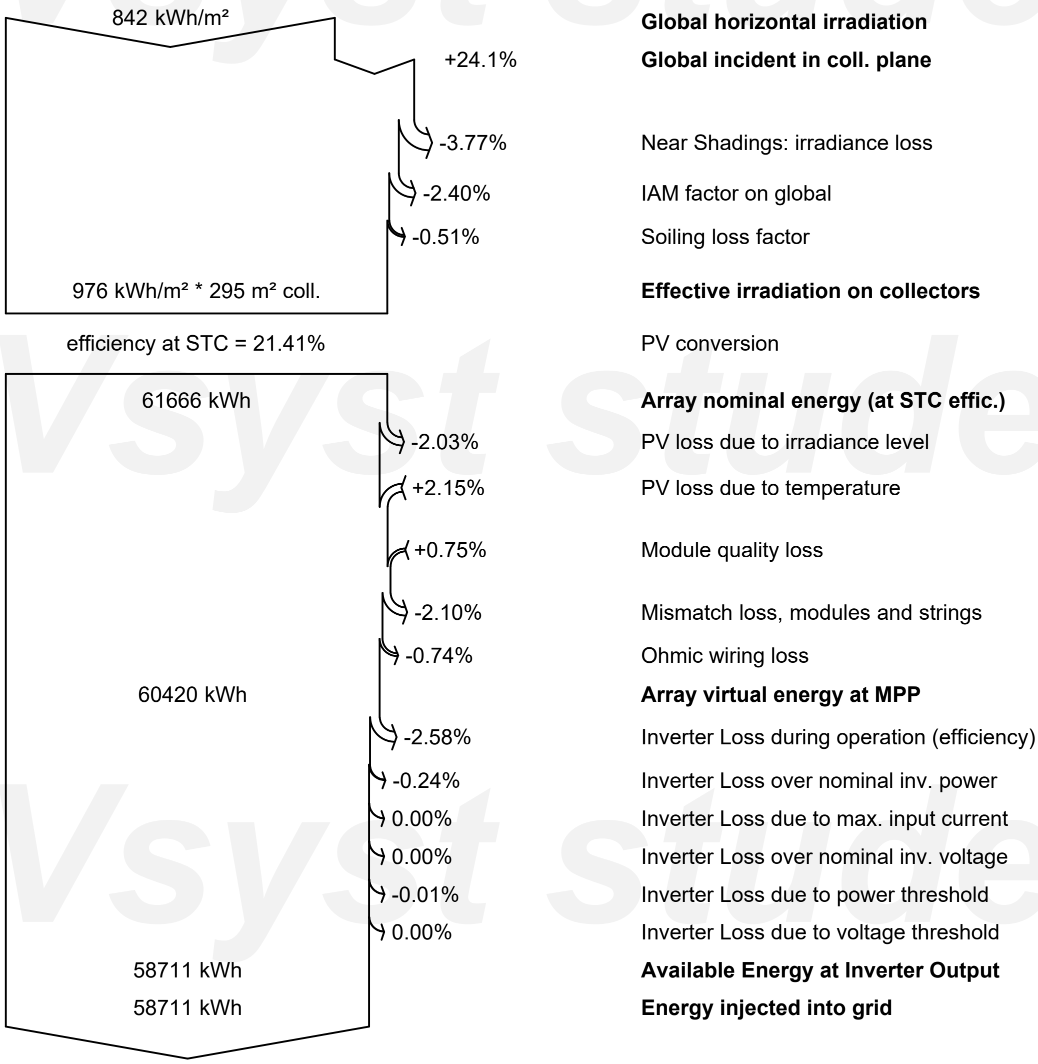
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_Grid kWh	PR ratio
Jan. 14	5.6	3.62	1.74	18.4	12.0	754	709	0.610
Feb. 14	20.1	12.44	4.40	43.9	35.4	2239	2159	0.779
Mar. 14	53.5	31.14	4.57	80.1	74.8	4731	4601	0.909
Apr. 14	100.0	52.69	5.69	125.7	120.0	7524	7351	0.926
May 14	147.2	75.28	7.57	167.7	160.8	9978	9761	0.921
June 14	162.0	81.91	10.73	173.9	166.7	10224	9999	0.910
July 14	150.5	80.66	14.50	164.1	157.0	9561	9346	0.902
Aug. 14	115.8	67.24	14.57	138.9	132.6	8105	7919	0.903
Sep. 14	51.8	38.74	12.84	64.1	60.7	3717	3589	0.887
Oct. 14	26.0	15.97	10.06	44.7	39.8	2454	2359	0.836
Nov. 14	7.8	5.36	7.15	20.6	14.5	893	839	0.646
Dec. 14	1.3	1.16	4.36	2.7	1.7	96	78	0.456
Year	841.6	466.20	8.20	1044.7	976.1	60276	58711	0.890

Legends

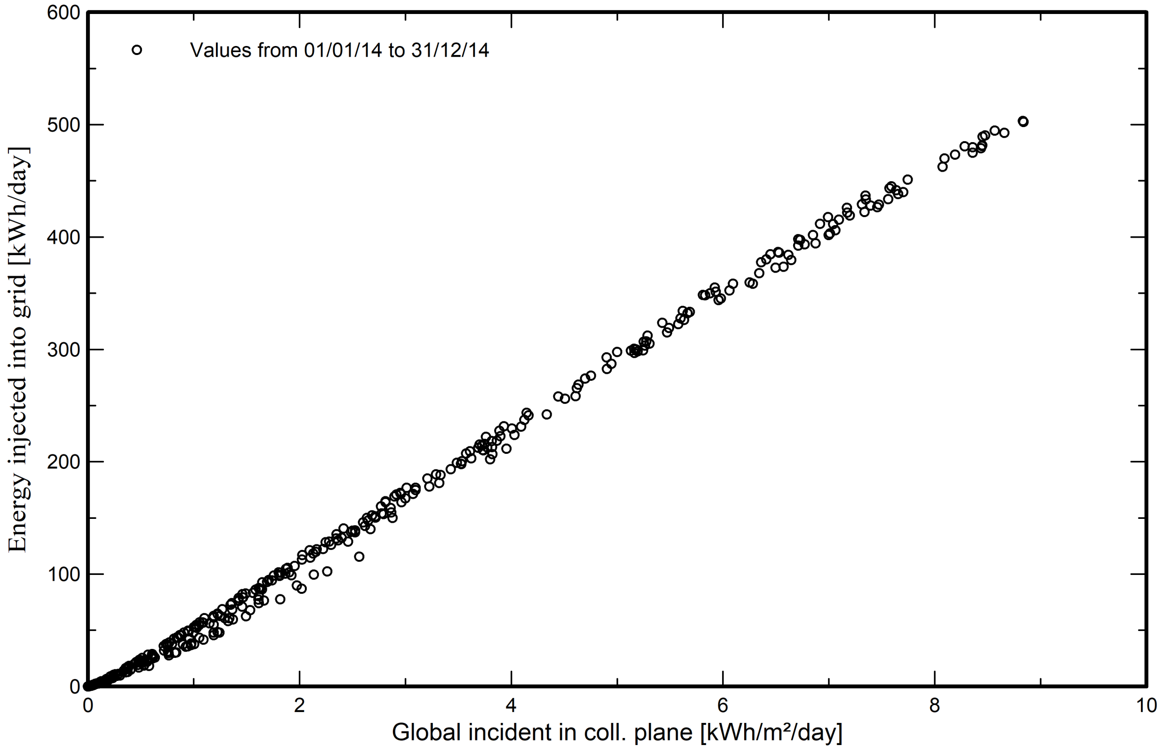
GlobHor	Global horizontal irradiation
DiffHor	Horizontal diffuse irradiation
T_Amb	Ambient Temperature
GlobInc	Global incident in coll. plane
GlobEff	Effective Global, corr. for IAM and shadings
EArray	Effective energy at the output of the array
E_Grid	Energy injected into grid
PR	Performance Ratio

Loss diagram

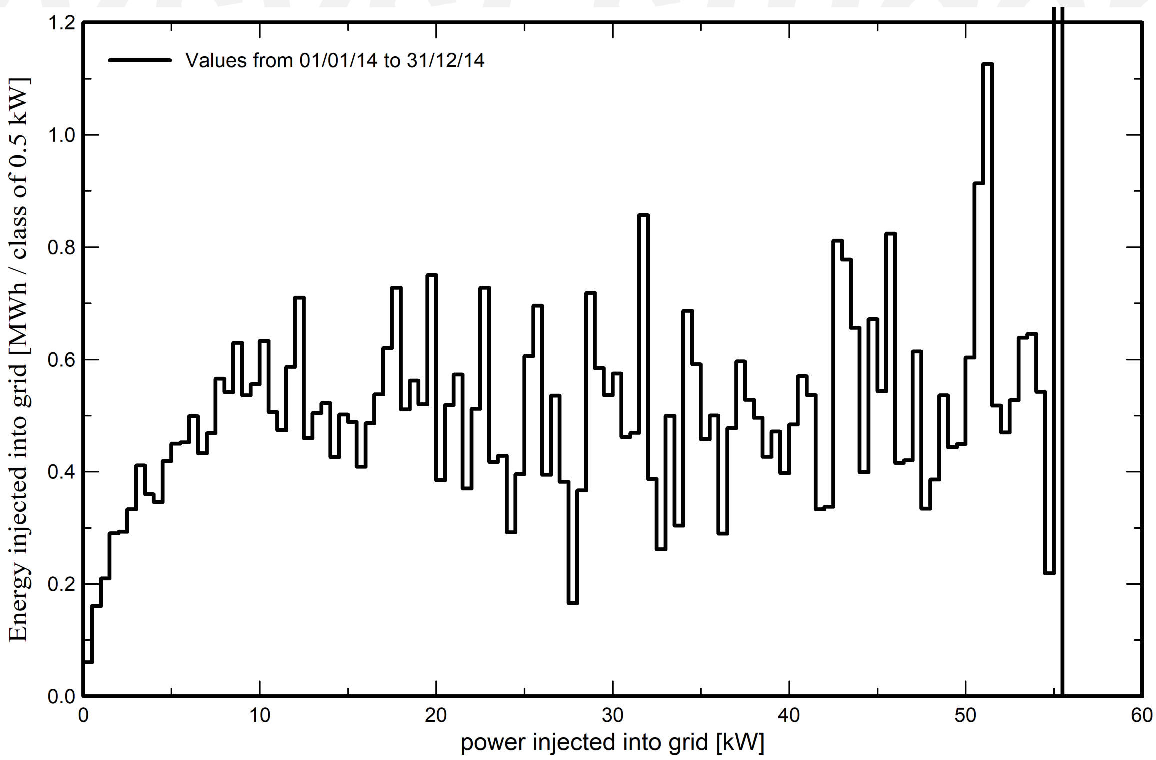


Predef. graphs

Daily Input/Output diagram

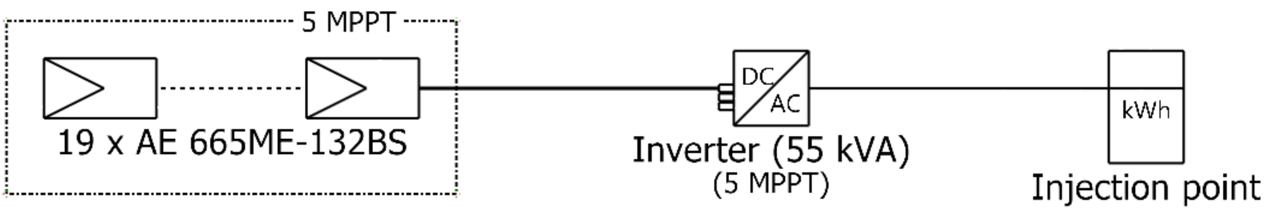


System Output Power Distribution



Single-line diagram

PVsyst V7.3.2
VC1, Simulation date:
27/02/23 12:10
with v7.3.2



PV module	AE 665ME-132BS
Inverter	SG50-CX
String	19 x AE 665ME-132BS

	Smøla Hybrid Power Park	Ida Aure (Norway)
	VC1 : Parking Area	27/02/23

C PVSyst Simulation Report: Building Roof

Version 7.3.2

PVsyst - Simulation report

Grid-Connected System

Project: Smøla Hybrid Power Park

Variant: Roof

Tables on a building

System power: 40.3 kWp

Smøla vindpark - Norway

Author

Ida Aure (Norway)

PVsyst V7.3.2
VC2, Simulation date:
27/02/23 12:12
with v7.3.2

Project: Smøla Hybrid Power Park

Variant: Roof

Ida Aure (Norway)

Project summary

Geographical Site
Smøla vindpark
Norway

Situation

Latitude	63.41 °N
Longitude	7.91 °E
Altitude	15 m
Time zone	UTC+1

Meteo data
Smøla vindpark
Custom file - Imported

Monthly albedo values

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Albedo	0.70	0.60	0.40	0.30	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.70

System summary

Grid-Connected System

Tables on a building

PV Field Orientation
Fixed plane
Tilt/Azimuth 20 / -2.7 °

Near Shadings
Linear shadings

User's needs
Unlimited load (grid)

System information

PV Array

Nb. of modules	109 units
Pnom total	40.3 kWp

Inverters

Nb. of units	2 units
Pnom total	37.5 kWac
Pnom ratio	1.075

Results summary

Produced Energy	35138 kWh/year	Specific production	871 kWh/kWp/year	Perf. Ratio PR	87.89 %

Table of contents

General parameters

Grid-Connected System | **Tables on a building**

PV Field Orientation

Orientation
Fixed plane
Tilt/Azimuth 20 / -2.7 °

Sheds configuration

Models used
Transposition Perez
Diffuse Imported
Circumsolar separate

Horizon
Free Horizon

Near Shadings
Linear shadings

User's needs
Unlimited load (grid)

PV Array Characteristics

Array #1 - PV Array

PV module

Manufacturer	Generic
Model	Mono 370 Wp Twin 120 half-cells
(Original PVsyst database)	
Unit Nom. Power	370 Wp
Number of PV modules	85 units
Nominal (STC)	31.5 kWp
Modules	5 Strings x 17 In series
At operating cond. (50°C)	
Pmpp	28.57 kWp
U mpp	526 V
I mpp	54 A

Inverter

Manufacturer	Generic
Model	30 kWac inverter
(Original PVsyst database)	
Unit Nom. Power	30.0 kWac
Number of inverters	1 unit
Total power	30.0 kWac
Operating voltage	450-700 V
Pnom ratio (DC:AC)	1.05

Array #2 - Sub-array #2

PV module

Manufacturer	Generic
Model	Mono 370 Wp Twin 120 half-cells
(Original PVsyst database)	
Unit Nom. Power	370 Wp
Number of PV modules	24 units
Nominal (STC)	8.88 kWp
Modules	4 Strings x 6 In series
At operating cond. (50°C)	
Pmpp	8.07 kWp
U mpp	186 V
I mpp	43 A

Inverter

Manufacturer	Generic
Model	7.5 kWac inverter
(Custom parameters definition)	
Unit Nom. Power	7.50 kWac
Number of inverters	1 unit
Total power	7.5 kWac
Operating voltage	150-750 V
Max. power (=>25°C)	8.00 kWac
Pnom ratio (DC:AC)	1.18
Power sharing within this inverter	

Total PV power

Nominal (STC)	40 kWp
Total	109 modules
Module area	204 m²
Cell area	181 m²

Total inverter power

Total power	37.5 kWac
Max. power	38 kWac
Number of inverters	2 units
Pnom ratio	1.08

Array losses

Array Soiling Losses

Average loss Fraction 0.6 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
1.0%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	1.0%

Array losses

Thermal Loss factor
Module temperature according to irradiance
Uc (const) 40.0 W/m²K
Uv (wind) 0.0 W/m²K/m/s

Module Quality Loss
Loss Fraction -0.4 %

Module mismatch losses
Loss Fraction 2.0 % at MPP

Strings Mismatch loss
Loss Fraction 0.1 %

IAM loss factor
Incidence effect (IAM): Fresnel, AR coating, n(glass)=1.526, n(AR)=1.290

0°	30°	50°	60°	70°	75°	80°	85°	90°
1.000	0.999	0.987	0.962	0.892	0.816	0.681	0.440	0.000

DC wiring losses

Global wiring resistance 10 mΩ
Loss Fraction 1.5 % at STC

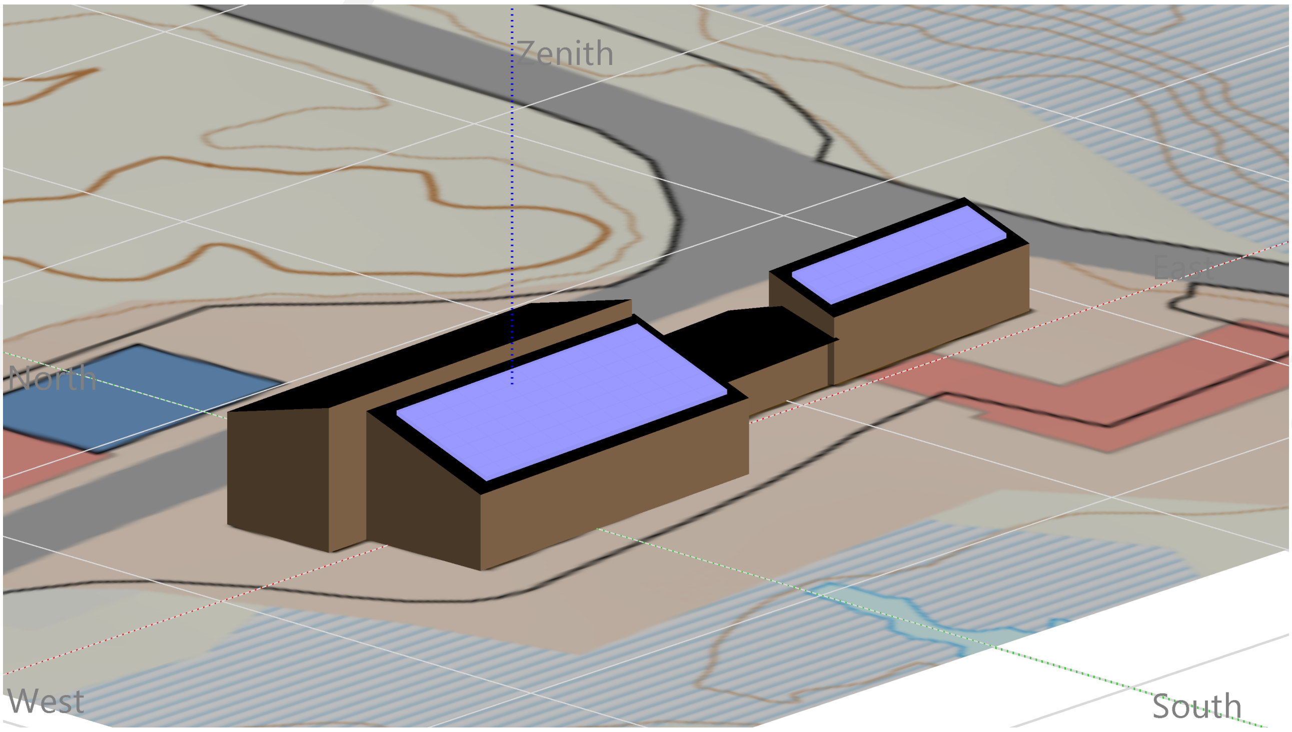
Array #1 - PV Array
Global array res. 162 mΩ
Loss Fraction 1.5 % at STC

Array #2 - Sub-array #2
Global array res. 71 mΩ
Loss Fraction 1.5 % at STC

PVsyst V7.3.2
VC2, Simulation date:
27/02/23 12:12
with v7.3.2

Near shadings parameter

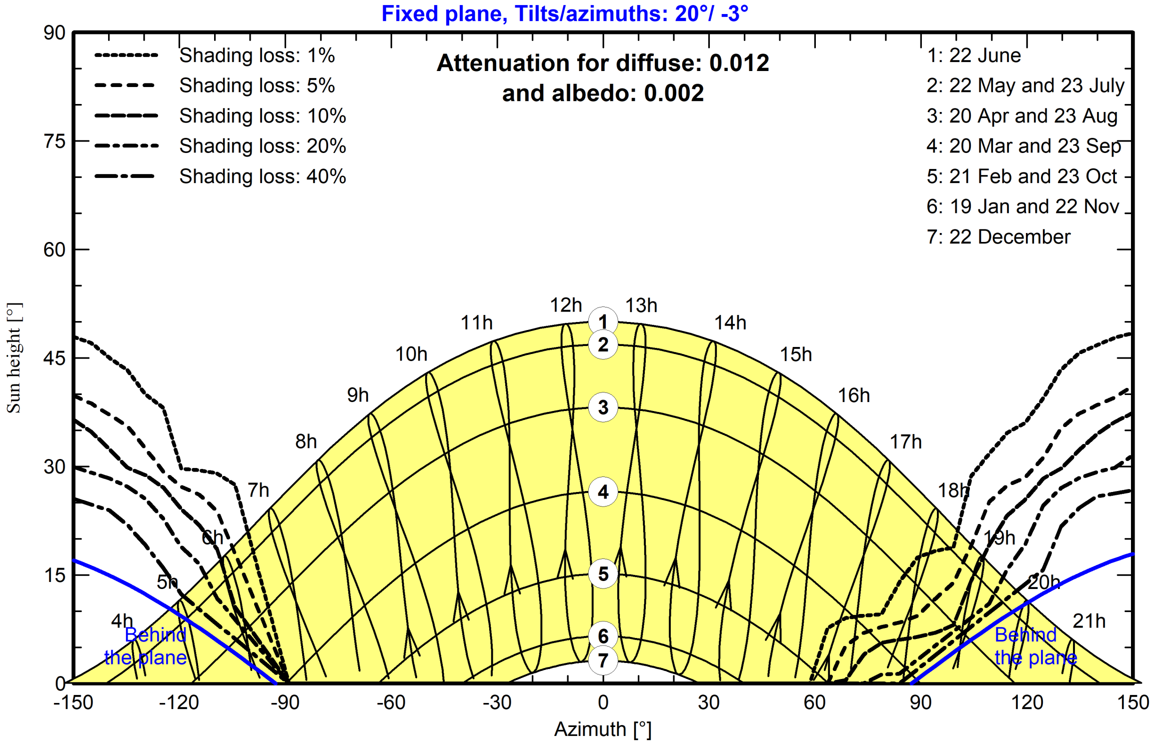
Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

Fixed plane, Tilts/azimuths: 20°/ -3°



Main results

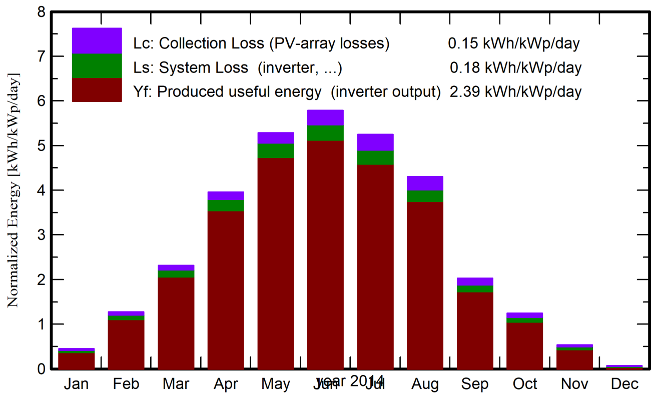
System Production

Produced Energy 35138 kWh/year

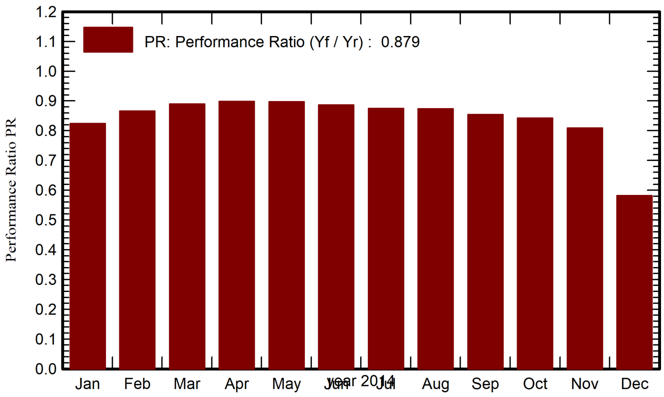
Specific production 871 kWh/kWp/year

Performance Ratio PR 87.89 %

Normalized productions (per installed kWp)



Performance Ratio PR



Balances and main results

	GlobHor	DiffHor	T_Amb	GlobInc	GlobEff	EArray	E_Grid	PR
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	kWh	kWh	ratio
Jan. 14	5.6	3.62	1.74	13.9	12.9	521	461	0.824
Feb. 14	20.1	12.44	4.40	35.7	33.7	1365	1249	0.866
Mar. 14	53.5	31.14	4.57	71.8	68.5	2779	2575	0.890
Apr. 14	100.0	52.69	5.69	118.7	114.2	4601	4298	0.898
May 14	147.2	75.28	7.57	163.8	158.3	6332	5930	0.898
June 14	162.0	81.91	10.73	173.6	167.6	6624	6202	0.886
July 14	150.5	80.66	14.50	162.9	157.2	6134	5742	0.874
Aug. 14	115.8	67.24	14.57	133.3	128.3	5022	4700	0.874
Sep. 14	51.8	38.74	12.84	60.8	58.2	2283	2093	0.854
Oct. 14	26.0	15.97	10.06	38.7	36.7	1450	1313	0.842
Nov. 14	7.8	5.36	7.15	16.1	15.2	600	527	0.810
Dec. 14	1.3	1.16	4.36	2.1	2.0	73	50	0.581
Year	841.6	466.20	8.20	991.3	952.8	37784	35138	0.879

Legends

GlobHor Global horizontal irradiation

DiffHor Horizontal diffuse irradiation

T_Amb Ambient Temperature

GlobInc Global incident in coll. plane

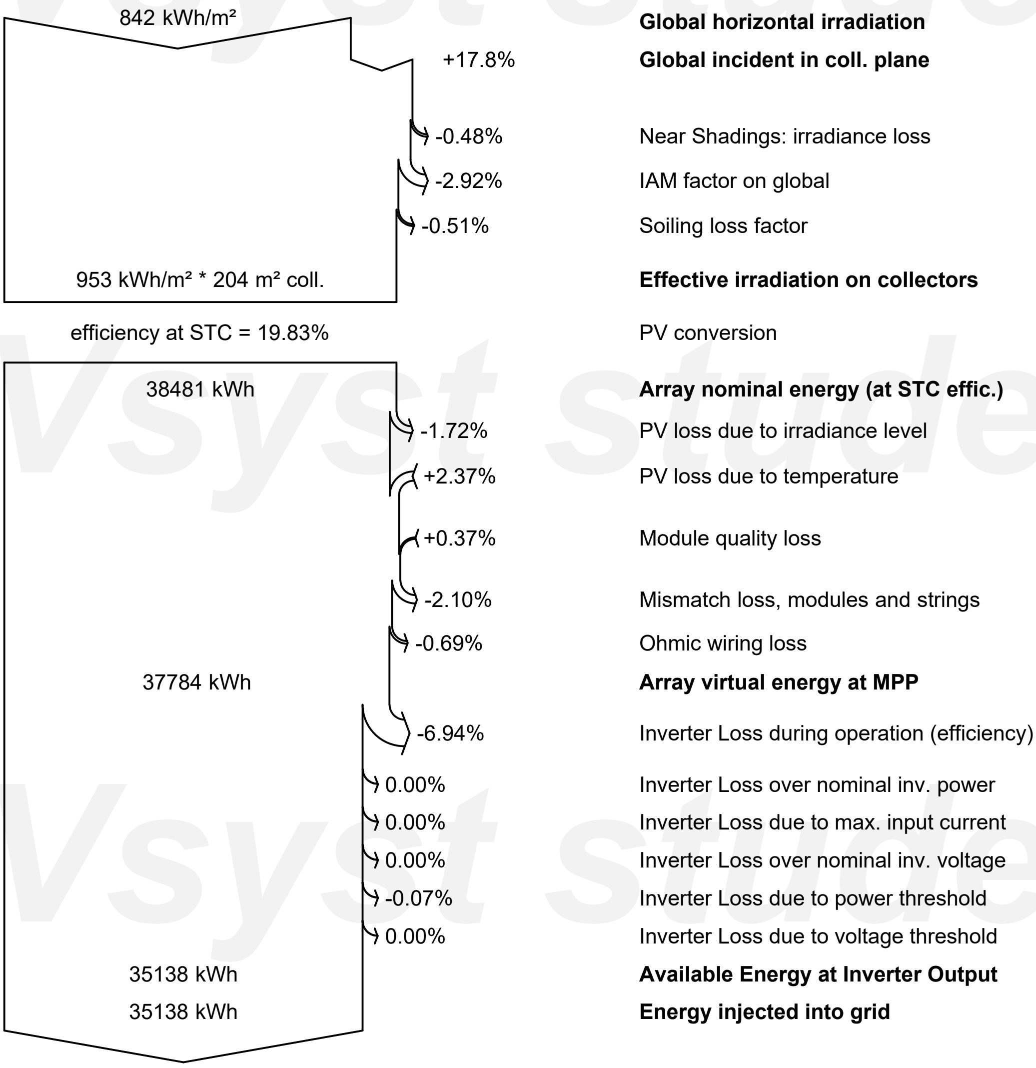
GlobEff Effective Global, corr. for IAM and shadings

EArray Effective energy at the output of the array

E_Grid Energy injected into grid

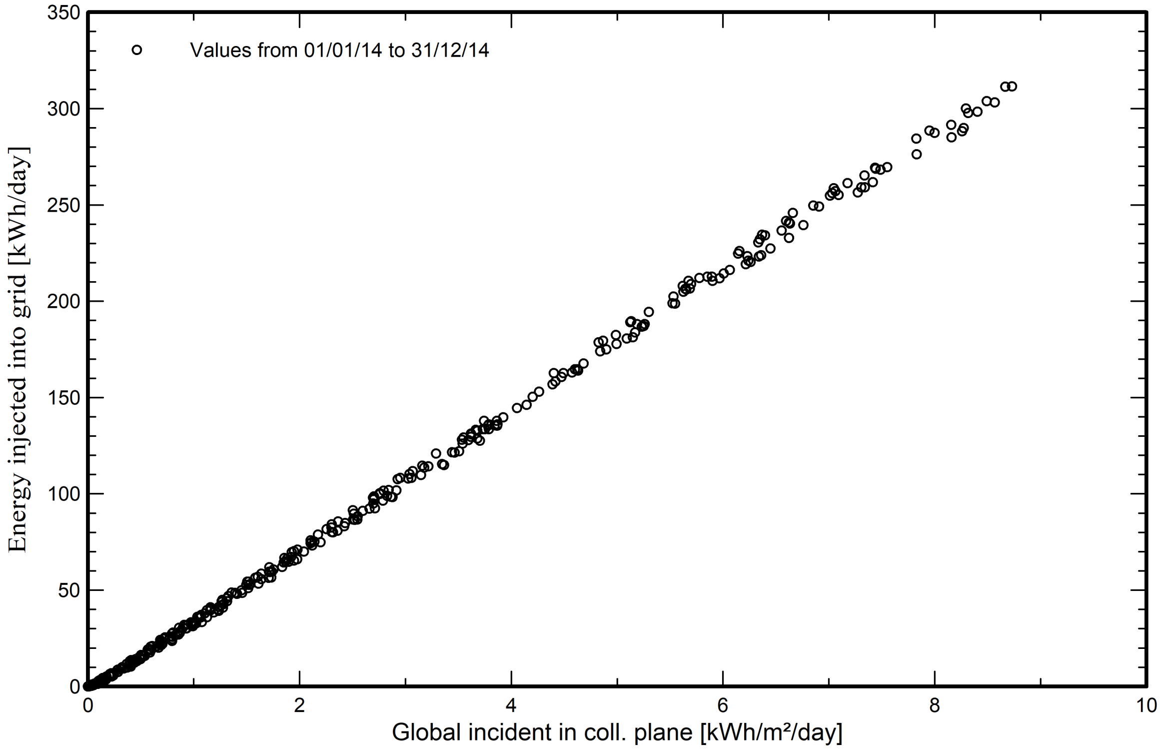
PR Performance Ratio

Loss diagram

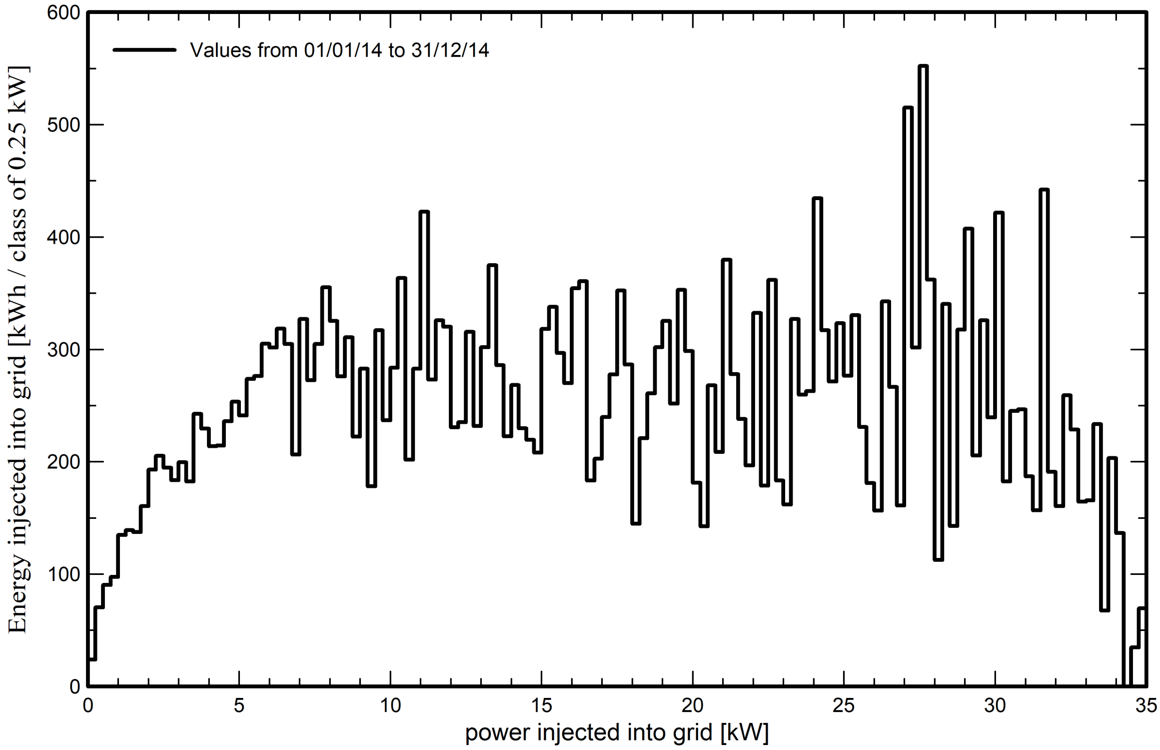


Predef. graphs

Daily Input/Output diagram

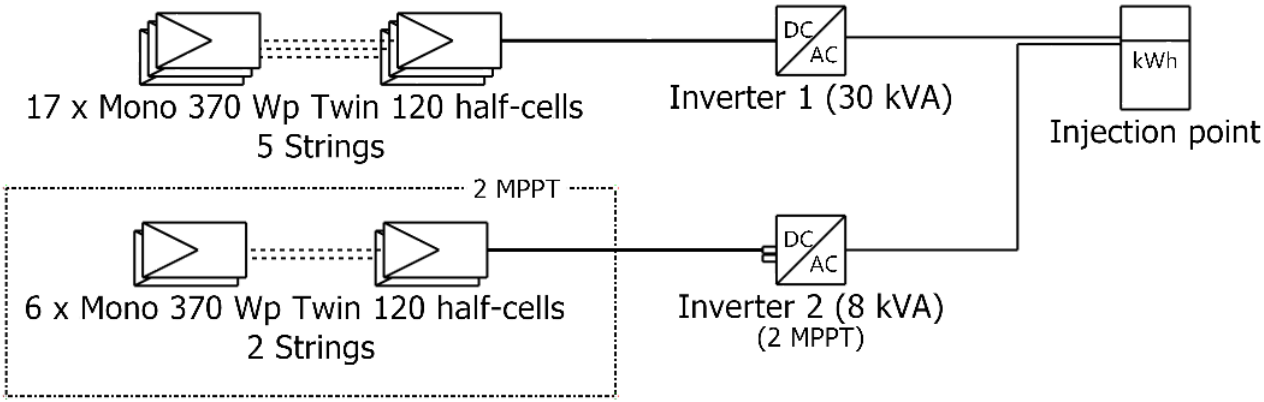


System Output Power Distribution



Single-line diagram

PVsyst V7.3.2
VC2, Simulation date:
27/02/23 12:12
with v7.3.2



PV module	Mono 370 Wp Twin 120 half-cells
Inverter 1	30 kWac inverter
Inverter 2	7.5 kWac inverter
String 1	17 x Mono 370 Wp Twin 120 half-cells
String 2	6 x Mono 370 Wp Twin 120 half-cells

	Smøla Hybrid Power Park	Ida Aure (Norway)
	VC2 : Roof	27/02/23

D PVSyst Simulation Report: Reference Area

Version 7.3.2

PVsyst - Simulation report

Grid-Connected System

Project: Smøla Hybrid Power Park

Variant: Referance Area

Ground system (tables) on a hill

System power: 143.8 MWp

Smøla vindpark - Norway

Author

Ida Aure (Norway)

Project summary

Geographical Site
Smøla vindpark
Norway

Situation

Latitude	63.41 °N
Longitude	7.91 °E
Altitude	15 m
Time zone	UTC+1

Meteo data
Smøla vindpark
Custom file - Imported

Monthly albedo values

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Albedo	0.70	0.60	0.40	0.30	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.70

System summary

Grid-Connected System
Ground system (tables) on a hill

PV Field Orientation
Fixed plane
Tilt/Azimuth 32.1 / 0.3 °

Near Shadings
Linear shadings

User's needs
Unlimited load (grid)

System information

PV Array

Nb. of modules	216311 units
Pnom total	143.8 MWp

Inverters

Nb. of units	36 units
Pnom total	123.7 MWac
Pnom ratio	1.163

Results summary

Produced Energy	130420651 kWh/year	Specific production	907 kWh/kWp/year	Perf. Ratio PR	86.76 %

Table of contents

General parameters

Grid-Connected System — **Ground system (tables) on a hill**

PV Field Orientation

Orientation		**Sheds configuration**		**Models used**	
Fixed plane		Nb. of sheds	9013 units	Transposition	Perez
Tilt/Azimuth	32.1 / 0.3 °	Identical arrays		Diffuse	Imported
		Sizes		Circumsolar	separate
		Sheds spacing	10.00 m		
		Collector width	4.79 m		
		Ground Cov. Ratio (GCR)	47.9 %		
		Shading limit angle			
		Limit profile angle	23.2 °		

Horizon	**Near Shadings**	**User's needs**
Free Horizon	Linear shadings	Unlimited load (grid)

PV Array Characteristics

PV module		**Inverter**	
Manufacturer	Generic	Manufacturer	Generic
Model	AE 665ME-132BS	Model	SG3400-HV-20
(Original PVsyst database)		(Original PVsyst database)	
Unit Nom. Power	665 Wp	Unit Nom. Power	3437 kWac
Number of PV modules	216311 units	Number of inverters	36 units
Nominal (STC)	143.8 MWp	Total power	123732 kWac
Modules	7459 Strings x 29 In series	Operating voltage	875-1300 V
At operating cond. (50°C)		Max. power (=>25°C)	3593 kWac
Pmpp	131.6 MWp	Pnom ratio (DC:AC)	1.16
U mpp	1007 V		
I mpp	130641 A		

Total PV power		**Total inverter power**	
Nominal (STC)	143847 kWp	Total power	123732 kWac
Total	216311 modules	Max. power	129348 kWac
Module area	671938 m²	Number of inverters	36 units
Cell area	629595 m²	Pnom ratio	1.16

Array losses

Array Soiling Losses

Average loss Fraction 0.6 %

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
1.0%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	1.0%

Thermal Loss factor		**DC wiring losses**		**Module Quality Loss**	
Module temperature according to irradiance		Global array res.	0.13 mΩ	Loss Fraction	-0.8 %
Uc (const)	40.0 W/m²K	Loss Fraction	1.5 % at STC		
Uv (wind)	0.0 W/m²K/m/s				

Module mismatch losses		**Strings Mismatch loss**	
Loss Fraction	2.0 % at MPP	Loss Fraction	0.1 %

Array losses

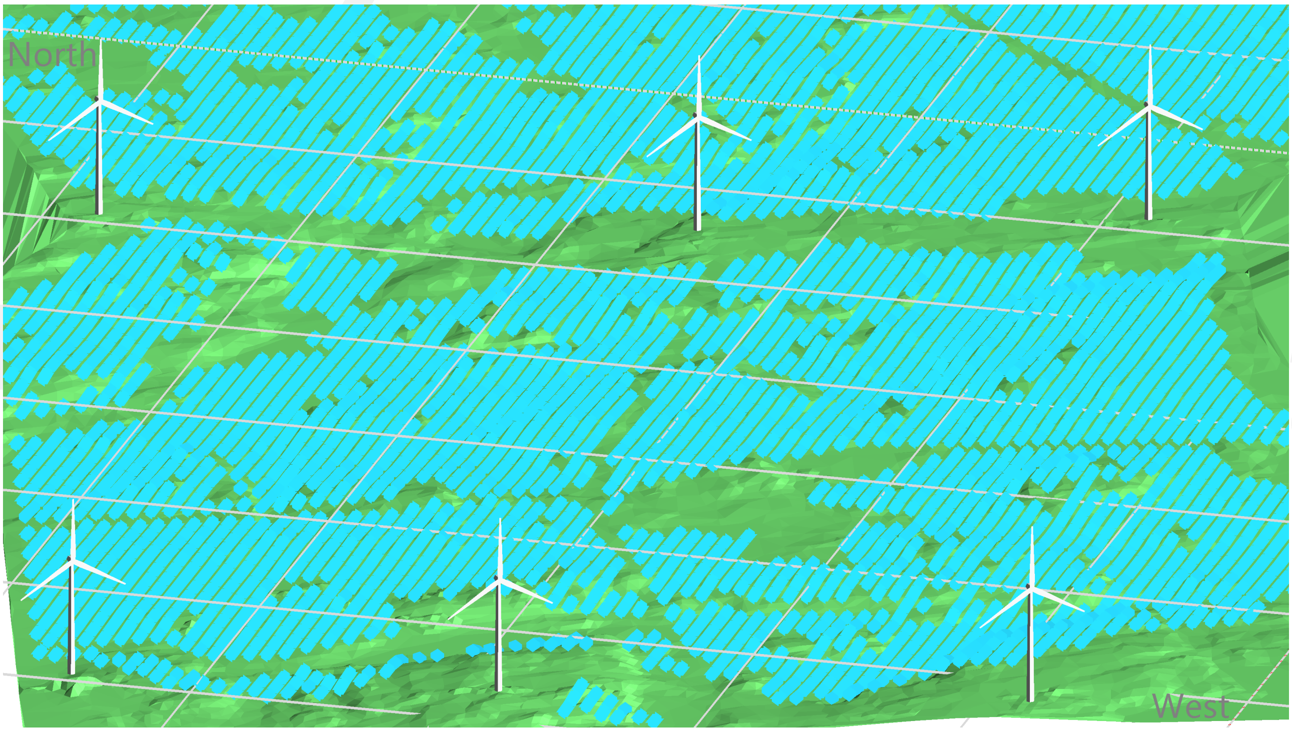
IAM loss factor

Incidence effect (IAM): Fresnel, AR coating, n(glass)=1.526, n(AR)=1.290

0°	30°	50°	60°	70°	75°	80°	85°	90°
1.000	0.999	0.987	0.962	0.892	0.816	0.681	0.440	0.000

Near shadings parameter

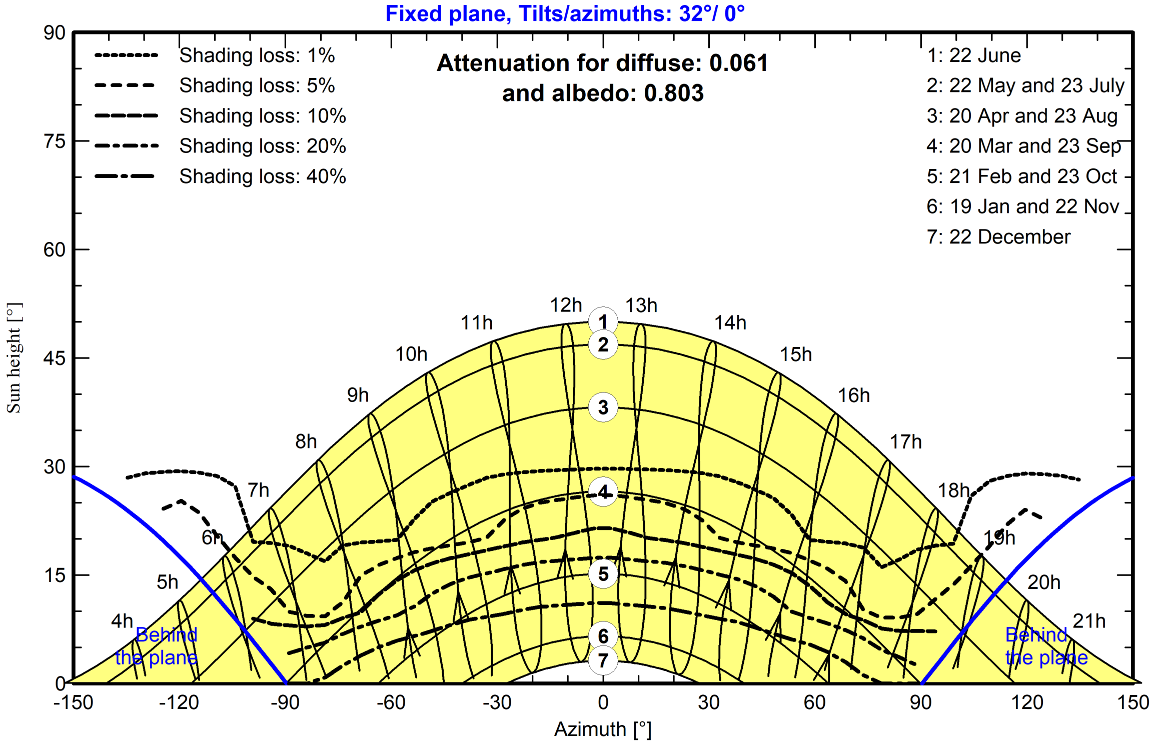
Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Orientation #1

Fixed plane, Tilts/azimuths: 32°/ 0°

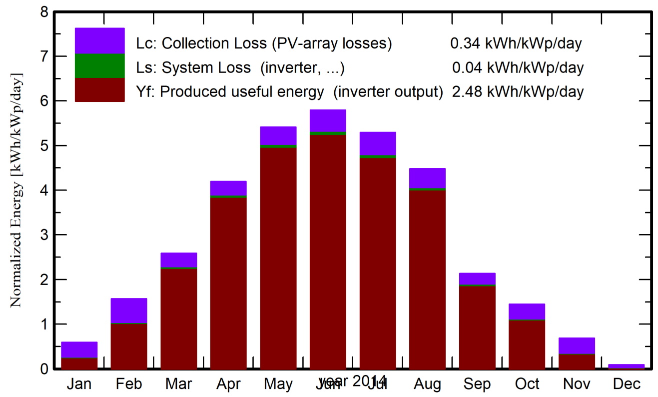


Main results

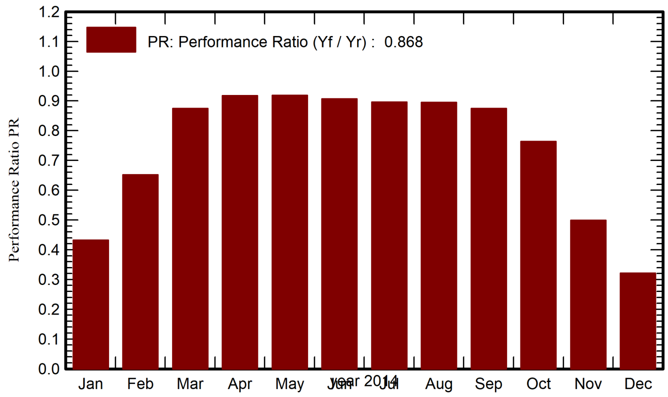
System Production

Produced Energy	130420651 kWh/year	Specific production	907 kWh/kWp/year
		Performance Ratio PR	86.76 %

Normalized productions (per installed kWp)



Performance Ratio PR



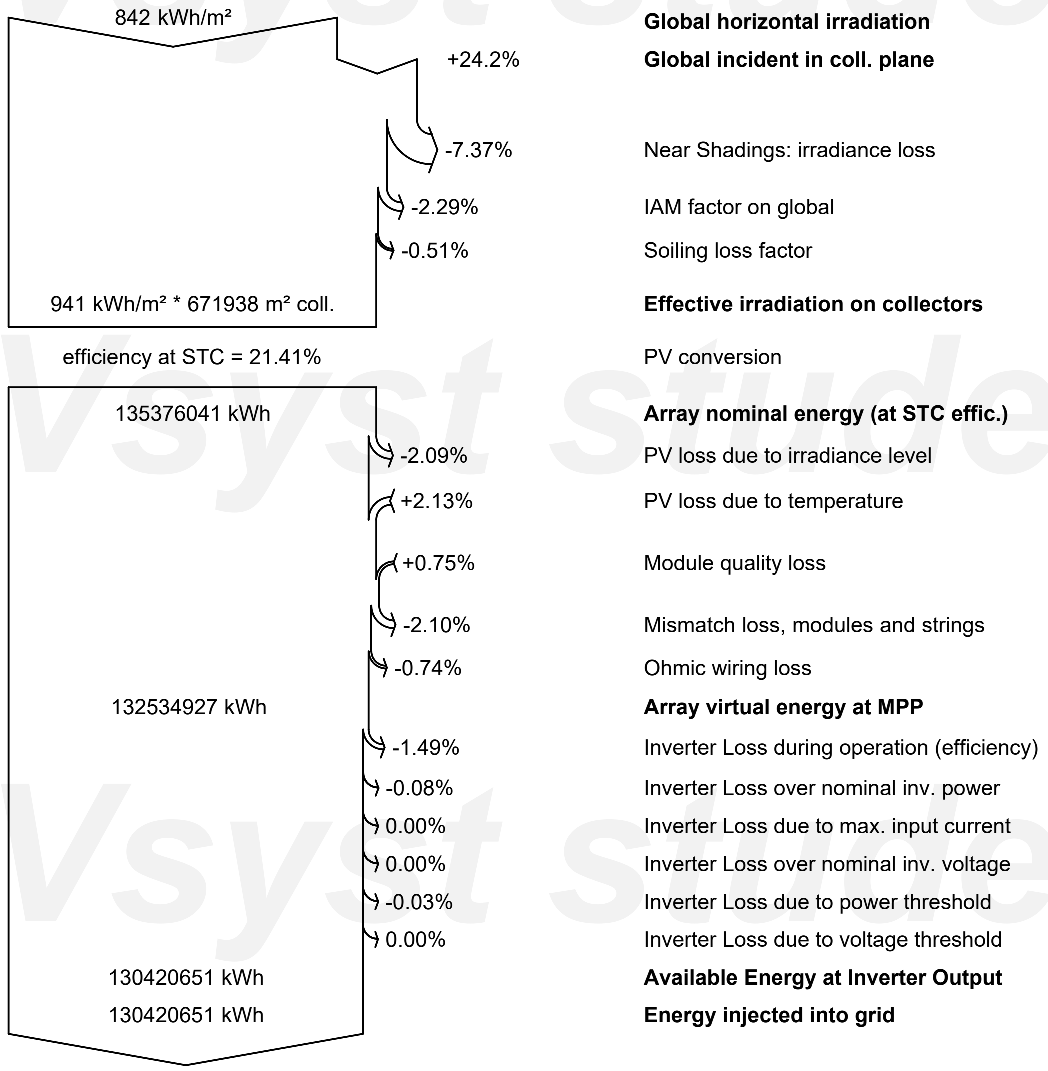
Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray kWh	E_Grid kWh	PR ratio
Jan. 14	5.6	3.62	1.74	18.4	8.5	1198450	1147325	0.432
Feb. 14	20.1	12.44	4.40	43.9	29.4	4200082	4116598	0.651
Mar. 14	53.5	31.14	4.57	80.1	71.2	10240348	10078620	0.874
Apr. 14	100.0	52.69	5.69	125.8	117.8	16841001	16613221	0.918
May 14	147.2	75.28	7.57	167.8	158.4	22460779	22163010	0.918
June 14	162.0	81.91	10.73	173.9	164.0	22992930	22686418	0.907
July 14	150.5	80.66	14.50	164.1	154.5	21438652	21147230	0.896
Aug. 14	115.8	67.24	14.57	138.9	130.4	18141780	17894015	0.895
Sep. 14	51.8	38.74	12.84	64.1	58.9	8209497	8059863	0.874
Oct. 14	26.0	15.97	10.06	44.7	35.8	5017745	4911355	0.763
Nov. 14	7.8	5.36	7.15	20.6	11.1	1535007	1478155	0.499
Dec. 14	1.3	1.16	4.36	2.7	1.2	151842	124840	0.322
Year	841.6	466.20	8.20	1045.1	941.1	132428113	130420651	0.868

Legends

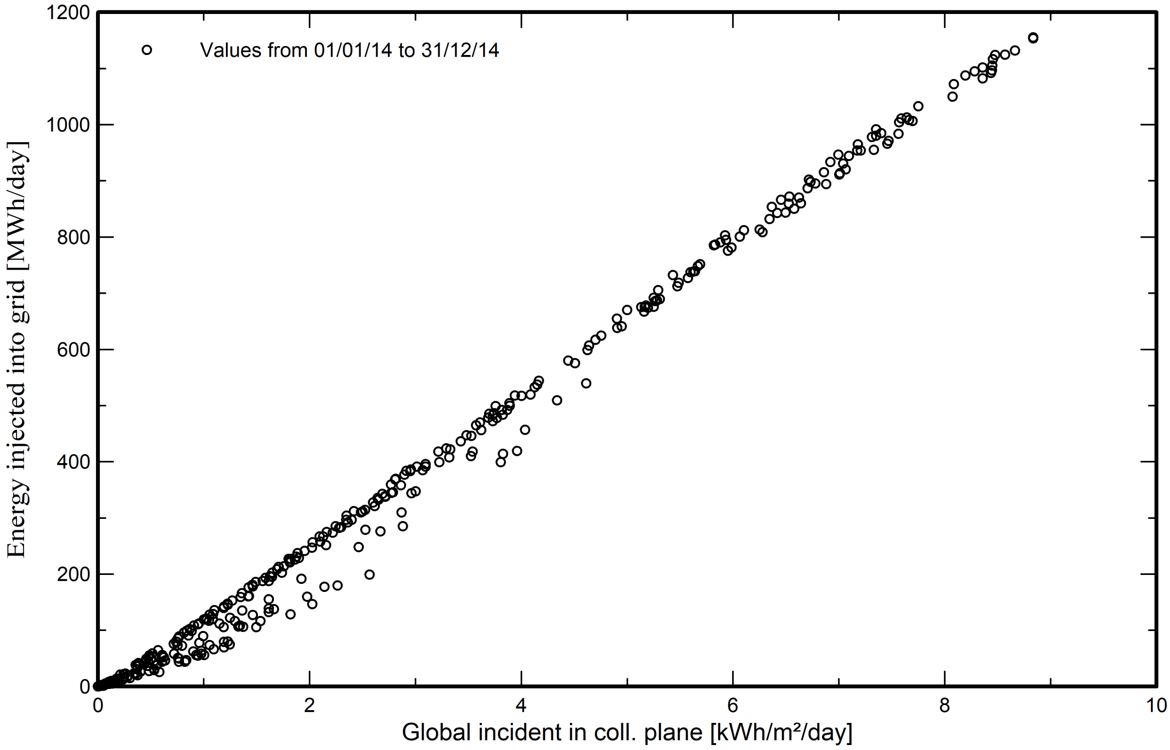
GlobHor	Global horizontal irradiation	EArray	Effective energy at the output of the array
DiffHor	Horizontal diffuse irradiation	E_Grid	Energy injected into grid
T_Amb	Ambient Temperature	PR	Performance Ratio
GlobInc	Global incident in coll. plane		
GlobEff	Effective Global, corr. for IAM and shadings		

Loss diagram

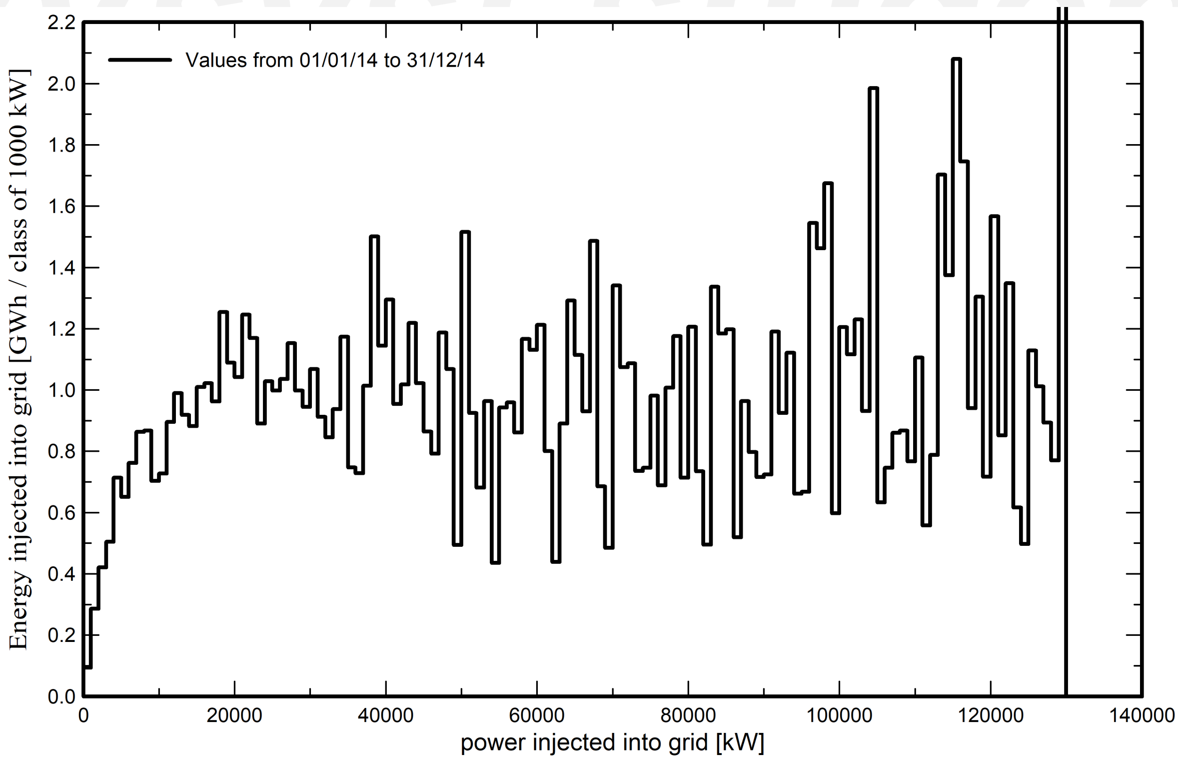


Predef. graphs

Daily Input/Output diagram

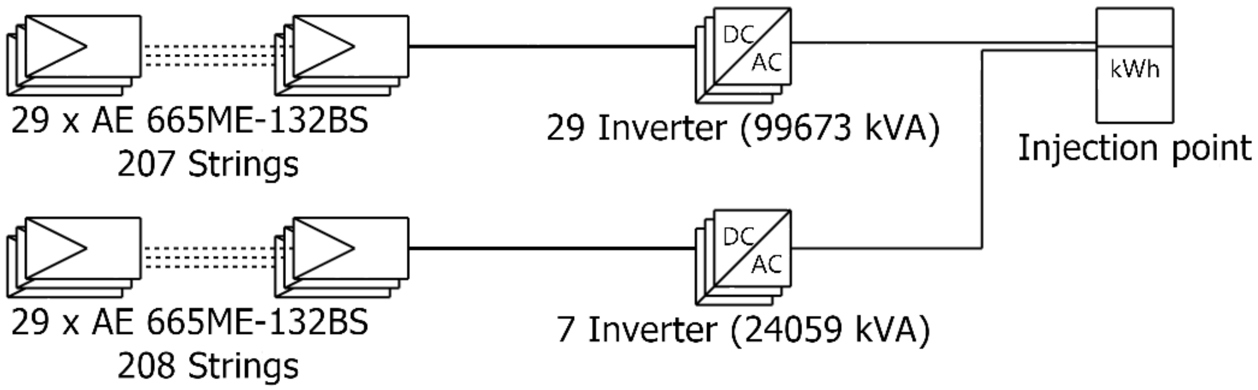


System Output Power Distribution



Single-line diagram

PVsyst V7.3.2
VC0, Simulation date:
27/02/23 11:49
with v7.3.2



PV module	AE 665ME-132BS
Inverter	SG3400-HV-20
String	29 x AE 665ME-132BS

Smøla Hybrid Power Park	Ida Aure (Norway)
VC0 : Referance Area	27/02/23

NTNU

Norwegian University of
Science and Technology