Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

Petry Kristine Nøttum Haaland

Impact of CO_2 compensation methods on the sizing of PV panels in Zero Emission Neighbourhoods

Master's thesis in Energy and Environmental Engineering
Supervisor: Magnus Korpås
Co-supervisor: Emil Dimanchev
June 2022

NTNU
Kunnskap for en bedre verden

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Abstract

To reach our climate goals, a reduction in total CO_2 emissions is a necessity. In Winter 2022, the intergovernmental panel on climate change (IPCC) published the Sixth Assessment Report, Climate Change 2022, highlighting the urgency of a rapid reduction in CO_2 emissions. Buildings account for 32% of total final energy use and 19% of energy-related greenhouse gas (GHG) emissions. Hence, a reduction in this sector would have a significant impact, in which zero emission neighbourhoods (ZENs) have been enabled as a possible abatement measure. The main objective of a ZEN is to achieve net zero emissions over the neighbourhood's lifetime. From local renewable power production, most often solar photovoltaics (PVs), the neighbourhood covers for its own consumption, in addition to compensating for embodied emissions from construction, materials, and maintenance by exporting power to the grid. Quantification of total emissions from the power system is therefore needed to understand the neighbourhood's environmental impact. Quantification of emissions from materials is fairly established while quantifying the emissions related to the energy demand has proven to be rather challenging. Today, there is no consensus on how to calculate the emission factors for electricity, leading to various methods being used depending on the purpose of study or the view of the analyst. In this thesis, different emission factors are investigated, namely the annual average-, hourly average-, short-run marginal- and long-run marginal emission factors. This, to see how the different factors would impact the optimal dimensioning of a PV system in a ZEN. A case study was created using the optimization model GenX, to study the required power capacity and area of a PV system based on the different emission factors in a simplified north-European power system. In addition, a case study of the port- and industrial area Nyhavna in Trondheim was investigated, an area that is planned to be established as a ZEN. This, to investigate how the different emission factors would influence the required installed capacity and PV area at Nyhavna. Based on the chosen emission factor, the resulting PV system areas gave differences up to 1 203 447.22 m^2. From this, it is seen that based on the chosen calculation method, it could be possible to achieve the status as a ZEN at a potentially lower cost. Further, it was found an opposite correlation between the sun availability and emission factors, making it difficult to compensate for embodied emissions using the hourly average emission factor. Because of this, a scenario was investigated using onshore wind power as the local renewable energy source (RES). This resulted in a significant reduction of the required installed power capacity. This thesis further takes into account the development towards a zero emission power system. One of the main points taken from this was that compensation of embodied emissions in a power system reaching zero emission is difficult. Based on the investigated case study, it is clear that more research is needed to understand the actual consequences of developing ZENs. Further, consensus regarding the choice of calculation method is important to ensure consistency regarding dimensioning of local RES systems.

Sammendrag

For å nå de satte klimamålene, er en reduksjon i totale CO_2-utslippene en nødvendighet. Vinteren 2022 publiserte IPCC the Sixth Assessment Report, Climate Change 2022, en rapport som fremhevet viktigheten av en rask reduksjon i CO_2-utslipp. Bygninger står for 32% av total, endelig energibruk, i tillegg til 19% av energirelaterte klimagassutslipp. En reduksjon i klimagassutslipp fra denne sektoren vil derfor ha en betydelig innvirkning, hvor videre nullutslippsnabolag (ZEN) har blitt ansett som et mulig reduksjonstiltak. Hovedmålet med ZEN er å oppnå netto nullutslipp over nabolagets levetid. Gjennom lokal fornybar kraftproduksjon, oftest solcelleanlegg, sørger nabolaget for at eget forbruk dekkes, i tillegg til at det kompenserer for tidligere utslipp fra konstruksjon, materialer og vedlikehold, ved å eksportere utslippsfri kraft til nettet. En kvantifisering av totale utslipp fra kraftsystemet er derfor nødvendig for å forstå miljøpåvirkningen av nabolaget. Kvantifisering av utslipp tilknyttet materiell er en ganske etablert prosess. Imidlertid har kvantifisering av utslipp knyttet til energibehovet vist seg å være ganske utfordrende. Per i dag er det ikke enighet om hvordan man skal beregne utslippsfaktorene for elektrisitet, noe som fører til at ulike metoder brukes avhengig av studieformålet, eller analytikerens syn. I denne oppgaven undersøkes ulike utslippsfaktorer, nemlig årlig gjennomsnittlig-, timesbasert gjennomsnittlig-, kortsiktig marginale- og langsiktig marginale utslippsfaktorer. Dette for å se hvordan de ulike faktorene vil påvirke den optimale dimensjoneringen av et solcelleanlegg i et ZEN. Et casestudie ble laget ved å bruke optimaliseringsmodellen GenX, for å studere nødvendig kraftkapasitet og arealet til et PV-system basert på de forskjellige utslippsfaktorene, i et forenklet nord-europeisk kraftsystem. I tillegg ble det laget et casestudie av havne- og industriområdet Nyhavna i Trondheim, som er planlagt å etableres som et nullutslippsnabolag. Dette for å undersøke hvordan de ulike utslippsfaktorene påvirket nødvendig installert kapasitet og solcelleareal på Nyhavna. Basert på den valgte utslippsfaktorenefaktoren ga de resulterende solcelleanleggsområdene forskjeller på opptil 1 203 447.22 m^2. Dette viser at man basert på valgt beregningsmetode, kan oppnå status som ZEN til en potensielt lavere kostnad, enn om man hadde valgt en annen kalkuleringsmetode. Det ble videre funnet en motsatt korrelasjon mellom soltilgjengelighet og utslippsfaktorer, noe som gjorde det vanskelig å kompensere for utslipp knyttet til materiell, konstruksjon og vedlikehold, ved å bruke timesbaserte gjennomsnittlige utslippsfaktorer når sol ble brukt som lokal fornybar energikilde. På grunn av dette ble det sett på et nytt scenario, hvor landbasert vindkraft ble brukt som lokal fornybar energikilde. Dette resulterte i en betydelig reduksjon av nødvendig installert kraftkapasitet. Denne oppgaven tar videre i betraktning kraftsystemets utvikling over tid, på veien mot et nullutslippskraftsystem. Et av hovedpoengene hentet fra dette, er at utslippskompensasjon i et nettonull kraftsystem er vanskelig. Dessuten, basert på casestudiet er det klart at det er behov for mer forskning, for å forstå de faktiske konsekvensene av å utvikle nullutslippsnabolag. Videre er konsensus om valg av beregningsmetode viktig for å sikre konsistens når det gjelder dimensjonering av lokale RES-systemer.

Forord

Da jeg var liten fortalte min far at kunnskap er som en sirkel. Det du kan er arealet av sirkelen, mens det du ikke kan er området utenfor. Omkretsen av sirkelen derimot, er alt du vet du ikke vet. Da jeg startet opp studieløpet mitt høsten 2017 var jeg overbevist om at jeg etter fem år skulle komme ut utlært, og klar for å redde verden. Når jeg nå står her nesten fem år senere, på nippet til å ta steget ut i den store verden, føler jeg meg langt i fra utlært. Derimot har jeg konkludert med at kunnskap rett å slett er det samme som å erkjenne at man ikke kan alt, og den viktigste lærdommen jeg tar med meg fra studieårene mine er derfor nysgjerrighet.

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List of Abbreviations

AEF Average Emission Factor

EMPS Multi-area Power Market Simulator

EPBD Energy Performance of Buildings Directive

EU ETS European Emission Trading Scheme

EV Electrical Vehicle

FLH Full Load Hours

GHG Greenhouse gases

IEA International Energy Egency

KRD Norwegian Ministry of Municipalities and Counties

LCA Life Cycle Assessment

LRMEF Long-Run Marginal Emission Factor

MEF Marginal Emission Factor

O&M Operation and Maintenance

PV Photovoltaic

RES Renewable Energy Sources

SRMEF Short-Run Marginal Emission Factor

TYNDPs Ten-Year Network Development Plans

ZEBs Zero Emission Buildings

ZENs Zero Emission Neighbourhoods

1 Introduction

This winter, the IPCC published the Sixth Assessment Report, Climate Change 2022. One of the key points in the report was, "If countries do not move quickly to reduce emissions – if reductions are delayed – a more rapid energy transition will subsequently be required to limit warming to 2°C or below..." [38]. The report showed the urgency of a rapid reduction in total GHG-emissions to limit the consequences of global warming. Globally, buildings account for 32% of total final energy use, in addition to 19% of energy-related GHG-emissions [45]. Therefore, reducing the building sector's GHG-emissions is crucial for reaching global climate goals. To address building emissions, the European Parliament initiated the Energy Performance of Buildings Directive (EPBD), which includes policies and support measures to improve the energy performance of buildings, in addition to improving the already existing building stock [18]. As of 2021, the EPBD requires all new buildings to be nearly zero-energy buildings, and the directive has further set requirements for minimum energy performance for new buildings, existing buildings reviewing renovation, or the replacement of building elements [18]. The directive further sets out a path towards achieving a zero emission and fully decarbonized building stock by 2050 [18].

In this context, the Research Centre on ZEN in Smart Cities (FME-ZEN) was launched in 2017. The research group aims to develop solutions for future buildings and neighbourhoods, as a contribution towards realizing ZENs [59]. This will ensure local production of renewable energy and effective energy use, which are essential to reaching national climate goals and improving the local environment [72]. ZENs are a further development of Zero Emission Buildings (ZEBs), which are buildings that reach zero emission throughout its lifetime. In ZEN, this is further developed, not only considering individual buildings, but neighbourhoods.

According to [38], it is likely that reducing CO_2 emissions in the electricity sector is the least costly solution to reduce GHG-emissions. Further, electrification of the energy system tends to be a key climate change mitigation strategy [38]. At the same time, electrification may cause additional emissions associated with electricity generation, and quantifying these emissions is necessary to inform future electrification planning. The emission impact of electricity has often been represented using CO_2 factors expressed, for example, in kg CO_2/kWh. However, quantification of emissions related to electricity has proven to be rather challenging. As of today, there does not exist consensus regarding how to calculate emissions from electricity, leading to various methods being used depending on the purpose of study or view of the analyst. The choice of calculation method could give major differences in final results, which eventually could influence political or commercial interests [63]. Therefore a common methodology is necessary to make well-informed decisions regarding the future energy systems.

The emissions of an isolated power generation plant can easily be determined by its fuel and efficiency. Similarly, one can determine total emissions from isolated power plants simply by looking at their corresponding emissions factors. The Norwegian power system is an interconnected energy system dominated by hydropower production, an energy source with approximately zero emissions. Using the emissions from the Norwegian power plants would thus lead to a Norwegian average emission factor close to zero.

Table 1: Emission factors for fossil-fueled power plants

	Plant technology	**Emission factor [g/kWh]**
Hard coal	Steam turbine	1002
Brown coal	Steam generator	1069
Fuel oil	Steam generator	844
Natural gas	Gas turbine	673
Natural gas	Combined cycle	449

Source: [41]

As observed in Table 1, the determination of the emission factor for power production is well established. However, modern energy systems are dynamic and highly interconnected systems, and only looking at a single power plant would not give a complete understanding of how the power flows. It is therefore not possible to measure the emission factors for consumption directly.

Consequently, it is more challenging to calculate emission factors for complex energy systems as they have several sources and consumers. What complicates the calculations even further is the interconnection between different areas and bidding zones. Additionally, it is not possible to trace a given consumer's consumption directly back to a given power plant. This gives rise to the following question; Should the emission factors for demand reflect the generation mix in a given country, or should emissions be allocated to the area where it is actually consumed? Earlier the CO_2-factor for electricity, from now denoted emission factor, was used for static purposes [10]. However, it is now increasingly used as an instrument to regulate the production and consumption of electricity [10]. Therefore, it is important that the emission factor communicates the actual emissions such that the correct abatement actions are performed.

Several methods exist to calculate the emission factors, while the question regarding when to use which method remains unanswered. This is because the different methodologies appear complicated, resulting in several methods being used depending on the analyst and purpose of the study. This thesis discusses different methods for calculating total emissions from electricity, namely the annual average-, hourly average-, short-run marginal- and long-run marginal emission factor. The different factors can result in very different results. An approach using average emission factors to calculate total emissions over a year would, for instance, not account for the fact that emission factors vary from season to season or hour to hour. On the other hand, calculating short-run marginal emission factors in case of added consumption, would fail to reflect future investment due to the new demand. However, using the long-run marginal emission factor could help highlight these changes (these different metrics are described in detail in Section 3.3).

Emission factors are further important when choosing the dimension of local production of renewable energy in ZENs. ZENs are neighbourhoods that achieves net zero emissions throughout the building's lifetime, meaning that the neighbourhood has to cover for its own power consumption with local renewable energy sources. In addition, the neighbourhood has to compensate for embodied emissions linked to construction, materials, maintenance, or power import in periods when the local power production is insufficient. This is done by exporting power from the neighbourhood to the grid in periods with power surplus. In Norway, the current practice is to use annual average emission factors for calculating necessary dimensions of the local renewable power production, in most cases solar PVs [45]. This is in accordance with the standard NS3720 [56]. However, it implies that the exported energy from the ZEN would replace the average of the electricity mix, which is not necessarily the case in reality.

This master thesis investigates the resulting dimensioning of local PV systems, using the above mentioned calculation methods for emission factors for electricity. Is the current method of using the annual average emission factor correct, or does it under- or overestimate the actual effects of the local RES? The main goal of the thesis is to get a deeper understanding of how the different calculation methods influence the resulting dimensions. The thesis further aims to answer the following questions: How do you dimension solar PV to compensate for embodied emissions; and how do different metrics for measuring emissions and compensation compare?

Further, this thesis is an extension of a specialization project from the fall of 2021. Parts of the material in Sections 2 and 3 is therefore taken from the specialization project [32].

The thesis is organized as the following: Section 2 describes the theory and background provided in this thesis. Section 3 presents the applied methodology used in this thesis, and the mathematical formulation of the optimization model GenX used to create the investigated case study is explained. In Section 4, a presentation of the investigated case study, together with input data used in GenX, are given. Section 5 presents the results, while Section 6 discusses the final results. Lastly, a conclusion is given in Section 7, while suggestions for further work is presented in Section 8.

2 Theory and Background

2.1 Emission factors

Since the decision of the chosen calculation method can lead to differing results, it is necessary for a consensus regarding how to perform the calculation and when to use which method. This section briefly presents different methods for calculating emission factors. However, a more thorough explanation of the calculation methods is presented in Section 3.

2.1.1 Average emission factor

The average emission factor is the most intuitive emission factor. This calculation method simply divides total emissions by total demand, and it is thus easy to calculate and convey to others. An important disadvantage with this calculation method is that the method implies that in case of a change in demand, this would influence the whole energy system equally, which is not the case in reality. An increased consumption would typically not affect the operation of the base-load but lead to an increase in the power plants with the lowest marginal costs.

2.1.2 Short-run marginal emission factor

This is attempted addressed in the calculation of the short-run marginal emission factor. In this calculation method, the emission factor is set equal to the change in emissions, divided by the change in demand. Thus, it is possible to observe which power plant would increase/decrease production due to the change in demand. However, the emission factor considers the power system as static, meaning that it does not take into account changes in the energy system in the long-run due to the changed consumption. Therefore the calculation method is true if the power system remains static over its lifetime, but this is never the case in reality. A permanent increase in electricity demand would lead to future investments in the power grid, which further could have an impact on the resulting emission factor.

2.1.3 Long-run marginal emission factor

The future consequences of a potential change in consumption are addressed in the calculation of the long-run marginal emission factor. In this method, the power system is no longer considered static but now allows for changes in the power system due to the change in demand. Similar to the short-run marginal emission factor, the long-run marginal emission factor is calculated as the change in total emissions divided by the change in demand. However, in the calculation of the short-run marginal emission factor, new demand was added on the top of the existing demand without adding any new generation. On the other hand, the calculation of the long-run marginal emission factor, allows for a change in the power system as a result of the added consumption, which increases the complexity of this calculation method. In section 3.6 three different variations of the calculation method are presented, where the chosen variation depends on the availability of models and data [41]. In this thesis, the long-run marginal emission factor is calculated using a power system model representing the considered power system and additionally allowing for commissioning/decommissioning of power plants. The results are then compared to the model results without the added consumption. However, this increases the need for consensus, as different power system models or analysts could lead to differing results. This method further increases the model uncertainties, as assumptions regarding the future power system has to be taken.

2.1.4 Literature review

Today, there is no clear approach or recommendation regarding which methodology for calculation of emission factors to use. Further, there does not exist consensus regarding how to perform the different calculations. An example of this is shown in [55]. Here the paper compares NVE's emission factor (which is approximately zero) to the Norwegian Ministry of Municipalities and Counties' (KRD's) emission factor for electricity (which equals approximately 0.36 kg CO_2/kWh). According to [55] the difference in the emission factors is due to the fact that the first emission factor represents the Norwegian average emission factor, whereas KRD presents the marginal emission factor. Depending on the choice of the above emission factors, one would get quite differing results in total emissions related to Norwegian electricity consumption, which shows the importance of a consensus.

One of the main challenges regarding choosing a method for calculating emission factors lies in what aspects to include or not. According to [53] it is important to include both production inside a bidding zone in addition to imports from other zones to get a proper estimation of the emission factor. The resulting emission factor in a zone is further highly dependent on the chosen geographical boundary. Another challenge is thus how to fix the geographical boundaries [10]. In Table 2 the Norwegian, Nordic, and European energy mixes are presented.

Table 2: Norwegian, Nordic and European electricity mix

	Electricity mix [gCO_2/kWh]
Norwegian	0
Nordic	130
European	350

Source: [41]

As observed in Table 2, the emission factors differ a lot. Using the Norwegian electricity mix would lead to an emission factor close to zero. This would be applicable if one were only to consider the Norwegian onshore power generation. However, this factor does not consider the impact of power imports, thus giving an incorrect picture of the dynamic power market.

As the modern energy system is not static, the emission factors vary both seasonal and from hour to hour. In [16], a methodology for calculating the hourly average emission factor in an interconnected power grid is developed. According to [16], it is expected more interaction between the Norwegian and European power grids in the future. As Norwegian power mainly comes from hydro, the impact of imported power from the European power grid will therefore be of great influence on the average emission factor [16]. The paper developed a method to balance the electricity consumption, including export, and electricity production, including import. In [16], average emission factor was evaluated as a function of electricity spot price, electricity import from foreign countries, filling level in water reservoirs, and electricity use in different bidding zones. This is because [16] showed that the average emission factor was low during peak hours since hydropower plants prefer to operate at high electricity prices, which usually coincides with high demand. In periods with low electricity price, the emission factor in some cases increased significantly, as electricity in these periods was imported from, for example, foreign countries with less amount of renewable electricity generation. From this, [16] concluded that it was important to consider electricity import when calculating the average emission factor.

In literature, several different approaches exist towards calculating the marginal emission factor, i.e. changes in total emissions due to a change in demand. In [53], the marginal emission factor is defined as the change in emissions from producing or consuming one more unit of electricity.

In [35], a study of the English and Welsh energy system was performed. Here the study calculates the short-run marginal emission factor, the long-run marginal emission factor, and the average emission factor to observe potential differences. In [35], marginal emission factors are defined as applications where one is to find the change in emissions due to a change in demand. The study further distinguishes between the direct and indirect effects, meaning respectively the short-run- and long-run marginal emission factors. The short-run marginal emission factor is calculated using the merit order of existing plants in the system, giving the expected priority order of which plant will increase or decrease generation. The long-run marginal emission factor is found by looking at different scenarios to find a possible merit order for the future energy system. However, both these methods are simplifications and would not give the actual solution. For the short-run marginal emission factor, the merit order for existing plants does not necessarily reflect the reality, and bottlenecks or constraints could lead to a deviating dispatch than expected. As for the long-run marginal emission factor, use of scenarios would lead to more uncertainty. Additionally, these methods are only applicable for the English and Welsh energy system, as the papers use the English and Welsh merit order to calculate the emission factors. In cases where it is necessary to allocate the total carbon emissions from a generating system across the demand side of the electricity, the paper uses the average emission factor. [35] concludes that applying the different methods depends on certain circumstances, however, used wrongly it can lead to misleading results. The paper further performs a study showing that applying average emission factors, when the marginal emission factor is more appropriate, can result in differences in total emissions in the order of 30%.

Based on the above study, [13] presents a new methodology to calculate the marginal emission factor. This article also uses the merit order. However, in [35] historical data about the unconstrained merit order was used to calculate the marginal emission factor. This does not account for bottlenecks, plant availability, or actual operation of the plants but is simply a most likely order in which the plants will be commissioned/decommissioned [13]. In this paper, one now looks at historical data of the actual half-hourly operation in the year 2000, which gives a representation more close to the reality than in [35]. This, as the merit order now accounts for seasonal variation, bottlenecks, and plant availability [13]. However, it is still not applicable for other energy systems than the English and Welsh, and the method is additionally still a simplification of the actual results. Similar to the previous study [13] looks upon different scenarios to observe the long-term effects of the marginal emission factor, which increase the uncertainty due to the need for assumptions regarding the future.

In 2010, Hawkes performed a study where he creates a methodology for calculating the marginal emission factor based on the observed dispatch of large generators in an electricity system [33]. Hawkes uses data from 2002-2009 to calculate the marginal emission factor to further compare this with the average emission factor in the same time period. The calculation of the marginal emission factor gives a marginal emission factor equal to 0.69 $kgCO_2/kWh$, whereas the average emission factor equals 0.51 $kgCO_2/kWh$. Using the marginal emission factor instead of the average could thus, according to Hawkes, give a difference in the view of the significance of various emission decreasing interventions. Hawkes shows the importance of selecting the correct method when calculating the emission factor. A change in demand would not necessarily impact the whole energy system, and using the average emission factor could, in some cases, be misleading. Further, as the eventual emission factor leads to decisions regarding emission reduction strategies, it is important with accurate and consistent emission rates [33]. In the study, an interesting observation is that the marginal emission factor decreases after 2006. According to [33], this could be due to the introduction of carbon prices in 2005, which shows that the emission factors can be dependent on policy decisions. [33] further looks upon seasonal and hourly marginal emission factors. The resulting data showed a trend of the marginal emission factor being low at late night and early morning for the hourly marginal emission factor. The emission factor was, on the other hand, quite high at peak demand [33]. This is according to Hawkes expected, as low marginal emissions tend to occur when the system load is low. From this, Hawkes managed to show that time-of-day marginal emission factors can be influenced by the operational patterns of a specific generator, leading to a varying, instantaneous marginal emission factor. Due to this, it could be interesting to look at the differences in total emissions when using the hourly versus annual marginal emission factor.

In [34], Hawkes uses the long-run marginal emission factor to calculate emissions in the British electricity system. The article's main motivation was that the previous approaches to find the long-run marginal emission factor only produced an estimate of the structural changes in the energy system. In [34], a simple conceptual model is presented, looking at a baseline and two different scenarios. An interesting result from this conceptual model is that the long-run marginal emission factor actually becomes negative in one of the scenarios. According to [34], this is due to that the increase in demand is met by the commissioning of a nuclear power station, which leads to a reduction in total emissions.

In [34], the paper further looks upon the structural changes in the British energy system due to changes in demand. [34] uses TIMES modeling environment, which is an optimization model that minimizes the cost of meeting energy demand by choosing between possible technologies over a given time horizon. [34] further looks at two different scenarios to calculate the long-run marginal emission factor. In scenario 1, a carbon tax is imposed on the power sector, whereas in scenario 2, the electricity system CO_2 emissions are instead constrained to maximum zero in 2050. From this, it was shown that the early emission factor was relatively high, because the increased demand in the scenarios led to the commissioning of gas-fired power stations. However, the emission factor decreased radically after 2035, giving a lower emission factor than the short-run marginal emission factors. According to [34], this shows that the long-run marginal emission factor has an important implication in terms of strategies for climate change mitigation. [34] states that it allows decision-makers to "target specific technologies for investment and R&D based on a more dynamic view of their interaction with long-term energy systems." This further, according to [34], enables a more informed decision-making when analyzing the relative efficiency of different abatement options.

In 2018, [52] compared the impact of a control strategy that exploited the energy flexibility of thermal loads in buildings equipped with heat loads. The hypothesis of the work was that shifting thermal loads to periods with lower CO_2-emissions in the national grid could lead to a reduction in total emissions. In this article, the marginal emission factor is calculated in order to observe the potential impact. Here the marginal emission factor is defined as the CO_2-emissions avoided for every kWh electricity saved at a specific moment and is calculated using the following steps:

1. Collecting hourly data from the Spanish energy mix.
2. Compute the hourly average emission factor of the year considering the CO_2-emission coefficient of each energy source.
3. Calculating the change in demand and average CO_2-emissions from one data point to the next.

The paper further highlights that this marginal emission factor is highly country dependent and that the marginal emission factor used in the paper only yields for the Spanish energy system. In addition to geographical dependency, [52] emphasized that the marginal emission factor also depends on the merit order between the different sources of the energy mix. From the study, it was observed that the marginal emission factor was highly dependent on the system load, in addition to the proportion of renewables in the system [52]. To address this, [52] decided to calculate the marginal emission factor as a function of system load and share of renewables.

In [14], a comparison of the average and marginal emission factors for passenger transportation modes, was performed. In the article the restriction regarding representing the marginal impact of changing demand using average emissions factors are discussed. [14] collects data from the U.S. Department of Transportation and the U.S. Bureau of Transportation Statistics, to calculate the average and marginal emissions factors. In [14] it is shown that marginal emission factors are lower than average emission factors for all studied passenger transportation modes. The differences are considerable, and [14] concludes that the current use of average emission factors misrepresents the energy and environmental impacts.

A similar comparison is made in [61]. In this paper, the environmental and economic impact of electrification of offshore oil platforms was investigated. [61] observed that the chosen method for calculating CO_2-factors had a strong influence on the resulting CO_2-emissions. Using the average emission factor led, for instance, to a decrease in the CO_2-emissions associated with the operation of the offshore oil platforms between 48 - 90%. [61] further emphasized the importance of the selected geographical scope. Defining proper boundaries can, according to [61], be challenging as the European energy system is an interconnected and dynamic system. When considering the marginal effect [61] gets an increase in total CO_2-emissions up to 40%. In [61] this is found to be due to the large utilization of coal plants to meet the marginal increase in power demand. This is, according to [61], more prominent in the first 20 years of the analysis, when CO_2- and fuel prices are low. However, the utilization of coal plants decreases after 2040, which decreases the marginal CO_2-factor in addition to the resulting emissions.

A similar trend is found in [60]. In this article, an annual marginal emission factor is used. Equivalently to [61] the emission factor is higher at the beginning of the analysis, as marginal power mainly comes from coal power. In the following years, [60] includes more renewable and natural gas power, causing the emission factor to decrease. [60] highlights how different values of the emission factor can modify final emission reduction strategies. Due to this, [60] concludes that to get the real extent of a reduction in total CO_2-emissions, it is important with a comprehensive analysis of the power system.

In [9], both the average and marginal emission factor is considered in order to calculate emissions from electric vehicle charging in future scenarios. In this project, hourly emissions are considered. By doing this, the project manages to show lower emission intensity during day time, when energy is produced by PVs, than during nights in which energy is produced by natural gas. This again shows the impact regarding the hourly calculation of emission factors and raises the question of whether the factors should be considered on an hourly basis, or over a specific time period. [9] concludes that the results from the study are robust when considering the average emissions factor due to the quantified effect of lower emission intensity during daytime being considerable. This additionally has a clear connection to the maximum output of solar PV. However, for the marginal emission factors the results are less robust [9]. This is because the effect is less prominent, and the mechanisms underlying the effect are more difficult to determine. According to [9] average electricity mixes are appropriate when identifying total emissions associated with a certain demand. Marginal emissions are, on the other hand, beneficial when analyzing how emissions change based on a change in demand.

Emissions from electricity can, as mentioned above, be time-dependent. This is addressed in [70], where the response to hourly demand-side changes is considered through the simulation tool PROMIX. PROMIX is a tool developed to simulate an entire energy system on an hourly basis using a dynamic priority listing program, where plants are activated according to the minimal marginal fuel costs [70]. According to [70], it is important to consider the time dependency of emissions from electricity partly because only the energy used during the operation time of a given application would have an impact on the resulting emissions. In data from the Belgium energy system from 1997, the article found that the instantaneous emission factor varied between 150 g/kWh and 450 g/kWh, while the average emission factor was constantly at approximately 330 g/kWh [70]. The article further differs between marginal- and average emission factors. The marginal emission factor is used in cases where one is to compare different situations and is in [70] found using the merit order of existing plants. This is because instantaneously changes in demand only would affect the activation of a number of plants in the energy system, whereas the rest would in fact stay unchanged [70]. On the other hand, the average emission factor is used when quantifying emissions from existing applications. To account for the time-dependency the average emission factor is in [70] calculated as a weighted average, based on the emission factor per hour multiplied by the hourly demand and further divided by the annual demand. The article further looks upon different case studies comparing running the system in winter versus in summer and in day versus at night. This results in different total emissions, showing that the hourly difference in emission factors could have an impact on resulting emissions.

Several of the above studies have used the merit order when calculating the marginal emission factor. This method is valid when considering historical data, but it has some restrictions. Firstly this method is only applicable for a single energy system, i.e. the British merit order is far from equal to the Norwegian. According to [33], another challenge using this approach is that it does not reflect upon reality. The main consideration to this suggests that the logistics of plant operation could provide constraints that lead to an operation in contravention to the merit order [33]. Additionally, the merit order approach does not account for possible changes in the energy system dispatch [33].

As observed above, there exists several possible procedures in order to calculate the emission factors. However, as of today there does not exist a standard strategy, and depending on analysts and study purpose different methods are chosen. Nevertheless, a standard is needed as it would allow for greater comparability of study results and transparency. In [63], an algorithm to help determine the best method for calculating the CO_2-emissions from an electrical load is established. Based on different input as region size, temporal resolution, and research question, the algorithm finds the most appropriate method. This is interesting as it could help standardize when to use the different calculation methods, which could lead to consistency in future studies.

However, chosen calculation method is not the only thing that could impact the emission factor for electricity. To identify the total emissions from the power market, it is important to include all relevant framework conditions. This further shows the complexity of the calculation of the emission factor for electricity.

2.1.5 Emission Trading Scheme

A factor that could influence emission factors, is the Emissions Trading System (ETS). The European ETS (EU ETS) was established in 2005 as the first international emission trading system [19]. The trading system was initially designed to meet the target of the 2012 Kyoto Protocol. Subsequently, EU has developed additional emission reduction targets for 2020 and 2030, and the trading system still has a major role in meeting these targets [36]. The trading system has further a key role in the EU's long-term mitigation goal of reaching climate neutrality by 2050 [36]. According to [38], the EU ETS avoided emitting approximately 1.2 Gton CO_2 in the period 2008 to 2016. This is approximately half the reduction of what was promised under the European Kyoto Protocol commitments [38].

The EU ETS is a "cap and trade"-scheme [19]. A cap is set on total emissions from certain GHGs emitted by the different installations in the system [19]. Installations further buy, or receive emission allowances, which can be traded among each other. Each emission allowance represents permission to emit 1 tonne CO_2-equivalents. Meaning that the power producer has to compensate for their emissions by buying emission allowances. The number of emission allowances is limited, which ensures the value of the allowances [10]. In addition, the total cap reduces by a 2,2% linear reduction factor each year, leading to a decrease in total emissions from the installations included in the system [57]. Theoretically, an increase in demand would not increase total emissions within the ETS [41]. However, for this to be true, the emissions-cap would have to be reached each year [41].

One important factor with the EU ETS is that total emissions do not change due to individual player adaptations in the market [10]. In the case of a decommissioning of a fossil-fueled plant due to reduced electricity demand, this would lead to a big decrease in the price of emission allowances. This would further lead to other installations increasing their production equivalent with the lost emissions [10]. This is shown in Figure 1, where the connection between power production and industry is presented.

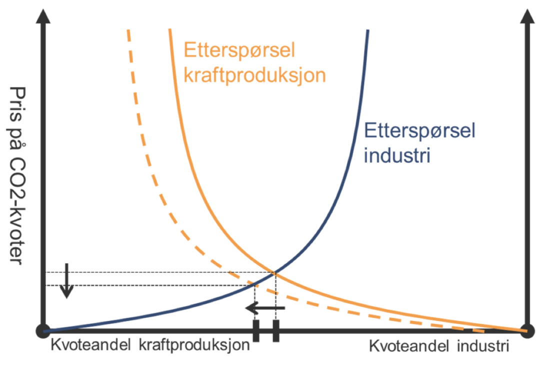


Figure 1: Change in price and emissions allowance due to change in demand for emission allowance in the power sector.

Source: [10]

In case of a decrease in demand for emission allowance in the power market, the power market curve would move to the left, which would reduce the price of emission allowances. The reduced price would further increase the demand for emission allowance in the industry, leading to increased emissions in this sector. Due to this, there is no reduction in total emissions, as the total number of emission allowance stays unchanged [10].

In this thesis, only an example system is considered. This could be considered as an individual player, and it would thus not be directly influenced by the EU ETS. If one, on the other hand, were to analyze the whole European energy system, it would have been necessary to include the impact of the EU ETS [10].

2.1.6 Green Certificates

Green certificates could be perceived as the opposite of the EU ETS. As the EU ETS sets a maximum cap for total emissions, the green certificates guarantee a minimum of renewable production [22].

The green certificate scheme is a market-based support scheme in which producers of renewable energy receive one certificate per MWh of electricity they produce for a period up to 15 years [48]. Further, electricity suppliers are required to purchase electricity certificates for a specific percentage based on their electricity consumption. In the Norwegian-Swedish scheme, this amount of renewable energy was gradually increased towards 2020 but will now start to decrease towards 2035. The scheme will be ended in Norway in 2036 [48].

The producers of renewable energy gain an income by selling their electricity certificates and electricity sales. The income from the green certificates is further intended to develop the new electricity production from renewable energy sources more profitable. In order to ensure demand, the authorities decide a given number of certificates that must be purchased, which corresponds to a yearly percentage of the turnover [10]. However, it is the market that determines the price and which projects are to be carried out [48].

It is the certificate quota that regulates the offer of renewable energy in the market [10]. In the case of a decrease in demand, this would decrease the price of power. However, this would again lead to an increase in certificate price, which is observed in Figure 2.

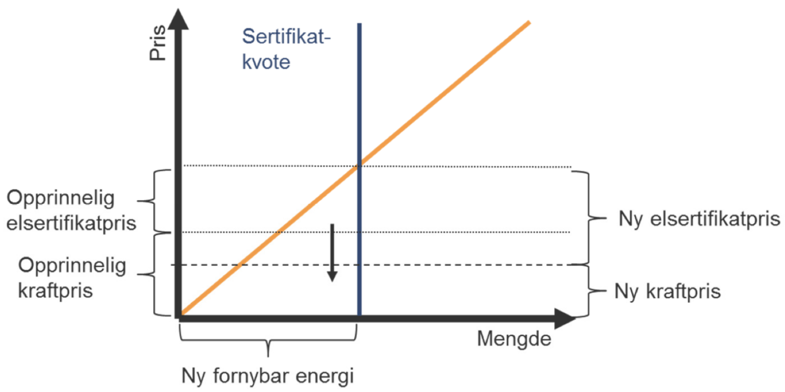


Figure 2: Consequences due to change in power price in a market with green certificates. Amount of respectively original certificate- and power price to the left, and amount of new certificate- and power price are seen to the right.

Source: [10]

As observed in Figure 2, the offer of renewable power production is constant and independent of changes in demand. Most likely it will not be developed more renewable production capacity in the Norwegian-Swedish market than what is decided by the certificate quota [10]. However, in case of an increase in electricity consumption and price level that would make the expansion of renewable power production profitable without green certificates, development of more renewable production capacity is possible. The price of green certificates would, in that case, equal zero [10].

Green certificates influence the power market when considering long term, and it ensures the addition of renewable energy in the power market, regardless of variations in demand or power price. In case of an increase in demand, one would utilize the surplus of renewable energy, as long as the increase in demand is less than the total certificate quota, which is illustrated in Figure 3 [10].

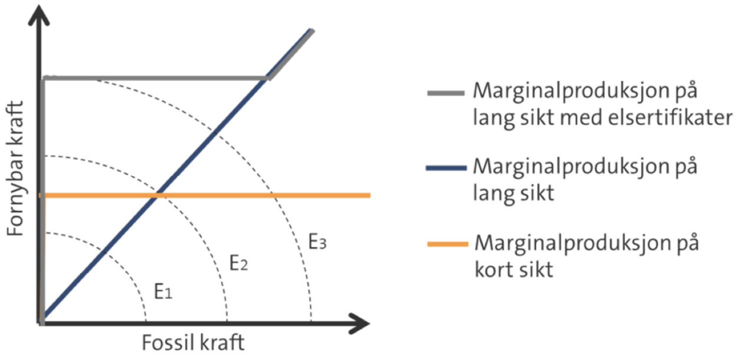


Figure 3: Marginal production changes due to changes in power consumption.

Source: [10]

Figure 3, E1, E2 and E3 represent changes in the consumption of electricity. Consumption is further constant along the curves. The coloured lines represent changes in the power market composition due to changes in demand. The orange line represents the marginal production when looking from a short-term perspective. An increase in demand would lead to an increase in renewable power production as long as available capacity exists. If the demand increases above this increased consumption will lead to increased fossil power production. The grey line represents the market composition regarding a market with a long-term green certificate scheme. As shown in the figure, the certificates ensure more development of renewable power production compared to the orange line. As long as the increase in electricity demand is less than the renewable power production covered by green certificates, the demand increase will lead to increased renewable power production. However, as it is observed in Figure 3 in case of an increase beyond this, there will be an increase in fossil power production. As for the blue line, this represents the changes in market composition in the long-term, without any limitation on renewable production capacity. In this case, it is the total costs for each technology that defines the market composition [10].

2.1.7 Guaranties of Origin

Guaranties of Origin is a voluntary certification scheme that allows consumers to choose their production source, typically between renewable and non-renewable production [65]. Europe has a common energy market leading to that energy can be produced in one country and delivered to another [24]. Meaning that even though the Norwegian power production mainly comes from hydro, a Norwegian citizen could possibly buy German power produced from fossil-fueled plants. As an example, the estimated emissions from the electricity disclosure was in 2016 set to 530 g/kWh [49]. However, if one buys Guaranties of Origin, one is guaranteed that the bought electricity comes from renewable sources.

Guaranties of Origin are further a way to increase the demand for renewable energy [24]. By purchasing Guaranties of Origin, one sends a signal to the market that there is a need for more renewable energy. Additionally, it gives the renewable power producers an increased income, leading to increased development of renewable energy production [24]. Thus the consumers have power over the market, supporting renewable power plants, technologies, or construction projects [65].

However, Guarantees of Origin do not mean that the power flowing into a specific household is renewable, which is illustrated in Figure 4.

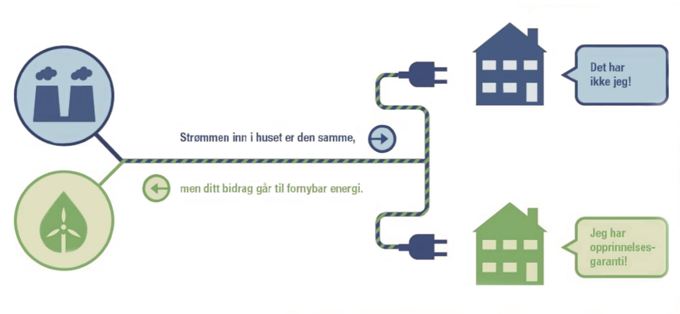


Figure 4: Actually power flow with Guaranties of Origin

Source: [42]

As observed in the figure the power into the household remains the same. However, the consumer only pays for the renewable production and by this increases the demand for renewable power production. This allows the consumer to claim credit for having caused additional renewable generation. Guaranties of Origin are therefore an important factor for estimating emission factors. Nevertheless, in the case study explored in this thesis, it is assumed that Guaranties of Origin will not be purchased.

2.2 Zero Emission Buildings

In Europe, the building sector accounts for 1/3 of the energy use and GHG-emissions. Similarly, in Norway, buildings account for 1/3 of total energy use in addition to approximately 80% of the Norwegian electricity use [28]. Therefore, a reduction in energy from the building sector is necessary to limit global warming.

Net zero energy buildings (net ZEBs) are buildings that produces the same amount of energy from renewable sources as the energy needed for operation [43]. The concept can further be expanded to include not only the energy used during the operation of the building but also energy demand from materials, transport, construction, and end of life energy [43]. This is the basis for ZEBs. Here the energy balance is not measured in terms of direct energy demand and generation but rather of the associated GHG-emissions during the building's lifetime, as observed in Figure 5.

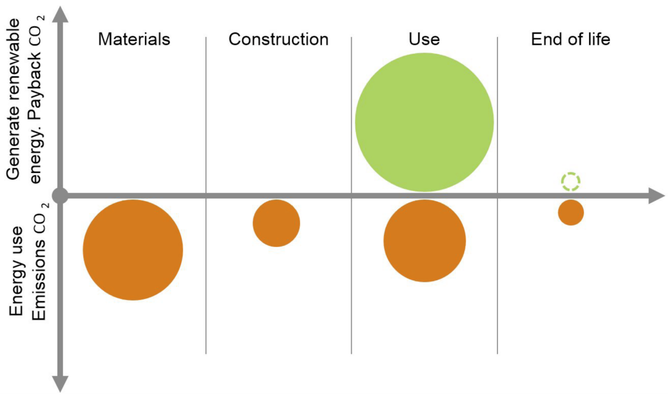


Figure 5: Balancing of energy demand in Zero Emission Buildings

Source: [43]

In order to reach the desired ambition level, emissions related to the different phases need to be compensated for through local renewable energy production, where solar power production currently is most commonly used [45]. ZEBs can further be characterized by a range of different ambition levels. As observed in Figure 6, the various ambition levels are decided based on the chosen system boundaries, i.e. what life cycle stages of the buildings are included or not.

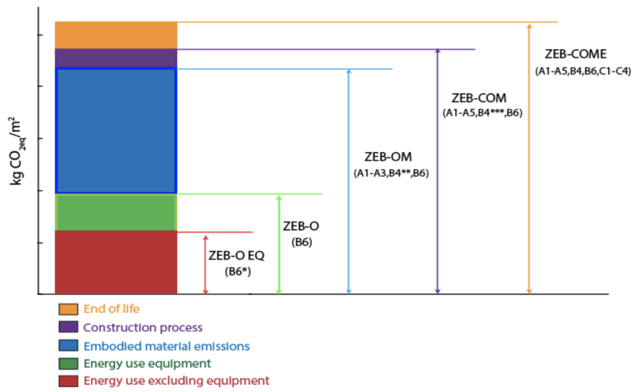


Figure 6: ZEB ambition levels

Source: [43]

Focusing entirely on individual buildings can, in some cases, lead to sub-optimal solutions due to fast load fluctuations, power peaks, or failing to meet the zero emission targets [28]. However, by considering groups of buildings rather than individual, the possibility of solving these challenges are often better addressed [28]. Due to this, the focus has shifted over to neighbourhoods over the last couple of years. Optimization on neighbourhood level could potentially reduce system-wide energy demand, reduce GHG-emissions, and include higher shares of renewable energy because of the integrated nature of the neighbourhood [44].

2.3 Zero Emission Neighbourhoods

In FME ZEN, a ZEN is defined as a "... group of interconnected buildings with associated infrastructure, located within a confined geographical area. A zero emission neighbourhood aims to reduce its direct and indirect greenhouse gas (GHG) emissions towards zero over the analysis period, in line with a chosen ambition level with respect to which life cycle modules and building and infrastructure elements to include." [11]. A ZEN has, as a whole, the goal of compensating for all indirect and direct greenhouse gas emissions related to materials, construction, and operation through export of local renewable energy. The neighbourhood achieves net zero emissions throughout the building's lifetime, typically of 60 years, by covering for its own power consumption with local renewable energy sources. In addition, the neighbourhood must compensate for the embodied emissions linked to construction, materials, maintenance, or power import in periods when the local power production is insufficient. To compensate for the embodied emissions, renewable power is exported from the neighbourhood, in periods with power surplus replacing non-renewable power from the grid.

Similarly to ZEBs, the ZENs have defined ambition levels based on what life cycle modules, buildings, and infrastructure elements to include [11]. In Figure 7, the different life cycle modules are presented.

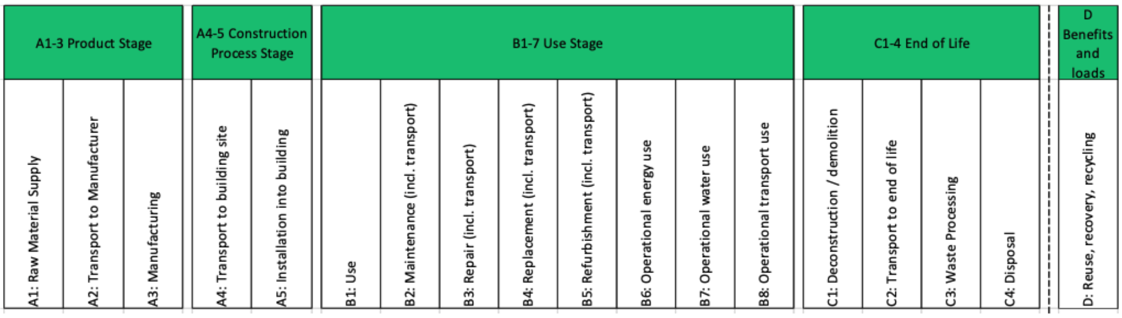


Figure 7: Module structure LCA

Source: [73]

Based on the module structure, the different ambition levels are defined as the following:

1. ZEN-O: Includes emissions linked to the operational energy use, corresponds to module B6 in Figure 7.
2. ZEN-OM: Emission related to all energy use during operation, in addition to indirect emissions from materials, corresponds to module A1-A2 and B4.
3. ZEN-COM: Equal to ZEN-OM, but additionally includes emissions related to the construction phase, i.e. module A4-A5.
4. ZEN-COME: Equal to ZEN-COM, but further includes emissions linked to the "End of Life" phase, i.e. module C1-C4.

FM-ZEN has further defined seven categories with assessment criteria and key point indicators, to assess whether the investigated ZEN accomplishes the desired ambition level.

1. GHG emissions
2. Energy (ENE)
3. Power/load (POW)
4. Mobility (MOB)
5. Economy (ECO)
6. Spatial qualities (QUA)
7. Innovation (INN)

GHG-emissions refer to the total GHG-emissions in kg CO_2 in a life cycle perspective [72], energy relates to the load on the grid over time expressed in kWh. The assessment criteria power/load relates to the instantaneous load on the grid given in kW or as the average energy in one hour in kWh/h. Mobility refers to the transport patterns of the users within the ZEN, whereas economy deal with the economic sustainability expressed in the life cycle costs of the ZEN. Spatial qualities refer to the delivery of final design based on the neighbourhood's user demands. Lastly, innovation is defined as new solutions/ideas that are of value for stakeholders in ZEN [72]. For the three first assessment criteria choice of the calculation method for emission factor would be of great significance in the final evaluation [46]

In order to identify the environmental impacts of the different elements in a ZEN, a life cycle assessment (LCA) is used. This is a standardized method used to give an overview of how different environmental impacts accumulate over different elements and phases of a system [45]. The environmental impacts of the product and construction stage, see Figure 7, are fairly established.

However, quantification of emissions related to emissions is, as seen above, a rather challenging task. In Norway, quantification of emissions related to energy consumption uses two different scenarios, namely the Norwegian and European electricity mix, in accordance with the Norwegian standard NS3720 [11]. Further, the emission factors are set equal to the average of the annual average emission factors throughout the neighbourhood's lifetime. In general, mainly average emission factors are used to decide the environmental impact of electricity consumption, with some exceptions. In the following section, a literature review is performed, investigating how the emission factor for electricity was calculated in previous studies.

2.3.1 Literature review

The building sector accounts, as mentioned, for a large share of the global CO_2 emissions, in which this sector has a great potential for reduction. Further, "On-site renewable energy generation is a key component for the building sector decarbonisation..." [38]. At the same time, the development of the power system is driven by policymakers to suppress climate change, aiming for a drastic reduction in total emissions [12]. Thus in parallel with the emission reduction in the building sector, a similar reduction is seen in the power system. In [12], the nexus between the decarbonisation of the power system, in combination with the development of ZENs were investigated. From this, it was found that there was little market-based development of ZENs before 2050 [12]. Further, that the surplus power from RES did not necessarily reduce GHG-gases. Thus [12] concludes that surplus power from ZENs not necessarily reduces GHG-emissions in the power system, given the current European cap on total emissions. This further shows that the current way of using ZEN as emission compensation could be misleading, which makes it important with a thorough understanding of the actual climate effects based on developing ZENs. According to [12], the role of emission compensation as a tool for GHG-reduction is a controversial assumption, which makes the results from the study important to quantify the actual benefit of ZEN in the European power system. From this, it is shown that more knowledge regarding the actual effects of ZEN is needed.

In [45], challenges regarding how to use LCA in ZENs are addressed. To calculate the emissions from a ZEN, the study divides the analysis into three subsystems, i.e. buildings, mobility, and energy systems. In [45], emissions from the energy system are calculated as the yearly delivered electricity minus yearly on-site electricity produced and multiplied by an annual emission factor. The article thus assumes symmetric emission factors, meaning that the exported energy replaces an average electricity mix. Further, the article uses different emission factors for electricity based on the Energy Technology Perspective scenarios from the International Energy Agency (IEA), in addition to the Norwegian electricity mix equal to 18 g CO_2/kWh. According to [45], the magnitude of energy system emissions and compensation depends on the net energy demand of a building, in addition to the carbon intensity from the grid electricity mix. Using the Norwegian electricity mix results in a small impact from the operational phase from the buildings. Additionally, emission compensation is of small significance. However, this changes using higher emission factors, leading to more emissions from the operational phase combined with more emission compensation. This shows an interesting aspect regarding the choice of emission factors for electricity in ZENs. Despite the same amount of exported electricity to the grid, would a ZEN using Norwegian emission factor be credited for less emission compensation than a ZEN using Europan emission factors.

In [45], yearly average emission factors were used to calculate the impact of emissions related to the energy systems. According to [62], "The development of on-site renewable energy production and demand management in buildings calls for a deeper understanding of the interaction between building operation and the electricity grid.". As mentioned in Section 2.1.4, emissions vary depending on the season, day of the week, or even hour of the day. Additionally, the hourly demand differs, resulting in demand peaks or periods with small consumption. The goal of [62] was to improve the evaluation of environmental impacts from an energy efficient house, both consuming and producing electricity, by looking at the temporal variation of the power production using historical data from 2013. From this, it was found that using the yearly average emission factor instead of an hourly could lead to an underestimation of the actual environmental impacts [62]. This is explained by a high share of thermal power production during winter, which coincided with higher electricity demand in the investigated houses due to space heating and lower on-site production from PVs.

The temporal variation is further discussed in [17]. In [17], a methodology for calculation of hourly average emission factors is developed, where the calculated emission factor takes into account the trading between different bidding zones and time dependency in CO_2 intensity. [17] further performs a case study looking at the demand response potential for heating in different Scandinavian bidding zones, based on the hourly average emission factor. From this, it was shown that control strategies based on hourly emission factor could lead to emission reductions. On the other hand, price-based control strategies usually lead to increasing total emissions, as optimal consumption is shifted towards the night. This is because electricity from thermal power is imported from the continental European power grid during the night due to lower electricity prices [17].

The methodology developed in [17] is further used in [68]. In [68], a stochastic planning model is used to analyze the expected cost of operation based on electricity prices and hourly average emission factors over a year in a ZEB located in Norway. According to [68], could using hourly average emission factors encourage power imports in periods when the grid has low CO_2 intensity in the electricity mix. As mentioned in [17], the Norwegian electricity price tends to be high in periods when the CO_2 intensity is low. This is because of the optimal dispatch of hydropower production, which store the water for production in periods when prices are highest [68]. The model explained in [68] would thus require ZEBs to implement tactics against the common strategy for the use of flexible assets if hourly average emission factors were to be used.

In [40], the hourly-based emission factors were determined using a merit order approach. The paper compared two households with the same total electricity consumption, but with different hourly consumption distribution. From this it was shown that using an average annual emission factor resulted in equal total emissions, while using hourly emission factors resulted in a difference of 250 kg CO_2 between the different households. Similarly to in Section 2.1.4, this shows the time dependency of emission factors, leading to the potential of over-/underestimating total emissions based on the chosen calculation method.

The Norwegian ZEB pilot buildings have used an emission factor for electricity equal to 132 g CO2/kWh to calculate the emissions from electricity, based on studies of the future energy systems [44]. It is further used a symmetric weighting approach when calculating emissions from electricity, meaning that the same emission factor is applied both for power export and import. In [44], this approach is supplanted due to the monthly differences in CO_2-emissions in Norway, to look upon possible reduction in emissions from eight Norwegian ZEBs. The seasonal sensitivity in Norway is observed in the context of electricity consumption and generation. Norway, where most electricity production comes from hydropower, generally has low emissions linked to production [44]. In general, Norway additionally produces more electricity than what is consumed, leading to the export of Norwegian electricity to other countries. However, during some spring and winter months, Norway experiences higher consumption than generation due to lower inflows and filling ratios [44]. In these months electricity import from countries with less amount of renewable energy sources is necessary. Norway would therefore experience higher emissions, which is not reflected by using only a symmetric emission factor. To deal with the seasonal variation [44] considers two different emission factors, i.e. a hydropower- and a marginal emission factor. The hydropower emission factor equals 15 g CO_2/kWh and is used in periods with power surplus. This emission factor represents the emissions linked to hydropower production. The marginal emission factor is set equal to 350 g CO_2/kWh, and is assumed equal to the European grid mix [44]. This emission factor is used in periods with power deficit. To look at the impact of using different emission factors, the paper looks at total emissions from the ZEBs using the hydropower and the marginal emission factor. When using the hydropower emission factor, it was shown that it is impossible to compensate for embodied emissions, as the emissions from installing solar PV surpass the compensation of exporting power from solar PV. This means that it is impossible to reach zero emissions in a Norwegian electricity context as the compensation is of less value, similarly to what was observed in [45]. The opposite is observed when the marginal emission factor is used to calculate total emissions from the ZEBs. In this case, it is shown that zero-emission is possible by compensating, as the exported electricity replaces more emissions than when using the hydropower emission factor. This again shows the importance of choosing the correct emission factor for exported electricity, as it affects whether a building can be classified as zero emission or not.

[31] addresses the challenges regarding the development of the power system over the lifetime of a ZEB, and how this would affect the resulting emission factors. The article further investigates two different emission factors, namely the average- and the marginal emission factor. The average emission factor is found using the Multi-area Power Market Simulator (EMPS), which is a stochastic optimization model for hydro-thermal electricity markets [31], and the average specific emissions for Europe. For calculations of the marginal emission factor, a marginal increase in demand is added to the model and the model re-run. The marginal emission factor is then calculated as the change in emissions divided by the change in demand. From this, the article concludes with the following usage of the different emission factors. For planning and designing of future deployment of ZEBs [31] recommend using the average emission factor over the lifetime of the ZEB. This is because the considerations could concern several buildings, meaning that a marginal approach would, according to [31], not be the correct approach. The marginal approach should, according to [31], be used for the optimal design of a single building in accordance with local conditions. In addition, emissions due to power export and import should be calculated using the marginal emission factor. Further, to credit the building for the correct reduction of emissions, a marginal emission factor for accounting and crediting is necessary [31]. This since the marginal reduction of consumption in a building would lead to a marginal reduction in emissions [31].

According to [47], the final energy system design of a ZEN is highly dependent on the ambition level, in addition to existing policy instruments and energy market conditions. This article performs a case study of a multi-family house in Germany, investigating cost-optimal solutions for energy system design in the ZEB and the following impact on the grid [47]. From this [47] finds three elements that decides the optimal ZEB PV size. The minimum PV size is determined by the electrical demand of the ZEB, as the building must export at least this amount of electricity in order to be classified as zero emission regardless of ambition level. In addition, the dimensioning of solar PV is influenced by ambition level and the emission factor for electricity. Including more embodied emissions to reach a higher ambition level would lead to the need for more compensation, resulting in a larger PV size. Further, [47] found that the emission factor for electricity greatly influences the dimensioning of installed solar PV. Intuitively would a low emission factor for electricity lead to less installed PV, as the imported electricity is greener [47]. However, from [47] the opposite was observed. As the exported electricity displaces less pollution in the grid, this leads to the need for more installation to compensate for the embodied emissions and imported electricity.

In this way, the choice of emission factor could influence the assessment of whether a building is, in fact, zero emission. Using high emission factors would lead to a quicker counterbalance of the embodied emissions. In [30], it was shown that in the context of low emission factors reaching ZEB-OM balance was unattainable. Thus could using, for instance, the Norwegian emission factor make it impossible to reach zero emission. The chosen CO_2 factor significantly impacts the overall CO_2 emission balance. This is clearly shown in [30], where the net ZEB performance is investigated for the Norwegian climate. From the results, it was shown that zero emission is reached easily when only considering the building operational phase. Reaching ZEB-OM was consequently more challenging, as embodied emissions were significant compared to the operational. According to [30], a fully decarbonized future energy system could handicap the energy-efficient measures in order to reduce operational energy. This is because low emission factors would lead to low emissions linked to consumption. In the same way could a high emission factor for electricity eventually handicap the efforts to reduce embodied emissions because the exported power would compensate for more emissions compared to when the emission factors are low [30]. However, [30] states that a failure to balance the emissions does not necessary mean that a net ZEB does not meet its objectives, as the solution still most probably is part of the solution to reach renewable electricity production. According to [30], ZEBs should be considered as a contribution towards a low carbon society, rather than focusing on optimizing a single building.

To deal with the question regarding the relevance of local renewable production in a power system dominated by hydropower [54] investigates the impact of allowing for buying CO_2 compensation to reach the desired ambition level in ZENs. As argued in [54], previous literature only considers local compensations. Thus developing ZENs in a power system dominated by renewable power production would experience difficulties in achieving the desired ambition level as the compensation has a smaller impact, similar to what was seen in [30]. In [54], an optimal ZEN energy system is investigated using different emission factors, i.e. the hourly and annual Norwegian- and annual European average emission factor, in addition to marginal emission factors. Using the Norwegian hourly and yearly average emission factor results in quite similar results. However, because of low emissions during summer, would using the hourly Norwegian emission factor result in a larger PV system [54]. On the other hand, using the European yearly emission factors yields a smaller PV system, as the exported power compensates for more than when using the Norwegian emission factors. The same is found when using the marginal emission factors. The marginal emission factors implied that the exported power compensated for more emissions, which resulted in a smaller PV system [54]. The article further shows that allowing for external investments could reduce the overall costs of the investigated ZEN, and asks if allowing for external compensation could have a bigger impact on the CO_2 emissions than forcing strictly local compensation [54].

[54] further highlights the importance of the choice of emission factor, as it is involved in accounting of emissions linked to imported electricity, in addition to compensation from exported energy from the ZEN. From [54] it is shown a substantial variety in choice of emission factors, which could be due to "an ease of access than because they are the best solution" [54]. This further indicates a lack of consensus, potentially giving quite different results based on the choice of calculation method. From this author's knowledge, most previous studies use the annual average emission factor for dimensioning of solar PV systems in ZEBs/ZENs. However, as seen above, there are several arguments against this method resulting in the question; does the current dimensioning of PV systems in ZEN result in the expected climate effects?

2.4 Nyhavna as a zero emission neighbourhood

In order to investigate the consequences of using different calculation methods for emission factors in the resulting PV system dimensioning for a ZEN, a case study was performed. The port- and industrial area Nyhavna was chosen as the investigated ZEN. Nyhavna is located in Trondheim, which in 2016 was decided to be developed into a city center district. The development was required to align according to principles for sustainable development in line with Trondheim municipality's environmental and sustainability goals [69]. In 2019 this decision was further sharpened when it was decided that Nyhavna should be developed as a zero emission neighbourhood with a desired ambition level of ZEN-COM.

In order to reach the above goals, the municipality has, together with the authors of [69], performed an ENOVA-supported concept study for innovative energy and climate solutions in area development, based on the seven main criteria, mentioned in Section 2.3, for ZENs. In this master thesis, only the ZEN-criterion for GHG is taken into account. This criterion include planning, designing, and operating an area with a climate footprint related to energy use, material use, mobility, and land use that is almost zero over the life cycle. Ref. [69] has further looked upon different scenarios to investigate the potential for Nyhavna as a zero emission neighbourhood. Based on the suggested energy concept [69] found a possible reduction in GHG emissions by 52% compared to a reference case using current standard solutions [69]. However, these reductions does not satisfy the goal of zero emissions, and thus using the suggested concepts and solutions, are not enough to reach the ambition level of ZEN-COM.

According to [69], the biggest contribution for a reduction in emissions is the electricity demand and emissions linked to materials in the buildings. In addition, more solar power production could make a positive contribution in the reduction of emissions [69]. In Table 3, the annual estimated emissions from Nyhavna are presented. In the concept study from [69], a comprehensive area solution for thermal energy supply was examined. However, this is out of scope in this thesis, and the associated emissions are thus not included in the table.

Table 3: Annual emissions Nyhavna

	Annual emissions [tons CO_2]
Electrical demand	1668.54
Electrical demand thermal	6.02
Buildings	1262.81
Solar cells	181.99
EV	380.70
Bus	80.69
Battery (materials)	49.20
Battery (losses)	19.90

Source: [69]

As observed in the table above, electrical demand accounts for a large share of the annual emissions. In the concept study, [69] has used an average emission factor for electricity equal to 0.0796 kg/kWh. This equals the average Nordic-European electricity mix for 2020-2079 and is in accordance with the current practice from [56]. It is further assumed a symmetric emission factor, meaning that one uses equal emission factors for both import and export. Based on this, a PV system of in total 98 000 m^2 is suggested as the optimal solution at Nyhavna, where 55 000 m^2 is placed on roofs, and the remaining area is placed on facades [69]. This would further give a potential yearly energy production equal to 15 GWh. However, as discussed in Section 2.1.4 exported power will not necessarily replace an average electricity mix. Using symmetric emission factors for both import and export could thus give misleading results. In Norway, there has been a tendency for emission factors to be low during the day and higher at night [68]. As solar PVs produce power during the daytime, this would, in the worst case, mean that the solar power potentially only would compensate for emissions close to zero, whereas the emissions from the imported power during night would stay high. This is closer examined in the case study presented in Section 4, where the optimal dimensioning of a PV system to reach the ambition level of ZEN-COM for Nyhavna is calculated using different calculation methods.

3 Method

As observed in Sections 2.1.4 and 2.3.1, there exists substantial variety in the calculation of emission factors for electricity. Determination of the emission factors is complicated, as it has to handle several assumptions and uncertainties. The emission factors further depend on several framework conditions, such as power market compositions, different technologies, or time perspectives. The choice of calculation method could potentially result in very different dimensions of required PV systems. It is therefore important with a consensus on the correct methodology to ensure consistency and comparability and give a better understanding of the actual climate consequences of increased development of ZENs.

In the following sections, different calculation methods used in this thesis are presented, in addition to an explanation of the different input data and parameters used to create the investigated case study.

3.1 Solar PV dimensioning

One of the questions asked in the introduction was how to dimension a solar PV system to compensate for embodied emissions. As mentioned above, the Nyhavna project has an ambition level of ZEN-COM, meaning that the solar PV installed at Nyhavna must be able to cover for its own demand and compensate for emissions linked to the construction, materials, and maintenance. In this section an approach for calculating the required solar PV area is established.

The minimum size of the installed solar PV, reaching an ambition level of zero energy, is calculated based on the annual electric demand similarly to in [47].

$$PV_{min} \cdot EF_{compensation} = D_{yearly} \cdot EF_{demand} \tag{1}$$

Here PV_{min} is the minimum produced annual electricity in kWh from solar PV, $EF_{compensation}$ is the emission factor for the exported electricity, D_{yearly} is the yearly demand for Nyhavna and EF_{demand} is the emission factor used for power import. In order to achieve ZEN-COM, the neighbourhood, as mentioned, has to cover for emissions from imported electricity in periods with production deficit, in addition to embodied emissions linked to the constructing phase and maintenance of the neighbourhood. This would eventually lead to the need for more power production, which can be found using the following equation,

$$PV_{embodied} \cdot EF_{compensation} = E_{solarPV} + E_{embodied} \tag{2}$$

here $E_{embodied}$ are emissions linked to materials and the constructing phase, in addition to maintenance of the ZEN, and $PV_{embodied}$ is the necessary power production exported to the grid, to cover for the embodied emissions, given in kWh. Lastly, $E_{solar_{PV}}$ equals emissions from materials and construction of the installed solar cells, given by the following equation,

$$E_{solarPV} = PV_{yearly} \cdot (EF_{solarPV,i} + EF_{solarPV,i+30}) \tag{3}$$

PV_{yearly} equals the annual power production from solar PV, in order to reach the desired ambition level. Further, solar cells have an expected lifetime of 30 years, meaning that the cells must be replaced once throughout the assumed lifetime of the buildings in Nyhavna [69]. In Equation (3), $EF_{solarPV,i}$ is given in kg/kWh and represents total emissions from installing the solar cells, and $EF_{solarPV,i+30}$ equals the emissions from the solar cells when replaced after 30 years. As it is expected a reduction in total emissions from electricity, this needs to be included in the future emission factor for solar cells. The emission factors for solar cells used in this thesis are presented in Table 4, and collected from [69].

Table 4: Emission factor for solar cells in different years

	EF [kg CO_2/m^2]	EF [kg CO_2/kWh]
2020	133.25	0.0200
2030	95.00	0.0160
2040	56.00	0.0095
2050	43.24	0.0100
2060	30.00	0.0050

Source: [69]

Based on the above equations, the annual power production from solar PV in order to reach the ambition level ZEN-COM, is derived after an algebraic conversion using the previous equations. This is further given by the following equation,

$$PV_{yearly} = PV_{min} + PV_{embodied} = \frac{D_{yearly} \cdot EF_{demand} + E_{embodied,yearly}}{EF_{compensation} - (EF_{solarPV,i} + EF_{solarPV,i+30})} \tag{4}$$

from Equation (4) the necessary installed capacity of solar PV can be found by

$$PV_{capacity} = \frac{PV_{yearly}}{CF \cdot 8760} \tag{5}$$

where CF equals the capacity factor for sun in Trondheim equal to 9.89%, collected from [21], and 8760 represents total hours during a year. The required area of solar PV is then found using the above equation, and further assuming 0.200 kW/m^2 per solar panel [67].

$$PV_{area} = \frac{PV_{capacity}}{0.200kW/m^2} \tag{6}$$

As observed in Equations (1) - (6) emissions linked to electricity plays an important role in the resulting installed solar PV. As observed in Section 2.1.4, there exists several methods in order to calculate the emission factor for electricity, which increases the complexity of the question: how do you dimension solar PV to compensate for embodied emissions? Determination of the emission factors for electricity is complicated as it has to handle several assumptions and uncertainties. Based on the utilized calculation method, the emission factors could vary a lot. It is thus important to choose the correct method, as the emission factor could have great influence on the final outcome, as well as future political- and commercial decisions.

3.2 Dimensioning of onshore wind power production

Even though solar PV is the most utilized local RES in ZENs, other renewable power producers could also be used. Norway, despite good wind conditions, has this last year experienced public opposition to the expansion of wind farms. However, there exist some Norwegian wind farms that could be interesting to compare with local PV, one of them is the Smøla wind farm. Smøla wind farm was developed in 2002 and further expanded in 2005 [50]. Today Smøla consists of 68 wind turbines with an annual average production equal to 356 GWh. This wind farm is used as the basis for further calculation of required dimensions in the Nyhavna project.

Similarly to in Section 3.1, the required wind power production to cover for the neighbourhood's demand, in addition with compensating for embodied emissions, are found using Equation (4). The emission factor for installation of onshore wind turbines is set equal 0.01 kg/kWh [7], [71]. Further, as onshore wind power is a well-developed technology, the emission factor is set equal when replaced after 30 years. It is further assumed a capacity of 2 MW per wind turbine [50]. Full load hours (FLH) are assumed equal to 3274 hours, which equals the FLH at Norwegian onshore wind power plants in 2020. Based on the above conditions, it is possible to find the necessary MW wind power to reach the ambition level ZEN-COM, using the following equation,

$$W_{turbines} = \frac{W_{compensated}}{FLH \cdot 1000 \cdot T_{cap}} \tag{7}$$

here $W_{turbines}$ is the required number of onshore wind turbines, $W_{compensated}$ is required power in kWh in order to reach ZEN-COM, FLH equals the full load hours and T_{cap} is the capacity per wind turbine. The required area is then found using the assumption that each wind turbine requires 50m x 50m, which is an assumption based on typical area needed for modern wind turbines [2].

$$W_{area} = W_{turbines} \cdot A_{req} \tag{8}$$

Here A_{req} equals the required area per wind turbine equal to 2500 m^2, and W_{area} is the resulting area required for wind power production in order to reach the ambition level ZEN-COM.

3.3 Emission factors

As observed in Sections 3.1 and 3.2, emission factors for electricity are necessary to calculate the needed area of local RES. In this section, the different calculation methods for emission factors for electricity are presented. System boundaries are chosen to include emissions only from electricity production and consumption. However, it is important to note that there exists further emissions, i.e. from distribution, construction and disposal of production and distribution facilities, refining of fuel etc. However, this is out of scope for this thesis.

Previous studies have attempted to set a standard in order to choose when to use which calculation method. In [10], the article differs between two cases; Tracking of externalities and impact assessment. The first case is suited for reporting accrued externalities, i.e. one uses historical data to find total emissions. In this case, [10] suggests using the average emission factor when calculating total emissions. The second method is suggested to use as decision support, i.e. one looks at the consequences as cause of power system changes. as for instance added consumption or power production, and further takes decisions based on this. In this case, only the processes that are influenced by the change are taken into account. Here [10] suggests using the marginal emission factor to calculate the total emissions. In [63], the developed algorithm chooses between using average- or marginal emission factor mainly based on whether a load is respectively existing or new. The choice of calculation method could result in different results. It is therefore important with an agreement on the correct methodology to get a proper understanding of the actual climate effect of different generation technologies and loads in the power system.

3.4 Average emission factor

The most common definition of the emission factor is the average emission factor. The main advantage of this method is that it is easy to calculate and intuitive to understand as the method simply divides total emissions by total demand. The calculation method further differs based on whether it is calculated for generation or consumption.

3.4.1 Annual average emission factor for generation

When calculating the average emission factor for generation only the existing power system is considered. This gives the following equation,

$$AEF_{g,i} = \frac{Emissions_{g,i}}{Demand_{g,i}} \tag{9}$$

here Emissions$_{g,i}$ represents the total annual emissions from generator g and Demand$_{g,i}$ the annual demand, in area i. The average emission factor is based on the chosen geographical boundaries, which differ a lot as observed in Table 2. Based on the chosen geographical boundary, one could get quite different results, which illustrates the main disadvantage of this method. The chosen geographical scope highly influences the resulting emission factor. Additionally, the calculation of the average emission factor does not include import or export from power production to or from different zones. The second yields especially when including the Guaranties of Origin, as discussed in Section 2.1.7. Though Norway has an average emission factor close to zero, Norwegian households without Guaranties of Origin would in fact be allocated European power production leading to higher total emissions than stated from the average emission factor for production.

3.4.2 Annual average emission factor for consumption

This method takes basis in the average emission factor for generation. However, it adjusts for electricity imports and exports between different areas. A possible way to do this is by using simplified power flow tracing [41], which trace the flow of electricity from source to end-use. In order to find the average emission factor for consumption the emission factors in the different areas has to be calculated.

$$AEF_i = \frac{Emissions_i}{Demand_i}, AEF_j = \frac{Emissions_j}{Demand_j} \tag{10}$$

Where EF$_i$ and EF$_j$ represents the emission factors respectively in areas i and j. The annual emissions from consumption is then calculated using the following,

$$Emissions_{c,i} = (AnnualDemand_i - \sum_{j \in J} Demand_{exp,i,j}) \cdot EF_i + \sum_{j \in J}(Demand_{imp,i,j} \cdot EF_j) \tag{11}$$

where the first part of the equation represent the domestic emissions due to consumption, while the second part represents the foreign emissions caused by import. The emission factor consumption in area i thus becomes,

$$AEFc, i = \frac{Emissions_{c,i}}{Demand_{c,i}} \tag{12}$$

where Demand$_{c,i}$ is the annual demand in area i. In this thesis, it is the average emission factor for consumption, i.e. the factor representing the emissions from electricity consumed in an area, that will be used in the dimensioning of the local RES at Nyhavna.

When calculating the current average emission factor, it is adequate to use historical emission and demand data, and therefore there is no need for a power system model. The average emission factor can also be used to calculate the emissions for future scenarios. In this case, a power system model is needed, leading to uncertainties due to possible assumptions and simplifications in the scenarios.

3.4.3 Hourly average emission factor

As mentioned in Section 2, hourly variation in emission factors occurs, in which the Norwegian power system is an excellent example. During the day, the Norwegian emission factors are close to zero, as the demand is mainly covered by renewable hydropower. However, at night power is imported from countries with less renewable power production, giving higher emission factors. Further, the Norwegian emission factors vary over a year. As Norwegian heating demand is mostly covered by electricity, this leads to higher demand during the winter months. This further leads to more power import from other countries, eventually leading to higher emission factors. The combination of higher demand with higher emission factors, is not necessarily caught by an annual average emission factor. However, this could be communicated by the hourly emission factor given by the following,

$$AEF_{h,i} = \frac{Emissions_{h,i}}{Demand_{h,i}} \tag{13}$$

where Emissions$_{h,i}$ and Demand$_{h,i}$ are the hourly total emissions and demand in zone i. Similar to the annual average emission factor, the hourly average emission factor can be calculated for generation and consumption. Further, from Equation (13) it is possible to calculate the annual hourly average emission factor based on the sum of the hourly average emission factors over a year.

$$Hourly_{annual} = \frac{\sum_H (AEF_{h,i} \cdot Demand_{h,i})}{\sum_H Demand_{h,i}} \tag{14}$$

Another challenge regarding calculation of the average emission factor, both the factor for generation and the factor for consumption, is discussed in [35].

3.5 Short-run marginal emission factor

When calculating the average emission factor, one implies that changes in demand would in fact influence the whole energy system equally. However, in case of a demand change not all power stations would be affected equally. Typically would the operation of base-loads stay unchanged, while the demand change is met by plants with low marginal costs and available capacity [35]. This challenge is considered when using the short-run marginal emission factor, as this method distinguishes between existing and new demand. In case of a sudden change in demand, this would be met by a marginal change in production based on the existing power system. The method does not take into account new investments due to the demand change but looks upon the marginal emissions based on the commissioning/decommissioning of existing power plants. Further, unlike the average emission factor for generation, this method takes into account grid constraints, which gives a more accurate picture of today's dynamic and interconnected power market. The short-run marginal emission factor is calculated with the following equation,

$$SRMEF = \frac{Emissions_{NewDemand} - Emissions_{base}}{Demand_{NewDemand} - Demand_{base}} = \frac{\Delta Emissions}{\Delta Demand} \tag{15}$$

where Emissions$_{base}$ and Demand$_{base}$ represent the total emissions and demand in the original system, and Emissions$_{NewDemand}$ and Demand$_{NewDemand}$ are the total emissions and demand after the change in consumption.

Unlike the average emission factor, the short-run marginal emission factor is not possible to calculate only based on historical data. Due to this, it is necessary to use a power system model to simulate the existing power system, with and without the change in demand. The marginal emission factor's precision is therefore dependent on the model quality and its assumptions.

The method can also be used to calculate the emission factor for future scenarios. If one calculates the emission factor for a single future year Equation (15) can be used. However, if one is to calculate the emission factor over several years the Equation (16) has to be used. Here it is the sum of the change in emissions divided by the sum of the change in demand for the years considered that is calculated.

$$SRMEF = \frac{\sum_{n=1}^{N} \Delta Emissions}{\sum_{n=1}^{N} \Delta Demand} \tag{16}$$

However, calculating the future short-run marginal emission factor leads to several assumptions regarding fuel price, installed capacity, CO_2-price, etc., which could give potentially big uncertainties.

Another important disadvantage of this method is how to consider what consumption that is marginal or not [41]. In the case of an electrification of the existing car fleet, this would lead to a change in demand, which should be considered in short-run marginal emission factor-calculations. In parallel with the electrification of the car fleet increase in demand due to new housing areas or an increase in installed heat pumps could occur. All these events would eventually lead to a change in consumption referred to the existing. An important question is thus; Should these new demands be included as marginal consumption? [41] further mentions another challenge regarding the short-run marginal emission factor: when does new consumption become a part of the existing? Again looking at the electrification example of the existing car fleet. Should emissions from existing electrical vehicles (EVs) be considered as average, while emissions for new EVs be considered as marginal?

An important aspect to include when choosing the method for calculation of the emission factor is whether or not a change in demand is permanent or temporary. A cold winter would lead to a temporary increase in demand due to more need for heating. However, this increase would not lead to new investments in the power grid. In this case, the short-run marginal emission factor is adequate in order to calculate the emission factor. If one, on the other hand, experiences a permanent change due to the electrification of gas platforms, this could have a long-term consequence for power demand. In this case, the short-run marginal emission factor would not be adequate, which is another disadvantage of this method.

3.6 Long-run marginal emission factor

In order to reach a zero emission energy system, it is necessary with accurate information to the energy system stakeholders. Use of the short-run marginal emission factor only gives a picture of the immediate change given a change in demand, and it does not reflect the future. For instance, could an investment in EVs immediately lead to an increase in the short-run marginal emission factor, as the marginal increase most likely would be covered by energy from coal or gas. However, an increase in the utilization of EVs could further lead to more investments in solar energy. In addition, with potential higher CO_2-prices and more renewable energy ,this could eventually give an emission factor of zero in the future.

In [34], Hawkes looks upon the challenges when calculating total emissions due to a change in demand. The change in emissions is, according to [34], a function of which generators that respond to a change in demand, in short-term. Additionally, it is based on which generators that are commissioned or decommissioned as a result of the changes in the long-term.

This has been addressed in the calculation of the long-run marginal emission factor. When calculating the long-run marginal emission factor, the power system is no longer considered static, i.e. one allows that marginal consumption can lead to new investments. As seen in section 2.1.4 there exist different approaches to calculate the long-run marginal emission factor. In [41] three different variations are presented, namely additional generation in equilibrium, optimal additional generation and manual additional generation. In the first method, it is assumed that it is possible to calculate an optimal capacity and dispatch in equilibrium with a future reference year for the system with and without additional demand [41]. By assuming static conditions over the years considered, this gives the same equations as for (15), but with different calculation methods for the denominator [41]. Though the method has a good theoretic fundament, it is difficult to use in practice. Additionally, because of the complexity of the method, it is hard to understand, which makes it difficult to communicate with stakeholder outside the research community. The method further assumes optimal future conditions, which most likely would not be the actual case.

When using the second method new generation is added to an existing power system. The additional generation is found using optimization models, which use either snap-shot years or range of years [41]. The power system model must further be able to account for changes over time as a result of changes in consumption. Another challenge is the consistency of the method as assumptions, parameters settings, and models could vary between different analysts [41]. However, this method is more intuitive than the equilibrium method and therefore easier to communicate and understand.

A simplified version of the above method is the manual additional generation [41]. In this method, the new consumption is met by manually adding new generation capacity and further run the power system model to observe the long-run effects. This method variation is easy to use and very understandable. However, it raises the question regarding the selection of the marginally added generators. Regarding the above example with an electrification of the car fleet, if the added demand was covered by only renewable power one can expect to get an emission factor close to zero, without doing any further calculations. However, selecting the additional demand would lead to assumptions regarding the future energy market, which could result in different results based on the analyst. Further, by selecting the added generation, one indirectly decides on the final emission factor [41].

In this report, the long-run marginal emission factor is calculated using the second approach. A power system model simulates the existing power system with and without new consumption and allows for changes in the installed capacity due to the marginal consumption. The long-run marginal emission factor is then found using the following equation,

$$LRMEF = \frac{Emissions_{NewDemand}(P_{new}^{cap}) - Emissions_{base}(P_0^{cap})}{Demand_{NewDemand} - Demand_{base}} = \frac{\Delta Emissions}{\Delta Demand} \tag{17}$$

where P_0^{cap} represents the original installed capacity, and $P_{new}^{cap} = P_0^{cap} + \Delta P(NewDemand)$ represents the new installed capacity due to the change in consumption.

As mentioned above, the main problem with the chosen method is large uncertainties and potential inconsistency due to different assumptions, parameter settings, or dissimilar power system models between different analysts.

For effective mitigation, it is important with accurate and consistent advice. A company using the Norwegian average emission factor to calculate annual emissions would not necessarily be interested in investing in emission reduction measures, as their annual emissions from electricity use appear to be close to zero. Using the short-run marginal emission factor to look at the impact of an electrification of the car fleet could be used as a counterargument for this solution. This due to, for instance, low CO_2-prices leading to that an increase in demand most likely would be covered by thermal power production, leading to an increase in immediate emissions. Consensus regarding how and when to use the different emission factors is therefore crucial to enable more targeted interventions and better decisions on the road towards a green society.

3.6.1 Emission factors for compensation

The emissions compensated by the local RES must also be determined to understand the environmental impact of ZENs. As mentioned in Section 2.3.1, the current practice is to use an average emission factor equal to the average of the electricity mix over the lifetime of the ZEN, where it is further assumed symmetric emission factors for electricity export and import from/to the neighbourhood. By doing this, one is assuming that the produced electricity from the ZEN replaces an average mix of electricity, which, as mentioned, is not necessarily the case. Additionally, this method does not take into account the hourly differences in the RES availability or emission factors. As observed in [68], it was shown a tendency of low emission factors in Norway during daytime and higher emission factors at night. Further, this interacts with solar power production, which only produces power when the sun is shining, in other words, during the day. It is therefore interesting to see whether it is possible reaching the ambition level of ZEN-COM when regarding the hourly variation in the exported power and the time-dependent emission factors.

In order to look into this three different calculation methods for emission factors for compensation are used, namely an annual average, an hourly average, and a marginal emission factor.

For the annual average emission factor, it is assumed symmetric emission factors for export and import similarly to in [56], and it is thus equal to Equation (12). For the hourly average emission factor, the availability of the local RES is taken into account and multiplied by the hourly average emission factor to find the compensated emissions. It is then divided by the hourly power production from the RES, to find the hourly emission factor for compensation.

$$Hourly_{compensation} = \frac{\sum_{h=1}^{T} AEF_{h,i} \cdot P_{RES,h}}{\sum_{h=1}^{T} P_{RES,h}} \tag{18}$$

Where $P_{RES,h}$ is the hourly production from the local RES in the investigated ZEN. Thus, $Hourly_{compensation}$ communicates the hourly emissions avoided due to the renewable power exported.

As mentioned above, using average emission factors for export implies that the renewable power production replaces an average electricity mix, which most typically is not the case. A marginal emission factor for compensation is thus calculated to find the change in emissions as a result of more renewable power production and is given by the following equation,

$$MEF_{compensation} = \frac{\Delta Emissions}{\Delta P_{RES}} \tag{19}$$

3.7 GenX

To analyse at how the different emission factors behave in different situations, a case study was performed. To calculate the power dispatch for the case study, a model of a simplified north-European power system was built by parameterizing and configuring the GenX modeling framework. This is an optimization model which utilizes minimum-cost planning in order to determine the investments needed to supply the electricity demand. GenX is developed in Julia and JuMP and allows for co-optimization of several power system decision layers [29]. The objective function of GenX is to minimize the total annual costs in an electricity system, where the costs concerned are the fixed-, operational- and total costs of unserved demand [29].

In GenX, simultaneous co-optimization of different interlinked power system decision layers are, as mentioned, performed in order to find the optimal solution [29]. Key features of the model include:

- Capacity expansion planning,
- Hourly dispatch of storage, generation and demand-side resources,
- Hourly unit commitment decisions and operational constraints for generation and storage units,
- Transmission network power flow,
- Policy constraints, and
- Scheduling of regulating and operating reserves by hydro, thermal and storage units meeting both operating- and capacity reserve requirements [29].

The model is deterministic typically solving capacity expansion problems for one future year [39]. The optimal solution is found using the following equation [39],

$$\begin{aligned} minCost = \sum_{g} (C_g^{Inv} \times A_g \times \delta_g^{Inv} + C_g^{FixOM} \times \Delta_g) + \\ \sum_{t} \Big[\sum_{g} (C_g^{VarOM} + C_g^{Fuel}) \times \varphi_{g,t} + (C_s^{VarOM} \times \varphi_{s,t}) + \\ (C^{ENS} \times \gamma_t^e) + (C^R \times \gamma_t^r) \Big] \end{aligned} \tag{20}$$

in Equation (20), the first summation represents the fixed costs where C_g^{Inv} is the investment cost for generation technology g given in \$/MW. Further, A_g represents the annuity factor ,and δ_g^{Inv} is the invested capacity in MW. C_g^{FixOM} represents the annual fixed cost for operation and maintenance (O&M) for generation technology g and is given in \$/MW-year. The last part in the summation, δ_g, is the total installed capacity of generation technology g in the considered year [39].

The second summation represents the variable costs and the costs for not meeting demand. Here C_g^{VarOM} and C_g^{Fuel} are respectively the variable O&M- and fuel costs for generation technology g, and $\varphi_{g,t}$ is the energy injected into the system at time t. C_s^{VarOM} represents the variable O&M cost, while $\varphi_{g,t}$ is the charged/discharged energy to and from the energy storage system. C^{ENS} and C^R are the penalties for respectively demand curtailment and unmet reserves, given in \$/MWh. Further γ_t^e and γ_t^r represents the demand curtailment and unmet reserves at time t, given in MWh [39].

GenX additionally works under several technology-specific constraints. Firstly the model cannot exceed the limitations of a specific generation technology's capacity. Secondly, operational limitations for the different generators are accounted for through information about for instance upper- and lower limits or startup costs and times. Further, there exist constraints regarding unit commitment, reserves, and regulations of the individual units [39].

The model also works with constraints on system level, including constraints for total CO_2 emissions, hourly energy balance, and total reserve requirements. CO_2-emissions are constrained through an emission cap, either per MWh or given by a total allowance for annual emissions, given in Mtons. The hourly energy balance ensures that generation and demand are in balance at each hour, while the last constraint guaranties the system reserves requirements [39].

4 Case Study: Climate effects in North-Europe based on the Nyhavna project

A case study was performed to look at the climate effects in the north-European power system based on local measures. More precisely, how the different calculation methods for emission factors influenced the dimensioning of a PV system at Nyhavna.

4.1 Input parameters

To look at the global climate effects of the Nyhavna project, the thesis developed a representation of a simplified north-European power system by parameterizing and configuring the general optimization model GenX. Further, the model was built up from scratch, as part of the master thesis.

The power system consists of three areas interconnected with transmission lines, as observed in Figure 8.

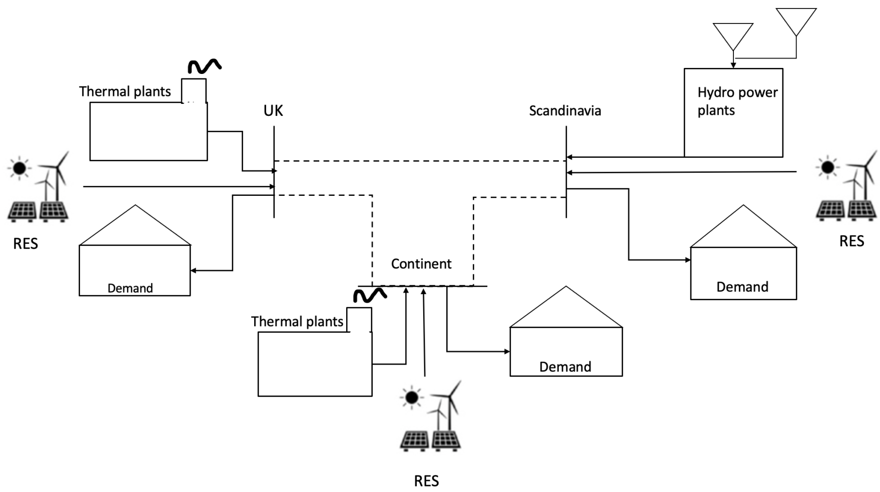


Figure 8: Network illustration presenting the most prominating energy sources in a given area.

Area one, hereby denoted Scandinavia, represents the Norwegian and Swedish power systems. These are power systems where power production is mainly produced by renewable energy sources. Area two represents Denmark, Germany, Belgium, and the Netherlands, whereas area three represents the United Kingdom. Areas two and three will be denoted respectively the Continent and the UK. In these areas, power production is mainly produced by thermal energy sources. However, some of the power production is produced from renewable energy sources, mainly solar and wind. It is important to note that this case study is only a simplification of the north-European power system. In reality, the areas would be interconnected with several other countries than those mentioned here. Additionally, transmission capacity between the different countries within areas one and two is not considered in this case study to simplify the calculations and reduce the running time. Thus, this case study is not a 100 % representation of the north-European power system. Nevertheless, as seen in Section 5.2.1, the results are quite close to historical values from 2019 from [27], providing a good representation for the calculations of emission factors.

In 2019, hydropower production from Norway and Sweden together counted for approximately 68% of the total power production, giving low total emissions [27]. Whereas for the Continent, more than 60% of the power production came from thermal power production [27], which led to high annual emissions compared to Scandinavia.

In order to investigate how using different calculation methods for the emission factors would impact the dimensioning of a PV system at Nyhavna, different simulations were investigated. The different simulations were further performed for two different years, i.e. 2019 and 2030.

The year 2019 is used as a reference for the current energy system, which is a mixture of renewable and non-renewable power production. The COVID-19 pandemic has influenced the power system, giving costs and power generation differing from expected outcomes which is the main reason for choosing 2019 to represent the present energy system. Further, to limit global warming, a reduction in current emissions linked to electricity generation is a necessity. This would eventually impact the possibility for compensation from the ZENs as the imported power to the grid from the ZEN would replace less polluting power production compared to in 2019. To observe this development, similar calculations as done for the 2019-case were performed using estimated cost data for 2030. It is assumed equal electricity demand for both 2019 and 2030. As it is expected more electrification in the future, this would not be the case in reality [66]. However, it is a simplification used in the case study for consistency between the different years examined.

Based on this, the following simulation was performed to investigate the dimensioning of a PV system at Nyhavna, given different calculation methods for emission factors.

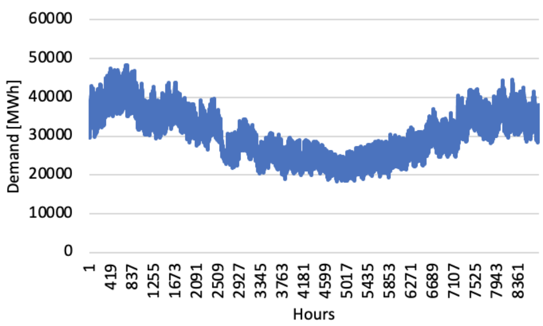
1. Simulation based on installed capacities, fuel- and CO_2 prices for 2019/2030,
2. Simulation for 2019/2030 where load profile for Nyhavna is added to the Scandinavian demand,
3. Simulation for 2019/2030 where load profile and local RES capacity for Nyhavna are added to the Scandinavian demand without allowing for investments in the power system,
4. Simulation for 2019/2030 where the load profile and local RES capacity for Nyhavna are added to the Scandinavian demand allowing for investments in the power system

The first simulation is performed to calculate the annual- and hourly average emission factors for 2019 and 2030. The second is performed to create a basis for the marginal emission factors, while the third simulation is run to calculate the short-run marginal emission factor and further observe the impact of developing ZEN at Nyhavna in the short-run. The last simulation is performed to calculate the long-run marginal emission factor, and further to observe the impact of Nyhavna in the long-run. Based on the calculated emission factors, the optimal dimension of a solar PV system is found using Equation (6). In addition, the 2019-simulations were re-run using onshore wind power as the local RES.

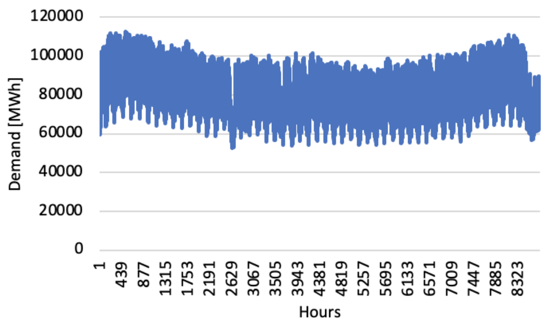
In order to perform the different simulations parameterizing and configuring of GenX is necessary. In the following subsections, the input parameters and assumptions needed to model the simplified north-European power system are presented.

4.1.1 European production mix and demand

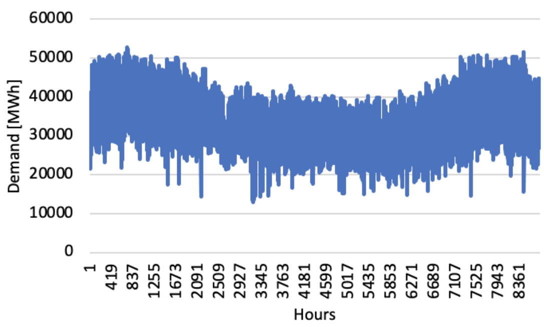
Table 5 presents yearly demand, and total installed capacity for the different areas. The demand data is collected from [23], and is presented in Figure 9. The load profiles, installed capacity, and yearly demand in the different areas are set equal to the sum of data collected for each individual country within one area.



(a) Scandinavia



(b) Continent



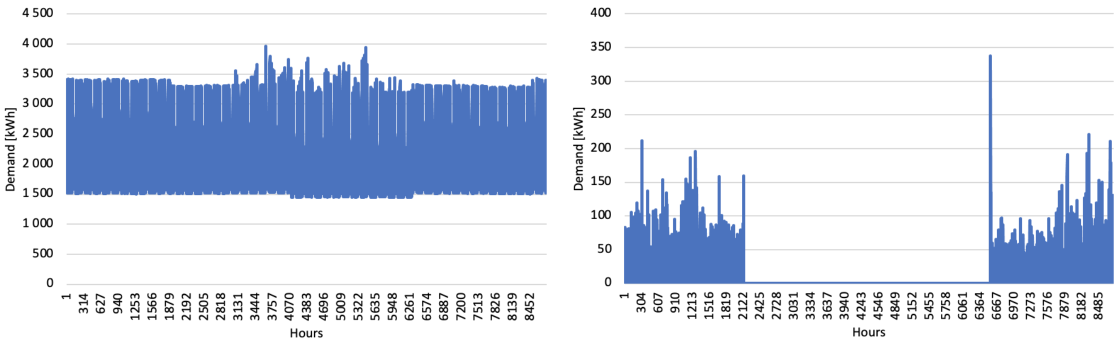
(c) UK

Figure 9: Demand data for the different areas.

Table 5: Yearly demand and installed capacity in case study.

	Total installed capacity [MW]	**Demand [TWh]**
Scandinavia	75 663	270
Continent	280 058	723
UK	103 269	306

In addition to load profiles for the different areas, consumption from Nyhavna must be included into the model. This is collected from the final report from [69], and can be observed in Figure 10. The load profile equals the sum of all electrical consumption at Nyhavna, including consumption from the industry- and building stock, thermal load profiles, and charging of passenger cars and public transport. It is further planned for seasonal heat storage in combination with a district heating network associated with the Nyhavna project. This is out of scope of this master thesis, and electrical consumption linked to the seasonal heat storage is thus not included here. For calculation of the load profile for the building stock, the simulation tool PROFet has been used [69].



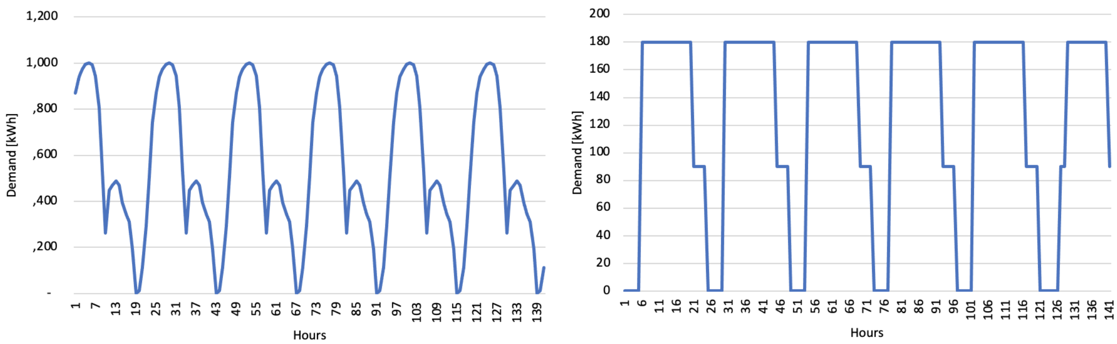
(a) Load profile building stock.

(b) Demand.

Figure 10: Load profile for building stock and electrical thermal demand for Nyhavna.

As observed from Figure 10, the load profile varies throughout the year. During summer, the electrical thermal demand equals zero resulting in lower demand. During winter, the electrical thermal demand increases, as Norwegian thermal demand is mostly covered by electricity [51], resulting in an increase in the load profile.

It is expected that the Nyhavna car park mainly will consist of EVs [69]. Additionally, it is assumed inductive charging for public transport driving through the neighbourhood. Based on this, [69] has developed expected future charging profiles, based on future driving habits and the number of residents at Nyhavna. The charging profiles are presented in Figure 11.



(a) Passenger car

(b) Public transport

Figure 11: Load profile for passengers cars and public transport for a typical week.

From the above load profiles the following summarized load profile for Nyhavna is added to GenX.

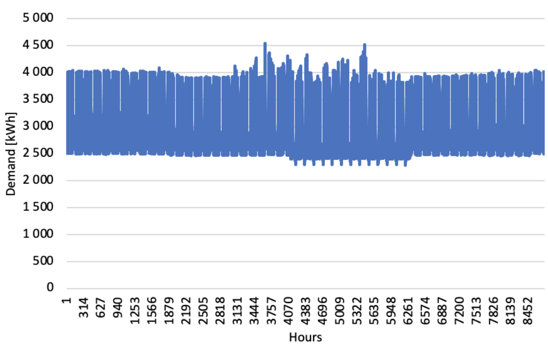
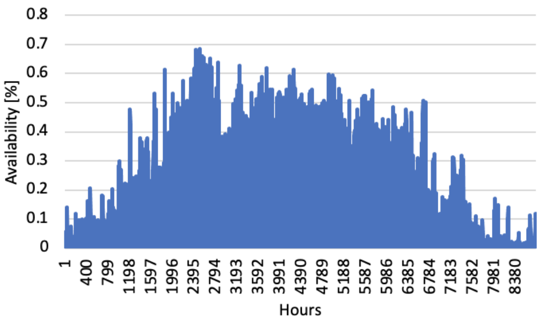


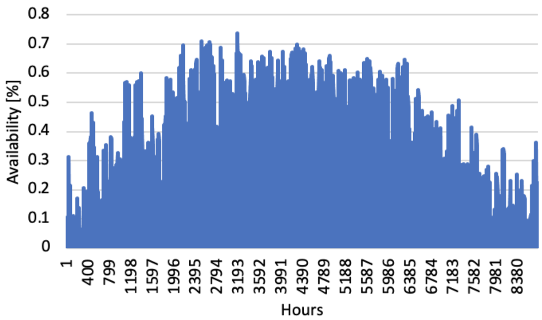
Figure 12: Load profile for Nyhavna

The hourly consumption in Figure 12 is given in kWh and does not give any easily observable differences when added to the Scandinavian demand, which is given in MWh. Thus, to more easily observe the impact of Nyhavna, the load profile was scaled up by 1000 before added to GenX.

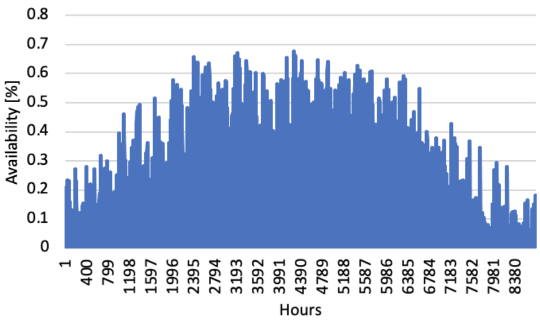
Wind- and solar availability is collected from [58], in which 2019 is chosen as the reference year. The different profiles can be observed in Figures 13 - 15. Inflow profiles are collected from [8] and can be seen in Figure 16.



(a) Scandinavia

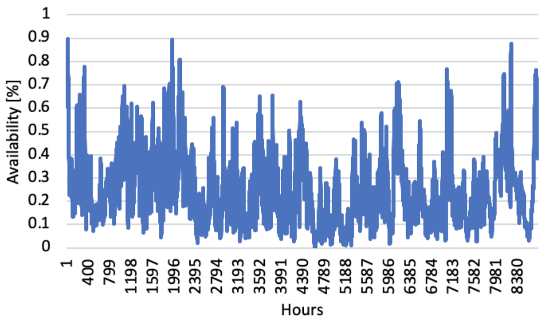


(b) Continent

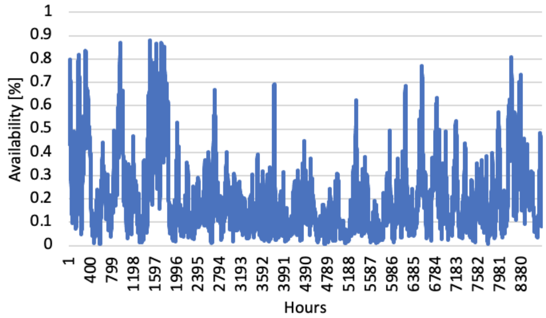


(c) UK

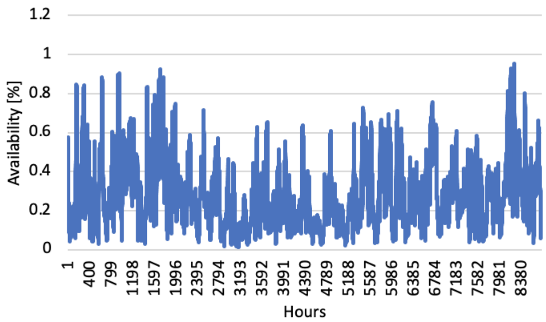
Figure 13: Solar availability



(a) Scandinavia

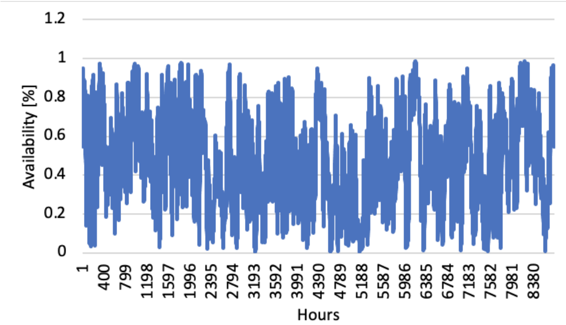


(b) Continent

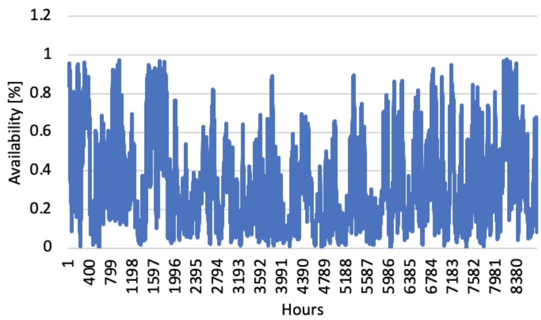


(c) UK

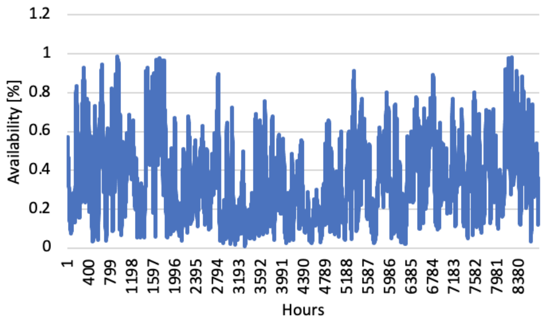
Figure 14: Onshore wind availability



(a) Scandinavia

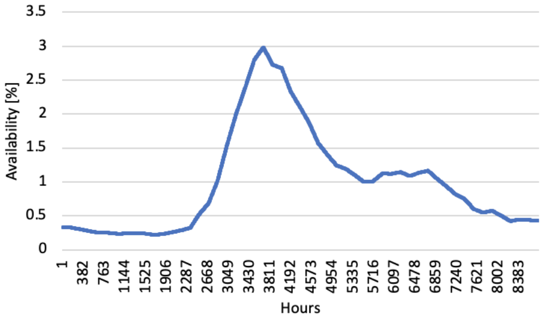


(b) Continent

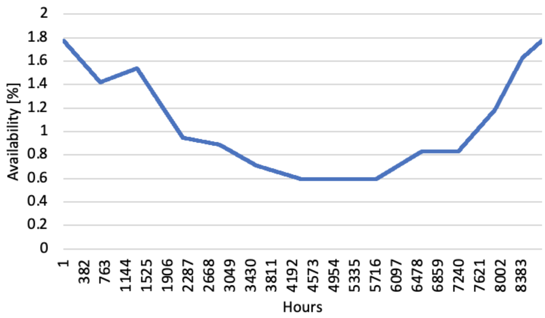


(c) UK

Figure 15: Offshore wind availability



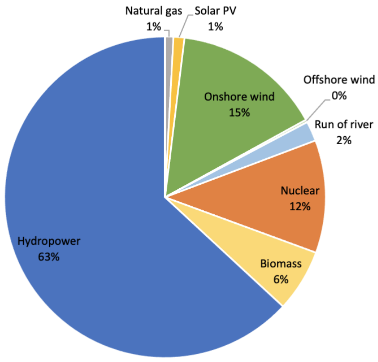
(a) Scandinavia



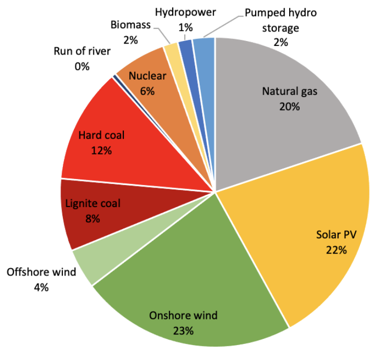
(b) Continent and UK

Figure 16: Hydro inflow profiles

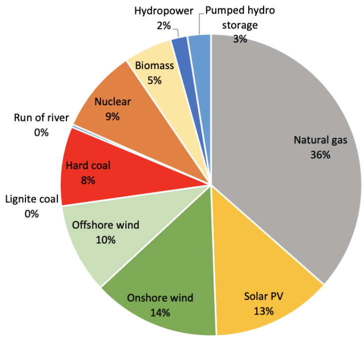
The composition of energy sources in the different systems is presented in Figure 17. Data for thermal power production is collected from [25], while installed renewable capacity is collected from [6].



(a) Scandinavia



(b) Continent



(c) UK

Figure 17: Approximate share of installed capacity of different energy sources in 2019

It is important to note that the share of energy sources in Figure 17 is just a simplification of the actual energy composition in the different areas. In the development of the case study, only the most prominent energy sources have been included. Thus, in reality there exist more energy sources, and the actual composition looks a bit different.

To model revision and maintenance of nuclear power plants, the availability of the nuclear generators has been reduced by a monthly aggregated reduction factor, collected from [8]. The availability is presented in Figure 18. It is further assumed the same availability in each area.

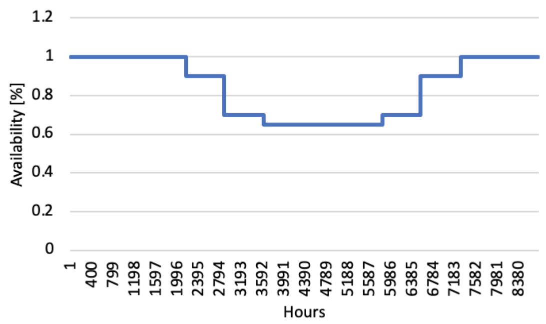


Figure 18: Monthly available nuclear capacity.

Source: [8]

For transmission capacity between the different areas, data from ENTSOG and ENTSO-E's Ten-Year Network Development Plans (TYNDPs) has been used. Further, the capacities between the different areas are set as the sum of all transmission capacity from each country in area i to area j, as observed in Equation (21).

$$TC_{ij} = \sum_{countries} TC_{ci,cj} \tag{21}$$

Here TC_{ij} is the final transmission capacity from area i to j, and $TC_{ci,cj}$ equals the transmission capacity from an individual country in area i to an individual country in area j. The resulting transmission capacity can be seen in Table 6.

Table 6: Transmission capacity

To area	From area	Capacity [MW]	Project Name(s)
Scandinavia	Continent	6795	Nordlink, Skagerak, NordNed
Continent	UK	4800	Viking and BritNEd
UK	Scandinavia	2800	North Sea Link and NorthConnect

Source: [26]

In Table 6, only the most prominent project names are mentioned.

4.1.2 Technology costs and energy prices

Data for the different fuel prices are collected from [5], heat rates are collected from [1] and fuel intensities are collected from [3]. The values are presented in Tables 7 and 8.

Table 7: Fuel prices

	Fuel price 2019 [$/MMBtu]	Fuel price 2030 [$/MMBtu]
Biomass	3.88	3.88
Hard Coal	3.61	5.17
Lignite Coal	1.32	1.32
Natural gas	6.74	7.5
Nuclear	0.67	0.67

Source: [5]

Table 8: Fuel intensities and heat rates

	Fuel intensity [tons/MMBtu]	**Heat rates [MMBtu/Mwh]**
Biomass	0	15.33
Hard Coal	0.1002	9.997
Lignite Coal	0.1069	9.997
Natural gas	0.0590	7.604
Nuclear	0	10.466

Source: [1], [3]

Cost data for 2019 and 2030 are collected from [64] and presented in Tables 9 and 10.

Table 9: Cost data for 2019

	Investment cost [$/MWyear]	**Fixed costs [$/MWyear]**	**O&M cost [$/MWh]**
Run of River hydro	138719.15	719.88	0
Reservoir and Pumped hydro storage	169860.18	2062.59	0.36
Nuclear	388251.84	9706.30	7.30
Natural gas combined cycle	44487.19	1617.72	2.63
Onshore wind	84930.09	1132.40	0.21
Offshore wind	159819.46	3397.20	0.44
Solar PV	37454.17	1214.50	0
Steam Turbine Hard Coal	117284.41	2070.68	2.74
Steam Turbine Brown Coal	137505.86	2628.79	3.42
Biomass	295516.98	8443.34	0

Source: [64]

Table 10: Cost data for 2030

	Investment cost [$/MWyear]	**Fixed costs [$/MWyear]**	**O&M cost [$/MWh]**
Run of River hydro	135079.29	663.26	0
Reservoir and Pumped hydro storage	169860.18	2062.59	0.36
Nuclear	363986.11	9301.87	8.44
Natural gas combined cycle	43354.79	1617.72	2.63
Onshore wind	80885.80	1132.40	0.21
Offshore wind	151579.99	2507.46	0.44
Solar PV	31302.81	1019.16	0
Steam Turbine Hard Coal	117284.41	2070.68	2.74
Steam Turbine Brown Coal	137505.86	2628.79	3.42
Biomass	295516.98	8443.34	0

Source: [64]

Lastly, for 2019 the CO_2 price is set equal to 27.36 $/tons CO_2 [4], whereas in 2030 the CO_2 price is set equal to 114 $/tons CO_2 [15].

5 Results

The main goal of the case study was to see how different choices of calculation methods for emission factors, would impact the resulting capacity and area of solar cells in the Nyhavna project. In the following section, the required PV area to reach the ambition level ZEN-COM at Nyhavna is calculated using the different calculation methods for emission factors. The section is further organized as the following: First, required capacity and area is found, reaching the ambition level zero energy. Then the dimensioning of a solar PV system at Nyhavna is estimated using the emission factors from [69]. Then the annual average emission factor is calculated in Section 5.2, based on the first simulation, presented in Section 4.1, and Equation (12). In Section 5.3, the hourly average emission factors are calculated, taking into account the seasonal and hourly variation of the power production and using Equations (13), (14), and (18). Section 5.4, uses simulation two and four together with Equations (15) and (19), to calculate the short-marginal emission factor. Next, Section 5.5 calculates the long-run marginal emission factor using simulations two and three, and Equations (17) and (19). Lastly, Section 5.6 re-calculates the different emission factors for 2019, using onshore wind power as local RES. This is to look at the consequences of more available RES in the resulting requirement for installed capacity and area.

It is important to note that this master thesis is only meant as a knowledge foundation to ensure well-informed decisions about climate compensation in the future. Therefore no conclusion is taken regarding which calculation method is the correct to use in developing zero-emission neighbourhoods.

5.1 NS3720 average emission factor

The minimum area for the Nyhavna project was found by observing at the solar PV power production required to cover the neighbourhood's consumption, i.e. the minimum area to reach a zero energy neighbourhood. It is further used symmetric emission factors for consumption and compensation equal to the values used in [69]. The values are presented in Table 11.

Table 11: Resulting area and installed capacity, reaching zero energy.

	MW$_{inst}$ [MW]	**Area [m^2]**
Zero energy	30.98	154 898.81

In Table 11, MW$_{inst}$ is the required installed solar PV capacity, and area equals the required PV area.

In order to reach the desired ambition level ZEN-COM, embodied emissions linked to construction, materials and maintenance must be compensated for during the neighbourhood's lifetime. In Table 12, the required area in order to reach ZEN-COM is found, using the same emission factors as in [69].

Table 12: Resulting area and installed capacity, using the NS3720 average emission factor.

	EF$_{cons}$ [kg/kWh]	**EF$_{comp}$ [kg/kWh]**	**MW$_{inst}$ [MW]**	**Area [m^2]**
European	0.0796	0.0796	82.89	414 471.20

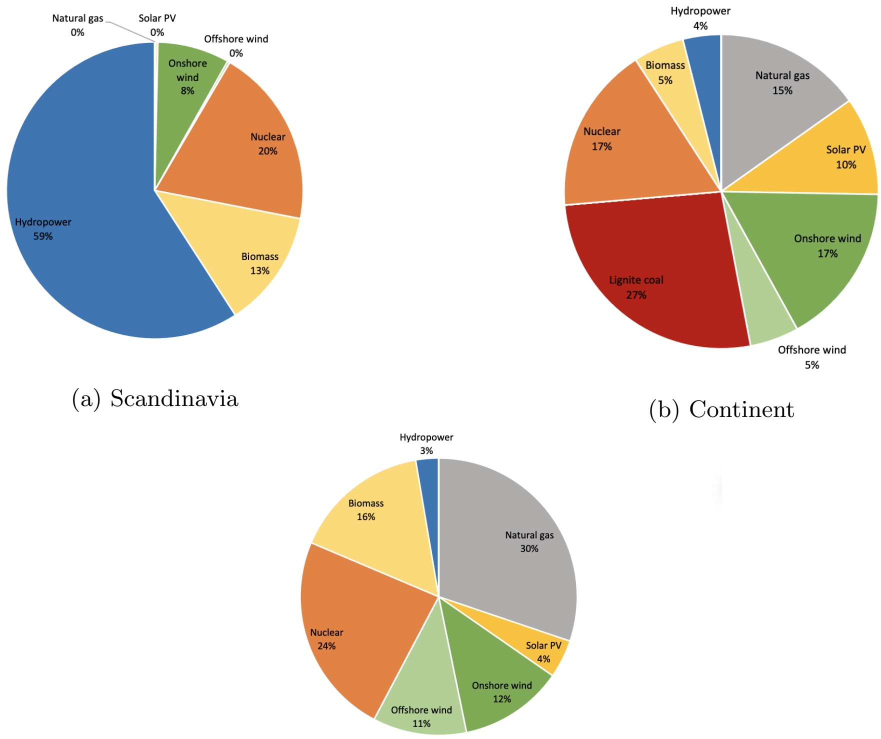
In Table 12, EF$_{cons}$ represents the emission factor for consumption and EF$_{comp}$ the emission factor for compensation. As observed in Table 12, including embodied emissions leads to almost a three-fold increase in the required solar PV area and installed capacity. This area is far higher than the available roof area at Nyhavna, meaning that the solution is infeasible. In [69], the available area was calculated. From this, the report came to the conclusion that available area was not sufficient to reach ZEN-COM. Thus, [69] uses a bottom-up approach to investigate whether or not reaching the desired ambition level is impossible. This thesis aims to observe the consequences of dimensioning of solar PVs, due to different calculation methods in which the opposite is performed. The thesis calculates the required capacity and area based on different emission factors and compares this to the available area. Using the emission factors presented in Table 12, resulted in an area significant larger than what is available at Nyhavna [69]. Therefore, similarly to [69], this thesis concludes that reaching ZEN-COM is not physically possible, within the area boundaries at Nyhavna.

5.2 Annual average emission factor

The following subsections show the annual average emission factors for 2019 and 2030. The annual average emission factor is found running GenX with installed capacity and demand from 2019. For consistency, the demand is further kept static for calculations in 2030.

5.2.1 Annual average emission factor 2019

For calculation of the annual average emission factor for 2019 GenX is run with installed capacity, fuel costs, and CO_2 prices for 2019. It is not allowed for any further investments in the power system, i.e. the power system is considered static. Based on the mentioned conditions, the power generation presented in Figure 19 is obtained.



(a) Scandinavia

(b) Continent

(c) UK

Figure 19: Power production base case 2019.

In 2019, the Continent's and UK's power systems are dominated by thermal power production, in addition to some renewable power, as observed in Figure 19. Scandinavia is dominated by hydropower production, with some production from wind, natural gas, solar, biomass, and nuclear power. The numbers are further quite comparable with historical values for 2019, with some exceptions [27]. As observed, GenX has chosen not to produce any power from hard coal, neither on the Continent nor in the UK. This does not match with historical values. However, GenX is a cost-optimizing model and does not consider any purchase contracts or political decisions, which could be the reason for the mismatch. In addition, only the most prominent energy sources were included in GenX.

In Table 13 the power generation in the different countries is presented.

Table 13: Yearly generation by energy source for 2019.

	Continent	Scandinavia	UK
	[TWh]	[TWh]	[TWh]
Hard coal	0.00	0.00	0.00
Lignite coal	183.00	0.00	0.00
Natural gas	104.00	0.38	87.20
Biomass	35.90	41.60	46.10
Solar PV	69.30	0.73	12.90
Onshore wind	114.00	25.40	35.10
Offshore wind	34.50	0.86	31.60
Nuclear	118.00	63.60	68.30
Reservoir hydro	27.00	192.00	7.70
Pumped hydro storage	0.00	0.00	0.00
Run-of-river hydro	0.00	0.00	0.00

Based on the resulting power dispatch the following annual average emission factors are obtained.

Table 14: Resulting area and installed capacity, using the annual average emission factor for Scandinavia and Europe, 2019.

	EF_{cons} [kg/kWh]	EF_{comp} [kg/kWh]	MW_{inst} [MW]	Area [m^2]
Scandinavia	0.0502	0.0502	149.22	746 084.70
Europe	0.2166	0.2166	45.33	226 658.46

In Table 14, the annual average emission factors for the Scandinavian and north-European power dispatch are presented. It is further assumed symmetric emission factors for consumption and compensation. For Scandinavia, the annual average emission factor is relatively small, as power production is mainly produced by renewable energy sources. However, some power production from natural gas exists, leading to some emissions. The low emission factor leads to small annual emissions linked to power import. This further leads to the embodied emissions linked to construction, materiel, and maintenance get a more significant role.

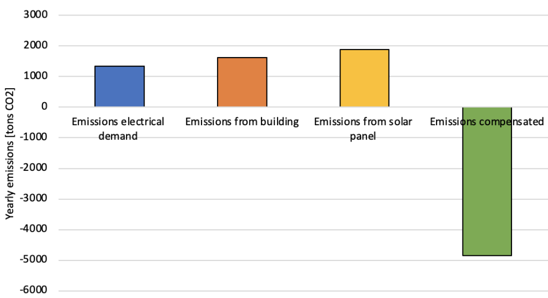


Figure 20: Yearly emissions from Nyhavna using the Scandinavian annual average emission factor, in tons CO_2.

In Figure 20, the blue bar represents emissions linked to electrical demand, without including PV production from Nyhavna, the orange represents emissions linked to construction, materials and maintenance of the neighbourhood and the yellow equals emissions linked to installing of the solar PVs. The green bar represents emissions avoided from PV production. As observed, the embodied emissions are quite dominant compared to those linked to consumption. In addition, because of the low annual average emission factor, the exported power from Nyhavna is "less worth" leading to a high requirement of PV area and installed capacity. However, the exported power from Nyhavna would not necessarily only replace Scandinavian power. Scandinavian annual net transmission equals 54.4 TWh, while net transmission for the Continent and UK is respectively -37.1 and -17.3 TWh, this is further presented in Appendices B and C. This means that Scandinavia is a net exporter, contrary to the UK and the Continent, which are net importers. Exported power from the Nyhavna neighbourhood could thus replace power generated on the Continent, which could lead to less required area of solar PVs.

As observed in Table 14, using the European annual average emission factor leads to a much smaller required area and installed capacity of solar PVs than using the Scandinavian. Due to the higher emission factor the compensated power is more worth, implying that the exported power replaces more emissions than when using the Scandinavian emission factor. The higher emission factor also leads to more significance from the emissions linked to power import, as observed in Figure 21.

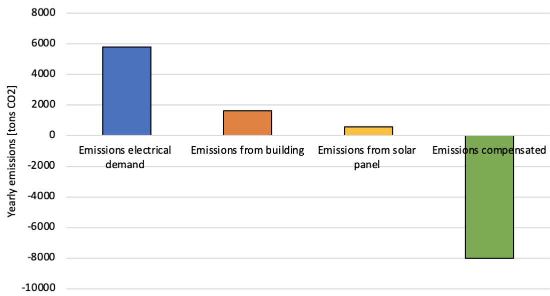
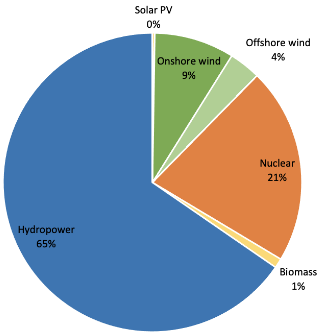


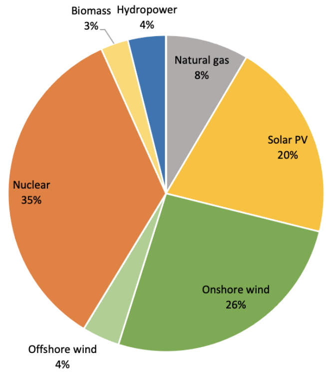
Figure 21: Yearly emissions from Nyhavna using the European annual average emission factor, in tons CO_2.

5.2.2 Annual average emission factor 2030

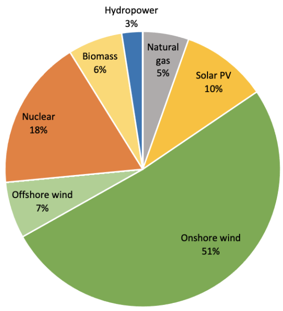
For 2030, GenX was run based on installed capacity and demand for 2019. However, the model was now allowed to build/decommission power plants based on the technology costs, fuel price, and CO_2 price for 2030. From this, the following optimal power production was found.



(a) Scandinavia



(b) Continent



(c) UK

Figure 22: Power production base case 2030.

As observed in Figure 22, running the model for 2030 leads to almost phasing out of power production from coal and gas, which is replaced by more generation from renewable energy sources.

Table 15: Yearly generation by energy source for 2030, and change from 2019, given in TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	0	-	0	-	0	-
Lignite coal	0	-183.00	0	-	0	-
Natural gas	58.80	-45.20	7.7E-03	-0.37	17.00	-70.20
Biomass	19.50	-16.40	3.01	-38.59	20.10	-26.00
Solar PV	141.00	+71.70	0.73	0.00	31.7	+18.80
Onshore wind	180.00	+66.00	25.40	0.00	161.00	+125.90
Offshore wind	26.60	-7.90	10.00	+9.14	20.80	-10.80
Nuclear	239.00	+121.00	62.30	-1.30	55.50	-12.80
Reservoir hydro	27.00	0.00	192	0.00	7.70	0.00
Pumped hydro storage	0	-	0	-	0	-
Run-of-river hydro	0	-	0	-	0	-

On the Continent, lignite coal has been phased out, and the area has further decreased power production from natural gas, biomass, and offshore wind. In addition, power production from the renewable energy sources onshore wind, solar PV, and nuclear has reviewed a significant increase due to the higher CO_2 prices and lower technology costs for the renewable technologies.

The changed power production has further influenced the transmission between the different zones. The Continent is still a net importer, where net annual import has increased to 31.2 TWh. On the other hand, the UK is now exporting power, with a net export equal to 7.92 TWh. This has further led to less need for Scandinavian power export, which has reduced to 23.3 TWh.

The reduction in power production from coal and gas further leads to significantly lower emission factors compared to in 2019, as observed in Table 16.

Table 16: Resulting area and installed capacity, using the annual average emission factor for Scandinavia and Europe, 2030.

	$\mathbf{EF}_{cons}$ [kg/kWh]	$\mathbf{EF}_{comp}$ [kg/kWh]	$\mathbf{MW}_{inst}$ [MW]	Area [m^2]
Scandinavia	0.0066	0.0066	infeasible	infeasible
Europe	0.0262	0.0262	516.16	2 580 795.81

The low emissions in Scandinavia lead to low emissions linked to power import from the grid. Similar to in Section 5.2.1, this makes the embodied emissions more significant. In this case, the low emission factor further makes it impossible to reach the ambition level of ZEN-COM, as the emission factor for compensation is lower than the emission factor for installing solar PVs. Similarly in Europe, the overall low emissions lead to a low annual average emission factor. Nevertheless, it is higher than the emission factor for installing solar PVs, making it theoretically possible to reach the ambition level ZEN-COM. However, an unrealistic area and installed capacity of solar PV is necessary to reach the desired ambition level.

5.2.3 Linear emission factor

As seen above, the emission factors differ a lot based on the development of the power system. In NS3720, this is handled by using an average emission factor equal to the average of the annual average emission factors over the neighbourhood's lifetime. Similarly is done in this case study to compare the resulting emission factors with the emission factors used in the Nyhavna project. It is further assumed that the power system becomes zero-emission in 2040 [37].

Table 17: Resulting area and installed capacity, using the linear annual average emission factor for Scandinavia and Europe, compared to the area found in [69]

	$\mathbf{EF}_{cons}$ [kg/kWh]	$\mathbf{EF}_{comp}$ [kg/kWh]	$\mathbf{MW}_{inst}$ [MW]	Area [m^2]
Scandinavia	0.0061	0.0061	infeasible	infeasible
Europe	0.0258	0.0258	infeasible	infeasible

As observed in Table 17, the annual linear average emission factor for Europe is considerably lower than the one found in [69] equal to 0.0796 kg/kWh, see Table 12. In this case study, it is assumed that Europe will reach net-zero emissions in 2040 [37]. In [69] it is, on the other hand, assumed some power production from coal and gas during the lifetime of Nyhavna, which is the reason for the higher linear emission factor. Further, it is observed that reaching net-zero in 2040 gives a linear annual average emission factor that is lower than both the annual average emission factor for 2019 and 2030. Further, as the emission factor of the power system is lower than the emission factor for the solar PV materials, this results in infeasible solutions.

Another interesting aspect of the linear average emission factors is the possibility of compensating today versus in the future. During the first years, solar power production from Nyhavna would compensate for high emissions. However, as observed in Figure 23, as the power system emissions reduce, one would compensate for less emissions until 2040, when emission compensation is impossible. This is an important observation as it shows that the current power systems compensation is worth more. Further, in order to reach net-zero, an over-compensation in the first years of the neighbourhood's lifetime is necessary.

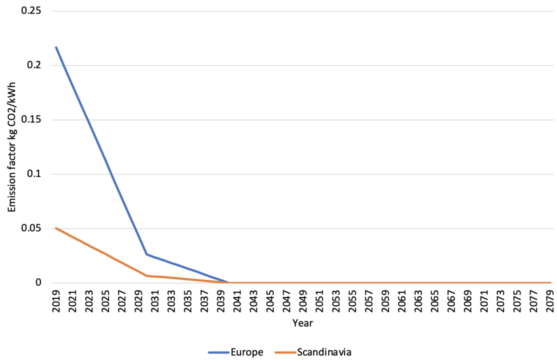
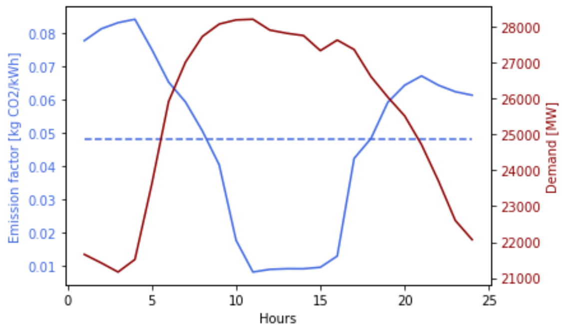


Figure 23: Development of the annual average emission factors during the lifetime of Nyhavna.

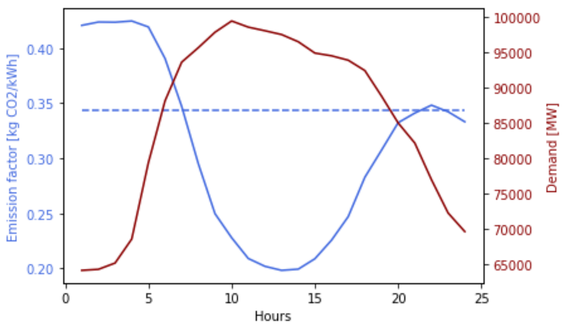
However, as mentioned in [68] emission factors are not constant throughout a year, as emission factors vary from hour to hour and season to season. Seasonal differences are not taken into account using an annual average emission factor, potentially resulting in over-/ under-compensating of total emissions. The potential over-/under-compensation is investigated in the next section, to get a deeper understanding of the seasonal, and hourly, variations.

5.3 Hourly average emission factor

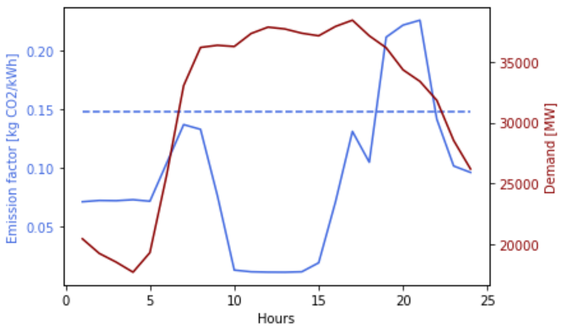
Emission factors could vary based on several conditions, such as peak demand, import or export to/from an area, or the availability of RES. In Figures 24 and 25, the hourly- and annual average emission factor is plotted against the hourly demand for the 31st of June and October, respectively.



(a) Scandinavia



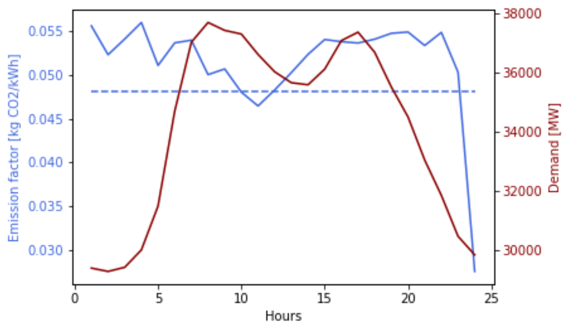
(b) Continent



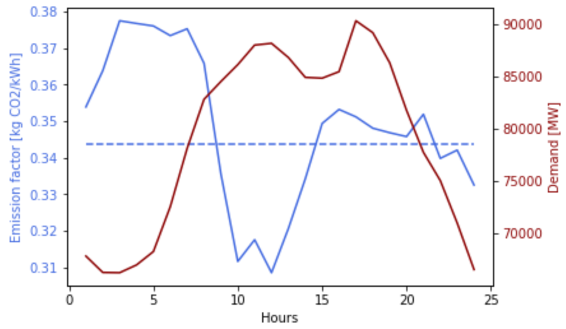
(c) UK

Figure 24: Demand, hourly- and annual average emission factor for 31st of June 2019.

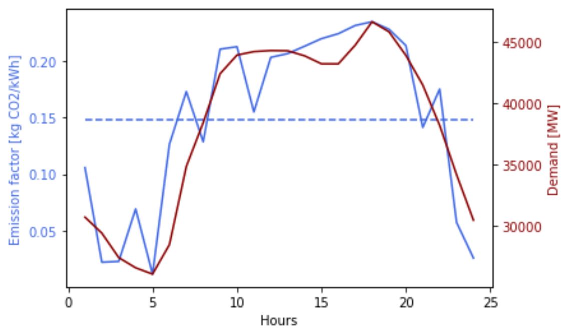
An inverse correlation between hourly demand and hourly average emission factors is observed for June. Demand is high during the day and lower at night, while the emission factors behave the opposite. This is especially clear during the spring and summer months which have better solar availability, resulting in more solar power production and consequently lower emission factors. Using the annual average emission factor, represented by a dashed line, would thus over-compensate total emissions.



(a) Scandinavia



(b) Continent

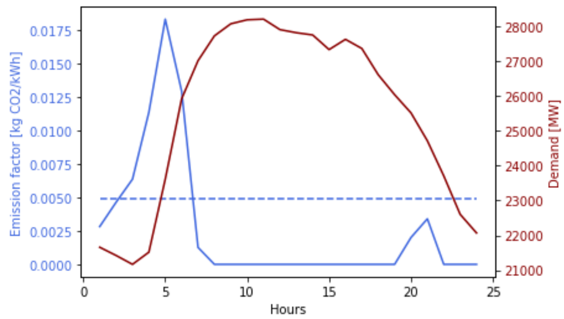


(c) UK

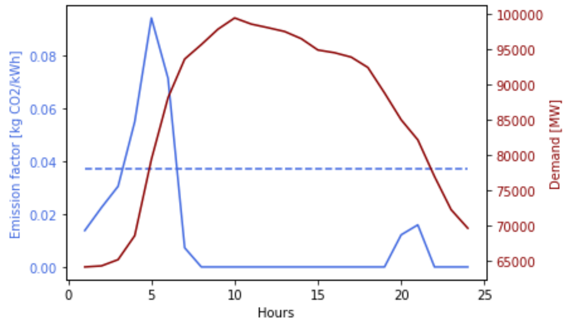
Figure 25: Demand, hourly- and annual average emission factor for 31st of October 2019.

In Scandinavia, heating demand is mainly covered by electricity, which results in higher demand during the winter months [51]. In combination with lower inflow and less sun availability, this leads to the need for more power import, leading to higher emission factors than in June. Less power export from Scandinavia and less sun availability during the winter further lead to higher emission factors in the other areas.

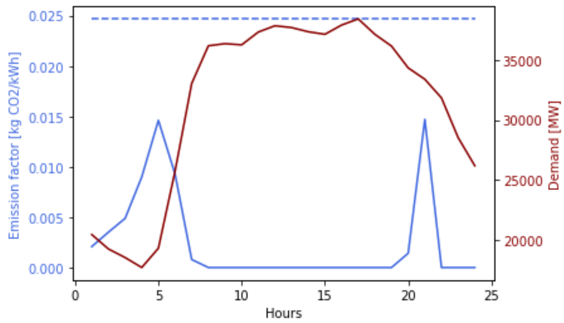
This trend is also observable in 2030, if not as clearly as in 2019.



(a) Scandinavia

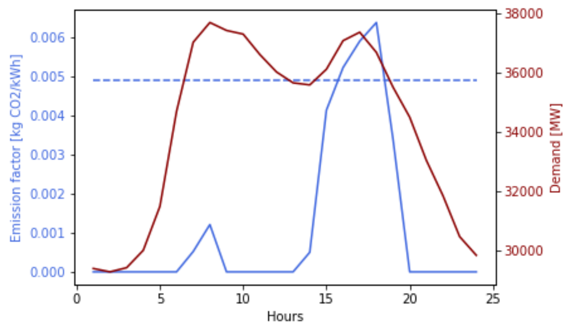


(b) Continent

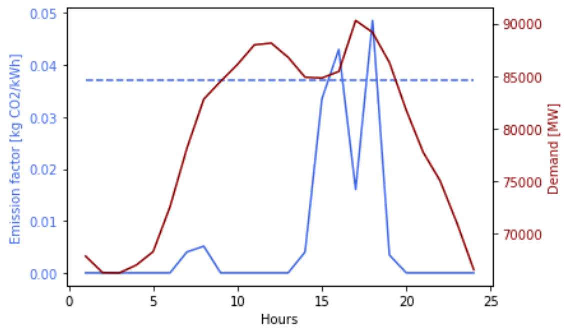


(c) UK

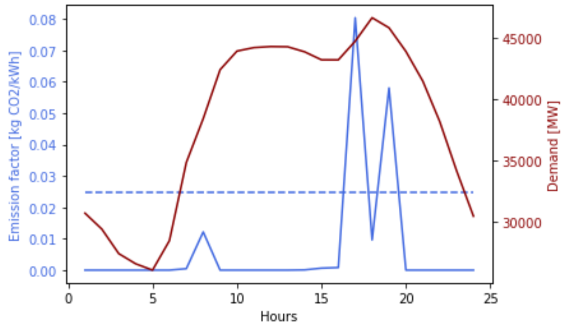
Figure 26: Demand, hourly- and annual average emission factor for 31st of June 2030.



(a) Scandinavia



(b) Continent



(c) UK

Figure 27: Demand, hourly- and annual average emission factor for 31st of October 2030.

In June, emission factors are close to zero or zero during the day, while they increase at night. In October, the emission factors are higher during the day while lower during the night. However, as the energy system in 2030 is more dominated by RES, emissions are quite low also in October.

It could be possible that the over-compensation of emissions during summer could equalize the under-compensation during winter. However, this case study found that this was not the case. This is further seen in Tables 18 and 19.

Table 18: Yearly emissions 2019, given in Mtons CO_2/yr.

	Continent	**Scandinavia**	**UK**	**Total**
Annual AEF_{cons}	248	12.97	39.20	300.17
Hourly AEF_{cons}	245	13.56	46.13	304.69
GenX	242	0.17	39.20	281.00

In order to find the hourly average emission factors, the model is run with installed capacity, fuel costs, and CO_2 prices for the considered year. The hourly average emission factor is then found using Equations (14) and (18) for consumption and compensation, respectively. In Table 18, yearly emissions using the hourly and annual average emission factor for consumption are presented together with the annual emissions from GenX. The emissions calculated in GenX are calculated from emissions linked to the power production in a given zone. This results in quite low emissions in Scandinavia compared to when using the emission factors for consumption. As mentioned above, emissions calculated with the emission factors for consumption are allocated to the area that consumes the power produced. Thus, emissions linked to the imported power are included in calculating the emission factors for consumption in Scandinavia. As Scandinavia imports power from more emitting power systems, this eventually leads to higher annual emissions, as observed in Table 18.

Further, it is observed that using an annual average emission factor for calculating yearly emissions, compared to using the hourly, underestimates total emissions in the UK and Scandinavia. In contrast, it overestimates the emissions on the Continent. Nevertheless, the total annual emissions are higher when using the hourly average emission factor, than when suing the annual. However, the yearly emissions using the annual average emission factor, are closer to the emissions calculated in GenX.

Table 19: Yearly emissions 2030, given in Mtons CO_2/yr.

	Continent	**Scandinavia**	**UK**	**Total**
Annual AEF_{cons}	26.85	1.33	7.55	35.73
Hourly AEF_{cons}	28.41	1.79	8.14	38.34
GenX	26.40	0.003	7.63	34.00

The same yields also in 2030. The yearly emissions using emission factors for compensation are higher than the emissions calculated using GenX, as this does not allocate emissions to the areas where it is consumed. Further, for 2030 using the annual average emission factor underestimates total emissions in all areas, though the differences are smaller than in 2019. However, the yearly emissions using the annual average emission factor are closer to the emissions found with GenX, similarly to above. 2030 has more power production from RES, leading to overall lower emissions. However, the same tendency as observed in 2019 also yields in 2030. In summer, demand is high when emission factors are low, while in winter, demand is high when emission factors are high. In the following sections, the hourly and seasonal differences are further investigated by looking at the resulting required area using hourly average emission factors.

5.3.1 Hourly average emission factor 2019

The hourly average emission factors for 2019 was then found, running GenX with installed capacity, fuel costs, and CO_2 prices for 2019. For the hourly emission factors, it is further assumed asymmetrical emission factors, as observed in Tables 20 and 21. This is in contrast with what was done in Section 5.2.

Table 20: Resulting area and installed capacity, using the hourly average emission factor for Scandinavia and Europe, 2019.

	$\mathbf{EF}_{cons}$ [kg/kWh]	$\mathbf{EF}_{comp}$ [kg/kWh]	$\mathbf{MW}_{inst}$ [MW]	Area [m^2]
Scandinavia	0.0502	0.0442	278.21	1 391 047.76
Europe	0.2166	0.1956	51.72	258 580.65

Using the hourly emission factors leads to a much larger required area and installed capacity of solar PV. The exported solar power from Nyhavna compensates for less emissions than suggested by the annual average emission factors, as the emissions are lower at day. This is especially clear using the Scandinavian emissions factors, which have emissions close to zero during the daytime.

5.3.2 Hourly average emission factor 2030

In the calculation of the hourly emission factor for 2030, similar results as presented in Section 5.3.1 was obtained. Because solar power is produced during the day, it compensates for less emissions than suggested by the annual average emission factors. This makes it impossible to reach the desired ambition level, both using the Scandinavian and European hourly average emission factors.

Table 21: Resulting area and installed capacity, using the hourly average emission factor for Scandinavia and Europe, 2030.

	$\mathbf{EF}_{cons}$ [kg/kWh]	$\mathbf{EF}_{comp}$ [kg/kWh]	$\mathbf{MW}_{inst}$ [MW]	Area [m^2]
Scandinavia	0.0066	0.0022	infeasible	infeasible
Europe	0.0262	0.0080	infeasible	infeasible

5.3.3 Linear emission factor

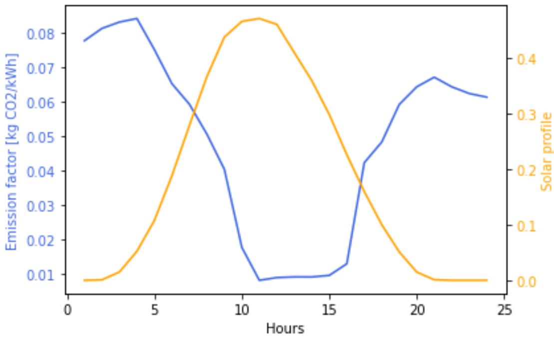
Similarly to the annual average emission factor a linear emission factor, based on the resulting hourly emission factors and assuming net zero i 2040, was calculated.

Table 22: Resulting area and installed capacity, using the linear hourly average emission factor for Scandinavia and Europe.

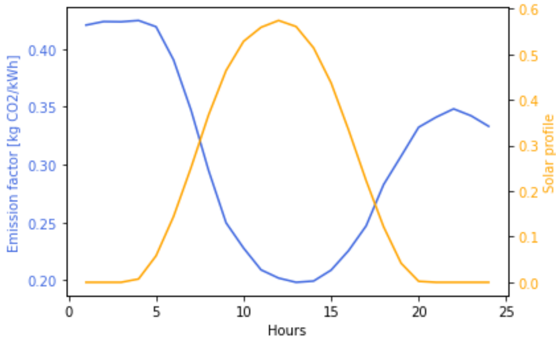
	$\mathbf{EF}_{cons}$ [kg/kWh]	$\mathbf{EF}_{comp}$ [kg/kWh]	$\mathbf{MW}_{inst}$ [MW]	Area [m^2]
Scandinavia	0.0061	0.0047	infeasible	infeasible
Europe	0.0258	0.0206	infeasible	infeasible

From Table 22, it is observed that it is not possible to reach the ambition level of ZEN-COM using solar PVs for compensation. Solar power production is not possible to turn on or off based on need, meaning that peak solar power production is in the daytime during the spring and summer months. As observed in Figures 24 and 26, this would imply that the solar power production would compensate for nearly zero emissions in Scandinavia and the UK and low emissions on the Continent. What even complicates the possibility of reaching ZEN-COM is that it is not possible to cover demand at Nyhavna with solar power production at night, when the imported power from the grid, in general, is more emitting than the emissions compensated at day.

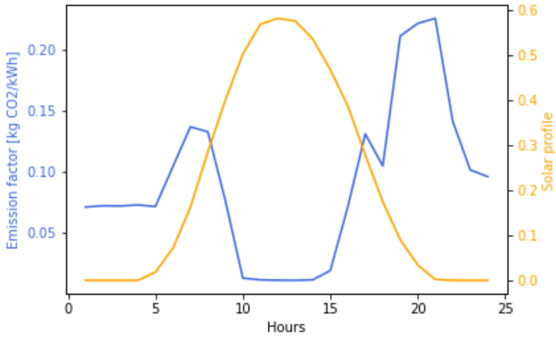
Figures 28 and 29, compare the sun availability and hourly emission factors for the 31st of June and October, respectively.



(a) Scandinavia



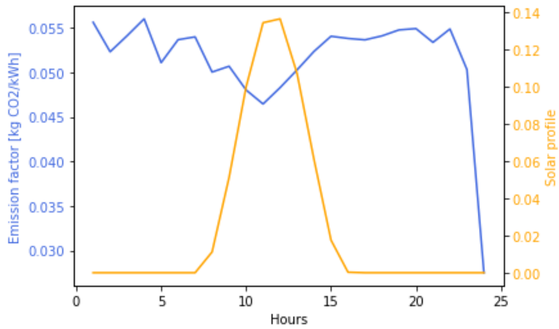
(b) Continent



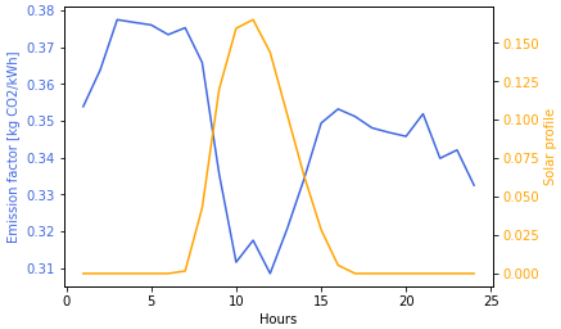
(c) UK

Figure 28: Solar profile and hourly average emission factor for 31st of June 2019.

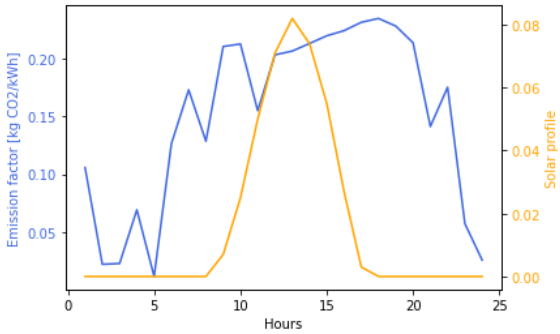
On the 31st of June, the solar availability is relatively high, and it is further observed a long period of sunlight. However, when compared to the hourly emission factor, it is observed an opposite correlation between the sun profile and peak emissions. The emission factors are quite low during the daytime, meaning that the solar power production compensates for emissions close to zero. It is consequently more difficult to reach the ambition level of ZEN-COM using hourly average emission factors, as the compensation is of less value compared to when using symmetric annual average emission factors.



(a) Scandinavia



(b) Continent



(c) UK

Figure 29: Solar profile and hourly average emission factor for 31st of October 2019.

Because of higher emission factors during daytime in winter than in summer, it is possible to compensate for more emissions in October than in June. However, the sun availability in October is much lower, meaning that it is not possible to produce the same amount of power as during the summer. In addition, it is observed a shorter period of sunlight compared to in June.

5.4 Short-run marginal emission factor

Using average emission factors for quantifying the exported solar power, could be considered as assuming that the solar power production replaces an average electricity mix. Nevertheless, this is not necessarily the case, as the solar power production exported to the grid typically would replace the marginal generator in the market (including variable generation and CO_2 costs). This would further result in that the compensating power would replace more emissions in reality than communicated by the annual- or hourly average emission factor (at least in the short run), which could be a motivation for using marginal emission factors.

5.4.1 Short-run marginal emission factor 2019

For calculation of the short-run marginal emission factor, a base case was first found running GenX with installed capacity, fuel costs and CO_2 prices for 2019. In addition, the load profile for the Nyhavna project, equal to 26.8 TWh, was added to the Scandinavian demand. This resulted in some power system changes, as observed in Table 23.

Table 23: Yearly generation by energy source for 2019 when Nyhavna demand is added, and percentage change from the 2019-case without the Nyhavna demand, given in TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	183.00	0.00	-	-	-	-
Natural gas	120.00	+16.00	1.33	+0.95	97.30	+10.10
Biomass	35.90	0.00	41.60	0.00	46.10	0.00
Solar PV	69.30	0.00	0.73	0.00	12.90	0.00
Onshore wind	114.00	0.00	25.4	0.00	35.10	0.00
Offshore wind	34.50	0.00	0.86	0.00	31.60	0.00
Nuclear	118	0.00	63.60	0.00	97.30	0.00
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

As observed in Table 23, the added demand from Nyhavna leads to an increase in power production from natural gas, which further increases the total emissions. GenX was then re-run with a marginal change in solar PV capacity at Nyhavna, equal to 2297.92 MW, and resulted in an increase in Scandinavian solar power production equal to 2.01TWh. This to observe the marginal effect of added solar power production from Nyhavna. Further, it was not allowed for any investments because of this change, to ensure that it is the short-run marginal effect that is investigated.

Table 24: Yearly generation by energy source for 2019 when Nyhavna demand and solar power production is added, and percentage change from base case with Nyhavna demand, given in TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	183.00	0.00	-	-	-	-
Natural gas	119.00	-1.00	1.34	+0.01	96.40	-0.90
Biomass	35.90	0.00	41.60	0.00	46.10	0.00
Solar PV	69.30	0.00	27.40	+2.01	12.90	0.00
Onshore wind	114.00	0.00	25.4	0.00	35.10	0.00
Offshore wind	34.50	0.00	0.86	0.00	31.60	0.00
Nuclear	118	0.00	63.60	0.00	97.30	0.00
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

The added solar capacity at Nyhavna leads to a reduction in natural gas power production in the UK and the Continent. Natural gas power production in Scandinavia has, on the other hand, increased. However, the increase is smaller than the reduction in the other areas, reducing total emissions. The added capacity further leads to an increase in Scandinavian net annual export, which now equals 30.50 TWh. Consequently, net annual import has increased on the Continent and in the UK. The change in emissions as a consequence of added demand and the added solar PV production, is presented in Table 25 and denoted the short-run marginal emission factor for respectively consumption and compensation.

Table 25: Resulting area and installed capacity, using the short-run marginal emission factor for 2019.

	$\mathbf{EF}_{cons}$ **[kg/kWh]**	$\mathbf{EF}_{comp}$ **[kg/kWh]**	$\mathbf{MW}_{inst}$ **[MW]**	**Area [m^2]**
SRMEF	0.4478	0.4493	37.52	187 600.54

As observed in Table 25, the emission factors for compensation and consumption are quite high. This is because added demand or solar power production leads to the increase and decrease in natural gas power production, respectively. It is further seen that the emission factor for compensation is higher than the emission factor for consumption, which is opposite than what was found from the calculation using hourly emission factors. Because of the high short-run marginal emission factor for compensation, less area and installed capacity of solar PVs is required than when using the average emission factors.

5.4.2 Short-run marginal emission factor 2030

In the calculation of the short-run marginal emission factor for 2030, the same approach is done as in Section 5.4.1, but now with cost data for 2030.

Table 26: Yearly generation by energy source for 2030 when Nyhavna demand is added, and change from the 2030-case without the Nyhavna demand, given in TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	-	-	-	-	-	-
Natural gas	59.00	+0.19	0.05	+0.04	17.60	+0.59
Biomass	19.90	+0.41	2.22	+19.16	23.60	+3.47
Solar PV	141.00	0.00	0.73	0.00	31.70	+0.04
Onshore wind	179.00	-0.98	2.54	0.02	162.00	+0.92
Offshore wind	26.70	+0.08	10.02	+0.19	20.80	0.00
Nuclear	240.00	+1.47	63.10	+0.78	56.10	+0.59
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

The most noticeable change compared to the base case is seen in Scandinavia. The added demand at Nyhavna leads to an increase in natural gas, biomass, nuclear, and onshore- and offshore wind power production, which makes sense as Nyhavna is located in Trondheim in Norway. It is further seen that it is mainly Scandinavian biomass that covers for the added demand at Nyhavna. Further, net annual Scandinavian power export has reduced due to the added demand, which now equals 23.1 TWh. This leads to an increase in the power export from the UK, equal to 8.3 TWh. The Continent is still a net importer, with an increased import equal to 31.4 TWh. On the Continent, power production from onshore wind has reduced, while power from natural gas, nuclear, biomass, and offshore wind has increased. The UK experiences an increase in power production from natural gas, solar PV, nuclear, and onshore- and offshore wind power production.

Solar PV power production is then added to Nyhavna without allowing for further investments in order to look at the short-run marginal effect of the ZEN.

Table 27: Yearly generation by energy source for 2030 when Nyhavna demand and solar power production is added, and change from base case with Nyhavna demand, given TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	-	-	-	-	-	
Natural gas	58.30	-0.30	0	-0.01	17.30	+0.20
Biomass	19.30	-0.10	2.62	-0.51	19.90	-0.20
Solar PV	141.00	0.00	2.74	+2.01	31.80	0.00
Onshore wind	179.00	0.00	25.4	0.00	162.00	0.00
Offshore wind	26.60	+0.10	36.50	-0.10	20.80	-0.10
Nuclear	239.00	0.00	61.80	-0.50	55.20	-0.20
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

Because of the added solar capacity at Nyhavna, natural gas power production in Scandinavia is not activated, leading to zero annual emissions linked to production. Natural gas power production has further decreased on the Continent, while it increases in the UK. However, this increase is smaller than the reduction in the other areas, reducing total annual emissions. Nevertheless, the reduction is relatively small, leading to a low short-run marginal emission factor for compensation as observed in Table 28. The added capacity further reduces biomass, offshore wind, and nuclear power production in Scandinavia, which also is the case in the UK. On the Continent, the added solar PV further leads to the reduction of biomass power production, while offshore wind power production increases.

Table 28: Resulting area and installed capacity, using the short-run marginal emission factor for 2030.

	$\mathbf{EF}_{cons}$ **[kg/kWh]**	$\mathbf{EF}_{comp}$ **[kg/kWh]**	$\mathbf{MW}_{inst}$ **[MW]**	**Area [m^2]**
SRMEF	0.0139	0.0023	infeasible	infeasible

As observed in Table 28, the small emission factor for compensation makes it impossible to cover the embodied emissions. This, although including Nyhavna has decreased the Scandinavian emissions to zero. However, because of low emissions in the first place, this was not enough to reach ZEN-COM.

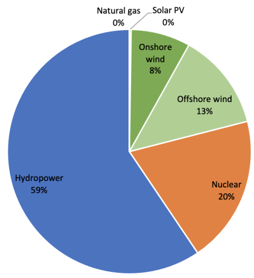
Looking at significant changes in the power system without allowing for investments is insufficient in order to understand the impact of the alteration. Added demand due to more electrification or establishment of ZEN would, in the long-run, trigger new investments in the grid. Due to this, it is interesting to look at the future consequence of the Nyhavna project.

5.5 Long-run marginal emission factor

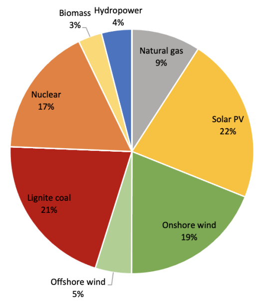
When calculating the long-run marginal emission factor, the same procedure is done as in Section 5.4. However, investments in the power system as a result of different changes are now allowed.

5.5.1 Long-run marginal emission factor 2019

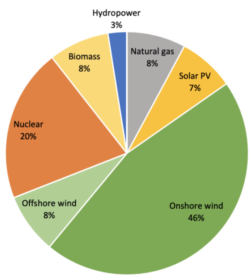
To calculate the long-run marginal emission factor for consumption, a base case for 2019 is necessary. Here GenX is run with installed capacity, fuel costs, and CO_2 prices for 2019, similarly to in Section 5.2, but now allowing for investments.



(a) Scandinavia



(b) Continent



(c) UK

Figure 30: Power production base case when allowing for investments in GenX.

Table 29: Yearly generation by energy source for 2019 allowing for investments, and percentage change from the 2019-case without allowing for investments, given in TWh.

	Continent		Scandinavia		UK	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	139.00	-44.00	-	-	-	-
Natural gas	61.30	-42.70	0.04	-0.33	24.10	-63.10
Biomass	21.10	-14.80	0.00	-41.60	24.70	-21.40
Solar PV	147.00	+77.70	0.73	0.00	22.90	+10.00
Onshore wind	127.00	+13.00	25.40	0.00	140.00	+104.90
Offshore wind	32.30	-2.20	41.60	+40.74	24.70	-6.90
Nuclear	115.00	-3.00	63.00	-0.60	62.60	-5.70
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

As observed from Figure 30 and Table 29, allowing GenX to find an optimal solution, based on 2019 data, leads to a significant reduction in power production from coal and gas. Additionally, power from renewable energy sources has increased a lot compared to when not allowing for investments, reducing total emissions. On the Continent and in the UK, solar PV power production has increased by 111.62 and 77.96 %, respectively. These areas further experience an increase in onshore wind power production by 11.12 and 300.38 %, respectively. In Scandinavia, allowing for investments leads to a substantial increase in offshore wind power production. This shows that there exists considerable, unused potential for offshore wind power production in Scandinavia, based on the current power system and costs.

The Nyhavna demand was then added and GenX re-run, to find the long-run marginal emission factor for consumption. The results are presented in Table 30.

Table 30: Yearly generation by energy source for 2019 with Nyhavna demand and allowing for investments, and percentage change from the 2019-case without the Nyhavna demand and allowing for investments, given in TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	139.00	0.00	-	-	-	-
Natural gas	61.90	+0.60	0.05	+0.01	23.80	-0.30
Biomass	21.10	0.00	0.00	0.00	24.80	+0.10
Solar PV	147.00	0.00	0.73	0.00	22.80	-0.10
Onshore wind	126.00	-1.00	25.4	0.00	141.00	+1.00
Offshore wind	32.30	0.00	68.50	+26.90	24.70	0.00
Nuclear	115.00	0.00	62.90	-0.10	62.50	-0.10
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

As observed, the increased demand from Nyhavna leads to more natural gas power production in Scandinavia and on the Continent. However, the increase is minor, resulting in a small long-run marginal emission factor as observed in Table 32. In the UK, power production from natural gas has decreased due to the added demand. The decrease is smaller than the increase in the other areas, leading to higher total emissions than in the base case. In Scandinavia, the added demand additionally leads to an increase in offshore wind power production combined with a small increase in hydropower production. The increase in offshore wind power production is almost equal to the increase in demand from Nyhavna. This means that Nyhavna without PV capacity, leads to the development of more offshore wind power in a perfect market in equilibrium. Power production from nuclear and onshore wind has slightly decreased due to the added demand. On the Continent, added demand has resulted in increased power from biomass, lignite coal, solar PV, offshore wind, and hydropower. Onshore wind- and nuclear power production has reviewed a decrease compared to the base case. As for the UK, the added demand from Nyhavna results in an increase in power from biomass, onshore wind, and hydropower. Power from solar PV, offshore wind, and nuclear has decreased because of the added demand.

The installed solar PV capacity from Nyhavna is then included to GenX to find the long-run marginal emission factor for compensation. The resulting power production is presented in Table 31.

Table 31: Yearly generation by energy source for 2019 when Nyhavna demand and solar power production is added, and percentage change from base case with Nyhavna demand, given in TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	139.00	0.00	-	-	-	
Natural gas	61.10	-0.90	0.05	-0.004	24.60	+0.80
Biomass	21.20	+0.10	0.00	0.00	24.80	0.00
Solar PV	147.00	0.00	2.74	+2.01	22.60	-0.20
Onshore wind	126.00	0.00	25.4	0.00	141.00	0.00
Offshore wind	32.30	0.00	66.50	-2.00	24.70	0.00
Nuclear	115.00	0.00	62.90	0.00	62.50	0.00
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

In the calculation of the short-run marginal emission factor for compensation, adding solar power production led to a decrease in total emissions. This is not the case here. The added solar power production leads to an increase in natural gas and a reduction of solar power production in the UK. On the Continent, natural gas power production decreases while biomass power production increases due to the added solar capacity. Similarly, Scandinavia reviews a decrease in natural gas power production. In addition, offshore wind power production decreases. However, the increase in natural gas power production in the UK is larger than the decrease in the other areas, increasing total emissions. This eventually results in a negative long-run marginal emission factor, meaning that in the long-run, a development of Nyhavna as a ZEN may lead to a small increase in more total emissions. On the Continent, the reduction of natural gas has led to an increase in net annual import compared to base case, which now equals 54 TWh. This is covered by more net annual export from the UK, which has increased to 1.39 TWh, and this could be one of the reasons for more natural gas power production in the UK. Despite the added solar capacity, annual power export in Scandinavia has remained constant. The explained power system changes eventually lead to the following long-run marginal emission factors.

Table 32: Resulting area and installed capacity, using the long-run marginal emission factor for 2019

	$\mathbf{EF}_{cons}$ **[kg/kWh]**	$\mathbf{EF}_{comp}$ **[kg/kWh]**	$\mathbf{MW}_{inst}$ **[MW]**	**Area [m^2]**
LRMEF	0.0089	-0.0459	infeasible	infeasible

As observed in Table 32, the long-run marginal emission factor for compensation is negative, meaning that including the solar power production and load profile from Nyhavna to Scandinavia results in higher total emissions compared to only including the Nyhavna demand. As for the emission factor for consumption, it is observed that only adding the Nyhavna demand leads to a small increase in total emissions. The increase is, on the other hand, smaller compared to when adding both Nyhavna demand and Nyhavna solar power production.

5.5.2 Long-run marginal emission factor 2030

The same approach as in Section 5.5.1 is used in the calculation of the long-run marginal emission factor for 2030. The base case is set equal to in Figure 22, as this already is optimized in GenX based on the given input data. The Nyhavna demand is then added to the Scandinavian load profile, and the model is re-run while still allowing for further investments.

Table 33: Yearly generation by energy source for 2030 with Nyhavna demand and allowing for investments, and percentage change from the 2030-case without the Nyhavna demand, given in TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	-	-	-	-	-	-
Natural gas	58.60	-0.20	0.01	+0.003	17.10	+0.10
Biomass	19.94	-0.10	3.13	+0.12	20.10	0.00
Solar PV	141.00	0.00	0.73	0.00	31.80	+0.10
Onshore wind	179.00	-1.00	25.40	0.00	162.00	+1.00
Offshore wind	26.50	-0.10	36.60	+26.60	20.90	+0.10
Nuclear	239.00	0.00	62.30	0.00	55.40	-0.10
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

To cover for the extra demand at Nyhavna, Scandinavia has increased power production from natural gas, biomass, and offshore wind. In the UK, there has been an increase in natural gas, solar PV, and onshore- and offshore wind power production, whereas nuclear power production has decreased. Although there is an increase in natural gas power production in Scandinavia and the UK, total emissions have decreased compared to the base case. This is because of a reduction in natural gas power production on the Continent, which is higher than the increase in Scandinavia and the UK. The Continent has further had a decrease in biomass, solar PV, and onshore- and offshore wind power due to the added demand at Nyhavna. However, this is covered by more import from the other areas. This is further seen from the net annual import, which has increased compared to the base case and now equals 31.40 TWh. The increase is handled by more power export from the UK, equal to 8.3 TWh. The export from Scandinavia has, on the other hand, decreased to 23.1 TWh to cover the added demand at Nyhavna.

Then the added solar capacity from Nyhavna is included in the model to find the long-marginal emission factor for compensation.

Table 34: Yearly generation by energy source for 2030 when Nyhavna demand and solar power production is added, and change from base case with Nyhavna demand, given in TWh.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	-	-	-	-	-	
Natural gas	58.40	-0.20	7.38E-03	-0.002	17.20	+0.10
Biomass	19.40	0.00	3.28	+0.15	20.10	0.00
Solar PV	141.00	0.00	2.74	+2.01	31.70	-0.10
Onshore wind	179.00	0.00	25.40	0.00	162.00	0.00
Offshore wind	26.60	+0.10	34.50	-2.10	20.90	0.00
Nuclear	239.00	0.00	62.20	-0.10	55.40	0.00
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

In Scandinavia, the added demand and solar power production at Nyhavna result in a reduction in natural gas, offshore wind, and nuclear power production. From this, it is observed that it is less optimal to invest in offshore wind power production in Scandinavia when there already is much installed solar PV. In addition, Scandinavia has reviewed an increase in biomass power production due to the added demand and solar power production. The added solar capacity at Nyhavna further leads to an increase in solar power production in Scandinavia. The Continent reviews a decrease in natural gas power production while offshore wind power production increases. In the UK, natural gas power production increases while onshore wind power production decreases. Nevertheless, the increase in natural gas is smaller than the decreases in the other areas, giving a reduction in total emissions compared to when not adding the solar capacity from Nyhavna. As for the net annual transmission, export and import have decreased in respectively the UK and the Continent. Scandinavia does not review any changes as a result of the added solar capacity. From the above results, the following long-marginal emission factors are found.

Table 35: Resulting area and installed capacity, using the long-run marginal emission factor for 2030

	$\mathbf{EF}_{cons}$ [kg/kWh]	$\mathbf{EF}_{comp}$ [kg/kWh]	$\mathbf{MW}_{inst}$ [MW]	Area [m^2]
LRMEF	-0.0029	0.0164	infeasible	infeasible

In 2019, the long-run marginal emissions factor for compensation was quite low, as the added demand mainly leads to more power production from offshore wind, see Table 30, meaning that including demand does not lead to any significant changes in total emissions. However, there are some following small shifts in other production, as a result of the added demand. Nevertheless, these are low, resulting in an emission factor for consumption close to zero. This is not the case in 2030, where adding the Nyhavna project to the Scandinavian power system, results in less power production from natural gas power plants leading to a reduction in total emissions. Another interesting aspect is found by looking at the negative long-run marginal emission factor for consumption, meaning that a marginal increase in demand would result in less emissions. As observed in Table 33 increasing the demand in Scandinavia leads to a reduction in natural gas power production on the Continent, giving lower emissions than in the base case. Nevertheless, the changes are small, making it impossible to reach the desired ambition level ZEN-COM.

As observed above, the resulting areas differ a lot based on the chosen calculation method. When using the short-run marginal emission factor for 2019 a smaller area was required, as added solar power production resulted in less power production from natural gas power plants. Similarly happened in 2030. However, as the power system in 2030 already has quite low emissions, the reduction was not significant enough, and reaching ZEN-COM was impossible. Using hourly emission factors also made it impossible to compensate for embodied emissions, given that the local renewable power producer was solar PVs. This is because solar power production only can compensate during the day, when emission factors tend to be low. According to [38] "Wind power is increasingly competitive with other forms of electricity generation and is the low-cost option in many applications (high confidence). Costs have declined by 18% and 40% on land and offshore since 2015 (high confidence), and further reductions can be expected by 2030 (medium confidence)." As wind power is not limited to only produce power during the day, it could thus be a potential local renewable energy producer in zero emission neighbourhoods.

5.6 Wind as compensation

One important obstacle when using solar power production as compensation was the solar availability. Solar power is only accessible during the daytime, in which emissions are relatively low as observed in, for instance, Figure 28. This led to a large required area of solar cells, and in some cases, it was even impossible to reach the desired ambition level. Because of this, the following section investigates the different emission factors for 2019, now using onshore wind power as compensation.

5.6.1 Annual average emission factor with onshore wind as compensation

The annual average emission factors were calculated based on the average of the current electricity mix, and they will thus not differ from the one presented in Section 5.2. However, as wind turbines and solar cells require different areas based on power produced, the resulting area would eventually differ from using solar PVs as local renewable power production. In Table 36, the required area is calculated using Equation (8), which is described in Section 3.2.

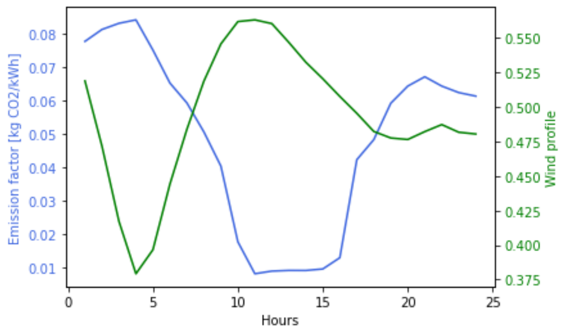
Table 36: Resulting area and installed capacity, using the annual average emission factor for Scandinavia and Europe, 2019. In the upper part, onshore wind is used as local RES, and the bottom represents required area suing solar PVs as local RES.

	$\mathbf{EF}_{cons}$ [kg/kWh]	$\mathbf{EF}_{comp}$ [kg/kWh]	$\mathbf{MW}_{inst}$ [MW]	Area [m^2]
Scandinavia, wind	0.0502	0.0502	27.51	34 389.11
Europe, wind	0.2166	0.2166	11.39	14 242.11
Scandinavia, PV	0.0502	0.0502	149.22	746 084.70
Europe, PV	0.2166	0.2166	45.33	226 658.46

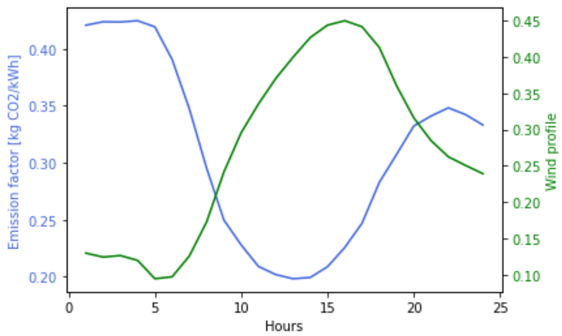
As observed in Table 36, using wind power as compensation would result in less needed area and installed capacity, to reach the ambition level of ZEN-COM. Further, the reduction is quite significant compared to in Table 14. Thus, despite using the same emission factors, one would achieve the desired ambition with a remarkably smaller area when using onshore wind, compared to when using solar PV as local RES. However, wind turbines can not be placed in the middle of a city, which could be a drawback for wind power. Thus, the onshore wind power should be considered as a regional RES, rather than local. Consequently, the produced wind power is not a part of the Nyhavna neighbourhood.

5.6.2 Hourly average emission factor with onshore wind as compensation

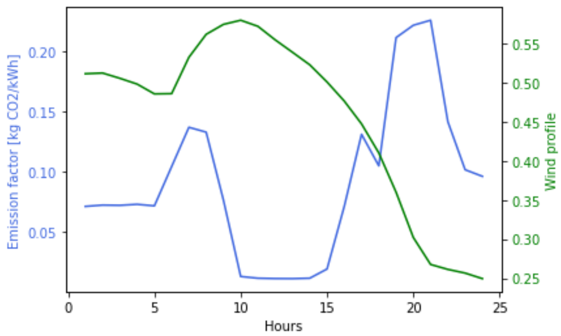
The resulting hourly emission factor for compensation differs on the other hand when using wind power as the local renewable power producer. The main reason for this is the wind availability, as observed in Figures 31 and 32.



(a) Scandinavia

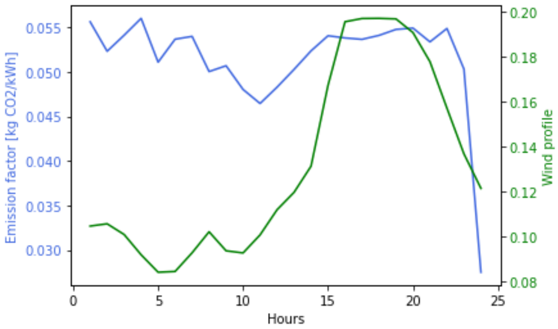


(b) Continent

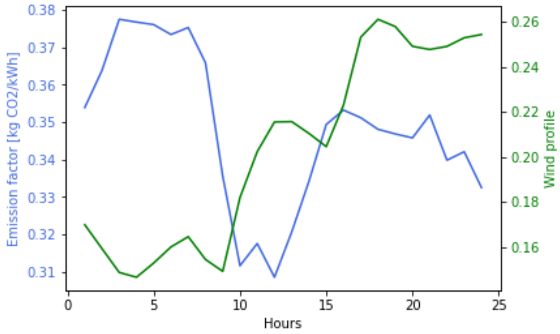


(c) UK

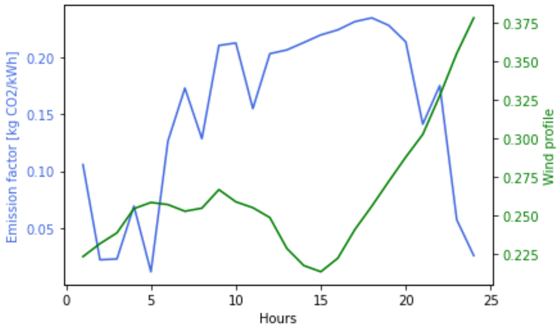
Figure 31: Onshore wind profile and hourly average emission factor for 31st of June 2019.



(a) Scandinavia



(b) Continent



(c) UK

Figure 32: Onshore wind profile and hourly average emission factor for 31st of October 2019.

As observed in the above figures, the wind profiles are more arbitrary than the solar profile. The wind availability is not determined based on the everyday routine, making it possible to compensate during, for instance, the night when emissions tend to be higher. In addition, wind availability is higher than solar during winter, and this makes it possible to generate more wind power to compensate for the higher emissions during this period. This is further seen in the hourly emission factors for compensation, as observed in Table 37.

Table 37: Resulting area and installed capacity, using the hourly average emission factor for Scandinavia and Europe, 2019. In the upper part, onshore wind is used as local RES, and the bottom represents required area suing solar PVs as local RES.

	$\mathbf{EF}_{cons}$ [kg/kWh]	$\mathbf{EF}_{comp}$ [kg/kWh]	$\mathbf{MW}_{inst}$ [MW]	Area [m^2]
Scandinavia, wind	0.0502	0.0479	29.65	37 057.78
Europe, wind	0.2166	0.2092	11.82	14 780.70
Scandinavia, PV	0.0502	0.0442	278.21	1 391 047.76
Europe, PV	0.2166	0.1956	51.72	258 580.65

As observed, the onshore wind power compensates for more emissions than when using solar power production as the local renewable power production. This, in combination with more power production per square meter installed capacity, further yields a lower required area and wind power capacity. The reduction is further quite significant where the necessary areas have reduced with approximately 97% and 94% for respectively Scandinavia and Europe, compared to in Section 5.3.1.

5.6.3 Short-run marginal emission factor with onshore wind as compensation

The same simulations as in Section 5.4.1 were then performed. However, added installed solar PV capacity was now replaced with onshore wind power capacity. Based on this, the following is obtained.

Table 38: Yearly generation by energy source for 2019 when Nyhavna demand and wind power production is added, and percentage change from base case with Nyhavna demand, given in TWh. It is not allowed for investments.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	183.00	0.00	-	-	-	-
Natural gas	119.10	-1.00	1.18	-0.15	93.30	-4.00
Biomass	35.90	0.00	41.60	0.00	24.80	0.00
Solar PV	69.30	0.00	0.73	0.00	22.60	0.00
Onshore wind	114.00	0.00	30.50	+5.10	141.00	0.00
Offshore wind	34.50	0.00	0.86	0.00	24.70	0.00
Nuclear	118.00	0.00	63.60	0.00	62.50	0.00
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

As observed, adding the onshore wind power installed capacity at Nyhavna leads to more power production from the local RES at Nyhavna compared to in Section 5.4. This shows the impact of more onshore wind power availability, compared to the sun availability in Section 5.4, resulting in more power production from Nyhavna. In the short run, including the Nyhavna onshore wind power production reduces natural gas power production in all areas. This reduction is higher than when using solar PV as local renewable power production. However, because of a larger increase in local RES than in the sun case, this eventually gives a smaller short-run marginal emission factor compared to in Section 5.4.1, due to the structure of Equation (19). This is interesting as it gives the impression of more emissions being compensated in Section 5.4.1, while this is not actually the case. The added wind capacity further leads to an increase in Scandinavia's net annual power export compared to in Section 5.4.1, equal to 33.5 TWh. This is consumed by the UK, which now is a net power importer, equal to 11.2 TWh. The power import on the Continent has increased due to the added onshore wind capacity, and now equals 22.3 Twh.

Table 39: Resulting area and installed capacity, using the short-run marginal emission factor for 2019. In the upper part, onshore wind is used as local RES, and the bottom represents required area using solar PVs as local RES.

	$\mathbf{EF}_{cons}$ **[kg/kWh]**	$\mathbf{EF}_{comp}$ **[kg/kWh]**	$\mathbf{MW}_{inst}$ **[MW]**	**Area [m^2]**
SRMEF, wind	0.4478	0.4475	9.91	12 392.59
SRMEF, PV	0.4478	0.4493	37.52	187 600.54

As observed in Table 39, despite the somewhat lower short-run marginal emission factor for compensation, the required area and installed capacity has reduced significantly compared to in Section 5.4.1, due to the technical design of the wind turbines.

5.6.4 Long-run marginal emission factor with onshore wind as compensation

The long-run marginal emission factor was calculated similarly to in Section 5.5.1, however with added onshore wind power capacity instead of solar PV.

Table 40: Yearly generation by energy source for 2019 when Nyhavna demand and onshore wind power production is added, and percentage change from base case with Nyhavna demand, given in TWh. It is further allowed for investments.

	Continent		**Scandinavia**		**UK**	
	Generation	Δ	Generation	Δ	Generation	Δ
Hard coal	-	-	-	-	-	-
Lignite coal	139.00	0.00	-	-	-	
Natural gas	62.90	+1.00	0.03	-0.015	22.30	-1.50
Biomass	21.10	0.00	0.00	0.00	24.70	-0.10
Solar PV	147.00	0.00	0.73	0.00	22.90	+0.10
Onshore wind	127.00	0.00	30.50	+5.10	141.00	0.00
Offshore wind	32.30	0.00	63.70	-4.80	24.60	-0.10
Nuclear	115.00	0.00	62.90	0.00	62.50	0.00
Reservoir hydro	27.00	0.00	192.00	0.00	7.70	0.00
Pumped hydro storage	-	-	-	-	-	-
Run-of-river hydro	-	-	-	-	-	-

As observed, adding onshore wind power leads to a significant increase in onshore wind power production in Scandinavia, in addition with a decrease in Scandinavian offshore wind. The added power capacity, further leads to an increase in natural gas power production on the Continent, while there is a reduction in Scandinavia and the UK. Compared to Section 5.5.1 total natural gas power production has decreased, leading to lower total emissions when using onshore wind power for compensation. In Section 5.5.1 it was further shown that total emissions increased as a result of the added solar power production, which made it impossible to reach the ambition level ZEN-COM. However, using onshore wind as local renewable power production leads to overall less total emissions, giving a positive long-run marginal emission factor. Scandinavian net annual export has increased to 52.9 TWh compared to in Section 5.5.1. This has further led to the UK becoming a net importer with annual import equal to 0.64 TWh. Power import to the Continent has further reduced and equals now 52.3 TWh.

Table 41: Resulting area and installed capacity, using the long-run marginal emission factor for 2019. In the upper part, onshore wind is used as local RES, and the bottom represents required area suing solar PVs as local RES.

	$\mathbf{EF}_{cons}$ **[kg/kWh]**	$\mathbf{EF}_{comp}$ **[kg/kWh]**	$\mathbf{MW}_{inst}$ **[MW]**	**Area [m^2]**
LRMEF, wind	0.0089	0.0774	9.46	11 820.19
LRMEF, PV	0.0089	-0.0459	infeasible	infeasible

As observed, total emissions reduce due to the increased onshore wind power production, which was not the case in Section 5.5.1. In Table 41 it is further seen that the resulting area and installed capacity are smaller when using the long-run marginal emission factor for compensation rather than the short-run. This is explained by the emission factor for consumption. Adding the Nyhavna demand when allowing for investments only results in a small increase in emissions. This further yields in a low long-run marginal emission factor for consumption, resulting in less emissions linked to power import compared to when using the short-run marginal emission factor. Due to this, there is a need for less compensation for the imported power from the grid compared to in Section 5.6.3, which explains the lower required area and installed capacity.

6 Discussion

6.1 How do different metrics for measuring emissions and compensation compare

In the introduction, the following research question was formulated: how do different metrics for measuring emissions and compensation compare? From the presented case study, it is evident that the choice of calculation method gives very different results. As observed in Tables 42 and 43 choice of emission factor gives a difference in the resulting area of at the most 1 203 447.22 m^2, given the same ambition level and using solar PVs as local RES. The fact that chosen calculation method gives such varying required areas clearly shows the need for a better understanding of the calculation of emission factors. Using the European annual average emission factor from 2019 would, for instance, result in the possibility of reaching an ambition level of ZEN-COM at a lower cost compared to using the Scandinavian hourly average emission factor.

Table 42: Resulting area in 2019 and 2030 based on calculation method, when solar PV is used as the local RES.

	2019 [m^2]	**2030 [m^2]**
Scandinavian annual AEF	746 084.70	infeasible
European annual AEF	226 658.46	2 580 795.81
Scandinavian hourly AEF	1 391 047.76	infeasible
European hourly AEF	258 580.65	infeasible
SRMEF	187 600.54	infeasible
LRMEF	infeasible	infeasible

Table 43: Resulting area based on linear emission factors when solar PV is used as the local RES.

	Scandinavia [m^2]	**Europe[m^2]**
Linear annual AEF	infeasible	535 091.13
Linear hourly AEF	infeasible	infeasible

As mentioned above, solar PVs are most widely used as local RES in ZENs [45]. However, as solar power is dependent on the sun availability and seasonal variation, as observed in Section 5.3, this could result in less power compensation than expected. This would further result in a large area of solar PVs in order to be able to compensate for the embodied emissions. As seen from the above results, this was also the case. To reach the desired ambition level, an area larger than the available roof area at Nyhavna was required. However, in comparison to solar power production, wind power is a more available energy source. Additionally, the power production is more volatile and could thus provide power both at night, and during the day. As a result of this, using onshore wind power as local RES could result in a decrease in the required area to reach ZEN-COM, as seen in Table 44. Nevertheless, as discussed below, onshore wind power has in Norway experienced public opposition over the last couple of years, meaning that such a solution might result in significant public resistance.

Table 44: Resulting area in 2019 based on calculation method, when onshore wind is used as the local RES.

	2019 [m^2]
Scandinavian annual AEF	34 389.11
European annual AEF	14 242.11
Scandinavian hourly AEF	37 057.78
European hourly AEF	14 780.70
SRMEF	12 392.59
LRMEF	11 820.19

6.2 Hourly and annual average emission factors

In Figure 24, it was observed an opposite correlation between the hourly emission factors and solar availability. Using the annual average emission factor would thus lead to an overestimation of the potential for compensation. Additionally, the annual average emission factor does not communicate seasonal variations. Because of less solar availability and increased demand during winter, this results in higher emission factors as the increased demand leads to more power production from natural gas. Combined with higher consumption this would eventually lead to high emissions, resulting in underestimating actual compensation when using the annual average emission factor. Further, using the annual average emission factor for calculation of total emissions would lead to an overestimation of emissions during summer, and an underestimation of emissions during winter. One could imagine that the overestimation during summer would even out the underestimation during winter. However, as seen in Section 5.3, using hourly average emission factors eventually led to higher annual emissions than using the annual average.

The seasonal and everyday availability of solar power production clearly impacts the resulting area required to reach ZEN-COM. A possible solution to this challenge is using batteries as storage in periods with power surplus to store this until periods with power deficit. This is not included in this master thesis. However, it could be interesting to investigate in further work. Would the usage of battery storage erase the difference between annual and hourly average emission factors, or would the seasonal and hourly differences still influence the final results?

Using hourly average emission factors to calculate solar PV dimensioning in ZENs further shows that the location of ZEN is of significance. A ZEN located in Kirkenes, located in the north of Norway, would not be able to produce any solar power during winter. In combination with cold weather, this would thus require power import from the grid without the possibility to compensate during the dark months. During summer, midnight sun could, on the other hand, lead to constant power production, giving the possibility to compensate for the higher emission factors at night. In contrast would ZENs located in more sunny areas be able to compensate throughout the year, which eventually could give a lower required area of solar PVs compared to when located in Kirkenes.

6.3 Short-run marginal emission factor

In [69], an average emission factor for electricity equal to 0.0796 kg/kWh was used. This emission factor was equal to the average of all expected annual average emission factors throughout Nyhavna's expected lifetime. This method is easy, and practical to use. However, it has some scientific limitations. As mentioned above, using average emission factors for compensation is the same as assuming that the exported solar power would replace the average electricity mix. However, as observed in Tables 24, 27, 31 and 34 including the solar capacity at Nyhavna mainly leads to changes in the natural gas power production, meaning that the solar power production would compensate for more emissions than communicated by an average emission factor. For the 2019-cost data this eventually leads to a smaller area of solar PV compared to when using the average emission factor, as observed in Table 42. For 2030 it is, on the other hand, not possible to reach the required ambition level. Even though the added solar capacity leads to a reduction in natural gas power production, the emissions were originally too small for the reduction in power production from natural gas to be of any significance. This is further observed in Table 28, where the emission factor for compensation is found equal to 0.0023 kg/kWh.

Using the short-run marginal emission factor for 2019 for dimensioning would as observed in Table 42 result in a small area of solar PV, making it possible to reach ZEN-COM at a low cost. As long as the power system remains static, this would result in the expected compensation. However, as power system emissions decrease, because of commissioning of RES and decommissioning of thermal power plants, the compensation would be of less worth. This is because there would be less emissions to compensate for, resulting in underestimating yearly emissions compensated. This would eventually result in the ZEN not being zero emission.

6.4 Long-run marginal emission factor

From [12], it was found that surplus power from RES did not necessarily reduce GHG-gases when considering CO_2 caps in European power production. This because the exported energy from the ZEN did not replace energy production with emissions, but rather energy with less emissions linked to production because of an emission cap. A CO_2 cap is not included in this case study. Nevertheless, total emissions increase as a result of including the added solar PV capacity at Nyhavna, in the long-run calculations for 2019. For the 2019-cost data, it was found that including both the added demand and solar capacity in Nyhavna led to more natural gas power production in the UK, leading to an increase in total emissions. In Table 31, it was observed a decrease in natural gas power production on the Continent and Scandinavia. However, the increase in the UK was larger than the decrease in the other areas, increasing total emissions. Additionally, power production from Scandinavian offshore wind and solar power production in the UK decreased as a result of the added solar PV power production at Nyhavna. This eventually resulted in a negative long-run marginal emission factor for compensation.

For 2030-cost data, it was found that including solar PV capacity at Nyhavna resulted in less emissions, giving a positive long-run marginal emission factor for compensation. Still the added capacity led to more natural gas power production in the UK. Nevertheless, the increase was nevertheless smaller than the decrease in the other areas resulting in a reduction of total emissions. Only adding the Nyhavna demand also resulted in emission reductions. This because the added demand triggered a significant increase in offshore wind power production in Scandinavia. This eventually resulted in a reduction in natural gas power production on the Continent, resulting in a decrease in total emissions.

6.5 Linear average emission factor

In the final report from [69], a linear average emission factor for the Norwegian-European electricity mix was calculated in order to embrace the development of the future power system. Similarly was done in this master thesis, in order to look at the required area when assuming that the power system becomes zero emission in 2040. Compared to the annual average emission factor used in [69], the emission factors found here was quite low. One explanation for this could be the assumption of achieving a zero emission power system by 2040. Another reason for the differences could be because of the assumptions when creating the case study. Further, GenX is simply a cost-optimizing model, meaning that potential agreements or political incentives are not considered.

Using linear average emission factors, further showed the impact of compensation now versus later. As observed in Figure 23, the European emission factor is in 2019 relatively high, because of a high share of coal and gas power production on the Continent and in the UK. The emission factors then decrease drastically towards 2030, before they become zero in 2040. This would eventually mean that Nyhavna would compensate for a lot during the first years. However, after 2040 Nyhavna would not be able to compensate for any emissions despite exporting power to the grid, as the electricity already is emission-free. This shows the importance of a rapid development of RES. Since emission compensation loses its value after 2040 the embodied emissions need to be compensated for before 2040, in order for the ZEN to actually be zero emission. The assumption of reaching a zero emission power system in 2040 further leads to low linear emission factors, as observed in Section 5.2.3 and 5.3.3. This eventually means that reaching ZEN-COM is impossible using the linear annual average emission factors.

Similarly was obtained when using the linear hourly average emission factors for compensation, where reaching the desired ambition level was impossible. One of the reasons for this, lies in the emission factor of installing solar PVs. As mentioned solar cells have an expected lifetime of 30 years, meaning that they would have to be replaced once during the lifetime of Nyhavna. From Equation (4), it is further seen that in order to reach a feasible solution, the emission factor for compensation would have to be higher than the sum of the emission factor for solar cells. As observed in Table 4, the emission factor for sun is expected to decrease the following years. However, it is currently quite high, making it difficult or impossible to reach the desired ambition level in power systems with low annual emissions. Therefore it could be of value using a local RES with a lower emission factor for installation, in which it would be possible to compensate for embodied emission even in power systems with low emissions.

6.6 Wind power as local RES

The opposite correlation between the sun availability and emission factors presented in Section 5.3, was one of the main motivations for investigating the consequences of using onshore wind as the local RES. Onshore wind power production is as mentioned a well developed technology, with reported emission factors for installation in the range of 0.007-0.015 kg/kWh. It is consequently possible to reach the desired ambition level of ZEN-COM, with lower emission factors for compensation than for solar PVs. Further, as observed in Table 44, using onshore wind for compensation requires smaller area and installed capacity compared to when using solar PV. However, it is important to note that the calculated area is based on the assumption of a required area per wind turbine, equal to 50 x 50 m^2. Another possible approach, to find this area, could be to divide the area at Smøla wind farm with number of wind turbines. An alternative approach could be considering the noise zone, which could range up to 600-800 m from the wind turbine in the worst case [2]. Additionally, even though using onshore wind power for compensation would require less area, the wind farm would require development of a new area. This is in contrast to the solar panels, which are intended to use rooftops of already developed areas, i.e. buildings at Nyhavna. Nevertheless, to achieve the desired ambition level using solar PV as local RES would require more roof area than is available. One possible solution to this could be to utilize facades on buildings in the Nyhavna neighbourhood. Another could be to use power production from solar PV, in combination with onshore wind power production.

Development of onshore wind farms would further set requirements for choice of location, to avoid noise and visual disturbance. Additionally, Norway has experienced public opposition regarding expansion of wind farms this last couple of years. Due to the Norwegian resistance against onshore wind, another possible solution could be to use offshore wind as local RES at Nyhavna. However, development of offshore wind power production is still in an early phase, and would lead to great expenses. This could further prevent policymakers from expanding the offshore wind power production.

6.7 From ZEN to a zero emission society

IPCC Sixth Assessment Report highlights the government's role for coordination and steering effects in order to accomplish effective climate mitigation [38]. According to [38], climate-related policies have contributed in decreasing GHG emissions in some context. For instance has CO_2 prices proven to be effective, where countries with a price on CO_2 have an emission growth rate 2% beneath countries without. According to IPCC, it is further unlikely that the society will be able to reduce emissions sufficiently to limit the global warming well below 2°C, without coordination and incentives from politicians [38]. Nevertheless, a proper knowledge foundation is necessary in order for policymakers to perform the correct abatement measures. It is thus important that the calculation methods for emission factors are understood, in order to ensure the correct consequences based on chosen action.

One of the main points in [38], is that abatement measures must be taken now. The report further highlights the urgency of change to avoid the potential consequences of not limiting the global warming below 2°C. This is further emphasized in REPowerEU, which "...is about rapidly reducing our dependence on Russian fossil fuels by fast forwarding the clean transition and joining forces to achieve a more resilient energy system and a true Energy Union." [20]. The consequences of taken actions now, rather than later was further observed in Section 5.2.3. As emissions are high at the beginning of Nyhavna's lifetime, this gives the possibility for more compensation. However, after 2040 emission compensation is not possible, as the power system is emission-free. Thus, Nyhavna must compensate for all embodied emissions before 2040, to be able to reach zero emission throughout its lifetime.

7 Conclusion

In light of the development towards low-emission energy systems, this thesis recommends that current methods for emission factors, and the basis for these, should be re-reviewed. In this thesis, different calculation methods for emission factors have been presented. Further, the climate effects in the north-European energy system when adding capacity of local RES in a zero emission neighbourhood, have been investigated. This in order to provide a sound knowledge foundation of the different emission factors, and further observe how the factors influence the resulting area of solar PVs in ZENs. A case study was created to investigate how the different calculation methods would influence the ZEN dimensioning, representing a simplified north-European power system. Further, different simulations were performed in order to look at the effects of marginal changes in demand and local renewable power production in the Nyhavna project.

By using a Scandinavian annual average emission factor for dimensioning the solar PVs, it was possible to reach the desired ambition level for 2019, while for 2030 the ambition level could not be reached. Additionally, since the Scandinavian energy system is dominated by RES this resulted in a high required area of solar PVs, due to low emission factors for compensation. When using European annual average emission factors it was possible to reach the ambition level ZEN-COM, both using cost data from 2019 and 2030. Nevertheless, a high share of RES in 2030 required a unrealistic large area of solar PVs. Solar power production can only produce power during the day because of the sun availability. It was thus interesting to see how using hourly average emission factors would influence the final dimensioning. Using hourly average emission factors eventually resulted in a significant increase in area size in 2019, especially using the Scandinavian emission factor. Moreover, for 2030 it was found that reaching ZEN-COM was impossible. As observed from Section 5, emission factors decreases a lot from 2019 to 2030. As emissions linked to power production would decrease throughout the lifetime of a neighbourhood this would lead to a different required solar PV area in 2030 than in 2019, as the compensated power would be of less worth. To handle this the current practise is to calculate an average emission factor equal to the average of the annual average emission factors over the neighbourhood's lifetime. Similarly was done in the case study. From this, it was found that it was impossible to achieve the desired ambition level of ZEN-COM using linear annual emission factor. The linear emission factors further showed the significance of rapid development of RES, as one would be able to compensate for more emissions today than in the future. Even though a ZEN was to be build today, it would enter a power system in development. The linear emission factors show the importance of taking into account that the power system is changing. Thus, the choice of method also must communicate this.

However, using average emission factors for power export implies that the exported power replaces the average of the electricity mix. As mentioned above, this is not typically the case as the added power production is most likely to replace the production with the highest marginal cost. Due to this a short-run marginal emission factor was calculated, to find the short-run consequences of developing Nyhavna as a ZEN. For 2019, it was found that including more solar power capacity would reduce natural gas power production, yielding in a high emission factor for compensation. This eventually led to a relatively small required solar PV area. Similarly was done using cost data from 2030. Even though this led to the reduction of natural gas power production, the reduction was too low for the compensation to be of any significance resulting in an infeasible solution. More consumption could in the long-run lead to further investments in the power system. This is included by using the long-run marginal emission factor, where the long-run consequences of developing Nyhavna as a ZEN was investigated. For 2019 it was found that including the added solar power capacity led to a reduction in Scandinavian offshore wind and solar power production in the UK. This further led to the increase of UK natural gas power production, eventually increasing total emissions making it impossible to reach ZEN-COM. For 2030 the added capacity led to a reduction in total emissions. However, similarly to the short-run marginal emission factor the reduction was too small to be able to compensate for the embodied emissions.

As observed from the above results, using only solar PV as local RES led to infeasible solutions in several of the calculation methods. Due to this, and because of the sun availability and high emission factors for installation of solar cells, a simulation was run using cost data for 2019 but using onshore wind power production as the local RES. From this a substantial reduction in required area was found, compared to when using solar PVs. However, as solar cells use already developed area a wind farm would require development of a new, separate area. Further, the choice of location would set requirements, to avoid noise and visual disturbance. In addition Norway has the last couple of year experienced reluctance against expansion of onshore wind power, and the solution could may not be possible to execute.

The above results show that the choice of calculation method gives quite differing results. Using the short-run marginal emission factor for 2019 for dimensioning would require a smaller area of solar PV, than when using the hourly average emission factor, making it possible to reach ZEN-COM at a lower cost. Dimensioning using the short-run marginal emission factor would result in expected compensation based on the existing power system. However, as the power system emissions would decrease due to more commissioning of renewable energy sources, this would result in an under-compensation, eventually resulting in the ZEN not being zero emission.

As seen from the above results, the choice of calculation has a clear impact on dimensioning of local RES, as well as project feasibility. Due to this it is necessary with a standard that communicates the actual global effects of local measures. Additionally it is observed that policymakers have an essential role in order to reach our climate goals [38], as they have the power to introduce decisive measures. However, to choose the correct abatement measures a knowledge foundation is of significance. This thesis has discussed the different calculation methods of emission factors to create a better knowledge foundation of the different emission factors. The different calculation methods are further used to find required solar PV area in a ZEN with an ambition level of ZEN-COM. As observed, using the different emission factors resulted in quite different areas, in which it is evident that more research is needed in order to understand the global climate effects of local measures.

8 Further Work

This thesis has investigated the resulting dimensioning of solar PVs as local RES in ZEN, using different calculation methods for emission factors. From this it was shown that the different calculation methods resulted in significant differences in the resulting area. However, the actual effect of the resulting solar PV area is not evaluated. As mentioned, dimensioning based on the 2019 short-run marginal emission factor would result in expected compensation as long as the power system remains static. However, if more RES are included to the power system, in combination with the decommissioning of thermal power plants, this would eventually result in less emissions being compensated as the power system develops. It could thus be interesting to look at the actual reduction in emissions based on including the suggested solar power capacity. This in order to observe the actual compensation throughout the ZEN's lifetime.

The case study used in this thesis is a simplification of the North-European energy system. The model only considers three zones, and does not consider the internal transmission capacity between the different countries or zones within the Continent, UK or Scandinavia. It could thus be interesting to see how internal bottlenecks in a country could influence the required area of solar PVs in a ZEN.

Because of the public opposition regarding the expansion of onshore wind farms, onshore wind power is perhaps not a feasible option as local RES. However, because of the seasonal dependency of solar power production, it could be interesting to look at different options for local RES. Due to this, it could be interesting to investigate how using solar PVs and onshore wind power in combination, to reach ZEN. Could it be possible to reach the desired ambition level with a realistic area, using solar PVs to cover for the neighbourhood's consumption (reaching zero energy), and onshore wind power to cover for the embodied emissions? Another possible solution could be offshore wind power production. Nevertheless, offshore wind power is still an early-stage technology and would thus require large costs associated with eventual development. It could thus be of interest using offshore wind power production as local RES for the Nyhavna project. Further to compare costs of expanding offshore wind power, compared to other local RES or continuing the state-of-art power production.

As mentioned in Section 2.1.6, the impact of green certificates could influence the resulting emission factors. Section 2.1.5 further discusses how a CO_2 cap would affect the emission factor. This was further reflected on in [12], where it was found that surplus power from RES did not necessarily reduce GHG-gases. Because of this it could be of interest to observe the consequences of including these effects to this case study, to see whether or not the same is found here.

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Appendix

A Inputs data to GenX

The following section present existing capacity in 2019 per technology in the different areas.

A.1 Generators data

Table 45: Capacity per technology 2019

	Existing capacity [MW]		
	Continent	Scandinavia	UK
Hard coal	33580	0	8794
Lignite coal	21205	0	0
Natural gas	55690	635	37698
Nuclear	15945	8586	9229
Solar PV	61939	834	13346
Offshore wind	11741	203	9970
Onshore wind	63430	11390	14125
Biomass	4338	4756	5333
Reservoir hydro	4249	47750	1873
Pumped hydro storage	6665	0	2600
Run-of-river hydro	1277	1509	300

B Annual import/export 2019

In this section the yearly flow between the zones in the different simulations for 2019 are presented.

B.1

Table 46: Original static power system, base case.

To area	**From area**	**Annual transmission [TWh]**
Scandinavia	Continent	36.3
Continent	UK	-0.79
UK	Scandinavia	-18.1

B.2

Table 47: Original power system allowing for decommissioning/commissioning, base case.

To area	**From area**	**Annual transmission [TWh]**
Scandinavia	Continent	41.5
Continent	UK	-12.0
UK	Scandinavia	-11.1

B.3

Table 48: Static power system with added Nyhavna demand.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	18.5
Continent	UK	-2.85
UK	Scandinavia	-10.0

B.4

Table 49: Power system with added Nyhavna demand, allowing for decommissioning/commissioning.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	41.5
Continent	UK	-11.7
UK	Scandinavia	-11.1

B.5

Table 50: Static power system with added Nyhavna demand and solar power capacity.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	20.6
Continent	UK	-1.9
UK	Scandinavia	-9.96

B.6

Table 51: Power system with added Nyhavna demand and solar power capacity, allowing for decommissioning/commissioning.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	41.5
Continent	UK	-12.5
UK	Scandinavia	-11.1

B.7

Table 52: Static power system with added Nyhavna demand and wind power capacity.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	22.1
Continent	UK	-0.18
UK	Scandinavia	-11.4

B.8

Table 53: Power system with added Nyhavna demand and wind power capacity, allowing for decommissioning/commissioning.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	42.0
Continent	UK	-10.3
UK	Scandinavia	-10.9

C Annual import/export 2030

In this section the yearly flow between the zones in the different simulations for 2030 are presented.

C.1

Table 54: Original power system allowing for decommissioning/commissioning, base case.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	19.6
Continent	UK	-11.6
UK	Scandinavia	-3.7

C.2

Table 55: Static power system with added Nyhavna demand.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	16.2
Continent	UK	-13.6
UK	Scandinavia	-0.39

C.3

Table 56: Power system with added Nyhavna demand, allowing for decommissioning/commissioning.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	19.5
Continent	UK	-11.9
UK	Scandinavia	-3.6

C.4

Table 57: Static power system with added Nyhavna demand and solar power capacity.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	19.5
Continent	UK	-13.1
UK	Scandinavia	-4.47

C.5

Table 58: Power system with added Nyhavna demand and solar power capacity, allowing for decommissioning/commissioning.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	19.6
Continent	UK	-11.7
UK	Scandinavia	-3.51

C.6

Table 59: Static power system with added Nyhavna demand and wind power capacity.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	20.7
Continent	UK	-12.9
UK	Scandinavia	-4.9

C.7

Table 60: Power system with added Nyhavna demand and wind power capacity, allowing for decommissioning/commissioning.

To area	From area	Annual transmission [TWh]
Scandinavia	Continent	19.5
Continent	UK	-11.9
UK	Scandinavia	-3.52

Kunnskap for en bedre verden