Mikkel Nærby

Towards zero-emission power systems – A generation expansion study of the North Sea region 2040

Master's thesis in Energi og miljø
Supervisor: Magnus Korpås
Co-supervisor: Martin Kristiansen
June 2022

Master's thesis

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Norwegian University of Science and Technology
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Department of Electric Power Engineering

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1 Abstract

Recently the UN published the Climate Change report 2021, concluding that the world is off-track to fight climate change. Data shows that greenhouse gas concentrations in the atmosphere continue to rise to record levels.[1] The European Union is targeting climate neutrality by 2050, meaning an economy with net-zero greenhouse gas emissions. Significant investment within a variety of sectors is needed to reach this goal. The transition to renewable energy generation is one of the critical factors in reaching a sustainable future.[2]

This master thesis utilizes a deterministic optimization model, PowerGIM, for power system simulations in the North Sea. The model simulates a year of operation with the objective of minimizing investment and operational costs. The main objective of the master thesis is to analyse the optimal generation expansion of the North Sea power system in 2040 in scenarios with flexible demand effects and zero-emissions requirements. Generation expansion planning showcases the optimal location, capacity, and generation technology to benefit the whole power system. Transmission expansion planning is included to give a realistic power system development. Power systems with a high share of renewable power sources(RES) have a considerable flexibility problem because the generation output from RES varies and is not controllable. The effects of flexible demand in a zero-emission power system are analysed in different power system configurations. The TYNDP 2020 scenario report for 2040 is the primary source of assumptions and input data in this master thesis.

The initial basis results show that batteries and expanded transmission will partly balance the power grid and efficiently exploit the power output, such that no generation expansion is needed. Investments in the transmission are more beneficial when added renewable generation leads to more flexibility issues than the power system can handle. The case studies show that an integrated international power system and a mix of variable power generation sources contribute to the balancing of the power system. However, less transmission is needed when flexible demand is included, and the results show that onshore wind generation expansion in Norway is the most cost-beneficial expansion. A share of 26 percent flexible demand results in a 94 percent reduction in emissions compared with the initial scenario. Nevertheless, reaching a zero-emission power system is increasingly more difficult. The variability of renewable power generation is the main obstacle to reaching a sustainable power system. With zero-emission requirements, the power system is experiencing more significant flexibility problems and periods of power shortages. In order to reach a functioning, fully renewable power system, additional energy storage and flexible demand are needed than what is investigated in this thesis.

2 Sammendrag

Nylig publiserte FN klimasrapporten 2021, som konkluderte med at verden ligger bak mål for å bekjempe klimaendringene. Data viser at klimagasskonsentrasjonene i atmosfæren fortsetter å stige til rekordnivåer.[1] Den europeiske union sikter mot klimanøytralitet innen 2050, som betyr en økonomi med netto null klimagassutslipp. Det er nødvendig med betydelige investeringer innenfor en rekke sektorer for å nå dette målet. Overgangen til fornybar energiproduksjon er en av de kritiske faktorene for å nå en bærekraftig fremtid.[2]

Denne masteroppgaven benytter en deterministisk optimaliseringsmodell, PowerGIM, for kraftsystemsimuleringer i Nordsjøen. Modellen simulerer et driftsår med mål om å minimere investerings- og driftskostnader. Hovedmålet med masteroppgaven er å analysere optimal produksjonsutvidelse av kraftsystemet i Nordsjøen for 2040 i scenarier med fleksible kraftetterspørsel og krav til null utslipp. Planlegging av generasjonsutvidelse viser den optimale plasseringen, kapasiteten og generatorteknologien til fordel for hele kraftsystemet. Transmisjonsutvidelsesplanlegging er inkludert for å gi en realistisk kraftsystemutvikling. Kraftsystemer med høy andel fornybare kraftkilder (RES) har et betydelig fleksibilitetsproblem fordi produksjonseffekten fra RES varierer og ikke er kontrollerbar. Effektene av fleksibel etterspørsel i et nullutslippskraftsystem analyseres i forskjellige kraftsystemkonfigurasjoner. TYNDP 2020-scenariorapporten for 2040 er den primære kilden til forutsetninger og inputdata i denne masteroppgaven.

De første basisresultatene viser at batterier og utvidet overføring delvis vil balansere kraftnettet og effektivt utnytte kraftuttaket, slik at det ikke er behov for produksjonsutvidelse. Investeringer i overføringen er mer fordelaktig når tilført fornybar produksjon fører til mer fleksibilitet problemer enn kraftsystemet kan håndtere. Casestudiene viser at et integrert internasjonalt kraftsystem og en blanding av variable kraftproduksjonskilder bidrar til å balansere kraftsystemet. Det er imidlertid mindre behov for overføring når fleksibel etterspørsel inkluderes, og resultatene viser at utbygging av vindkraft på land i Norge er den mest kostnadsgunstige utvidelsen. En andel på 26 prosent fleksibel etterspørsel gir 94 prosent reduksjon i utslipp sammenlignet med utgangsscenarioet. Likevel blir det vanskeligere å konvertere de resternde prosentene. Variasjonen i fornybar kraftproduksjon er hovedhindringen for å nå et bærekraftig kraftsystem. Med nullutslippskrav opplever kraftsystemet mer betydelige fleksibilitetsproblemer og perioder med strømmangel. For å nå et fungerende, fullt fornybart kraftsystem, trengs det ytterligere energilagring og fleksibel etterspørsel enn det som er undersøkt i denne oppgaven.

3 Preface

This master's thesis concludes the author master's degree within Energy and Environment at the Norwegian university of Science and Technology(NTNU), and marks the ending of five incredible years as a student in Trondheim. The author of this thesis has specialized within power systems and optimization. The motivation in both the chose of thesis and specialization is the belief towards greener technologies and a sustainable future. This master's thesis gave meaningful insight in the development of future power system and the economical incentives for investing in renewable energy generation sources.

A special thanks to my supervisor Magnus Korpås from NTNU which has contributed with formulation and insight of future power system and related components. A huge thanks must also be given to co-supervisor Martin Kristiansen who help with the understanding and decoding of PowerGIM. Martin have also shared valuable reports of relevant topics related to the thesis. Both have been helpful with constructive discussions and appreciated feedback. Gratitude is also extended to my fellow students for a healthy and including working environment.

The author will look back at the time when writing this thesis as meaningful, challenging, interesting and rewarding.

Trondheim, June 2022
Mikkel Nærby

4 Abbreviations

AC Alternating Current

CAPEX Capital Expenditures

CCGT Combined Cycle Gas Turbine

CCS Carbon Capture and Storage

DC Direct Current

ENTSO-E European Network of Transmission System Operators for Electricity

FL Flexible load/Flexible demand

GEP&TEP Generation and Transmission Expansion Planning

GEP Generation Expansion Planning

HVDC High-Voltage Direct Current

LP Linear Program

NPV Net Present Value

O&M Operation and maintenance

OCGT Open Cycle Gas Turbine

OPEX Operational Expenditures

PowerGIM Power Grid Investment Module

RES Renewable Energy Source

TEP Transmission Expansion Planning

TYNDP Ten-Year Network Development Plan

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5 Introduction

In the transition to a sustainable future, the development of the power system is a crucial component. In order to reach the goal of climate neutrality by 2050, stated by the European Commission[2], the world needs to take action. Decarbonizing the power grid is necessary, requiring huge investments in renewable power generation. The key drivers in this transition are wind and solar. Investments in renewable energy sources are becoming more affordable, and profits are rising beyond fuel-based energy production. Developing a renewable power system brings huge flexibility problems, which will be a central theme in this thesis. Power system flexibility is defined as the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant timescales[3].

In 2020, while the world is struggling with a pandemic, renewable energy sources like wind and solar are still rapidly growing, and electric vehicle sales are at an all-time high. According to Bloomberg, wind and solar are now the cheapest of all new electricity generation in most markets.[4] However, 2021 is the year where coal and oil have had a considerable rebound in an uneven economic recovery. The consequences are that 2021 has had the second-largest annual increase in CO2 emissions in history. The choice of energy sources is not only important considering emissions. Today, the consequences of a gas-dependent energy system in Germany and EU affect the national economy and security. Nevertheless, the energy sector is accountable for almost three-quarters of all the emissions that have pushed the global average temperature 1.1 Celsius higher since the pre-industrial age. The global population is predicted to grow by 2 billion people by 2050. The growth of the population and rising incomes follow a higher energy demand, which requires an even larger expansion of energy generation.[5]

The main objective of this master thesis is to simulate and analyse optimal generation expansion of the North Sea power system in 2040 in scenarios with flexible demand effects and zero-emissions requirements. The represented North Sea power system model consists of seven countries with an aggregated load and power production representation. The analysis consists mainly of annual power production for each generation technology, capacity factors, the share of renewable energy sources(RES), electricity prices, emissions, investment and operational costs, generation and transmission expansion (GEP&TEP), and flexible demand management. These results are compared in mainly four different scenarios. The first scenario is the reference, which results from a simulated year without GEP&TEP, flexible demand or net-zero requirements. The second scenario is investigating GEP&TEP and comparing it with the reference. Analysing generation expansion planning implies the optimal decision on where and at which capacity to build different generation technologies. The transmission system must also be considered to represent a realistic power system. The third scenario will also include flexible demand management and will analyse the effect on the flexibility problem of the power system. Lastly, the fourth scenario will investigate a zero-emission scenario with and without installed nuclear power capacity. Further, a sensitivity analysis will be conducted considering climate conditions and threshold price of flexible demand.

This master thesis is separated into four main sections and includes a brief introduction and conclusion. The introduction explains why this topic is of interest and the thesis's main objective and scope. The conclusion summarizes the most important results and findings. The first section consists of a literature review, where the point is to investigate other results and similar works. The section will consist of future scenarios and other power system simulation models. The second section consists of fundamental theory, which includes background information supporting the methodology in the thesis. The theory will consist of scenario building, GEP&TEP, flexible demand and fundamental optimization problems. The third section looks into the methodology of the thesis. The Power Grid Investment Module(PowerGIM) will be described, and all the input data for the model will be explained. The section will also present model improvements, the case study and an evaluation of the model and the data. The last section consists of a result and discussion, where all simulation results will be presented, analysed, and discussed.

The author's specialization project, prior to this master thesis, investigated generation expansion on the future power system with an unmodified PowerGIM. This means that certain parts of the Literature Review, Theory and Methodology are based on the work done in the specialization project. The specific parts will be highlighted at the beginning of each section.

6 Literature Review

6.1 Scenarios for the future power system

The following section aims to provide an overview of different scenarios for future power systems. This is important when analysing the results, such that large deviations may be highlighted. Different approaches and assumptions are also helpful to be aware of. Net-zero-emissions scenarios are also included in order to compare with the net-zero-emissions results. Predicting future trends is always based on assumptions with a variety of uncertainties. For this reason, a vast collection of scenarios will present a better overview of the future power system. The most recent publications are prioritized in order to get the most up-to-date predictions. All parts, with the exception of the net-zero-emission scenarios are based on work from the authors specialization project.

6.1.1 The World Energy Outlook 2030

The World Energy Outlook report(WEO) is designed to assist decision-makers in crucial decisions in the clean energy transition. WEO is simulating three different scenarios for the year 2030; Stated Policies Scenario(STEPS), Announced Pledges Scenario(APS) and Net Zero Scenario(NZE). More than 50 countries and the European Union have committed to meet net zero-emission targets in APS. The APS predicts a doubling of renewable energy investment over the next decade. In this scenario, in 2030, the vast majority of energy sources are low emission. The main energy sources wind and solar have an annual growth of 500 gigawatts worldwide. As a result, power generation from coal is 20 percent lower than recent highs. With the growth of electric transportation and improvements in fuel efficiency, the scenario predicts a peak oil demand in 2025. [5]

The STEPS look at what governments have done, as well as specific initiatives that are under development. In this scenario, almost all new generation is renewable energy sources, but in 2050 the emission level stays approximately at current levels. The reason is the prediction of a doubling of electricity demand in 2050. Meaning a high adoption of renewable energy sources, but they are not replacing fossil fueled-based energy sources due to high demand. As a result, the average global temperature in 2100 are 2.6 Celsius higher than pre-industrial levels. [5]

NZE is based on the minimum requirements needed to hold the 1.5 Celsius trajectory for 2030. This scenario requires a 4 trillion USD investment by 2030, which is 70 percent higher than the APS. The additional spending mainly targets countries with developing economies and emerging markets. In both APS and NZE, the power production of coal is decreasing. The difference is the speed of a 10 percent decline by 2030 in APS and a 55 percent decline in NZE. In all three scenarios, natural gas demand increases over the next five years, but there is a significant divergence after this. The share of renewable generation in the power system is increasing in all scenarios. The NZE predicts around 240 million rooftop solar PV systems and 1.6 billion electric vehicles in 2050. Such a power system requires a robust and flexible power grid with many storage opportunities. Digital technologies are also needed to support demand response and manage the multi-directional flow of energy. [5]

6.1.2 TYNDP 2022

The Ten-Year Network Development Plan (TYNDP) 2022 is building on the previous TYNDP 2020 report, which is the report most av the input data in this master thesis is based on. In that context, it is interesting to view the development of the TYNDP reports. The TYNDP 2022 is more ambitious, inclusive, and transparent than previous reports. Distributed Energy and Global Ambition are the two scenarios relevant in this report. The scenarios cover a wide variety of topics, but this section focuses on the energy mix scenarios for the European power system. Both scenarios stretch to 2030, 2040 and 2050. [6]

Distributed energy(DE) and Global Ambition(GA) scenarios are in line with achieving carbon neutrality by 2050 and a minimum of 55 percent emission reduction in 2030. The difference is the path for achieving these goals. DE scenario relies on the willingness of society to achieve a sustainable future. Decarbonization through local initiatives supported by authorities is a crucial aspect. Focusing on decentralizing technologies and reduced energy demand are the drivers to reaching carbon neutrality. On the other hand, Global Ambition(GA) is driven by developing new renewable and low-carbon technologies. GA focuses on significant cost reduction by economies of scale and utilizing a global energy trading market. [6]

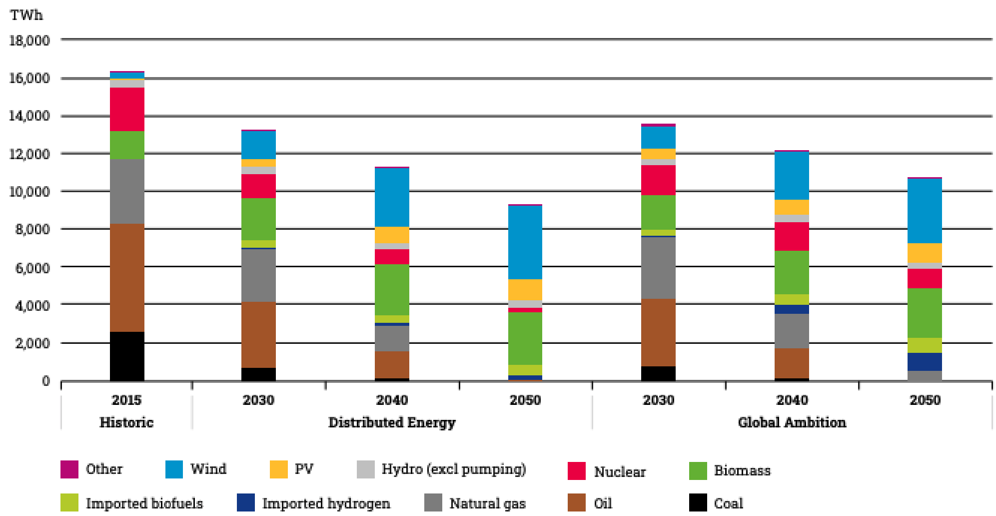

Figure 1: Primary energy supply in the GA and DE scenarios[6]

Both GA and DE are targeting energy effectiveness and decarbonization of the energy supply, resulting in a reduction of around 15 percent and 40 percent energy demand in 2030 and 2050 compared to 2015, respectively. Coal and oil will be phased out by 2050, and electricity and gas production will be decarbonized by 2040. Viewing the results for both scenarios in Figure 1 one can observe a significant increase in renewable energy production. The share of renewable energy production will reach 80 percent for GA and 96 percent for DE by 2050. DE is almost phasing out nuclear by 2050, while GA keeps nuclear at a significant share. In both scenarios, wind and solar PV power generation are growing to be significant contributors. The energy mix presented in Figure 1 is the primary energy supply for both scenarios, meaning that this is not only for power generation but also for transportation, industry, etc., which is outside the scope of this master thesis. Nevertheless, the results in the TYNDP 2022 report indicate future trends of the European power mix.[6] The following NVE report does only consider the power generation mix.

6.1.3 NVE

NVE is making a scenario for the combination of 19 countries in Europe. The model simulates scenarios for 2025, 2030 and 2040, utilizing 2021 as a reference year. Interpolation is implemented in the visualization of Figure 2 between the years. NVE utilizes three optimization models in their analysis: TIMES, TheMA and Samnett. The models maximize the socio-economical profits by analyzing power production technologies, production costs, production profiles, power infrastructure, demand profiles, price elasticity for consumption, etc. The method used by NVE is mainly directed towards power prices analysis, but the future energy mix is also a part of the analysis. [7]

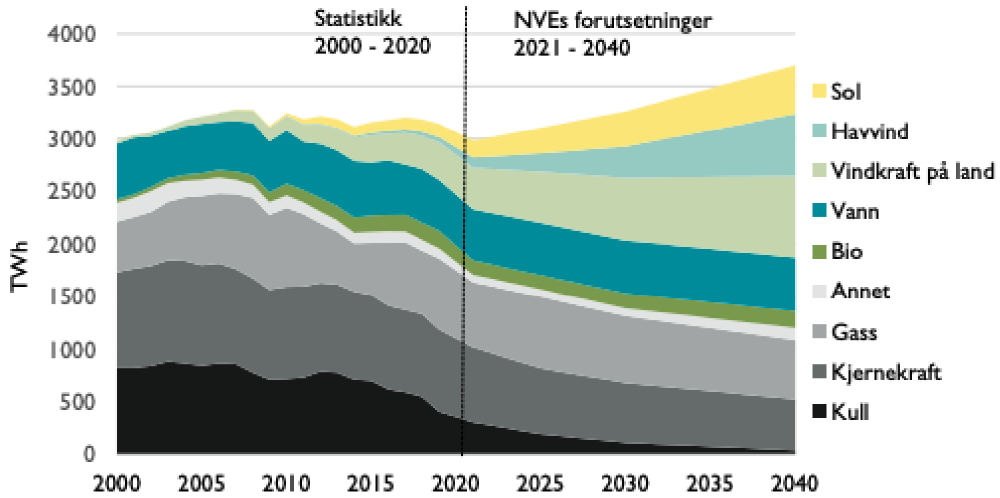

Figure 2: NVE's prediction of power production in Europe from 2020 to 2040[7]

The scenario presented by NVE shows that the annual power production in Europe will grow by 811 TWh towards 2040. Coal is almost phased out by 2040, which is in line with most policies stated by European countries. Due to the rise of renewable sources and storage opportunities with hydrogen and batteries, gas production will decrease 17 percent between 2025 and 2040. NVE has assumed high CO2 prices and decreased production costs, contributing to a more profitable expansion of renewable power production. The expansion of wind and solar are estimated to result in around 1200 TWh produced in 2040. It is noted that such a growth in renewable sources will require a large land area and may cause significant conflicts of interest. Unlike most other scenarios, NVE estimates that the share of nuclear will stay approximately the same.[7]

6.1.4 Net-zero-emission scenarios

The Joint Research Center(JRC), the European Commission's science and knowledge service, has published a technical report consisting of numerous scenarios of the EU energy system towards 2050. The report aims to reach insight in line with the 2030 and 2050 ambitions of the European Green Deal. The report compare different net-zero-emissions scenarios for the European power system in 2050 and how this generation mix could look like. In Figure 3 14 of these scenarios are compared with the generation mix of 2017. A more detailed description of the different scenarios can be found in the technical report[8].

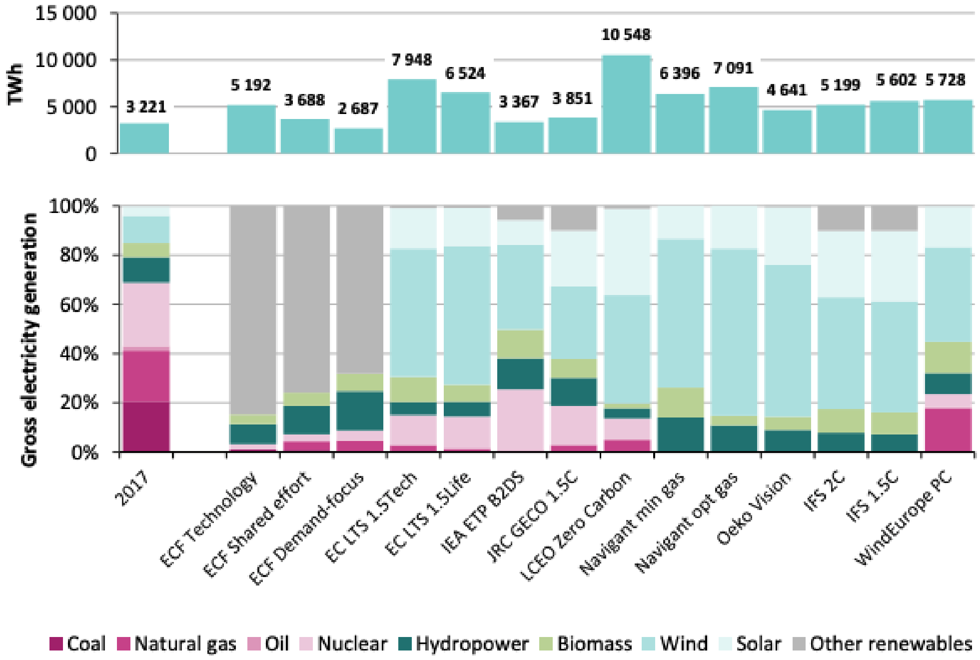

Figure 3: JCR Technical Report, towards net-zero-emissions in th EU energy system by 2050[8]. Note: "Other renewables" includes ocean and geothermal energy. In ECF it aggregates wind and solar, without specifying their respective shares.

The majority of the scenarios show a annual electricity generation between 3 850 and 6400 TWh in 2050, which is an increase of 20 to 95 percent compared with 2017. The higher scenarios showcase a two-fold and even three-fold increase in power production compared with today. The higher range projections are relying heavily on hydrogen to decarbonize the energy system. In most scenarios one-third of the gross electricity production is used to produce hydrogen, which is consumed by end-users either directly or as e-fuel for transport. It is emphasized that low electrification of final demand could impede with the long term goals. Therefore, the power sector growth, either due to direct or/and indirect consumption of electricity, is the preferred pathway by most scenarios in order to meet the long-term vision.

It is clear that the generation mix has dramatically changed from 2017 to the mid-centry. The fossil fuel current share of 43 percent has decreased between 0 and 5 percent in most scenarios. The remaining fossil fuel-based production is used as peak plants to provide flexibility to the power system. Most fossil fuel-based production is coupled with CCS technologies to abate the remaining emissions. A significant reduction in nuclear power is also seen throughout the scenarios. Certain scenarios are accounts for 100 percent renewable power system by 2050, from a current 31 percent. Wind and solar provide 60 to 90 percent of the total renewable electricity in 2050, with many multiples compared with 2017.

6.2 Optimization models for power systems

The following section will give two examples of different optimization models used for different power systems. The purpose is to get an insight of possible types of models used when analyzing power systems. It is essential to choose a methodology that correlates with the scope of the report.

6.2.1 Nordic hydropower flexibility and transmission expansion to support integration of wind power

"Nordic hydro power production flexibility and transmission expansion to support integration of North European wind power" is a paper written by H.Farahmand, S.Jaehnert, T.Aigner and D.Huertas-Hernando. The paper is a case study assessing the potential of increased hydropower production flexibility and the required transmission expansion to ensure the integration of wind power production. The paper utilizes a market model and a flow-based model in order to find the optimal strategy for the power system in 2030. The market model optimizes the strategic flexibility of hydropower production in the day-ahead market. The market model has a fundamental optimization model designed for the mid-and long-term simulation of hydro-thermal power systems. This model utilizes stochastic dynamic programming in order to determine water values. The model is stochastic because of the variation of variables such as wind speed, temperature and inflow. The model is dynamic because of the utilization of reservoir dispatch decisions in time. The input data for this model consist of capacity and marginal cost for thermal production, wind production, solar production, electricity consumption, transmission capacity and information about historical climate variables such as inflows and temperature. The result produced by the market model is verified using the flow-based model. This model run simulations based on the flow-based power market simulation using DC optimal power flow. The model simulates a detailed grid and computes the optimal generation dispatch and power flow through transmission lines for each hour of the year. An optimal solution is given by minimizing the operational cost based on the different marginal generation costs for different countries and generation types. The results imply grid implications surrounding the offshore grid and the HVDC links in the northern European power system. The detailed inclusion of hydro generation and reservoirs distinguishes this methodology from other optimal DC power flow simulations. The marginal cost of hydro units is dependent on the reservoir levels. The model simulates the effect of inflow variation and reservoir level variation for hydro generators. Modeling by considering water values in hydro production results gives a more realistic simulation of the power system.[9]. The methodology considers transmission expansion with the integration of offshore wind, which is essential in developing the future power system.

6.2.2 Generation expansion planning, Jiangsu Province

The paper "Generation expansion planning considering the output and flexibility requirement of renewable energy" is a case study on the Jiangsu Province. The paper presents generation expansion planning with the main focus on wind and solar output with its flexibility requirements simulated in an optimization problem. This paper uses two models: one wind-solar output model and another power system planning model. It is stated that the methodology is significantly different from other capacity expansion models and is more suitable for future renewable-dominated power systems. The power system planning model is a mixed-integer linear programming problem that minimizes the system cost relating to the decision variables during the planning period, from 2018 to 2050. The input data for this model consist of technical-economical parameters of generation such as lifetime, investment cost, OM cost, output factor, flexibility factor and annual generation hours. Further are six scenarios with varying power demand, subsidies and carbon emission reduction targets used as input data. Wind and solar generation are investigated using a large amount of historical meteorological data, analyzing these resources' actual power generation capacity. The wind-solar model results are added to the optimization model to present the actual wind and solar output. An overview of the methodology is presented in Figure 4.[10]

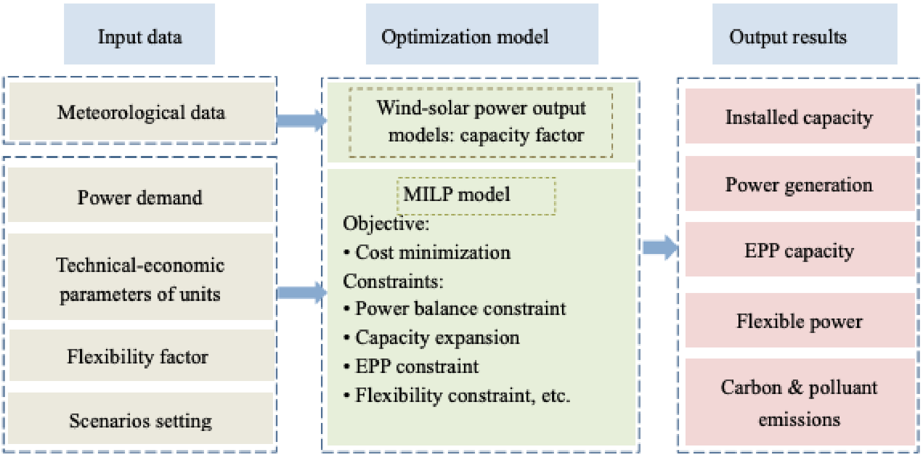

Figure 4: Generation expansion model Jiangsu Province case study[10]

The optimization model only includes variables and parameters related to power generation. Power flow with transmission capacity constraints is not accounted for. This model is not simulating the power system as done in this master thesis. The methodology presented in this paper is suitable when analyzing power generation within a small area. The master thesis analyzes the power system on a larger scale, where the transmission becomes a more prominent limiting factor. Nevertheless, investigating other models gives perspective. This paper shows that the generation mix depends on multiple factors, such as resource potential, subsidies, and carbon emission policies. Concluded in this paper, increased power demand is one of the most significant obstacles when transitioning from coal to wind and solar power.[10]

7 Theory

The purpose of scenarios and how they are built will be explained in this section. It is crucial to have an understanding of scenario creation, which is one of the building blocks in this master thesis. All input data is based on scenarios and it is essential to understand the assumptions and uncertainties behind these scenarios. Further, the concept of generation and transmission expansion with different methodologies will be described. Lastly will general theory for optimization problems and flexible demand be elaborated. Scenario creations and generation expansion is based on work from the specialization project.

7.1 Creating scenario

Cambridge Dictionary defines a scenario as "a description of possible actions or events in the future".[11] A scenario is a story outline describing a possible future. A scenario is not necessarily the most likely future outcome, which normally is referred to as a prediction or forecast. Scenarios are supposed to investigate various futures, regardless of how realistic they are. It is important to consider the uncertainty factor when creating or investigating scenarios, especially those with a long time horizon. With a large number of unknown variables, many simplified assumptions are being made, which is why most future predictions are wrong. Therefore, presenting multiple scenarios in combination minimizes the uncertainty factor and maps out a room of possibilities. This way, scenarios act like guidelines to understand the future. Further, scenarios can be used as decision support when doing risk analysis, which is highly relevant for businesses and politicians. A decision can often be made considering the worst-case scenario, regardless of the likeliness. With scenarios, policymakers can evaluate different decisions based on the corresponding scenario. In this way, scenarios may have more influence than single forecasts. [12]

When creating scenarios e.g., for the power market, it is possible to separate scenarios into two categories, dynamic or static. In a static scenario, the energy market is cleared for one future characteristic year. In a dynamic scenario, the development from one year to another is important, and the development over several years is evaluated, typically starting from the present situation. This is an important aspect when analyzing renewable energy sources with high investment costs and low operation costs.[13]

The building process of scenarios can be separated into two steps: a qualitative and a quantitative step. The qualitative step consists of creating the story line, including a scope description, main driving forces and larger uncertainties. The story line defines a base case, but several story lines are often created to establish a solid foundation. The second quantitative step is focused on the consistency of data and satisfactory resolution. The consistency of data meaning e.g., in a power system, that the data is based on market equilibrium in all the relevant markets. An increase of renewable energy in the power system influences the fossil fuels power generation, which in the EU will affect the CO2 price of the EU Emission Trading System, which again will influence the investments in renewable energy sources. Reaching good resolution data is often related to time and scale. For example, time steps of one week must be avoided when the market has hourly power price variation. Europe can not be defined in one node if analyzing power flow between European countries is simulated. Models are the best tool to avoid contradictions in data consistency and resolution when quantifying scenarios.[13]

Creating scenarios for the future power system in 2040 is challenging and comes with a high degree of uncertainty, which is why one should be critical when investigating these scenarios. This is important to consider since the master thesis is based on simulation and analysis from these scenarios. Investing in generation facilities is capital intensive and involves typically complex financial arrangements. The building period may take years and the facilities can effectively operate for decades. For this reason, the methodology should take a long-term view, carefully account for uncertainty and have a large-scale optimization problem. Uncertainties have always characterized long-term planning of power systems. Typical uncertainty factor for the conventional generation expansion problems is related to the input parameters, such as weather forecast, load forecast, fuel costs, economic growth, construction time, regulator policies, etc. A simple summarizing of the uncertainties related to traditionally generation expansion planning are represented in Figure 5. However, there are certain methodologies developed to address these uncertainties. Most commonly are scenario analysis, probabilistic analysis and sensitivity analysis.[14]. These methods are derived from deterministic models to take uncertainties into account. Robustness and flexibility evaluate the effectiveness of the models to withstand uncertainties, which will be further elaborated in the next section.[15]

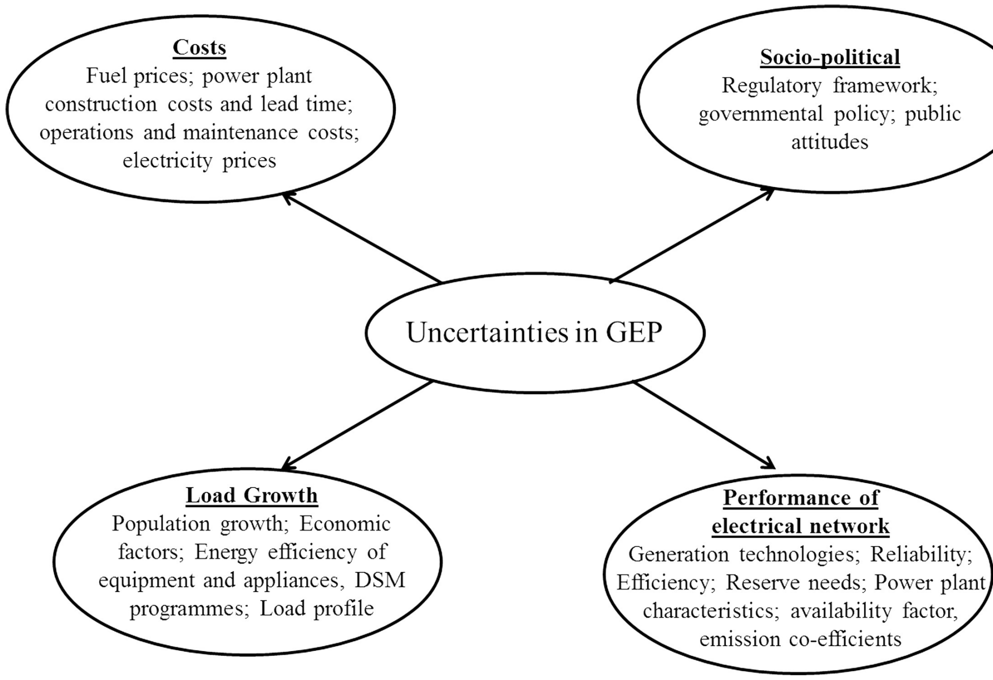

Figure 5: Uncertainty related to traditional generation expansion planing.[15]

7.2 Generation expansion planning

This section will describe the different aspects of generation expansion planning(GEP). Two perspectives are mostly considered when planning for generation expansions: centralized expansion problems or market-orientated generation investment problems. The centralized expansion plan is interested in the most profitable operation of the whole power system. A central planer does not necessarily build the generation, but encourages other operators to do so, also called an independent market operator(ISO). A market-oriented planer consists of a single power producer competing in the electricity market, aiming to maximize its own profits by making the best investment decisions. Market-oriented problems are often more complex due to additional uncertainty related to the behavior of other rivals.[16]

The main problem in power system planning is to guarantee that demands are supplied reliably and efficiently. In order to supply all demands, a sufficient transmission network and power production are required. The aging of existing power production facilities and the future power demand growth are two fundamental challenges related to GEP. These issues are fundamental in deciding whether to expand existing power production facilities or invest in new power generation. GEP are formulated as optimization problems and a central planer will e.g., formulate the objective function by minimizing bottleneck, minimizing generation costs or maximizing social welfare. The centralized method is also known as a command-and-control approach. [17]

In GEP, several aspects need to be determined, such as capacity, location, timing, and generation technology being the most important decision factors. Generation technology evaluations are mostly dependent on investment and operational costs. These expenses vary between the technologies and the variety of cost and other factors needs to be compared, e.g. lifespan, availability, emission cost, curtailment cost, ect. The capacity decision is also dependent on investment cost, but the demand must also be considered. With an oversized demand, a higher income can be expected. Most renewable energy sources are weather-dependent and limited to a certain location. Usually, the power system has most of the demand concentrated in certain regions. This means that the increased penetration of renewable energy sources has resulted in a more congested transmission network. Therefore, building new power generation to avoid transmission congestion is crucial. For this reason, it is more accurate to include the transmission network in the GEP problems.[18] Determining the optimal timing to expand power generation is difficult and done in different ways. One possibility is to consider generation expansion decisions as a single point in time, meaning a static approach. With this approach, the whole planning horizon is represented by a single decision year, which normally is the last year of the planning horizon. Usually, the latest year normally has the highest expected demand, assuming that demand keeps growing over time. The static approach leads to simpler problem formulations, but time-dependent variables could be inaccurate, especially with long planning horizons. With a high demand at the reference year, this approach will lead to overcapacity until the last year of the planning horizon. This approach is not suitable if unexpected changes in the power system occur. Considering different points in the planning horizon is called the dynamic approach. The planning horizon is divided into different periods, each period having its decision year, normally the last year of the period. This allows us to adapt to changes in the power system throughout the planning horizon. The approach is more accurate but with a downside of complex formulations and possibly intractable problems. A simple visualization is presented in Figure 6.

In GEP models, there are two different ways to represent the transmission network. The simplest is the single-node model, in which case no network constraints are modeled in the GEP problem. This means that all generation and demand units connect to one virtual node. This approach was executed in GEP for Jiangsu Province described in the Literature Review. The solution to this GEP problem might result in the required generation capacity but not the location of where to build it. The GEP problem becomes simpler and it may be suitable when simulating power systems on smaller footprints, meaning the variety of generation locations are limited. The second approach is a network constrained model where the transmission constraints are added to the GEP problem. The result of this model will give the optimal capacity and the optimal location of the generating unit. It is essential to consider the network constraints in a system with congested transmission lines. In larger power systems, a simplification of the network might be needed. Representing all

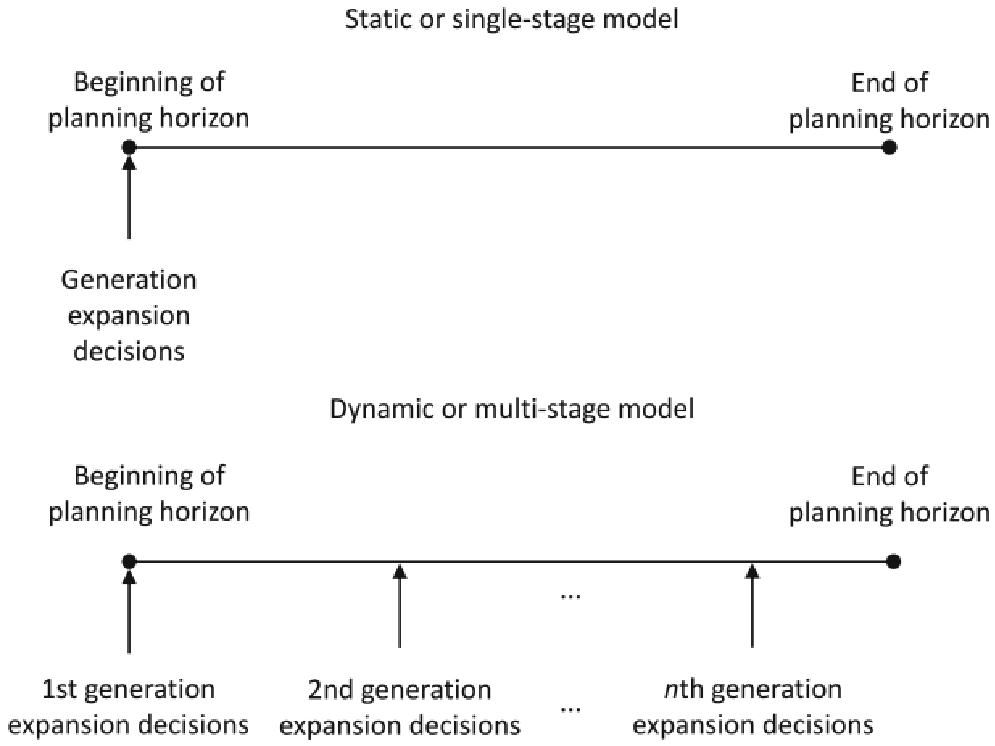

Figure 6: Static and dynamic generation expansion models.[16]

single cables in an international power system brings unnecessary complexity. The alternative is to include the total transmission capacity between regions represented by a single cable.

All models, especially those with long time horizons and many variables, have uncertainty factors. GEP uncertainties related to demand growth, regulatory changes, investment and operational cost change rival producers' behavior. With the focus of uncertainty characterization, it is possible to formulate two GEP different models. The deterministic model assumes that the GEP has perfect information at the decision time of expansion, which means that the planner knows the power system's future demand perfectly. The stochastic model assumes that the expansion decision is made within an uncertain environment. Normally such models utilize a stochastic programming framework, which means that the model simulates a set of scenarios with certain probabilities. It is possible to consider the uncertainty factor on specific data, e.g., the uncertainty only applies to the demand in the power system. [19]

As previously mentioned, generally, the GEP aims to decide the optimal expansion plan, which maximizes the overall social welfare and minimizes the investment costs. These are dependent factors that gives an interesting effect. The result of the market-clearing computes the social welfare, and the market-clearing is affected by generation expansion. Market clearing is an optimization problem by itself, a pool-based electricity market is considered with an independent system operator who clears the market once a day, one day ahead and on an hourly basis. Maximizing social welfare, the market operator evaluates the bidding curve submitted by consumers and the offering curve submitted by producers. The result of market-clearing is the hourly production, consumption and clearing prices. In order to simplify the model, it is possible only to consider the day-ahead market, which usually is the market with the highest trading volume of energy. The optimization model will determine the scheduled power quantities to be consumed by demands and supplied by producers to maximize overall social welfare. This means that the GEP problem is an optimization problem subject to another optimization problem. This architecture is also known as a complementarity model and is simply visualized in Figure 7

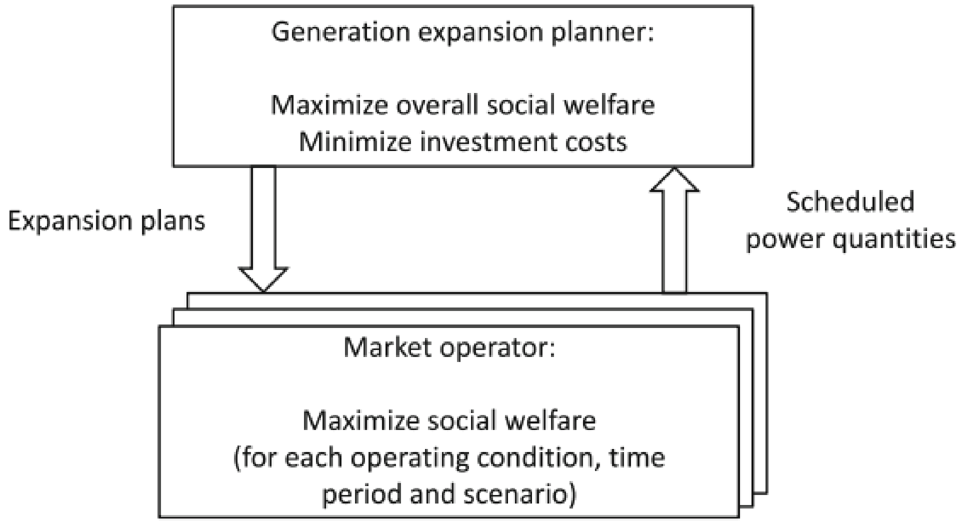

Figure 7: Complementarity GEP model[16]

Further, the generation expansion planner decides the optimal generation units built in the power system. The information about the GEP is used in the market-clearing problem and the output of the market-clearing problem is the produced quantities of existing generation, which is again used in the GEP.[16]

The complementarity model may also be applied to market-oriented generation investment problems, meaning a market with strategic producers optimizing their profits. The strategic decision of each producer is related to other producers due to market interactions, which means that the strategy made by one producer may influence the decisions of other producers. This is an example of applied game theory, and within this framework, several investment equilibriums typically exist.[20] The market may also be called an oligopoly, meaning that all large producers can affect the market outcome based on their strategies. The perspective of investment equilibrium analysis enables regulators to understand producers' investment behavior and the evolving production market. With this insight, regulators can develop better market rules, which may enhance the competitiveness of the market and stimulate investments in generation capacity.[16]

In summary, the PowerGIM simulation model utilized in this master thesis consists of different aspects described in this section. Our model considers a centralized expansion problem, meaning that the objective is to optimize the GEP for what is most beneficial for the whole power system. The model is a static single-stage model, utilizing power system scenarios for 2040 and simulating the power system for one year of operation. PowerGIM is based on a deterministic model, meaning that no uncertainty factors are considered in the model, but some uncertainties are assessed with several scenarios and sensitivity analysis. It is possible to simulate a stochastic model with probability factors in PowerGIM, but this is not done in this master thesis. A network constrained model represents the transmission, meaning that a simulation of the transmission network is considered to account for congestion. However, it is a simplification of the transmission system, which includes the capacity limits between regions and main subsea cables. A complete detailed transmission system would be too complex and not contribute to the scope of the project.

7.3 Transmission expansion

Transmission expansion planning(TEP) is not part of the main scope in this master thesis, but it is included in the modeling to get a realistic results in the power system development. In order to understand the impact and incentive for TEP, a short section of theory and background info is included.

Transmission expansion planning(TEP) can be defined as "a transmission planner which identify the optimal transmission reinforcements to be carried out with the aim of facilitating energy exchange among producers and consumers, e.g., by reducing generation or load-shedding costs".[21] The transmission network is a natural monopoly an is used by all consumers and producers to trade electric energy. The investment and operational cost are relatively small compared to generation facilities, but the effect on the functioning power system is huge. It is important to realize that the transmission system is designed to operate under the worst plausible conditions, which is generally true for infrastructures. Nevertheless, the worst conditions are priory unknown, which is an uncertainty that needs to be considered. TEP refers to decision process met by the transmission system operator(TSO) to unsure an optimal way to expand or reinforce an existing transmission network. The TSO is a public controlled entity with the objective to maximize the social welfare, which corresponds to the objective to GEP.

There are mainly two different methodologies used in TEP. One is a deterministic model which solves the TEP problem utilizing future demand forecasts. The second is an adaptive robust optimization(ARO) model, which account for different sources of uncertainties, such as the availability of generation unites future demand growth. The uncertainties can be handled in two ways, stochastic programming or with robost optimization sets. Stochastic programming requires scenarios of uncertain parameters with their probability distribution function, this normally leads to computationally complex problems. Robust optimization allows the uncertain parameters to be presented in a robust sets, which are generally easier to obtain than probability distribution functions, and less complex computationally problems. Both models are formulated with a static approach where the TEP decicion are made at a single point in time and for a future planning horizon.[21]

The deterministic TEP approach is the used method for PowerGIM in this master thesis. In order to formulate a deterministic TEP planning model binary varibles are necessary in order to determine whether a prospective transmission line is built. In systems with larger number of nodes, the transmission expansion options increases in complexity. Avoiding a complex problem, a static approach is used, similar to the GEP. However, it can be noted that it is generally possible to consider a dynamic approach under deterministic assumptions. The problem is formulated to be most beneficial for the whole power system (the perspective of the TSO). Hence, the objective function is to minimize generation and load-shedding costs, contributing to maximal social welfare for the system. [21]

7.4 Flexible demand

In order to understand a net-zero-emission future power system, it is important to understand the impact of flexible demand. Most renewable energy sources have a varying fixed output, which cause a flexibility problem in the power system as analysed in the specialization project connected to this master thesis. The balance in the European power system have been controlled by fossil power plant, which can adjust to the demand. With a high share of renewable power sources, flexible demand is an essential part in order to balancing the grid.

The conventional power system had the main source of variability from demand, including both intra-day and seasonal variability[22]. In future power system with a high share of renewables, the main source of variability will come from the supply. Meaning that in future power system it will be important to adjust the demand in correlation with supply, which is the meaning of flexible demand. Flexible demand is the opportunity to turn up or down, off or on, electricity consumption in response to external signals[23]. Flexible demand could be divided in three categories:

- Consumption movement - Move the consumption from hours with high spot price to hours with low spot price, which is close in time and without changing the annual consumption. EV charging is an example.
- Consumption reduction - Consumption which is sensitive to high spot prices and not necessarily dependent on a continuous load, for example certain industries.
- Consumption increase - Hours of surplus power could be used for extra production, such as hydrogen from electrolysis or heat from heat pumps.

Flexible demand could e.g be applied to hydrogen electrolysis, industry production, smart storage heaters, heat pumps and EV charging. These components could be adjustable depending on the renewable power generation. At times of high renewable power output these loads would be active in line with the power output, and at times with low power output these loads would be inactive. This is better visualised in Figure 8 made by Aurora making a scenario for flexible demand in 2050.

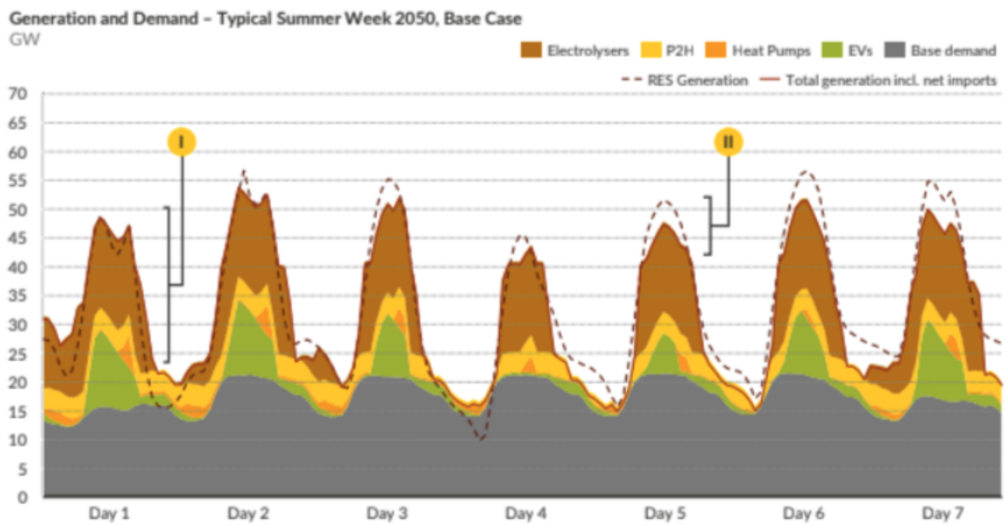

Figure 8: Example of flexible demand technologies on the Dutch power system[24].

The electrolysers, power-to-heat(P2H), Heat pumps and EV are flexible demand in this scenario. The base demand is the remaining load which is not flexible. The red dashed line represent the renewable power generation which is almost in balance with with the demand curve. The continuous red line is the generation including import and export of power to neighboring countries, which balances supply and demand. Interval I shows when power is imported and interval II shows when power is exported. In order to complete the balance, storage possibilities such as batteries could also be utilized instead of import/export of power. This example showcase the importance of flexible demand and how it contributes to balance a power system with renewable energy sources. As well as balance management, flexible demand will have a potential business case. Hydrogen production by electrolysis can be exploit when power prices are low or there is an surplus of power production. This incentive could accelerate the growth of flexible demand.

Statnett's marked-analysis for Europe towards 2050 assume that the existing consumption will decline due to efficient consumption and more energy saving, and that new consumption mostly will be flexible[25]. Figure 9 illustrate the base case of annual demand for EU11 and the expected share of flexible demand in the years to come. The percentage of the flexible demand is later used for case studies in this master thesis.

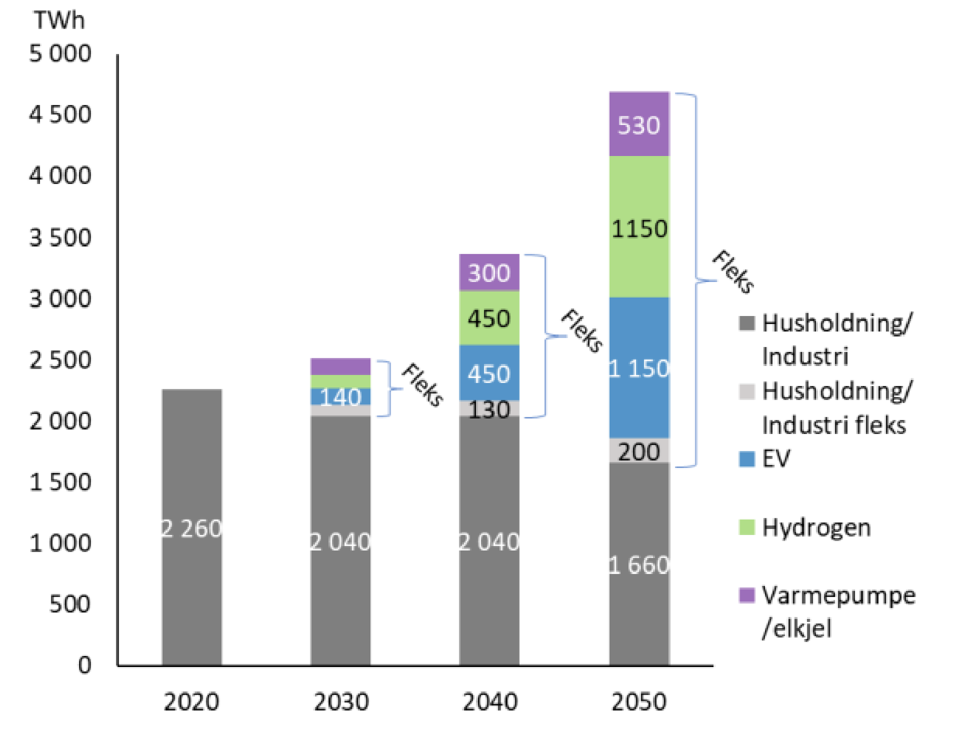

Figure 9: Statnett's projection of flexible demand in future Europe.[25]

The European Commission has targeted a significant growth in green hydrogen production in future years, and expect hydrogen to be a key element in a sustainable future[26]. There is numerous project and initiatives about converting existing fossil fuel production and infrastructure to/for hydrogen. Hydrogen has also the potential to solve problems that electrification does not, such as converting steal production to zero-emission. Hydrogen is useful in a variety of sectors and industries, which makes it favorable in flexible demand. Hydrogen production could exploit surplus power from renewable energy sources. Hydrogen works as energy storage, which is highly attractive for both transportation and industry. Hydrogen could also bring flexibility back to the power grid, by producing power when there is a lack of power from renewable energy sources.[25]

7.5 Linear programming optimization

The simulation model, PowerGIM, used in this master thesis is based on a linear programming(LP) optimization problem which mimics the characteristics of the power system. In order to evaluate the generated results, it is important to understand the basic of linear programming on optimization problems.

LP is one of the simplest ways to preform optimization. The method can help solve large and complex problems by considering a few simplifying assumptions. The concept is based on breaking down complex relationships through linear functions and then find the optimum points. The classic utilization example of LP is on a shortest path problem, e.g., a delivery person must visit ten houses. The technique of choosing the shortest path is called linear programming. LP is used on real-life problems to find the most optimal solution with given constraints, which are formulated as a mathematical model.

There are four essential elements in LP optimization formulation, objective function, decision variables, constraints, non-negativity restriction. The objective function is defined as the objective of making decisions, meaning what is the goal of our problem. This could for example be maximizing profit or minimizing a path. The decision variables are the variables that will decide my output, they will represent the optimal solution. Decision variables could be amount of units produced when maximizing profit, or which direction to choose when finding the shortest path. The constraints are the restrictions or limitations on the decision variables. They usually limits the value of the variables. A production facility will have a limit of how many units it can produce every hour, or a delivery person will have a limit of where to move (road system). The non-negativity restriction are applied to the variables make sure they are greater than or equal to zero. This is to keep the problem linear, which is important for an easier solving process. The objective function, variables and constraints all have to be linear functions.[27] A linear programming problem on standard form are visualized in Figure 10. The variables are defined as x, parameters connected to the objective function are defined as c, and a and b are parameters correlating to the constraints.

$$
\begin{aligned}
&\text{Maximize } c_1x_1 + c_2x_2 + \cdots c_nx_n \\
&\text{subject to} \quad
\begin{array}{r}
a_{11}x_1 + a_{12}x_2 + \cdots + a_{1n}x_n \leq b_1 \\
a_{21}x_1 + a_{22}x_2 + \cdots + a_{2n}x_n \leq b_2 \\
\vdots \\
a_{m1}x_1 + a_{m2}x_2 + \cdots + a_{mn}x_n \leq b_m \\
x_1, x_2, \ldots, x_n \geq 0
\end{array}
\end{aligned}
$$

Figure 10: Linear programming problem on standard form[28]

The simplex method is one of the most powerful and popular methods for linear programming, and it is the applied method for PowerGIM. Simplex is an iterative procedure for getting the most feasible solution. The principle is easy, the variables are altered in every iteration towards a better solution until the optimal solution is found. In simple problems with a small number of variables and constraints, the solution can be found by hand. With a growing number of variables and constraints, the computations becomes exponentially harder. Most real-world LP problems are solved by computers, and some problems becomes larger and more complex for any current computer to solve. For reference, our simplified model consist of some hundred thousands variables and constraints. A standard computer solve this in about four hours. [27]

8 Methodology

Power Grid Investment Module(PowerGIM) is the simulation tool used for this master thesis.[29] PowerGIM is an open-source Python-based optimization model developed by SINTEF Energy Research.[30] The model is based on an optimization problem which is used to represent the North Sea offshore grid. The investment, operation and maintenance costs are minimized in this model. The constraints simulate a high-voltage offshore grid, with all transmission, generation and demand specifications and limits. The model's functionality and all input data are thoroughly elaborated in this section. The utilized sampling method, model improvements and validation of the model will also be described. With PowerGIM the goal is to analyze the generation dispatch, costs and emissions for different scenarios for 2040.

8.1 Input data

The majority of the input data is selected from ENTSO-E Ten-Year Network Development Plan(TYNDP) 2020 Scenario Data, which is a data set contributing to the TYNDP 2020 Scenario Report.[31]. The data is open source with a high level of consistency, which is one of the reasons why this data is chosen. Other sources are implemented where the TYNDP 2020 is missing data. The TYNDP report contains scenarios for the development of the European power grid in 2030, 2040 and 2050. In this master thesis, scenarios for 2040 are chosen. If not differently specified, the mentioned data is selected from TYNDP 2020. In our model of the North Offshore grid, data from the following countries are utilized: Great Britain, Germany, France, Netherlands, Belgium, Denmark, and Norway. The input data includes the basic parameters of a power grid system; Generation type, efficiencies, location and capacity, transmission capacity, operational and maintenance costs, emission costs, variable non-fuel costs and more. A scenario of demand values for each hour every day of the year at each node is given for this simulation. The same applies to renewable sources that are weather-dependent, which follow a time-to-power profile. This gives how much the other controllable generators must produce in order to reach a sufficient supply. When simulating for a generation- and transmission expansion, investments cost for transmission lines and every generator technology are also added. All input data is presented in this section and all tables not presented can be found in the Appendix.

8.1.1 Power system representation

In our model, a simplification of the North Sea power system is applied. There are 25 nodes representing an aggregate supply, demand, and grid capacity at each point. The transmission lines are represented as the total transmission capacity between the nodes. In reality, the transmission system is more complex, but the simplification works with the scope of this thesis. The transmission capacity and the nodes are provided by TYNDP 2020 and presented in Table 24 and Table 25 in the Appendix. A representation of the power system simulated in this model is visualized in Figure 11

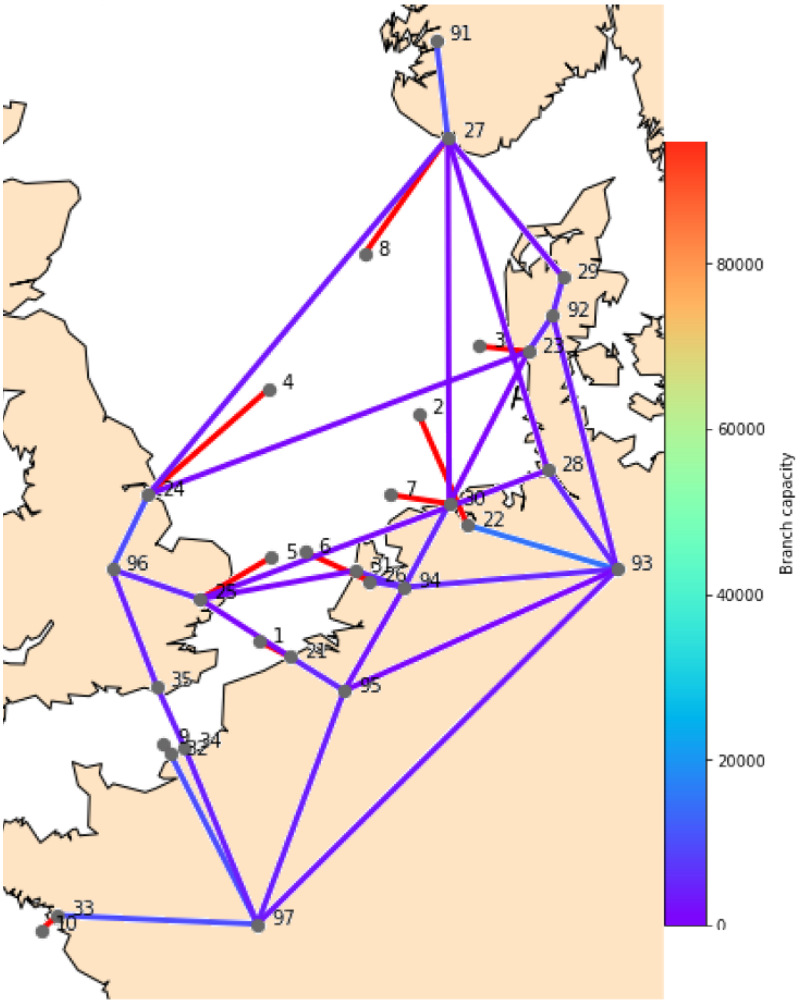

Figure 11: Representation of the offshore North Sea power system used in PowerGIM.The colors visualises the transmission capacity in MW. The visualization is a direct output from PowerGIM.

8.1.2 Generation capacity

The power generation technologies analyzed in this master thesis are solar, on- and offshore wind, hydro, nuclear, gas, coal and oil. There is also a collect category Other RES (renewable sources), including geothermal, biofuel, wave and tidal power generation. Other non-RES include mostly small-scale combined heat and power(CHP) generators. Hydropower is divided into two categories, Reservoir and Run-of-River hydropower. Reservoir hydro includes all hydro with storage capabilities, including hydro with pumping solutions. Run-of-River is all other hydropower generation. Gas generation is divided into three categories: combined-cycle gas turbine(Gas CCGT), open cycle gas turbine(Gas OCGT) and Gas conventional. In the energy transition, it is expected that gas will replace coal and oil options. For this reason, different gas technologies are presented, but coal and oil are simplified into single categories. Bio-fueled generation capacity is not presented as individual capacity in the TYNDP 2020 Report. Certain gas and coal plants are running on gas-bio or coal-bio-based fueled, but the documentation is limited. The result is that bio-fueled generation is indirectly included in coal, gas, Other RES and Other non-RES. The simplification with Other RES and Other non-RES are a weakness in the input data, especially considering biofuel. However, simplification is the trade-off of having consistency in the data from mostly one source. Batteries are included in the list of generation capacities and refers to the aggregated discharge capacity for each country. Even though "Batteries" are listed as generation technologies, it is important note that it is not producing energy. When charging the batteries, it act similar to a load, and when discharging it acts similar to a generator, but the net energy is always zero. The installed capacity for every generation technology at every node is presented in Table 1, and this data is collected from the TYNDP 2020 Scenario Report. [31]

Table 1: Generation input: Installed generation capacity of each generation technology in each country.[31]

Generation Technology	BE	DE	DK	FR	GB	NL	NO
Solar PV	12318	105032	27232	41186	27232	19450	54
Onshore Wind	7130	95401	6329	43855	15508	10100	7948
Offshore Wind	6030	23878	12625	12425	36765	16500	2417
Reservoir hydro	1395	11334	0	11700	4004	0	36061
Run-of-River hydro	148	4036	0	13600	1969	46	0
Nuclear	0	0	0	37239	18552	0	0
Other RES	206	5235	629	2549	4700	540	76
Gas CCGT	7606	15299	430	6552	34986	8651	0
Gas OCGT	292	3250	0	392	2128	642	0
Gas Conventional	787	2627	520	0	57	0	0
Coal	615	0	767	0	3699	3381	0
Oil	158	223	412	0	371	0	0
Other non-RES	1324	20565	497	6533	7432	3770	265
Batteries	950	8114	1021	7122	2130	1737	0
Total	38959	294994	25080	183153	159533	64817	46821

8.1.3 Generation ramping rates

The generators ramping rates are not found in TYNDP2020 report or similar sources, but is collected from a thesis from the University of Waterloo.[32] The ramping rates found in this thesis are given in fraction per minute, meaning how big a fraction of the total installed capacity can be altered in a minute. Therefore these fraction must be multiplied by 60 to match the hourly simulation samplesize. The source include ramping rates for coal, gas, nuclear, hydro and biofuel. Since Other RES consist of mostly biofuel, this generation technology is given the ramping rate of biofuel. Nuclear has a low ramping rate, but it is fixed to zero since nuclear power plants rarely alter power output. Hydro, wind and solar is given 1 as ramping rate, which results in full flexibility. Since the simulation is done on an hourly basis, this is a fair assumption.

Table 2: Maximum ramp-up/ramp-down rate[32]: The rates are given in fraction per minute. The input rates are these rates multiplied with 60 and with the total installed capacity for the given generator. The generation technologies not listed are assumed to have full flexible ramping, with a ramping rate of 1.

Generation Technology	up_i(fraction per minute)	dn_i(fraction per minute)
Coal	0.0093	-0.011
Gas CCGT	0.0081	0.0114
Gas OCGT	0.0119	-0.0123
Gas Conventional	0.0119	-0.0123
Other RES	0.014	-0.012
Nuclear	0	0

8.1.4 Operational and maintenance cost

Operational costs are calculated based on fuel costs and non-fuel operational costs. The fuel costs are calculated by the power plant efficiencies and fuel prices. The fuel prices for nuclear, gas, coal and oil are given in [EUR/GJ]. An added emission cost is based on the CO2 emission factor and the current CO2 price. Data for the emission factor are selected from the U.S Energy Information Administration(IEA)[33] and presented in Table 26. The CO2 emission factors are given in [tCO2/MWh] and are given as average values per electricity generated in OECD countries (Organisation for Economic Co-operation and Development). The CO2 price is found in the TYNDP 2020 and projected in the Global Ambition scenario as 80 EUR/tCO2.[31] The efficiencies for gas generators are found in the TYNDP 2020 Scenario Building Guidelines[34], but the efficiencies for nuclear, coal and oil generation are found in the ASSET project report 2018.[35]. Both generation efficiencies and fuel cost are presented in Table 27. With generation efficiency and fuel costs, the input price can be calculated with equation Equation 1.

$$c_f = \frac{p_{fuel} * 3.6}{\eta_{tech}} \tag{1}$$

where c_f is the input cost, p_{fuel} is the fuel price, η_{tech} is the generation efficiency and 3.6 is added in order to convert from GJ to MWh.

Fixed operation and maintenance(O&M) costs and variable non-fuel costs for all generators are given from the ASSET Project Report 2018[35]. The O&M costs for Gas OCGT and Gas Conventional are assumed to be the same when the ASSET report does not separate them. All costs from the ASSET project report 2018 are presented in Table 3. All renewable energy sources are only dependent on non-fuel-based operational costs since there is no fuel input. Hydropower with storage capabilities is the only exception because the opportunity to store water represents a value. An arbitrary price of 10 EUR/MWh is included in the generation cost of reservoir hydro in all countries except Norway to reflect the added value. A price profile is added for Norwegian hydropower to capture a more precise production, as hydropwer is most of the installed generation capacity in NO. The price profile is elaborated further down in this section. The operational cost for batteries are set as an average of "Large scale batteries" and "Small scale batteries" which is separated by the ASSET project report.

Table 3: Operation and maintenance cost: O&M and variable non-feul cost per electricity produced.[35]

Generation technology	Fixed OandM cost [EUR/MW year]	Variable non-fuel costs[EUR/MWh]
Solar PV	11650	0.00
Onshore wind	16750	0.20
Offshore wind	32500	0.39
Hydro reservoir	25500	0.32
Hydro run-of-river	8200	0.00
Nuclear	108000	7.60
Other RES	47600	0.38
Other non-RES	15000	3.50
Gas CCGT	15000	1.81
Gas OCGT	15000	2.31
Gas Conventional	15000	2.31
Coal	25600	2.40
Oil	20700	2.76
Batteries	9975	0

8.1.5 Investment cost

Analyzing generation expansion, the capital expenditures(CAPEX) for new generators are essential. Investment data is collected from TYNDP 2020 Scenario Building Guidelines Annex 2: "Cost Assumptions for the Investment Modelling"[36]. The CAPEX pricing predicts a high factor of innovation and economy of scale, resulting in a cost reduction in offshore wind and solar technologies. Investments in generation capacity are given in [EUR/MWh] and presented in Table 4. In order to correspond the input data to PowerGIM, all CAPEX values are discounted over 30 years, with a fixed discount rate of 5 percent. CAPEX for hydro, nuclear, coal, Other RES, and Other non-RES is significantly higher than gas, solar, and wind. For this reason, generation expansion of these technologies will not be built and the accurate CAPEX price is not relevant. The CAPEX simplification of Other RES and Other non-RES is not accurate, which has to be considered when analyzing the results of generation expansion. Generation expansion has an default expansion limit of 30 000MW per generation technology per node. In lack of available expansion limits for different countries, this expansion limit is kept.

Table 4: CAPEX: Investment cost is given per relevant generation technology in [TEUR/MW][36].CAPEX is assumed yearly discounted over 30 years with a discount rate of 5 percent.

Generation Technology	CAPEX[TEUR/MW]	Yearly discounted CAPEX [EUR/MW year]
Gas OCGT	440	28623
Gas CCGT	750	48789
Onshore wind	732	47618
Offshore	1345	87494
Solar PV	590	65051

Investment cost for transmission infrastructure in this model are based on the presented methodology in this Electrical power system research[37]. The costs are collected from the National Grid ESO[38] and the input parameters are presented in Table 5 and Table 6. AC/DC converters/inverters have a loss value of 1.6 percent, and the power loss slope of AC and DC technology is 0.005 and 0.003 percent respectively. PowerGIM has an default expansion limit of 4000 MW for AC and 10 000MW for DC per branch, this limit is kept in lack of better data.

Table 5: CAPEX: Investment cost of new branches given by B, B^t, B^{dp} : branch mobilization, fixed- and variable cost [EUR,EUR/km, EUR/kmMW]

Branch Type	B^t[kEUR/km]	B^{dp}[kEUR/kmMW]	B[kEUR]
AC	1193	1.416	312
DC	1236	0.578	312

Table 6: CAPEX: Investment cost of endpoint to new branches is given by C_p^L, C^L, C_p^S, C^S : onshore/offshore switchgear fixed and variable cost [kEUR/km,kEUR]

Branch Type	C_p^L[kEUR/km]	C^L[kEUR]	C_p^S[kEUR/MW]	C^S[kEUR]
AC	0	1 562	0	5 437
DC	93.2	58 209	107.8	453 123
Converter	46.6	28 323	53.9	20 843

8.1.6 Renewable power profiles

The power generation from renewable sources are time-dependent parameters. Hence, our input data are profiles with 8760 values, representing every hour of a given year. For wind and solar, every value is between 0 and 1, representing the percentage of the maximum generation output. Solar and wind data are collected from renewables.ninja website[39]. Three editions of the solar and wind profiles, based on the climate years 1982, 1984 and 2007 are used. The reason is to compare wind and solar generation over different climate years. These years are the same which is those found in the TYNDP 2020. A description of how these profiles are generated are given by Pfenninger and Staffell.[40][41]. For solar PV and onshore wind, country aggregated power profiles are utilized, but for offshore wind, specific profiles for each offshore node location is used. To accurately simulate the wind potential, renewables.ninja require a reference hub high and turbine model. The hub height is set to 140 meters and the V164 9500 turbine model is selected as reference. This turbine is the largest available on renewable.ninja with a rated power of 9.5MW. The turbine properties are intended to reflect an average offshore wind turbine in 2040.

The Norwegian power system and electricity prices are highly dependent on water values of the reservoirs. The water values are affected by weather conditions, current reservoir levels, expected inflow and demand. In order to accurately simulate the Norwegian hydro production, a price profile from 2016 reported by Nord Pool is used[42]. The year 2016 represent a decent average considering price magnitudes and price volatility. The hourly spot price from area NO2 are used since the transmission connection and the node is located in this power electricity zone. The spot price is adjusted for inflation in order match other prices, assuming an annual inflation rate of 2 percent. The year of reported spot prices should be in line with the climate years 1982, 1984 or 2007, but the hourly spot prices for these years are not open-source data. Utilizing hydro prices from 2016 in the model is not ideal, but this is the applied method lacking other simple solutions.

8.1.7 Capacity factors

The capacity factor is a percentage telling us how much power each generator are producing compered with its installed capacity. The capacity factor is calculated by dividing average generation output by installed capacity. A functionality in PowerGIM is the opportunity to constrain the annual average capacity factor of different generators. Constraining the capacity factor of certain generators reduces the flexibility and contribute to more consistent scenarios[43]. In this model, the capacity factor of nuclear, run-of-river and reservoir hydro are modified with a fixed upper limit in order to enhance the model performance. The capacity factor of reservoir hydro set to 30 percent. Setting an upper capacity factor limit is a simplified way to ensure storage characteristics of reservoir, without available water values. Norwegian reservoir hydro is the exception which do not has this limit, as already explained. The limit of 30 percent is based on the level of hydro production in the TYNDP market run[31]. Run-of-river hydro power has a fixed upper limit capacity factor of 40 percent also collected from TYNDP market run. This capacity factor is meant to represent the average hydro inflow, since their are no storage possibilities. A default production profile provided in PowerGIM is included for all installed capacities of run-of-river, taking account for the seasonal variations in inflow. It is worth mentioning that the power profile for wind and solar makes an indirectly limit to the capacity factor of their generators. It is impossible to produce more energy than the energy potential in solar irradiance and wind strength.

Great Britain have measured a capacity factors for nuclear power in the range of 60-80 percent in the past fifty years. In 2018, France reported an annual capacity factor of 77 percent for nuclear power. Based on these findings, it is decided to set a upper capacity factor limit of 80 percent for nuclear in both UK and France. In current state, PowerGIM can not accurately model a battery with a given storage capability in our simulations. For this reason, it is important to give the batteries a capacity limit, which can mimic the storage capacity. These capacity factors for batteries for every country can be found in Table 7.

Table 7: Upper limit of battery capacity factor for each country, except Norway which is assumed to have no battery storage opportunities.[31]

Battery	BE	DE	DK	FR	GB	NL
Capacity factor[%]	11.0	11.6	13.6	9.3	9.3	7.3

8.1.8 Demand

The load profiles are provided by TYNDP 2020[31] and the annual load demand, average load and peak demand for each country are presented in Table 8. The load profile are used in a similar way as the renewable power sources. The load profile consist of 8760 values for every country varying around 1, commonly between 0.6 and 1.4. This value is multiplied with the average demand value in order to get varying load through the year.

Table 8: Demand input: Annual electricity demand, peak load and average load for each country. [31]

Country	Annual Electricity Demand[TWh]	Peak Load[MW]	Average Load[MW]
Belgium(BE)	97.2	14643	11096
Germany(DE)	571.2	82711	65203
Denmark(DK)	59.3	9262	6768
Great Britain(GK)	397.9	62763	45422
Netherlands(NL)	120	17651	13698
France(FR)	502	88029	57316
Norway(NO)	149	27549	17005

Statnett's marked analysis for 2040 estimates that 26.1 percent of annual demand is flexible, not counting EV charging as flexible demand. EV charging is excluded as an flexible demand in this master thesis. The reason is that EV flexibility is only flexible in time periods of hours. EV charging can only be optimized for a couple of hours during the day, but in our power system analysis the flexible demand must endure time periods of days. The flexible demand scenario reduce the original demand by 26.1 percent and add this quantum as flexible demand. The input data for flexible demand is presented in Table 9. The base load plus the flexible load is equal to the average load in Table 8. Of the flexible demand, Statnett estimates that 56.25 percent of this is hydrogen production through electrolysis. These processes are installed adjacent to wind or solar system in order to capture surplus energy at low cost, and research are being done placing this on offshore hubs with offshore wind[44]. The hydrogen production will be further analyzed in the results.

Table 9: Flexible demand input: Base load and flexible demand for each country. The flexible demand is 26.1 percent of the original average demand given by TYNDP2020.[31] [25]

Country	Base load[MW]	Flexible load[MW]
Belgium(BE)	8200	2896
Germany(DE)	48185	17018
Denmark(DK)	5002	1766
Great Britain(GK)	33567	11855
Netherlands(NL)	10123	3575
France(FR)	42357	14960
Norway(NO)	12567	4438

The price level of flexible demand is one of the most uncertain input value in this model, and it will differ from hydrogen electrolysis to industry, but this model assume only one price. Since there is a lack of valid data to set a price, it is unnecessary to split the flexible demand with different pricing. The uncertainty is better accounted for with a sensitivity analysis for the price level. Statnett estimates a price of hydrogen produced through electrolysis(green hydrogen) to be around 40€/MWh H2[25]. Assuming an efficiency of electrolysis of 67 percent[45], the flexible demand price is set to 26.8€/MWh. This implies that if the power price is under 26.8€/MWh, it is profitable to produce hydrogen, which you can sell with a margin at 40€/MWh.

In general, the input data for PowerGIM is reasonable but has some weaknesses, as mentioned in this section. Small changes in the input data may significantly influence the results, especially fuel and other operational costs. The quality of the input data should be considered when evaluating the results.

8.2 Mathematical model formulation

In Table 10 all sets, parameters and variables are described, which is further presented in the optimization problem. The sets and parameters are based on the described input data and the variables are optimized and presented as the fundamental results.

Table 10: Parameters, variables and sets to the optimization model

Sets and Mapping	
$n\epsilon N$	: nodes
$i\epsilon G$	: generators
$b\epsilon B$	: branches
$l\epsilon L$	: loads, demand, consumers
$t\epsilon T$	: timestep, hour
$i\epsilon B, l\epsilon L_n$	: generators/load at node n
$n\epsilon B_n^{in}, B_n^{out}$	: branch in/out at node n
$n(i), n(l)$	: node mapping to generator i/load unit l
Parameters	
a	: annuity factor
ω_t	: weighting factor for hour t (number of hours in a sample/kluster)[h]
$VOLL$	: value of lost load (cost of load shedding)[EUR/MWh]
MC_i	: marginal cost of generation, generator i [EUR/MWh]
$CO2_i$	: CO2 emission costs, generator i [EUR/MWh]
D_{lt}	: demand at load l, hour t [MW]
B, B^t, B^{dp}	: branch mobilization, fixed- and variable cost [EUR,EUR/km, EUR/kmMW]
CS_b, CS_b^p	: onshore/offshore switchgear (fixed and variable cost), branch b [EUR, EUR/MW]
CX_i	: capital cost for generator capacity, generator i [EUR/MW]
P_i^e	: existing generation capacity, generator i [MW]
γ_{it}	: factor for available generator capacity, generator i, hour t
P_b^e	: existing branch capacity, branch b [MW]
$P_b^{n,max}$	: maximum new branch capacity, branch b[MW]
D_b	: distance/length, branch b [km]
l_b	: transmission losses (fixed + variable w.r.t distance(, branch b
E_i	: yearly disposable energy (e.g energy storage), generator i [MWh]
M	: a sufficiently large number
RU_i	: ramp-up rate for generator i [MW]
RD_i	: ramp-down rate for generator i [MW]
V_n	: variable load at node n[MW]
Primal variables	
y_b^{num}	: number of new transmission lines/cables, branch b
y_b^{cap}	: new transmission capacity, branch b [MW]
z_n	: new platform/station, node n [0,1]
x_i	: new generation capacity, generator i [MW]
g_{it}	: power generation dispatch, generator i, hour t [MW]
f_{bt}	: power flow, branch b, hour t [MW]
s_{nt}	: load shedding, node n, hour t [MW]
δ_{nt}	: binary variable which activates a load in node n at hour t if beneficial [0,1]

8.2.1 Optimization problem

PowerGIM takes the perspective of a centralized system operator, meaning the model optimizes social welfare, which benefits the whole system. Maximizing total welfare is the same as minimizing the net present value of the total system cost. The optimization problem is formulated as a mixed-integer linear program with inelastic demand and assumes perfect competition in generation operations and investments. The model formulation is collected from Martin Kristiansen doctoral thesis[46], with the exception of alterations in constraint (7) and the added constraint (14) and (15). The model description is all done by the author of this master thesis.

$$\underset{x,y,z,g,f,s}{\text{minimize}} \quad IC + a \cdot OC \tag{2}$$

$$\text{where} \quad IC = \sum_{b \epsilon B}(C_b^{fix} y_b^{num} + C_b^{var} y_b^{cap}) + \sum_{n \epsilon N} CN_n z_n + \sum_{n \epsilon N} CX_i x_i \tag{3}$$

$$OC = \sum_{t \epsilon T} \omega_t (\sum_{i \epsilon G}(MC_i + CO2_i) g_{it} + \sum_{n \epsilon N} VOLL s_{nt}) \tag{4}$$

$$C_b^{fix} = B + B^d D_b + 2CS_b \qquad \forall b \epsilon B \tag{5}$$

$$C_b^{var} = B^{dp} D_b + 2CS_b^p \qquad \forall b \epsilon B \tag{6}$$

$$\text{subject to} \quad \sum_{i \epsilon G_n} g_{it} + \sum_{b \epsilon B_n^{in}} f_{bt}(1 - l_b) - \sum_{b \epsilon B_n^{out}} f_{bt} + s_{nt} = \sum_{l \epsilon L_n} D_{lt} + V_n \delta_{nt} \qquad \forall n, t \epsilon N, T \tag{7}$$

$$s_{nt} \leq \sum_{l \epsilon L_n} D_{lt} \qquad \forall n, t \epsilon N, T \tag{8}$$

$$P_i^{min} \leq g_{it} \leq \gamma_{it}(P_i^e + x_i) \qquad \forall i, t \epsilon G, T \tag{9}$$

$$\sum_{t \epsilon T} \omega_t g_{it} \leq E_i \qquad \forall i \epsilon G \tag{10}$$

$$-(P_b^e + y_b^{cap}) \leq f_{bt} \leq (P_b^e + y_b^{cap}) \qquad \forall b, t \epsilon B, T \tag{11}$$

$$y_b^{cap} \leq P_b^{n,max} y_b^{num} \qquad \forall b, \epsilon B \tag{12}$$

$$\sum_{b \epsilon B_n} y_b^{num} \leq M z_n \qquad \forall n, \epsilon N \tag{13}$$

$$g_{it} - g_{i(t-1)} \leq RU_i \qquad \forall i, t \epsilon G, T \tag{14}$$

$$g_{i(t-1)} - g_{it} \leq RD_i \qquad \forall i, t \epsilon G, T \tag{15}$$

$$x_i, y_b^{cap}, g_{it}, s_{nt} \epsilon \mathbb{R}^+, \quad f_{bt} \epsilon \mathbb{R}, \quad y_b^{num} \epsilon \mathbb{Z}^+, \quad z_n \epsilon \{0, 1\} \tag{16}$$

The objective function (1) of the optimization problem is minimizing investment cost (2) and operational cost (3) for the total system. When correctly adding investment cost and operational cost, an annuity factor a is needed. The annuity factor is the net present value of future cash flow related to operational cost. In our simulation, a discount rate r of 5 percent and a time horizon n of 30 years are implemented. The annuity factor is calculated with the following formula:

$$a = \frac{1 - (1 + r)^{-n}}{r} \tag{17}$$

The investment cost(2) is considering three potential expenditures. The first part considers transmission expansion. If upgrading existing transmission capacity, only the variable cost(5) apply, while $C_b^{fix} = 0$. When building new transmission lines, both fixed and variable cost apply. The next part considers expanding the grid by investing in new platforms(nodes). Lastly, investing in generation expansion is dependent on the generator technology, which has a fixed capital expenditure.

The second part of the objective function is operational costs (3). ω_t is the number of hours in the sample. Sampling is further elaborated on in section 5.2.2. The marginal cost of generation consists of fuel costs and non-based fuel operational costs, such as maintenance and emission costs. $VOLL$ is the value of the lost load and the load shedding cost. In other words, the cost of not supplying power to a node.

The first constraint describes the nodal energy balance (7). This implies that all supply has to meet demand at every node at all hours during the simulation period. Power generation dispatch, load shedding, import and export with transmission losses are equal to the demand in each node. D_{lt} represents the load profiles given for every hour of the year at each aggregated country. V_n is the flexible demand which activates when the spot price is lower than a set trigger price. Constraint (8) ensures that the load shedding at each aggregated country does not exceed the total demand at any hour during the year.

Further, there is the maximum/minimum generation limit constraint (9). Generators have to comply with the physical limitations and resources available. The upper limit is the existing generation capacity and the possible new generation capacity. The upper limit is also multiplied with a factor γ_{it} which varies between 0 and 1. This factor is relevant for renewable energy sources, where the upper limit is dependent on energy inflow. There is no time-dependent ramp variable in this constraint, meaning that the generation may change instantly, which is unrealistic for most generators.

Constraint (10) restricts the producers from producing more than the yearly disposable energy, implemented as fixed capacity. This constraint is primarily relevant for storage units, typically hydropower, where the production is limited by the amount of energy stored in the reservoir.

The following constraint is the power flow constraint (11), limiting the transmission capacity and accounting for transmission expansion. The power flow can not be higher than what the transmission corridors are built for, which applies to power flow in both directions. Constraint (11) ensures that new transmission capacity is held under the maximum for new branch capacity. The last constraint x(12) is needed when new nodes, e.g., offshore platforms, need to be installed. The binary variable z_n is forced to be one if new branches are built with no existing nodes.

Constraint (14) and (15) are the ramping constraints, which controls the generators flexibility from one hour to the next. Constraint (14) ensure that generators output are less than a certain ramp-up rate compared to the hour before. The ramp-up rate are given in [MW] and calculated of a percentage of the total capacity of the specific generator. The same apply for constraint (15) only it considers ramp-down. The first hour in the simulation is neglected from the ramping constraint due to index use of (t-1).

8.2.2 Sampling

PowerGIM used in this master thesis initially runs 8760 simulation, representing every hour of the year, each simulation including thousands of variables and constrains. The input data of solar, wind, hydro and demand consist of values for every hour and all these values are represented at every node. When the model optimizes the power system 8760 times, the simulation time is between 4-24 hour, depending on expanding requirements. In order to reduce the simulation time, a sampling method of the data set is applied. Figure 12 illustrates the sampling of the data, with the complete data set represented to the left and the reduced set to the right.

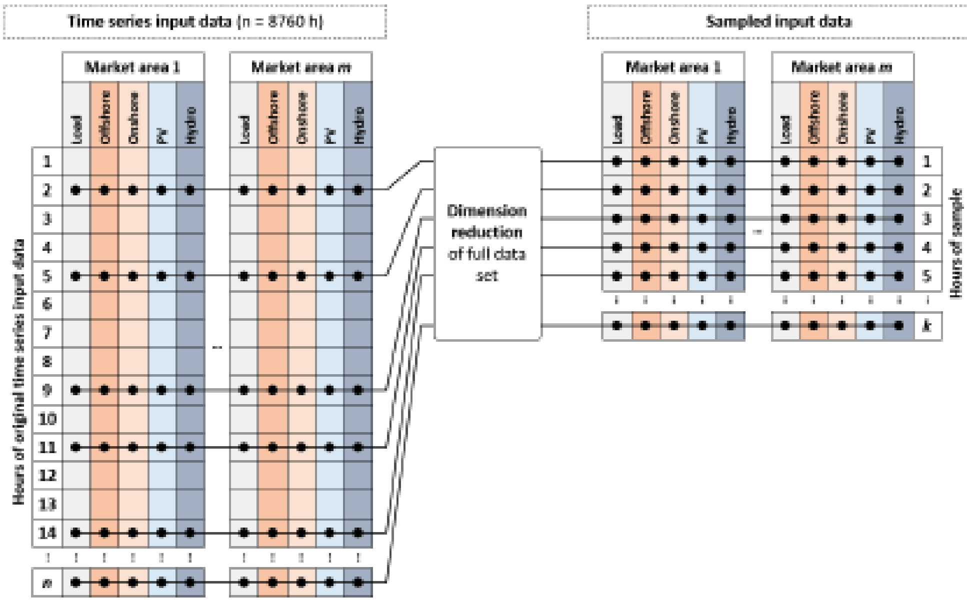

Figure 12: Illustration of sampling method used to compress input data[47]

The sampling clusters are selected randomly, and the number of k represents the number of sampling clusters. The mean value of the data within a sampling cluster will be used in the model and be represented as single values in the sampled input data set. When compressing the data, it is essential to find the balance of a reasonable simulation time without changing the characteristics of the data. Each subset is a random sample of the complete data set. According to another paper utilizing the same sampling method, to maintain a robust solution with the same characteristic, at least 400 such subsets are needed.[48] The paper presents the divergences between the number of sampling clusters and accurate results. This divergence is around 400 sampling clusters, meaning that 400 samplings will give a viable result. In this master thesis, a reduction to 1000 sampling clusters is applied, resulting in a simulation time of around 1-4 hours.

8.2.3 Model modifications

Batteries as storage units are not an original functionality implemented in PowerGIM. Storage opportunities are essential components in the development of future power system and is necessary to simulate realistic results. Batteries are simulated as a new generation technology which are able to "produce" positive and negative power, meaning that the generation also has a negative installed capacity. These battery generation technology are connected to the aggregated consumption node for each country through a transmission line. These transmission lines have a fixed power loss of 10 percent in each direction, which represent the round trip losses in batteries of 20 percent. To make sure that the amount of produced and consumed energy are the same, a power balance set to zero is added. To ensure a reasonable energy storage capacity, the batteries are implemented with a annual average capacity factor presented in the input data. This combination simulates the effect of batteries in a larger power system.

The original model had full flexibility for all generators, meaning that e.g a coal generator could produce zero power at one hour and maximum power the next hour. In reality, all thermal generator needs time to alter the power output. This is mainly due to the time it takes to change the heating temperature in the power plants. Since PowerGIM originally did not consider this, the simulated power system became unrealistically flexible. By adding one ramp-up and one ramp-down constraint to the model, this inaccuracy is now accounted for. The ramping applies to the thermal power plant such as coal, gas, oil and nuclear. Nuclear power is set with zero ramping capability in our model. It is possible to alter the power output in nuclear power plants, but in reality most nuclear plants run at a steady rate. Hydro power is easily altered and considered fully flexible in this model, along with the renewable energy sources.

A higher share of renewable power production improves the business case for flexible demand. The extra flexible demand prevents the capture price of wind and solar from dropping to zero hours with high renewable production. Adoption of flexible demand reduce the flexibility problem in the power system and support the growth of more renewable capacity. PowerGIM is improved with the opportunity of flexible demand, meaning that extra demand is activated when the spot price is low. The extra demand can e.g be heat pumps or electrolysis producing hydrogen. The flexible demand is implemented similar as the battery. A new generation technology "flexible demand" with max capacity of zero and minimum capacity as the negative of the flexible demand capacity is added. This generation technology is given a marginal cost equal to the break point of when the flexible demand should be active and not. PowerGIM is adjusted such that e.g if the marginal cost of flexible demand is set to 10€/KWh the flexible demand is active when the spot price is lower than 10€/KWh and not active otherwise.

8.2.4 Case study

The main objective of the master thesis is to analysis optimal generation expansion of the North Sea power system in 2040 in scenarios with flexible demand effects and zero-emissions requirements. The analysis consist mainly of annual power production for each generation technology in each country, capacity factors, share of RES, electricity prices, investment and operational costs, emissions, GEP&TEP and flexible demand management. In order to get a complete overview, four different scenarios are simulated, investigated and compared. The first scenario is the reference case, which is the results of a simulated year without, GEP&TEP, flexible demand or net-zero requirements. The second scenario is investigating GEP&TEP and comparing it with the reference case. The third scenario will also include flexible demand management and will analyse the effect on the flexibility problem of the power system. Lastly, the fourth scenario will investigate a zero-emission case with and without installed nuclear power capacity. The last scenario will also be done with and without flexible demand in order to investigate its effects in a zero-emission scenario. A sensitivity analysis of flexible demand prices, weather profiles and investment cost will also be done, in order to reflect on the uncertainty.

8.2.5 Model validation

A simple validation of the PowerGIM model is executed to ensure that the model behaves as expected and highlights deviations and uncertainties. In order to validate, the base PowerGIM results and the TYNDP 2020 results are compared. This is reasonable because most of the input data in PowerGIM is taken from the TYNDP 2020 report. Input data from external sources are also used in PowerGIM, which will result in additional deviation, but the goal is not to replicate a perfect result. The purpose is to confirm that the model is within a reasonable margin of error. Including the comparison, significant simplifications and assumptions not mentioned in the input data, are also highlighted in this section.

Each country's resulting annual power production is generally similar with the same characteristics for both models. The general energy mix is inside a reasonable margin of error but has some repeating deviations. All countries with an installed capacity of reservoir hydro have a slightly higher production in PowerGIM compared with the TYNDP 2020. The reason is the lack of accurate water values, which results in a lower marginal price of production, leading to higher hydropower production. Further, overall increased wind power production is observed corresponding to a decreased production of fossil-fueled generation in PowerGIM compared to TYNDP 2020. The difference is not significant and will not make a big impact on the results. The reason is probably the addition of operational costs and CO2 costs taken from external sources. This might result in a higher marginal cost of operation, which will favor renewable power production. These differences will also affect the electricity prices of the power system. The electricity prices calculated from PowerGIM are generally higher than the obtained values from TYNDP 2020, which makes sense with the difference between wind and fossil-fueled generation. Nuclear power production is also higher in PowerGIM compared with the TYNDP scenario. Nuclear power production is a significant part of the energy mix in both Great Britain and France. The reason is due to the low marginal operational cost of nuclear. Higher penetration of nuclear may change the energy prices and the system's power flow, which must be considered when evaluating the final results. A direct consequence of the high nuclear penetration is the direction of power flow between Great Britain and Norway. In the TYNDP 2020, Norway is a net exporter of energy to Great Britain. In PowerGIM, due to the high nuclear penetration, the net power flow is in the direction from Great Britain to Norway. This means that the nuclear from Great Britain is competitive with the Norwegian hydropower for the majority of the year.

The input data of both nodes and transmission lines are a significant simplification of the real-world power system. This model assumes that all generation and load are produced and consumed at the aggregated national node. In reality, load and generation nodes are spread across the countries, and all internal congestion and power losses are not considered with the aggregated nodes. The onshore transmission lines are also merged and will not reflect the actual congestion between countries but a less accurate overall capacity limit. A more detailed power system would represent a more realistic model, but the model would also be significantly more complex. Less accurate results are the trade-off for a simplified model, and considering the scope of this master thesis, a detailed power system is not necessarily needed. There are numerous assumptions behind the scenario 2040 input data, making accuracy less critical.

In our simulation model, only seven countries are considered, which exclude the remaining parts of the European power system. In reality, the surrounding countries do trade energy with the respective countries. Excluding the rest of Europe gives unrealistic power flow and electricity prices. Including more countries will again complicate the model and might be unnecessary when those countries are outside the scope. A possible midway is to add average external load and generation, which will simulate other countries' influence on the relevant countries.

9 Results and Discussion

The results and discussion will be presented in this section. The results will highlight annual power production, capacity factor, renewable share, average baseload prices, emissions, investment and operational costs for different scenarios. Batteries, flexible demand and net-zero-emission effects will be presented in belonging scenarios. The results are based on direct output data from PowerGIM with the given input data. This section are constructed of four main scenarios and a sensitivity analysis. Visualizations will be included where relevant, and extra results can be found in the Appendix. Observations and direct comparison will be described with the presentation of the results, reflections will be elaborated in the discussion.

9.1 Results

9.1.1 Reference scenario

The reference scenario simulates the power system without GEP&TEP, flexible demand or net-zero-emissions requirements. The intent is to have a basic evaluation of the results and have a comparison basis for the other scenarios. This simulation is also necessary to highlight basic deviations and evaluate that the model behave as expected. The annual production of every generation technology at each country is visualized in Figure 13. Accurate annual production values are found in Table 29.

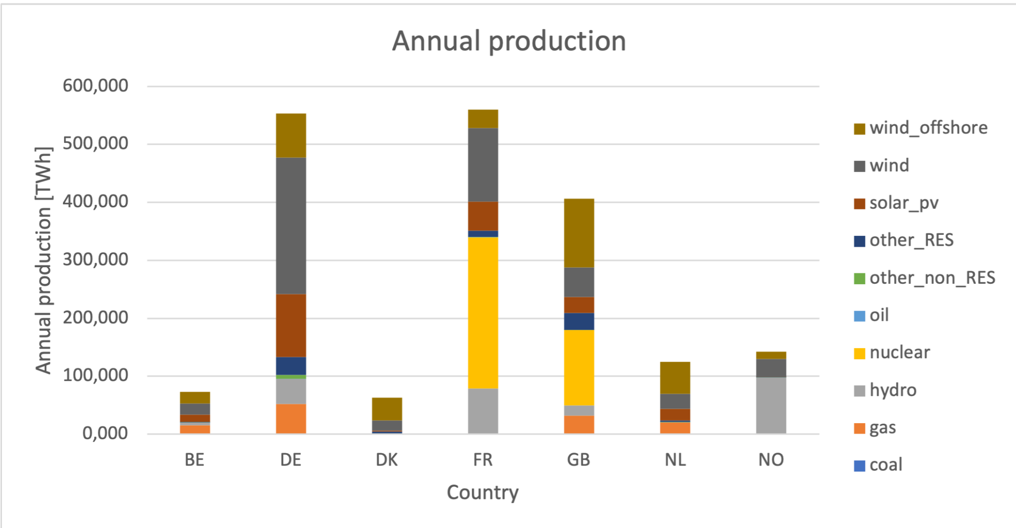

Figure 13: Annual power production given for every country by generation technology, reference case. Power production is given in TWh.

The results show that wind, solar, nuclear, hydro, and partly Gas CCGT and Other RES has the most significant share of power production in the North Sea power system for 2040. If compared with the NVE report reviewed in the Literature Review, the growth of wind and solar and general energy trend are corresponding. The exception is the share gas power production, which is significantly higher in the NVE report. The reason could be that NVE is predicting for the whole Europe, and this master thesis is just considering seven specific countries. Nevertheless, the annual power production results are reasonable. When observing the annual energy demand of each country compared to the annual production, it tell us which countries are energy exporters and importers. The annual energy demand are part of the input data found in Table 8. The comparison shows that Belgium, Germany and Norway are all net energy importers, meaning that they consume more energy than they produce over the year. Denmark, Great Britain, the Netherlands and France are net energy exporters and produce more power than they consume. It is observed that the base load of nuclear power in Great Britain and France makes them less dependent of surrounding countries. Germany have around 75 percent of their power from wind and solar and are in periods highly dependent on energy import from other countries and their own gas power production. However, Denmark is a net energy exporter and have approximately 89 percent of their energy from wind power. Similar to Germany, Denmark is in periods dependent of imported energy and are producing power from both gas, coal and oil. The reason Denmark is a net energy exporter is that their total wind power production is significantly higher compared with the demand, this is not the case for Germany. Further, is it observed the total annual power production for the whole system is approximately 27 TWh higher than the total annual power consumption, which is expected due to transmission losses. Figure 14 are visualizing the share of renewable power production compared to the countries total generation and consumption.

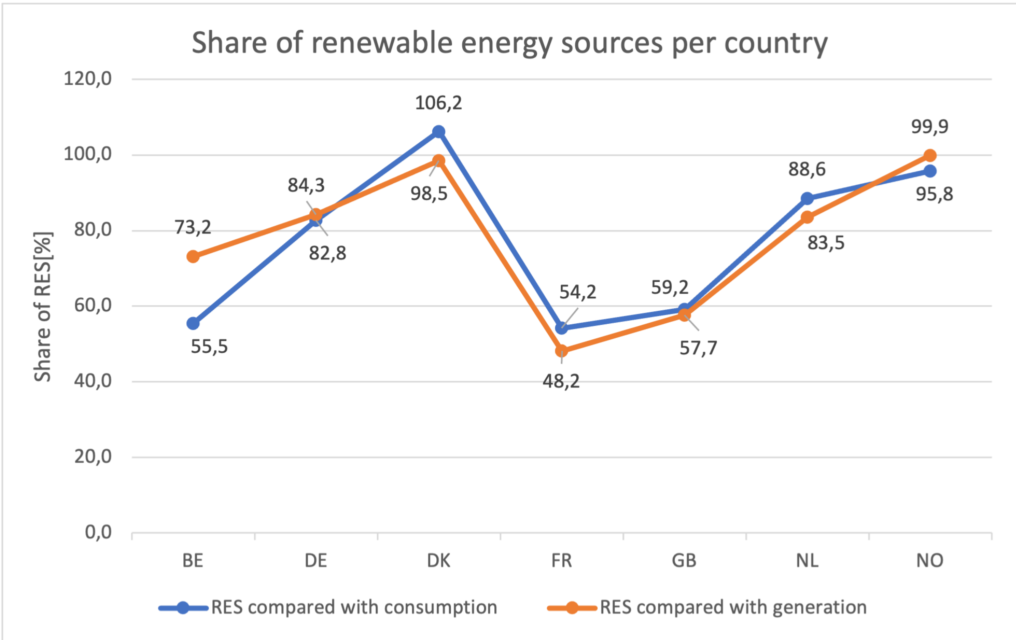

Figure 14: Share of renewable energy sources per country

The orange line represent the share of RES of the total power generation in each country. Nuclear power is not considered as a RES, which explain the low percentage of FR and GB. DK and NO has close to 100 percent of their production from RES, which correspond to the annual power production in Figure 13. The blue line represents the power production from RES compered to the countries consumption(RES production divided by consumption). This visualization confirms the net energy importers/exporters. If the RES share is higher for generation than consumption, the country is a net energy importer, and exporter if not. This is key when analysing the RES% of actual consumption. For energy importers, the RES% of actual consumption can be interpreted as the RES share of consumption, assuming all imported energy comes from non-RES. If all imported energy comes from RES, the RES share of consumption will be the same as RES share of generation, assuming no export of non-RES(all countries import and export in different periods).

In reality, the imported energy is a mix of RES and non-RES, which puts the actual RES share of consumption somewhere in between for net energy importing countries. For net energy exporting countries, the same interpretation can not be applied. For example, it is observed that DK has an RES% compared to consumption of 106,2 percent. This means that DK is producing more power from RES than their total consumption. Nevertheless, the RES share of consumption is not a 100 percent due to certain periods with low RES production and active non-RES. The actual RES share of consumption require a complete power flow analysis for the whole year, but this visualization gives a fair estimate. The total RES share for the reference scenario is at 72.9 percent

The reason why non-RES is not phased out completely is due to the flexibility need. All RES, except reservoir hydro, have a variable power output, which makes it difficult to match demand and supply of power at every hour. This is why controllable power sources such as gas is needed. The following scenarios will most likely optimize for flexibility as the most cost-beneficial solution.

The capacity factor is a percentage telling us how much power each generation technology are producing compered with its installed capacity. The capacity factor is calculated by dividing average generation output by installed capacity. All capacity factors for each generation technology in each country is found in Table 32 and a visualization is given in Figure 15.

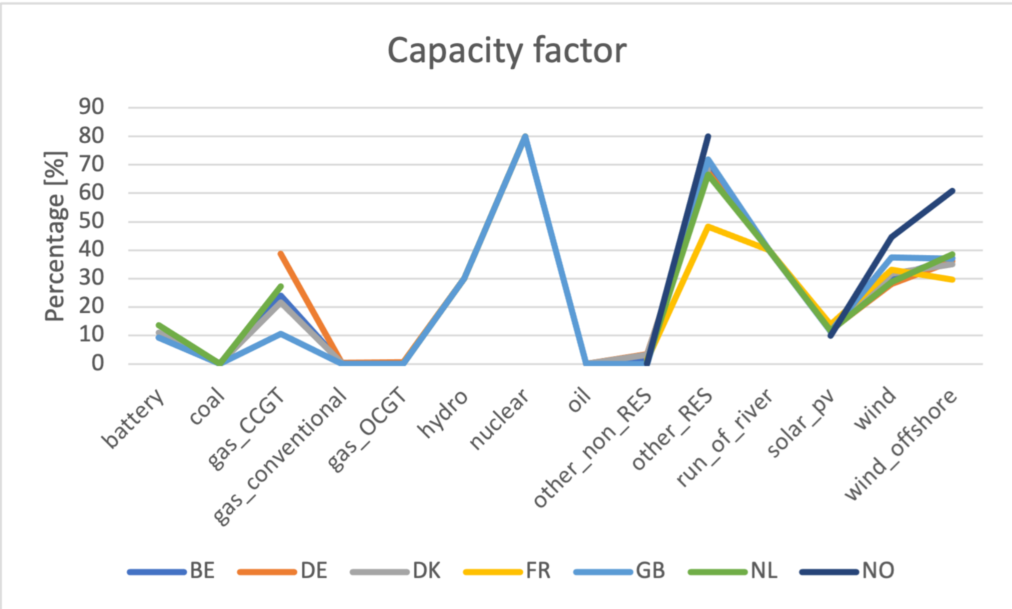

Figure 15: Capacity factor given for every country by generation technology

It is observed that certain generation technologies have zero or a close to zero capacity factor, meaning that actual production is minor compared to the installed capacity. For example, coal has installed generation capacity in Belgium, Denmark, Great Britain and the Netherlands. However, only Denmark and the Netherlands produce energy from these coal plants, and the energy produced is on average 1 and 0.23 percent of the installed capacity in the respective countries. This means that power generation from coal is almost phased out. The same applies to oil, Gas conventional and Gas OCGT, which have similar low capacity factors. These generation technologies have too high operation costs to compete in the electricity market, which explains their low capacity factors. The discontinues parts in Figure 15 is due to no capacity installed. There is important to differentiate having a capacity factor of zero and no capacity factor.

Notice that technologies such as hydro and nuclear have consistent capacity factors across the countries. The only exception is Norwegian hydro which have a capacity factor of 31.1 percent instead of 30 percent. This different is due to Norwegian hydro prices are following a price profile. The rest of hydro and the nuclear power has a fixed power output, which explain the consistency in the capacity factor. Gas CCGT has a high degree of deviation in their capacity factor, varying from 38.7 percent in Germany to 0.3 percent in France. The capacity factor of gas is a indication of the countries flexibility need. This is because Gas CCGT has the cheapest controllable power production. Solar is mostly consistent with a capacity factor of around 12 percent, with the exception of France and Norway, which have factors around 14 and 10 percent, respectively. This is due to the variation of solar irradiation in the different countries. The same applies to wind generation, where Norway has a significantly higher capacity factor than the other countries. This will be important when GEP is considered.

The capacity factor of batteries are a little different then the generation technologies. The capacity factor can be measured in both power output or energy storage. The capacity factor of the power output is put beside the other generation technologies. This is calculated the same way as the generation technologies and only tells the used potential of max charging and discharging. It does not tell anything about the energy storage capabilities and how much of the energy storage potential is exploited. The energy storage is limited by an power average for batteries given in the input data. This power average matches the resulted capacity factor of power output. This mean that the model maximizes the potential of the energy storage limit.

The model presents power prices for every hour during the year, the average base load prices for each country is found in Figure 16, which indicates how much consumers in certain countries are paying for power. Low power prices are due to a stable power system with saturated energy need coming from generation technologies with low marginal costs. High prices could indicate lack of power supply and high marginal costs on energy production.

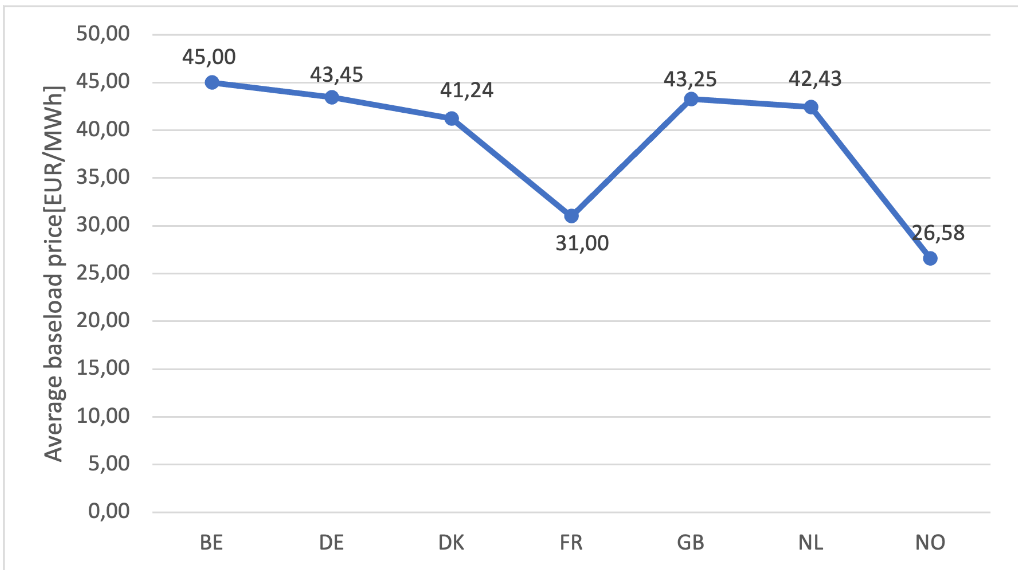

Figure 16: Visualization of average baseload price for each country.

NO and FR has the lowest prices on average. NO has hydropower which varies in price, in certain periods is it cheaper for NO to import energy from other countries, and in other periods when NO has surplus energy, the energy is exported. In this model will export/import of energy always be beneficial for NO and lead to lower average prices. Since the model is not considering water values will exported energy from NO not drive up the power prices. However, this only gives unrealistic results if NO export considerable amount of energy, which it does not in this scenario. FR has low prices due to relative cheap nuclear power and surplus energy, which means that FR may sell when prices are high and buy when they are low. DK also has surplus energy, but the wind power is not controllable. DK is dependent on the surrounding countries and are often "forced" to sell on lower prices and buy in higher prices. BE has the highest prices mostly due to their high energy import need. BE has the lowest share of power production compared with consumption. In general, the average prices are reasonable compared with the predictions done by Statnett of continental European prices of 35-60 EUR/MWh in 2040[25].

The annual emissions are trivially following the annual power production of the polluting energy sources, which are coal, oil, gas and Other non-RES. Gas and partly Other-non RES are the main sources of emission in the North Sea European power system for 2040. The total amount of emission by source and country are given in Figure 17. The emissions are only accounting for power generation and not the total emission of entire countries. Accurate emission values are found in Table 35 in the Appendix.

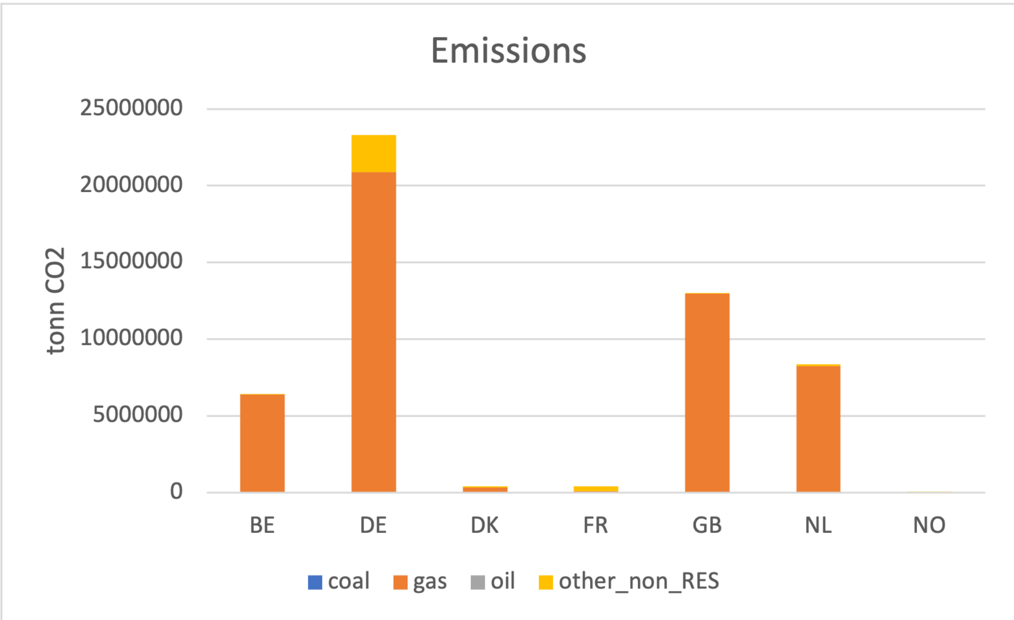

Figure 17: Visualization of annual emissions from power production given for every country by the polluting energy sources.

As mentioned with the annual power production, Germany has the highest flexibility issue, and has the highest need for gas power production. As expected, Germany has the highest annual emissions followed by Great Britain, the Netherlands and Belgium. 99,7 percent of the gas emissions are emitted by the Gas CCGT variant. This showcase the small fraction of Gas Conventional and Gas OCGT, their contribution are so small that it could be neglected. Norway has close to zero annual emissions, with only a tiny fraction generated from Other non-RES. The total annual emissions in our reference scenario are approximately 51.87 million tons CO2, where Germany stands for 44.90 percent of the total emissions. Gas CCGT are the main pollution generation technology making up 93.4 percent of the total emissions. It is worth mentioning that gas still has the lowest emission factor, and are only the main polluter because it is a better alternative compared with coal and oil.

There is no investment cost related to the reference scenario since no new generation or transmission capacity is built. The total operational cost is approximately 272,45 billion euros, equivalent to 143.65 euros per MWh delivered. The operational cost consist of fuel costs, emission cost, fixed O&M cost, and non-variable fuel, which are mostly related to non-renewable energy sources. For reference, with a CO2 price of zero, the total operational cost would be reduced by approximately 59 billion euros.

9.1.2 GEP&TEP scenario

The following scenario has the same base as the reference case, but allow for generation and transmission expansion. It is observed that only TEP is valued as beneficial in this scenario, which is interesting. The specialization projected connected to this master thesis, had a similar scenario without a modified PowerGIM, which resulted in GEP as well. The main reason is probably the inclusion of batteries, which makes the power system much more flexible. The TEP results in a higher degree of utilization of RES and lower usage of operational expensive generation technologies. Since the demand is satisfied by the power production, no added generation is needed. Without TEP or with a higher CO2-price, the results would have included GEP, as a RES or gas CCGT would have substituted more expensive types of generation. A sensitivity analysis of CO2-prices was investigated in the specialization project. GEP will be more investigated in the net-zero-emission scenarios. This scenario will investigate the TEP effects on the power system, which is important to keep in mind. Table 11 shows the expanded transmission lines by location and capacity.

Table 11: Resulting transmission expansion, GEP&TEP scenario

From node	To node	Type	Existing capacity MW	Expanded capacity(MW)
23,DK	92,DK	AC	5 000	3 876
24,GB	96,GB	AC	10 000	4 000
26,NL	94,NL	AC	5 000	1 191
27,NO	91,NO	AC	10 000	3 855
30,NL	94,NL	AC	5 000	1 247
27,NO	28,DE	DC	1 400	3 847
27,NO	29,DK	DC	1 640	2 706
27,NO	30,NL	DC	700	1 047
23,DK	30,NL	DC	700	533
31,NL	25,GB	DC	1 000	101
21,BE	25,GB	DC	1 000	409

A large amount of transmission capacity has been built both internally and between countries. Denmark, Great Britain, Norway and the Netherlands has the highest increase of transmission capacity. GB reach the default maximum capacity expansion of 4000MW. DK and NO has increased their internal transmission capacity by 78 and 39 percent. The model also show that it is beneficial with external transmission expansion, especially connected to NO. This is most likely with the benefit of hydropower in a power system witch needs more flexibility. A more optimal exploitation of RES is the main reason for this TEP, which is shown by the annual power production in **??** in the Appendix. Table 12 shows a comparison of annual production for each generation technology between the reference and GEPTEP scenario.

Table 12: Comparing annual production by generation technology for reference and GEP&TEP scenario.

Generation tech	Reference [TWh]	GEP&TEP[TWh]	%
coal	0,017	0,002	-90,313
gas	122,142	83,999	-31,229
hydro	242,245	253,902	4,812
nuclear	390,983	390,983	0
oil	0,003	0,000	-94,625
other_non_RES	7,481	4,637	-38,008
other_RES	80,061	77,093	-3,707
solar_pv	220,521	220,491	-0,013
wind	506,065	507,060	0,197
wind_offshore	354,148	389,217	9,902
Total:	1923,683	1927,386	0,193

It is clear that the need of non-RES is decreased since extra transmission can compensate for the flexible generation. With additional transmission offshore wind and hydro is exploited in a better way. This means that offshore wind experienced curtailment in the reference scenario. Curtailment is loss of potentially useful energy. Norwegian hydro has increased their power production by 11.2 percent, making Norway an energy exporter instead of importer. The original power grid had a lower limitations of how much NO could export in a given hour, which again limited the amount of hydro power produced. Hydro power in the other countries have a fixed output and therefore no change is observed. Coal, oil, gas and Other non-RES have seen the biggest decline in power production. The operational cost are too high, and the power system has less of a flexibility problem compared with the reference scenario. The increase of offshore wind is observed in DE, GB and NL which previously had transmission capacity limitations. The total amount of power production has increased by 0.2 percent, which is due to higher transmission losses in a scenario with more power flow.

The total RES share for GEP&TEP scenario 75.4 percent, which is an increase of almost 3 percent compared with reference scenario. The small percentage increase is because nuclear has a large share and is counted as non-RES here. The difference can be observed in Figure 18, where DK and NO and has the biggest visual differences. Less changes in the larger DE,FR and GB makes the total reduction of non-RES less significant.

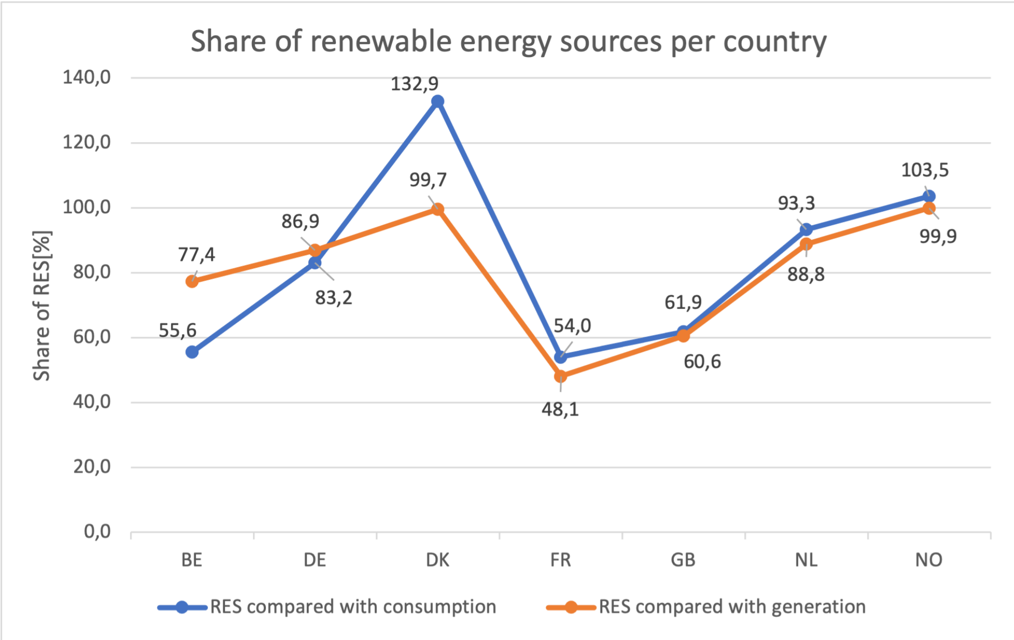

Figure 18: Share of renewable energy sources per country in GEP&TEP scenario

Optimizing for cost-beneficial solutions has resulted in a significantly lower average power price, as seen in Figure 21. The prices has on average decreased of 17.2 percent for all countries in GEP&TEP scenario. As observed, DK has the highest price decrease of 32.0 percent. The reason is due to the higher offshore wind power output and better exploitation of the varying energy sources. Even DE which now has a higher degree of imported energy are seeing lower power prices. A high share of RES with low operational costs and added transmission lines are benefiting the whole integrated power system. Contradictory to certain beliefs in the general public about new external transmission lines in Norway today.

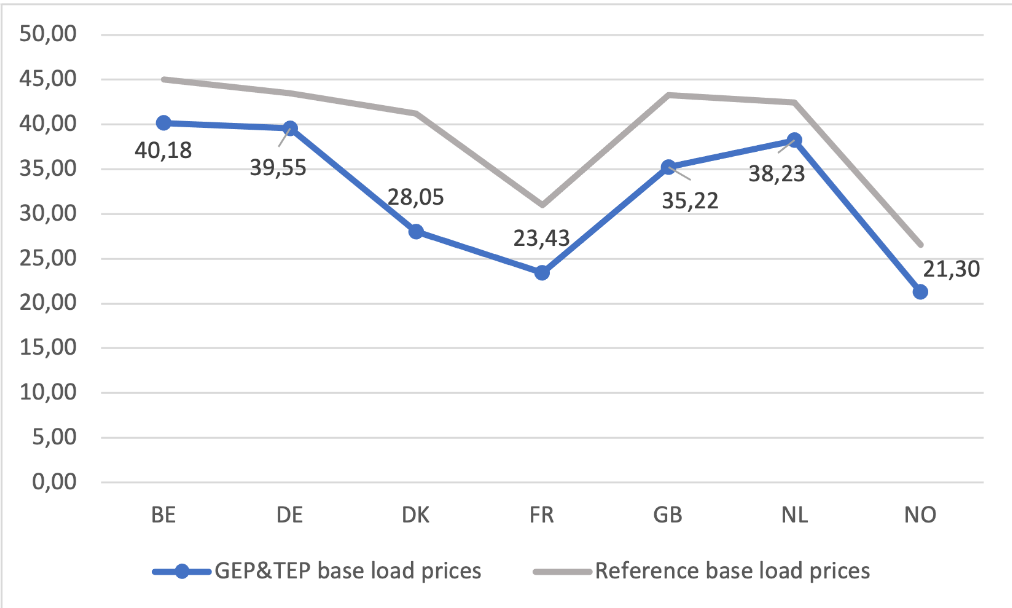

Figure 19: Visualization of average baseload price for each country in GEPTEP scenario.

Emission has dropped considerably as seen in Table 13, which follows the reduction of non-RES. This showcase how important it is to exploit the power production in the most efficient way. All countries see a significant reduction except NO which still has close to zero-emissions. The small part of emissions from NO comes from Other non-RES, which in a short period during the year is more cost-beneficial than hydro power. The hydro power follows the same price profile, which is why the emission amount is exactly the same. In order to change this, an other price profile or CO2-price must be applied. A total reduction of 31,5 percent emissions is significant considering the a investment cost of transmission of 20,6 billion euros.

Table 13: Comparing annual emissions by countries for reference and GEP&TEP scenario.

Country	Reference [tCO2]	GEPTEP[tCO2]	%
BE	6 438 170	4 837 819	-24,86
DE	23 292 133	16 709 753	-28,26
DK	395 156	109 424	-72,31
FR	409 544	341 336	-16,65
GB	12 958 023	7 832 809	-39,55
NL	8 371 931	5 624 201	-32,82
NO	806	806	0
Total	51 865 762	35 456 147	-31,64

Optimizing the distribution of RES and reducing power production of non-RES gives a significant reduction in operational costs. The operational costs are reduced with approximately 15 percent compared with the reference. Even considering the investment cost of over 20 billion euros, the total cost is reduced with almost 8 percent. This results in a price of 132,5 euros per MWh delivered.

Table 14: Investment and operational cost GEP&TEP case

	Value	Unit
Total operational cost	230,83	10^9 EUR
New transmission investment cost	20,62	10^9 EUR
Total cost	251,45	10^9 EUR
Total cost per MWh delivered	132,60	EUR

9.1.3 Flexible demand scenario

The flexible demand scenario include GEP&TEP and substitute 26 percent of the demand into flexible demand. When comparing this to the reference and the GEP&TEP scenario, the significant of flexible demand becomes clear. Table 15 presents the transmission expansion for this scenario, which is considerably less than the previous scenario.

Table 15: Resulting transmission expansion, flexible demand scenario

From node	To node	Type	Existing capacity (MW)	Expanded capacity(MW)
23,DK	92,DK	AC	5 000	3 799
24,GB	96,GB	AC	10 000	2 111
26,NL	94,NL	AC	5 000	388
27,NO	29,DK	DC	1 640	1 741

Denmark has noticeably the most added transmission, both internally and between Norway. The model has found new transmission in DK, GB and NL most beneficial in order to exploit most of the offshore wind, which earlier were limited by the transmission. However, much less transmission is needed due to the flexible demand, which contributes to balancing the grid.

Interestingly, in this scenario it is cost-beneficial to expand onshore wind generation in NO. Offshore wind has a higher capacity factor, but comes with a higher CAPEX as well. In this scenario, onshoer wind will give the lowest cost per MWh produced. The generation expansion results in an increase of 15 percent of NO onshore wind installed capacity. Even with a investment cost of 1.542 billion euros, the operational savings compensate for this investment. More details around operational costs are presented further down in this section.

Table 16: New installed generation capacity, flexible demand scenario

	Onshore wind(NO)
Expanded capacity(MW)	1 192
Increased onshore wind(NO) capacity(%)	15
Investment costs(10ˆ6 EUR)	1 542

With flexible demand the power systems flexibility issue with RES is reduced, and additional RES can be added without increasing the problem. This is the reason why no GEP found place in the GEP&TEP scenario, but in this scenario it did. It is extremely difficult to reach a 100 percent RES with the flexibility conditions in the GEP&TEP scenario. Flexible demand make the transition realistic.

With a threshold price of 26.8€/MWh, the total flexible demand is on average active 75,4 percent of the hours during the year. This means that the total annual demand is reduced by 6.5 percent compared with the reference. Ideally, the base load should be increased such that the total annual demand is more or less the same. Nevertheless, this is a detail which do not affect the scope of this master thesis. It can be argued that flexible demand is a more efficient use of demand, which can make the total demand reduction realistic. However, the main goal of the flexible demand is to balance the grid. In Figure 21, the amount of active flexible demand is compared with the installed flexible demand capacity. DE has an active flexible demand at 60 percent, which means that the power price in DE is under 26.8€/MWh 60 percent of the time during the year. This tell us that the visualization should follow similar trends as the average power price for the specific countries.

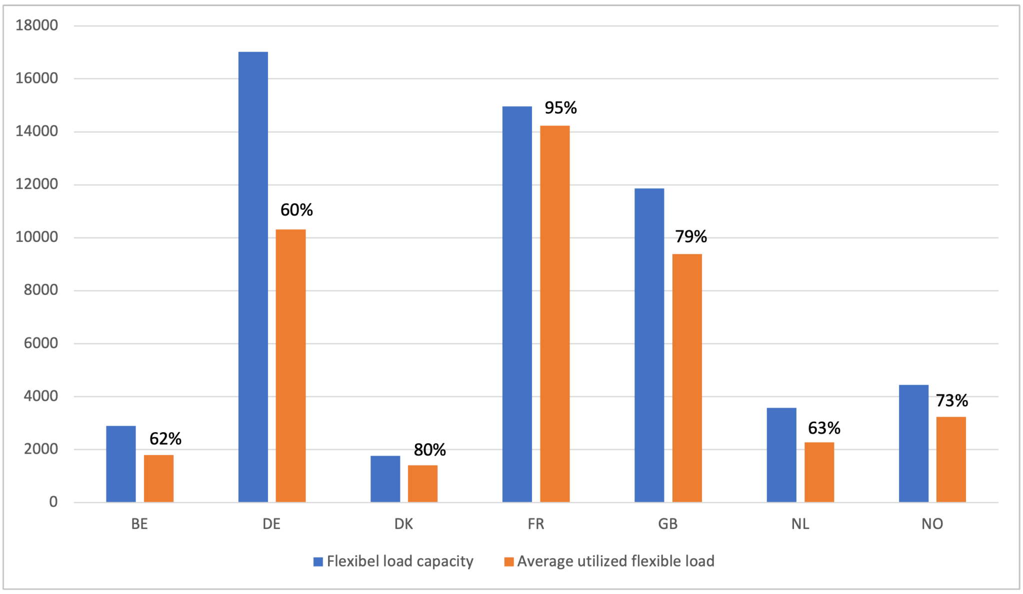

Figure 20: Visualization of active flexible demand compared with installed flexible demand capacity.

When observing the annual power production compared with the reference and GEP&TEP scenario, the affects becomes clear. Table 17 shows that coal and oil are completely phased out, and Other non-RES are almost phased out. Gas power has had a reduction of 93,5 percent compared with the reference case. This means that the share of non-RES are now minor, not accounting for nuclear power which is unchanged. The polluting energy sources that remains does only account for 0.44 percent of the annual power production. In the reference case, this share was 6.7 percent. It is also observed that the total annual production is reduced with 6.4 percent, which corresponds to the 6.5 percent reduction in annual demand. However, if the annual demand was just reduced with 6.5 percent and there was no flexible demand in the system, the share of non-RES would be similar to the GEP&TEP scenario. The accurate power production values can be found in Table 31 in the Appendix.

Table 17: Comparing annual production by generation technology for reference, GEP&TEP and flexible demand scenario.

Generation tech	Reference [TWh]	GEPTEP[TWh]	%	GEPTEP FL[TWh]	%
coal	0,017	0,002	-90,3	0,000	-100
gas	122,142	83,999	-31,2	7,951	-93,5
hydro	242,245	253,902	4,812	211,732	-12,6
nuclear	390,983	390,983	0	390,983	0
oil	0,003	0,000	-94,6	0	-100
other_non_RES	7,481	4,637	-38,0	0,052	-99,3
other_RES	80,061	77,093	-3,7	78,119	-2,4
solar_pv	220,521	220,491	-0,01	220,491	-0,01
wind	506,065	507,060	0,2	512,387	1,3
wind_offshore	354,148	389,217	9,9	379,724	7,2
Total:	1 923,683	1 927,386	0,2	1 801,440	-6,4

The capacity factors are found in Table 34 in the Appendix. It shows that Gas OCGT and Gas conventional are also completely phased out, making Gas CCGT and Other non-RES the remaining polluting flexible energy sources. Since coal, oil, gas OCGT and Gas conventional are never active means that Gas CCGT and Other non-RES never reaches full capacity during the year. Other non-RES are only active in DE and NO, which means that Gas CCGT never reach full capacity in the reaming countries. The reasoning is that the more expensive generation technologies are only active when the cheapest(Gas CCGT) produce at full capacity. The offshore wind capacity factors are slightly reduced in certain countries due to curtailment with transmission constraints, which was less expanded in this scenario. Nevertheless, the impact is small and not noticeable on the larger system.

The share of non-RES are now so small that nuclear power is the only reason that "RES compared with generation" is not flat close to 100 percent in Figure 21. The "RES compared with consumption" makes less sense in this scenario, but tell us which countries are energy importer/exporters. NO has again changed from been an energy exporter to be an importer. The reason is generally lower power prices in Europe, which makes Norwegian hydro power less competitive.

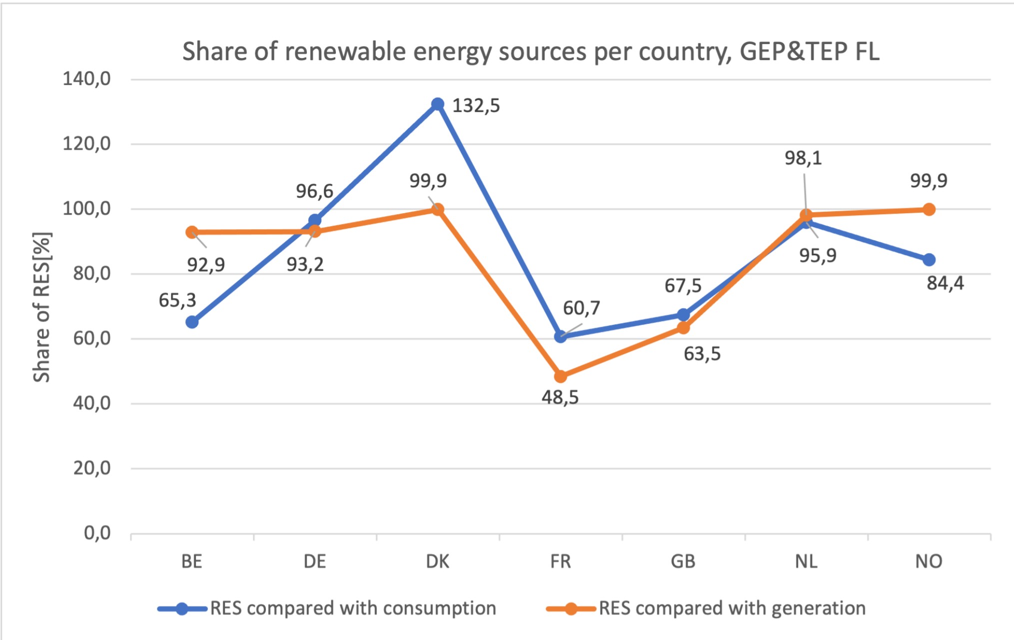

Figure 21: Share of renewable energy sources per country in flexible demand scenario

In Figure 26 the average base load price for this and previously scenarios are visualized. For all countries, the average price is at 19,07€/MWh, which is a decrease of 51 percent from the reference and a decrease of 40 percent compared with the GEP&TEP scenario. In relation with the activity of flexible demand, FR has by far the cheapest power prices. This is due to low operational costs on nuclear and that power production is considerably higher than demand in FR. GB has a similar share of nuclear power, but their total power production is close to balanced with their demand. In general, the low prices are due to a higher share of RES and a significantly reduced flexibility issue. NO is the only country which has small deviations on their prices through the different scenarios. The reason is that most of the Norwegian power production is from hydro, which follows a fixed price profile. The small deviation in prices comes from the remaining sources such as wind and solar. NO has their lowest prices in the GEP&TEP scenario, which is a scenario where there is little or non transmission capacity limit and the energy prices are still competitive with the other countries.

Figure 22: Visualization of average base load price for each country in flexible demand scenario.

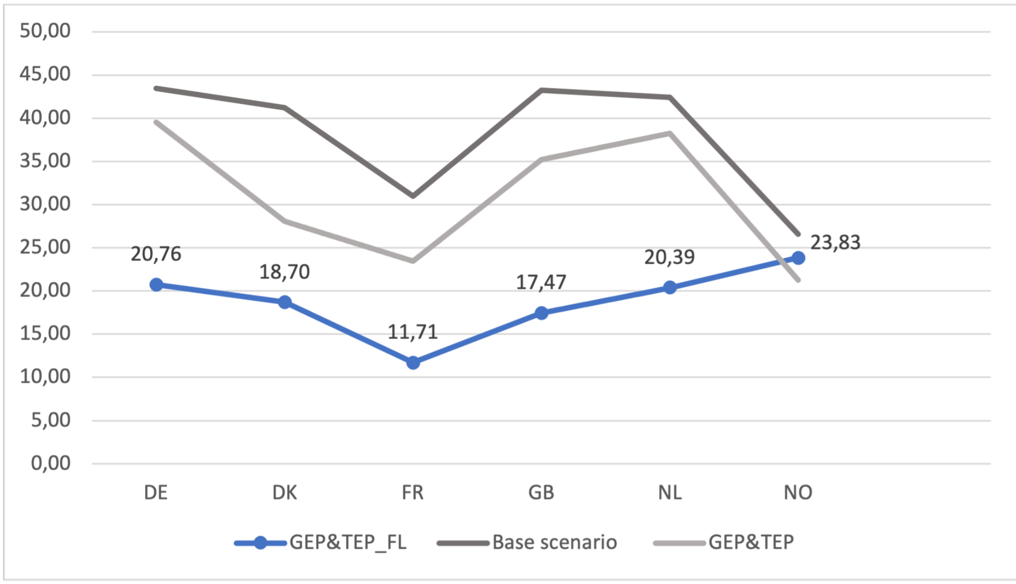

Figure 23: Visualization of average base load price for each country in flexible demand scenario.

In Table 18 a comparison of annual emissions is presented. As observed in the annual power production, the power production from non-RES is significantly reduced compared with the reference and GEP&TEP scenario. FR has reached a zero-emission state, where no power production comes from polluting sources. In total, the annual emissions are reduced by 93,8 percent compared with the reference scenario.

Table 18: Comparing annual emissions by countries for reference and GEP&TEP scenario.

Country	Reference [tCO2]	GEPTEP[tCO2]	%	GEPTEP FL[tCO2]	%
BE	6 438 170	4 837 819	-24,86	181 234	-97,19
DE	23 292 133	16 709 753	-28,26	1 965 306	-91,56
DK	395 156	109 424	-72,31	13 255	-96,65
FR	409 544	341 336	-16,65	0	-100
GB	12 958 023	7 832 809	-39,55	234 066	-98,19
NL	8 371 931	5 624 201	-32,82	805 772	-90,38
NO	806	806	0	806	0
Total	51 865 762	35 456 147	-31,64	3 201 438	-93,83

The total cost are reduced by 53 and 49 percent compared with the reference and GEP&TEP scenario, respectively. All operational expensive sources are phased out and the total power production are reduced. Since the demand is also reduced in this scenario it is more comparable to observe the total cost per MWh delivered. Where the cost reduction is closer to 50 and 45 percent. The cost of implementing the flexible demand is not accounted for in this scenario, which is important to keep in mind. However, the decrease in operational cost are the interesting part.

Table 19: Investment and operational cost flexible demand scenario

	Value	Unit
New transmission investment cost	4,932	10ˆ9 EUR
New generation investment cost	1.542	10ˆ9 EUR
Total investment cost	6,474	10ˆ9 EUR
Total operational cost	121.42	10ˆ9 EUR
Total costs	127.895	10ˆ9 EUR
Total cost per MWh delivered	72,05	EUR

9.1.4 zero-emission scenario

In the zero-emission scenario, all polluting generation technologies are set to zero and PowerGIM will optimize GEP&TEP in order to replace the flexible generation. With much of the flexible generation gone, the power system is expected to have larger flexibility issues. Four different configurations are simulated in the zero-emission scenario: One including both nuclear and flexible load(With Ncl&FL), one including nuclear but not flexible load(With Ncl), one including flexible load but not nuclear(With FL), and one where neither nuclear or flexible load(Without Ncl&FL) are included. The different configurations are chosen to showcase the effect of nuclear and flexible load in a power system with only RES. In Table 20 the GEP for the zero-emission scenario are presented.

Table 20: Comparing GEP between the different net-zero-emission configurations. All values are given in MW.

Generation tech(Country)	With Ncl&FL	With Ncl	With FL	Without Ncl&FL
Offshore wind(BE)	-	3 920	2 534	18 719
Offshore wind(DE)	-	9 705	-	21 613
Offshore wind(DK)	-	9 718	-	15 936
Offshore wind(GB)	-	-	-	30 000
Offshore wind(NL)	-	322	-	13 348
Offshore wind(NO)	-	15 160	6 433	20 118
Offshore wind(FR)	-	4 219	16 016	60 000
Onshore wind(BE)	-	-	3 270	27 392
Onshore wind(DE)	-	-	-	19 306
Onshore wind(DK)	-	6 650	1 436	15 267
Onshore wind(GB)	-	30 000	30 000	30 000
Onshore wind(FR)	-	30 000	30 000	30 000
Total	-	109 694	108 995	301 699

Considering GEP, the results clearly shows big differences between the configurations. Including both nuclear and flexible load, no GEP is required, which is interesting when comparing with the ”Flexible demand scenario”. That scenario is including the polluting generation, but otherwise similar. Nevertheless, the ”Flexible demand scenario” did find it optimal with added generation, but the configuration with Ncl&FL did not. The difference is the flexibility need and transmission, which will be further elaborated in the Discussion. The total amount of generation expanded is almost equal of the configuration With Ncl and With FL. However, the distribution is different. Without nuclear, optimal expansion is directed more towards FR, but without flexible load the expansion is directed more towards NO,DK and DE which possibly relies more on Norwegian hydro. As expected the configuration without Ncl&FL needs considerably more generation expansion. Onshore and offshore wind are the only generation technologies which are expanded, and which reach its default maximum expansion of 30 000MW. Offshore wind in FR reach 60 000MW because offshore wind are placed on two nodes in FR. The lack of Solar PV is due to low capacity factor and with a too small price difference on investment costs. In order to get PowerGIM to expand solar PV, must there either be lower investment price or a lower maximum capacity expansion on wind. In Table 21 the associated TEP results are presented.

Table 21: Comparing TEP between the different net-zero-emission configurations. All values are given in MW.

From node	To node	Type	With Ncl&FL	With Ncl	With FL	Without Ncl&FL
21,BE	95,BE	AC	-	-		4 000
22,28,DE	93,DE	AC	398	5 709	-	8 000
23,DK	92,DK	AC	3 547	3 895	727	2 641
24,25,35 GB	96,GB	AC	3 663	7 589	6919	11 589
26,30,NL	94,NL	AC	372	4 000	4 491	8 000
27,NO	91,NO	AC	4 000	4 000	4000	4 000
32,33,34,FR	97,FR	AC	195	4 000	540	12 000
93,DE	94,NL	AC	-	-	-	2 178
93,DE	92,DK	AC	-	4 000	-	4 000
93,DE	95,BE	AC	-	1 154	-	4 000
94,NL	95,BE	AC	911	-	4 000	1 908
97,FR	95,BE	AC	4 000	4 000	2 302	4 000
97,FR	93,DE	AC	-	4 000	394	4 000
27,NO	24,GB	DC	-	-	2 704	3 261
27,NO	28,DE	DC	2 869	9 515	4 131	10 000
27,NO	29,DK	DC	3 060	3 567	1 580	3 567
27,NO	30,NL	DC	2 315	5 021	3 745	3 415
23,DK	30,NL	DC	424	1 691	2 461	4 046
23,DK	24,GB	DC	-	2 466	987	4 449
31,NL	25,GB	DC	1 737	3 109	1 097	3 979
21,BE	25,GB	DC	3	1 107	852	3 981
28,DE	25,GB	DC	-	-	2 279	3 468
34,FR	35,GB	DC	125	3 867	465	3 867
Total			27 619	72 690	43 674	114 349

As with the GEP, the configuration with Ncl&FL require the least TEP. However, notice that it require about 440 percent more transmission than the "Flexible demand scenario". Different from the GEP, it is observed that the configuration with FL require much less TEP than with Ncl. This is expected as flexible load contributes more to the flexibility problem compared with nuclear. Without neither nuclear or flexible load the transmission need is considerably higher. In all configurations, between 38-44 percent of the TEP are internal and the rest are between countries. A large degree of external and internal TEP in NO are found consistently in all configurations. Further is a variety of TEP found between most countries. For TEP, the maximum default capacity expansion of 4000MW is reached in numerous cases. In Figure 24 the amount of active flexible demand of the configurations with Ncl&FL and with FL are presented.

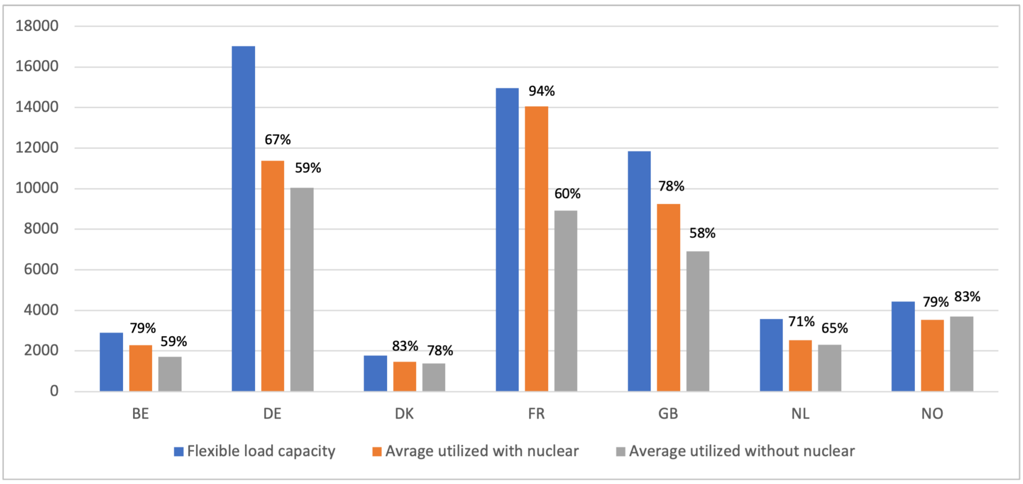

Figure 24: Visualization of average baseload price for each country in flexible demand scenario.

In all countries, except NO, the flexible demand is more active in the configuration with nuclear then without nuclear. This is because the nuclear with low marginal costs drives the average power price down. The biggest differences are observed in the countries with nuclear, which are in FR and GB. BE are also effected as it is highly dependent on power production from FR and GB. NO is the only exception where the lack of nuclear in the North Sea power system do not results in higher power prices. Hence, the amount of active flexible load is higher. The reason is that NO is mostly dependent on hydro and the configuration without nuclear "force" NO to built more wind. In that scenario, NO is in the unique situation with fixed hydro prices and cheaper wind power prices. In a more realistic scenario, where the water values were dependent on demand, the NO power prices would look different, most likely more similar to the other countries.

In Figure 25 a visualization of the annual production are presented. More accurate values are found in Table 38, Table 39, Table 40 and Table 41 in the Appendix.

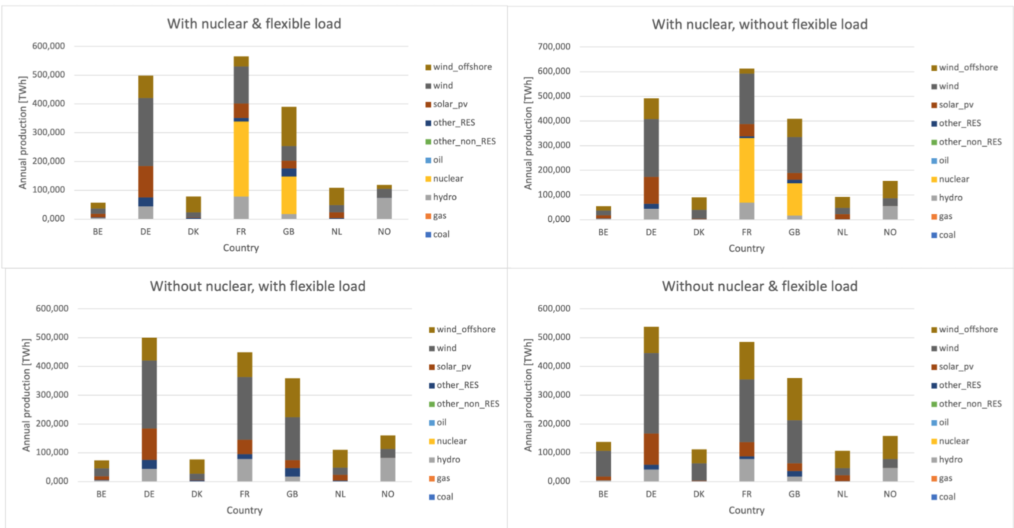

Figure 25: Annual power production for all the configurations.

It is clear that on- and offshore wind has a higher share in all configurations compared with the reference. In the cases without nuclear, wind takes a 74(with FL) and 69(without FL) percent share of the total annual power production. In both cases, FR and GB has a significant increase in wind power production in order to compensate for the lost nuclear power. However, the total annual power production in FR and GB are reduced, and the countries are converted to net-energy importers without their nuclear power. In order to balance the power grid, other countries such as BE, DE and DK needs to increase their output. The most significant alterations are seen without Ncl&FL where BE has an increased total annual power production of 140 percent, making BE a large net-energy exporter. Increasingly higher share of wind power in NO, decreases the power output of Norwegian hydro because of more competitive prices. With more RES will the power system experience periods with lack of power and periods with surplus power, which gives a bigger variety in power prices. The wind power output varies differently between the nodes, which contributes to grid balancing if the distribution of capacity is done optimal. This is one of reasons why PowerGIM not only match the demand in every country.

The average power prices for all four configurations are visualized in Figure 26. In this results the models limitations becomes clear.

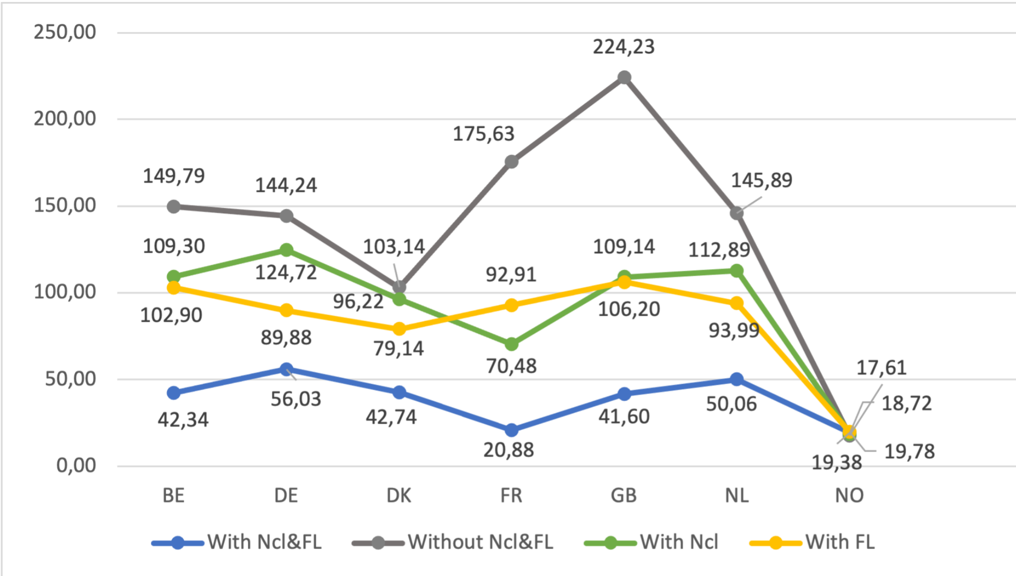

Figure 26: Visualization of average baseload price for each country in flexible demand scenario.

In general will more renewable energy gives a bigger variety of power prices during the year. However, the power prices in this zero-emission scenario indicate an unstable and non functioning power grid. The prices visualized are only an average through the year, the actual prices varies between 0.2-1000€/MWh in short periods. When the prices reach 1000€/MWh is that a result of demand exceeding power production. The high pricing is also called scarcity pricing. Meaning that the system is not able to produce enough power to meet demand at that hour. This happens when the majority of power comes from variable sources and the storage opportunity is not sufficient enough. Normally will RES give low power prices due to low marginal costs, which means that the average power prices gives an indicator of how often the price reach 1000€/MWh. Meaning that this power prices is meaningless to compare with the reference, but should instead be evaluated as in which degree the power system is functioning. By functioning is it implied how often the power system will experience blackouts. High average power prices is an indication of a less functioning power system. The importance of both nuclear and FL becomes clear in this visualization in order to operate a zero-emission power system.

Investment and operational costs are presented in Table 22. The configuration with Ncl&FL are the only configuration which has lower cost compared with the reference. However, the cost are higher than the "Flexible demand scenario". Investment cost are higher because more transmission is needed to compensate for the non-RES, and operation cost slightly higher because of a few periods with insufficient power supply. The effect of flexible demand becomes clear when comparing the cost, FL has a larger impact then nuclear power. The operational cost presented her is also an indication of how well the power system is functioning.

Table 22: Investment and operational cost zero-emission scenario

	With Ncl&FL	With Ncl	With FL	Without Ncl&FL	Unit
New transmission investment cost	32,922	111,948	56,291	172,196	10ˆ9 EUR
New generation investment cost	0	190.035	143.965	591.260	10ˆ9 EUR
Total investment cost	32,922	301.983	200,255	763.455	10ˆ9 EUR
Total operational cost	167.439	380.489	227,875	629.048	10ˆ9 EUR
Total costs	200.361	682.472	428.130	1 392.503	10ˆ9 EUR
Total cost per MWh delivered	112.879	359.840	241.198	734.210	EUR

9.1.5 Sensitivity analysis

The following section investigate how adjustments in the input data effect the results generated by the model. The intention of the sensitivity analysis is to observe the effect of specific deviations in the input data in order to understand the consequences of uncertainty. Sensitivity is done by changing one input parameter at the time and observing the impact. In this case study, a short sensitivity is done on the threshold price of flexible demand, the weather inflow profile based on different climate years, and investments cost of solar PV. The threshold price and weather profile parameters are extracted from other sources than the main input data, which is mainly collected from the TYNDP2020 report. The mismatch and uncertainty linked to weather and flexible demand makes it important to show small deviations effect the results. Since no expansion of solar PV was observed in previously scenarios, this sensitivity also intend to investigate when solar PV becomes a cost-beneficial solution. A complete review of the results are not necessary, the direct effect are presented and the indirect effects are commented.

For the threshold price of flexible demand, a half and doubling of the original price are investigated. This sensitivity is done on the "Flexible demand scenario", with no zero-emission requirements. The resulting share of active flexible demand is visualized in Figure 27.

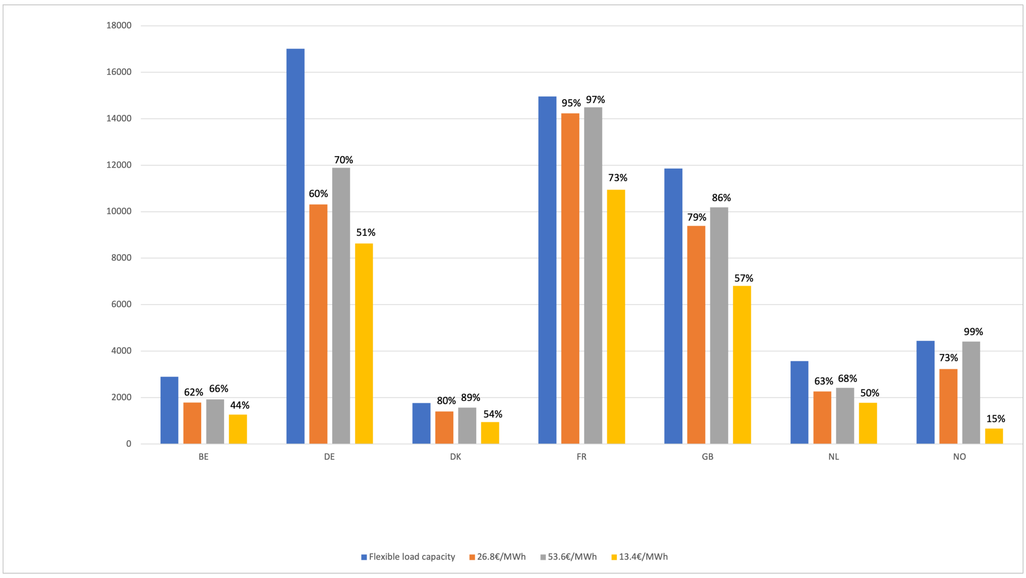

Figure 27: Visualization of the share of active flexible demand for different threshold prices compared with installed flexible demand capacity.

As expected, higher threshold price leads to more utilization of flexible demand. It is observed that reducing the price mostly gives larger effects than increasing the price. The main reason is that the original share of active flexible demand is over 50 percent, and reaching 100 percent (or 0) require much more aggressive pricing. In general, the results are reasonably, again with the exception of NO because of their fixed hydro profile prices. It is important to understand how this affect the reaming results. Lower demand, leads to less need of power production which drives down the total operational costs. This is true if the total demand are reduced in line with the flexible demand, as done in this model. If the total demand remained the same, more flexible demand would lead to a more stable power system with a possibility of a larger share of RES.

The affect of different wind speeds and solar irradiation are investigated by simulating the model with inflow profile based on the climate years 1982, 1984 and 2007. 1984 is the inflow profile used in the main scenarios, 1984 and 2007 are corresponding climate years used in the TYNDP 2020 Report, but collected from renewable.ninja as described in the Methodology. For this sensitivity, the reference scenario is chosen. The capacity factor of wind and solar are the direct effect of different inflow profiles, and the results are visualized in the Figure 29. Accurate capacity factor values are found in Table 42 in the Appendix.

Figure 28: Visualization of the capacity factor of solar, on- and offshore wind on the climate years 1982, 1984 and 2007.

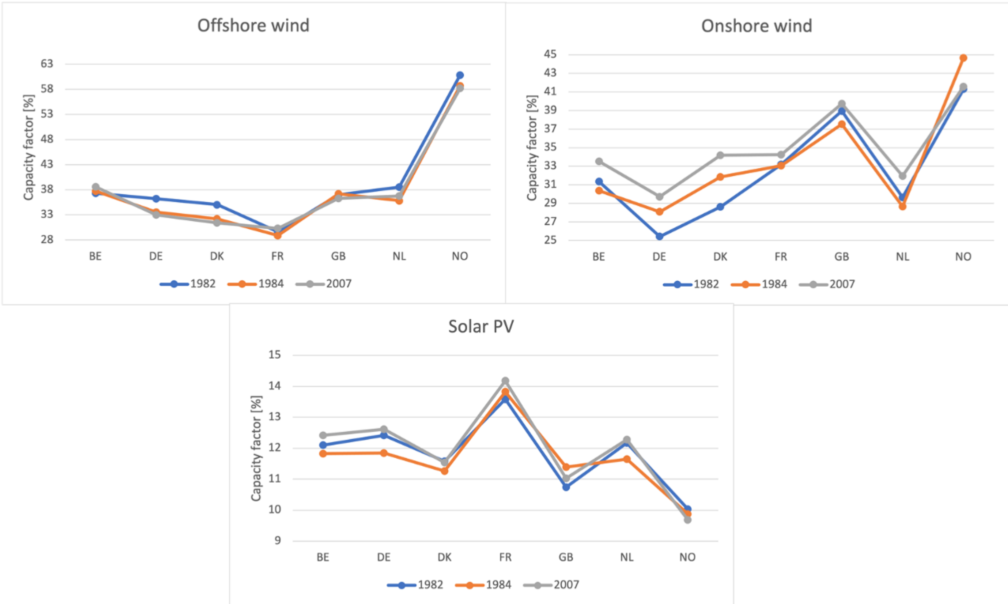

Figure 29: Visualization of the capacity factor of solar, on- and offshore wind on the climate years 1982, 1984 and 2007.

The results show that on average the power production from wind and solar are following the same trends. The largest deviations are for onshore wind in DK and DE. The difference of total annual power production from offshore wind and solar are minimal between the different climate years, the deviation as under 2 percent. The total annual power production of onshore wind is close to 10 percent between the year 1982 and 2007. The total annual power production of onshore wind is somewhere in the middle for the year 1984. It is clear that the year 1984 is not a special climate year which stands out from the other years. The observed differences between the climate years appears to be minor, but even small margins could be meaningful for the power system. The intention of this sensitivity is not to explain the specific affects in the results, but rather to get an understanding of the impact of different climate years.

The generation expansion in the main scenarios never found it cost-beneficial to expand solar PV. Solar has a higher investment cost than onshore wind, but lower cost than offshore wind. The operational cost of solar are the cheapest of all generation technologies. However, the low capacity factor of solar is the big disadvantage. With the different solar irradiation profiles used, the capacity factor is rarely over 14 percent, which is half of the capacity factor of a typical onshore wind installation. This means that solar PV must be half the investment price in order to be cost-beneficial, not accounting for operational cost or the benefit of having different generation technologies. The original investment cost of solar PV are 65 051 EUR/MW year, a sensitivity is done with half and a quarter of this price. The GEP results can be found in Table 23.

Table 23: Comparing GEP between the different investment cost of Solar PV of 65 kEUR/MW, 32 kEUR/MW and 16 kEUR/MW. All values are given in MW.

Generation tech(Country)	CAPX:65	CAPEX:32	CAPEX:16
Offshore wind(BE)	18 719	18 324	17 430
Offshore wind(DE)	21 613	21 301	20 967
Offshore wind(DK)	15 936	15 597	14 796
Offshore wind(GB)	30 000	30 000	30 000
Offshore wind(NL)	13 348	13 347	12 954
Offshore wind(NO)	20 118	19 929	18 784
Offshore wind(FR)	60 000	60 000	60 000
Total Offshore wind	179 734	178 498	174 931
Onshore wind(BE)	27 392	26 782	25 040
Onshore wind(DE)	19 306	17 986	16 368
Onshore wind(DK)	15 267	13 815	10 169
Onshore wind(GB)	30 000	30 000	30 000
Onshore wind(FR)	30 000	30 000	30 000
Total Onshore wind	121 965	118 583	111 577
Solar PV(FR)	0	24 769	30 000
Solar PV(BE)	0	0	3 422
Solar PV(GB)	0	0	22 740
Total Solar PV	0	24 769	56 162
Total	301 699	321 850	342 670

The results show that expansion of solar PV are most optimal in FR, which has the highest capacity factor of solar and a need of power generation to account for no nuclear power. BE has a higher capacity factor for solar than GB, but the need of power is much greater in GB, which is why more solar is expanded there. However, the expansion of solar is still less than on- and offshore wind, even with an investment price of 16 kEUR/MW. The reduction of on- and offshore wind are less than the increase of solar PV. With a lower capacity factor, more installed capacity is needed in order to generation enough power, which the reason why the total amount of installed capacity is increased with more solar. With a higher degree of solar it is observed that the total cost of both operation and investment are decreased. Solar PV has lower operational costs and the combination of solar and wind gives less flexibility problem, which will be elaborated in the Discussion.

9.2 Discussion

The main focus of this master thesis is to investigate optimal generation expansion with the impact of flexible demand and zero-emissions requirements for the North Sea power system in 2040. This discussion section will elaborate on different topics related to the main focus. The general model and result weaknesses will also be commented in this section.

9.2.1 Flexible demand

The impact of flexible demand based on the generated results shows the importance of grid balancing in a power system with a high share of RES. The flexible demand scenario phased out almost all polluting energy sources and drove down power prices significantly. Notice that if flexible demand were implemented in a power system without RES, only with the controllable generation, the impact would not be correspondingly significant. In that case, the flexible demand will contribute to balancing the variation in the load curve, but no balancing is needed for the power generation.

Statsnett's marked analysis report assumed that the flexible demand would mainly consist of hydrogen production, house/industry optimization or heat pumps. Hydrogen, the largest part of the flexible demand, can be used as energy storage. With a simple calculation of energy losses, an estimation of the profitability of using hydrogen to produce power again can be evaluated. The technology to convert power to hydrogen and back to power has a round-trip efficiency of 18-46 percent, according to data from the Massachusetts Institute of Technology and the scientific journal Nature Energy[49]. In the flexible demand scenario, approximately 373 TWh of the annual consumed demand where flexible. For this thought experiment, all the flexible demand is used in hydrogen production through electrolysis and again converted back to electrical power. 18-46 percent is a large interval, but let us assume with technologies for 2040 that this round trip efficiency is consistent at 40 percent, which leaves us with 149 TWh of electrical power to distribute back to the grid. The hydrogen was produced with a power price of 26.8€/MWh or less. To ensure of profitability, the power must be sold at a price of 67.1€/MWh, which is a very high spot price. However, with the benefit of choosing when to sell and buy power with hydrogen as storage, it is possible to make a profitable business, especially with the variation in power prices seen in the zero-emission scenarios. Nevertheless, due to the low round trip efficiency, it is likely more profitable to sell the hydrogen for other usages, such as fuel for heavy transport. Additionally, the competition from other power storage possibilities such as large battery farms might make the hydrogen option obsolete.

The flexible demand analysis in this thesis does not account for any investment cost. In theory, it shows great potential, but the investment cost and operation reliability need to be investigated in order to reach a final conclusion. However, it is clear that flexible demand is needed, to some extent, to develop a zero-emission power system.

9.2.2 Generation expansion

The first GEP&TEP scenario resulted in no expansion of generation capacity. However, in the following scenario, when flexible demand was added, PowerGIM found it optimal to expand onshore wind capacity in Norway. From the initial power system, onshore wind in NO is optimal due to the low investment cost for onshore wind and NO having the highest capacity factor for wind. However, the generation expansion is not found in the first scenario due to the transmission expansion. In the GEP&TEP scenario, flexibility was needed to exploit RES generation better, hence considerable transmission was added. With all the expanded transmission, the utilization of the RES is sufficient enough that no added generation is needed. In the flexible demand scenario, the power system is close to optimally balanced, and little transmission expansion is required. With less transmission, the utilization of RES is not similarly sufficient, resulting in a more optimal solution for expanding onshore wind capacity. In general, transmission expansion balances the generation side, and flexible demand balances the demand side, giving different optimal solutions. The same effect is seen in the zero-emission scenario with Ncl&FL, where no generation capacity is expanded, but a considerable amount of transmission capacity is expanded. Nevertheless, this showcases the benefit of international energy trading and smart demand management.

A more comprehensible GEP is investigated in the zero-emission scenario, especially the configurations without Ncl&FL. Interestingly, onshore wind in NO was not expanded in any of the zero-emission configurations. The reason is that all countries except NO have "lost" their non-RES generation capacity. NO with its hydropower has the slightest problem adjusting to a power system with zero-emission requirements. However, it is observed that offshore wind is expanded in NO, and all the other countries. Offshore wind has a more stable power profile(more stable wind) compared with onshore wind. In a power system with flexibility issues, this is beneficial. It is only the configuration without Ncl&FL, which has the highest share of offshore wind, the other configuration has the most expansion in onshore wind.

In addition to the investment cost and capacity factors, there are two other main reasons for the distribution of generation expansion. Trivially, generation capacity is located geographically near the consumed demand. Without nuclear, FR and GB must expand generation capacity in order to compensate for the limitation of power output. The model evaluates the optimal solution considering the capacity factor and transmission losses to the location where the power is consumed. Further, will the model find it more optimal to expand generation capacity in more locations and diversify the generation technologies. This is because the locations and different generation technologies have different power profiles. The combination of many power profiles leads to a more balanced power system, less oscillations in the total power out.

9.2.3 zero-emission power system

Considering all scenario simulated in this model, it is clear that reaching 90 percent renewable power system is doable, but converting the last percentages is increasingly more difficult. All zero-emission scenarios have to a certain degree a reliable issue. This becomes clear from the extreme spikes in power prices for certain hours. When the power prices are reaching 1000€/MWh, is this an indication of a shortage in the supply. This price is also called scarcity pricing. This happens when the RES generators are not producing enough power compared with demand. It is often due to little wind and weak solar irradiation but could also happen in periods with demand spikes. However, the consequences could be power blackouts in certain parts of the power system. In the configuration with Ncl&FL, the scarcity prices only occur a few times, and the power system is mostly functional. In the other configurations, scarcity pricing happens more regularly, which can be seen in the average base load pricing in the different scenarios. Scarcity pricing is the main reason for the different pricing between the configurations. It is observed that only flexible demand contributes a bit more to stable pricing than with only nuclear, but the difference is not significant. Again, nuclear and flexible demand contributes to balance in different ways. Nuclear establish a consistent base of power production, which raises the lower limit of the total power output. Flexible demand compensates on the demand side, intending to match the power output for every given hour. Nevertheless, it is observed that without nuclear or flexible demand, the power system is experiencing significant flexibility issues.

In order to reach a reliable zero-emission power system, the simulation must be done under different conditions. The batteries have been utilized at maximum through all the scenarios, meaning that additional batteries would most likely be preferred in an updated model. Expanding battery storage, flexible demand or nuclear capacity are specific possibilities that will make the transition in this model doable. This could be done manually in the input data, but the best option is to modify the model to expand these parameters optimally. Then the analysis of battery storage expansion, flexible demand expansion and nuclear expansion can be conducted. The results shown in the zero-emission scenario show that these parameters are essential in order to reach a fully sustainable power system.

The initial power system could be designed differently to better fit a zero-emission scenario. A meshed offshore power grid system could be a solution to further optimize the utilization of offshore wind. Storage solutions such as batteries located in the nodes connected to offshore wind are also possible solutions. Both options would contribute to less curtailment of offshore wind generators. A meshed grid or batteries can be simulated in PowerGIM, but are not included due to the number of different simulation scenarios.

9.2.4 Results and model validations

The GEP has a default expansion limit which does affect the results. Especially onshore wind has an actual expansion limit dependent and land area and political interest. In NO the expansion limit of 30 000MW onshore wind capacity is unrealistically high, but considering offshore wind, this value could be too low(depending on the development of floating offshore wind). Research of relevant generation limits was done, but consistent data was difficult to collect. However, the GEP limit is only relevant in large expansion scenarios.

As observed in the results, the Norwegian hydro profile pricing gives unrealistic results when the model is pushed to a zero-emission scenario. Under normal conditions, the modeling of Norwegian hydro works fine, but with extreme prices, the modeling is not representative anymore. In order to model hydro, water values must be included. Water values decide the pricing of hydro power production, which is based on current demand, future demand, reservoir levels, and expected inflow. Calculating the specific water values in a generalized model such as PowerGIM, might be exaggerated, and the simulation time might be drastically increased. However, the importance is to understand why the NO power pricing is deviating from the rest of the countries. Since NO initially almost has zero-emission from power production, it is worth noticing that NO would have considerably lower power prices in a zero-emission scenario. Hydropower also has a more stable power output than wind and solar. Nevertheless, the hydro prices would be affected by power demand from other countries in such an integrated power system.

From the reference scenario, it was clear that Gas CCGT was the only significant gas contributor. With such a low output from Gas OCGT and Gas Conventional, it would be sufficient enough to only consider one type of gas power generation. In the specialization project linked to this master thesis Gas OCGT and Gas conventional were more significant contributors, and their roles were meaningful. The inclusion of batteries made the difference, which showcases the effect batteries could have on a power system.

In the zero-emission scenario, enormous investment costs are observed, affecting the optimization problem's objective function. PowerGIM optimizes the power system by minimizing investment costs and operational costs. When the investment cost are at such scale, the balance between investment cost and operational cost changes. In the GEP&TEP and flexible demand scenario, relatively small investments are executed to reduce operational costs. Total operational cost is the largest share of the objective function, meaning that in practice, PowerGIM minimizes the operational cost. This balance changes in the zero-emission scenario where the investment cost is the same size as the operational cost. Due to a high shortage in supply, investment in new generation technology is inevitable. Hence, minimizing investment costs comes at the expense of operational costs compared with the other scenarios.

10 Conclusion and further work

This report provides different scenarios and analyses for the development of the North Sea power system towards 2040. A deterministic optimization model, PowerGIM, is utilized for simulations and optimal power system expansion planning. The model simulates a year of power system operations with different configurations for the different scenarios. The primary input data is collected from the TYNDP 2020 scenario report, which provides the initial fundamentals for a possible European power system in 2040. Other external sources are implemented where the TYNDP2020 report lacks relevant data. Different scenarios are simulated to get a comprehensive overview of crucial components in a future power system. The main objective is to investigate optimal generation expansion with the impact of flexible demand and zero-emission requirements. The objective is investigated through four different scenarios and sensitivity analysis of climate power profiles, flexible demand pricing and solar PV investment costs.

The results generally showcase the challenges of integrating a high share of renewable energy sources in the power system. A fully renewable power system can only be achieved by solving the power balancing on the demand and supply sides. There are several methods to enhance the power balance in a power system. However, energy storage possibilities, sufficient transmission and flexible demand is observed to be a necessary part of the solution. With a share of 26 percent of the demand being flexible, optimal GEP&TEP and batteries implemented as an energy storage solution, the power system would almost be fully renewable. With flexible demand and optimal GEP&TEP, a 94 percent reduction in CO2 emissions are observed compared with the reference scenario. That being said, converting the last percentage of non-RES becomes increasingly more difficult.

From the initial power system condition, it is found that onshore wind in NO is the most cost-beneficial expansion option. Onshore wind has the lowest investment cost with relatively low operational cost and high capacity factor, making it the optimal solution. The capacity factor of onshore wind is highest in NO for all three investigated weather power profiles, making NO the optimal country for wind power generation. Solar PV requires a lower investment cost than the future expected investment cost from the TYNDP 2020 in order to compete with wind, as investigated in the sensitivity analyses. In the zero-emission scenario, the optimal criteria change and onshore wind in NO are not expanded anymore. The reason is that NO has kept its hydropower, but the reaming countries have "lost" their non-RES, resulting in a shortage of installed generation capacity in the other countries. In the zero-emission scenario, all countries expect NO need expanded generation capacity, which is why the optimal expansion solution changes.

The zero-emission scenarios are experiencing scarcity power pricing, which means the demand is not met at that given hour. This is one of the most prominent problems with a fully renewable power system. The power and demand dips/peaks are not sufficiently handled through the installed energy storage, flexible demand or transmission. This is especially true if nuclear power production is shut down. In order to completely avoid scarcity pricing in a fully renewable power system, additional flexible demand and energy storage capacity are required.

The model has certain simplifications and uncertainties, which are vital to keep in mind. However, the objective was not to present the most accurate prediction of the future power system, but rather to investigate different aspects and effects.

10.1 Further work

This master thesis has established a groundwork with numerous opportunities for further work. The topics mentioned in this section are only based on the authors' ideas for further exciting work. The presented possibilities are enough workload for another master thesis.

The methodology can be modified to make the power simulation more realistic. A deeper investigation of the onshore wind generation capacity limit for the different countries should be included. If pushing the power system to unstable levels, an alternative to the Norwegian hydro profile pricing should be evaluated. It is possible to include water values, but this can be a comprehensive process. An alternative is to include different price profiles and match the price profile closest to the current state of the power system.

A zero-emission power system should be optimized with the requirement of never reaching scarcity prices, meaning no power shortage. The model can be modified to expand energy storage and flexible demand in order to find a "perfect" balance of the two contributions. This would also require an investment analysis of both energy storage and flexible demand.

It would also be interesting to investigate the stochastic programming model embedded in PowerGIM. This is a stepwise multi-period optimization model, which can assess risk and uncertainties at a more detailed level, an essential aspect of investment decisions.

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Appendix

A Input data

Table 24: Node input: Overview of the aggregated nodes representing the grid.[31]

Node	Country	Latitude	Longitude	Offshore	Function
1	BE	51.45	2.45	Yes	Offshore wind production
2	DE	54.58	6.16	Yes	Offshore wind production
3	DK	55.59	7.58	Yes	Offshore wind production
4	GB	55.01	2.65	Yes	Offshore wind production
5	GB	52.67	2.72	Yes	Offshore wind production
6	NL	52.75	3.50	Yes	Offshore wind production
7	NL	53.56	5.50	Yes	Offshore wind production
8	NO	56.80	4.90	Yes	Offshore wind production
9	FR	49.92	0.20	Yes	Offshore wind production
10	FR	47.01	-2.64	Yes	Offshore wind production
21	BE	51.22	3.17	No	Land connection point
22	DE	53.13	7.31	No	Land connection point
23	DK	55.52	8.73	No	Land connection point
24	GB	53.56	-0.15	No	Land connection point
25	GB	52.07	1.06	No	Land connection point
26	NL	52.33	5.02	No	Land connection point
27	NO	58.28	6.85	No	Land connection point
28	DE	53.90	9.18	No	Land connection point
29	DK	56.50	9.54	No	Land connection point
30	NL	52.43	6.88	No	Land connection point
31	NL	52.48	4.69	No	Land connection point
32	FR	49.76	0.37	No	Land connection point
33	FR	47.24	-2.27	No	Land connection point
34	FR	49.86	0.70	No	Land connection point
35	GB	50.79	0.05	No	Land connection point
91	NO	59.47	6.58	No	Land connection point
92	DK	56.00	9.30	No	Aggregated country
93	DE	52.50	10.8	No	Aggregated country
94	NL	52.24	5.83	No	Aggregated country
95	BE	50.72	4.43	No	Aggregated country
96	GB	52.50	-1.00	No	Aggregated country
97	DR	47.10	2.40	No	Aggregated country

Table 25: Branches input: Overview of the transmission capacity between every node. This is an simplification of the real world transmission system. [31]

Node from	Node to	Capacity[MW]	Connection type	Project Name
21,BE	95,BE	5000	AC	
22,DE	93,DE	15000	AC	
23,DK	92,DK	5000	AC	
24,GB	96,GB	10000	AC	
25,GB	96,GB	5000	AC	
26,NL	94,NL	5000	AC	
27,NO	91,NO	10000	AC	
28,DE	93,DE	5000	AC	
29,DK	92,DK	5000	AC	
30,NL	94,NL	5000	AC	
31,NL	94,NL	5000	AC	
32,FR	97,FR	10000	AC	
33,FR	97,FR	10000	AC	
34,FR	35,GB	4000	AC	
93,DE	94,NL	5000	AC	
93,DE	92,DK	3500	AC	
93,DE	95,BE	1000	AC	
94,NL	95,BE	2400	AC	
96,GB	35,GB	4000	AC	
97,FR	34,FR	4000	AC	
97,FR	95,BE	4300	AC	
97,FR	93,DE	3000	AC	
1,BE	21,BE	10000	DC	
2,DE	22,DE	10000	DC	
3,DK	23,DK	10000	DC	
4,GB	24,GB	10000	DC	
5,GB	25,GB	10000	DC	
6,NL	26,NL	10000	DC	
7,NL	30,NL	10000	DC	
8,NO	27,NO	10000	DC	
9,FR	32,FR	10000	DC	
10,FR	33,FR	10000	DC	
27,NO	24,GB	2800	DC	North Sea Link and NorthConnect
27,NO	28,DE	1400	DC	NordLink
27,NO	29,DK	1640	DC	Skagerakk
27,NO	30,NL	700	DC	NordNed
23,DK	30,NL	700	DC	COBRA
23,DK	24,GB	1400	DC	Viking
31,NL	25,GB	1000	DC	BritNed
21,BE	25,GB	1000	DC	NEMO
28,DE	25,GB	1400	DC	Neuconnect

Table 26: Emission factors: CO2 emission factors from fuel used for electricity generation.[33]

Fuel type	Emission factor[tCO2/MWh]
Coal	0.860
Oil	0.675
Gas	0.400

Table 27: Efficiency and fuel cost: Input fuel cost per generation technology, calculated by fuel price and generation efficiencies at optimal operation. Data for gas and Other non-RES are collected from TYNDP 2020[31]. Data for nuclear, oil and coal are collected from ASSET project report 2018[35].

Generation Technology	Efficiency Ratio	Fuel Price[EUR/GJ]	Input co[EUR/MWh]
Nuclear	0.38	0.47	4
Other RES	0.58	7.31	45
Gas CCGT	0.55	7.31	48
Gas OCGT	0.40	7.31	66
Gas Conventional	0.39	7.31	67
Coal	0.43	6.91	58
Oil	0.35	18.45	190

Table 28: Maximum ramp-up/ramp-down rate: The rates are given in fraction per minute[32]. The input rates are these rates multiplied with 60 and with the total installed capacity for the given generator. The generation technologies not listed are assumed to have full flexible ramping, with a ramping rate of 1.

Generation Technology	up_i(fraction per minute)	dn_i(fraction per minute)
Coal	0.0093	-0.011
Gas CCGT	0.0081	0.0114
Gas OCGT	0.0119	-0.0123
Gas Conventional	0.0119	-0.0123
Other RES	0.014	-0.012
Nuclear	0	0

B Results

Table 29: Annual production reference scenario [TWh]

	BE	DE	DK	FR	GB	NL	NO
coal	0.003	0.000	0.005	0.000	0.000	0.008	0.000
gas	15.955	52.146	0.838	0.200	32.391	20.613	0.000
hydro	4.185	43.928	0.000	78.402	17.422	0.161	98.148
nuclear	0.000	0.000	0.000	261.000	130.000	0.000	0.000
oil	0.000	0.001	0.002	0.000	0.000	0.000	0.000
other_non_RES	0.132	6.083	0.136	0.824	0.004	0.300	0.002
other_RES	1.243	30.961	3.773	10.759	29.644	3.148	0.533
solar_pv	12.759	109.000	1.825	49.869	27.174	19.847	0.047
wind	18.959	235.00	17.650	127.000	50.990	25.371	31.095
wind_offshore	19.712	75.804	38.743	32.265	119.081	55.659	12.884
Total:	72.949	552.923	62.972	560.318	406.707	125.107	142.708

Table 30: Annual production GEP&TEP scenario [TWh]

	BE	DE	DK	FR	GB	NL	NO
coal	0.002	0.000	0.000	0.000	0.000	0.000	0.000
gas	11.988	38.167	0.250	0.138	19.582	13.874	0.000
hydro	4.185	43.928	0.000	78.402	17.422	0.161	109.805
nuclear	0.000	0.000	0.000	261.971	130.012	0.000	0.000
oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_non_RES	0.103	3.607	0.024	0.716	0.000	0.186	0.002
other_RES	1.227	31.052	3.743	10.402	27.010	3.127	0.533
solar_pv	12.759	108.970	1.825	49.869	27.174	19.847	0.047
wind	18.959	235.746	17.650	127.247	50.990	25.374	31.095
wind_offshore	19.787	76.830	54.587	31.542	132.407	61.358	12.707
Total:	69.010	538.301	78.078	559.286	404.597	123.927	154.187

Table 31: Annual production flexible demand scenario [TWh]

	BE	DE	DK	FR	GB	NL	NO
coal	0.000	0.000	0.000	0.000	0.000	0.000	0.000
gas	0.453	4.863	0.033	0.000	0.588	2.014	0.000
hydro	4.185	43.928	0.000	78.402	17.422	0.161	67.635
nuclear	0.000	0.000	0.000	260.971	130.012	0.000	0.000
oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_non_RES	0.000	0.050	0.000	0.000	0.000	0.000	0.002
other_RES	1.217	30.350	3.636	10.943	28.348	3.091	0.533
solar_pv	12.759	108.970	1.825	49.869	27.174	19.847	0.047
wind	18.959	235.464	17.650	128.193	50.990	25.372	35.758
wind_offshore	20.027	76.293	51.245	33.615	130.106	55.566	12.871
Total:	57.601	499.919	74.389	561.993	384.641	106.051	116.846

Table 32: Capacity factor reference scenario

	BE	DE	DK	FR	GB	NL	NO
battery	9,30	11,60	11,00	7,30	9,30	13,60	-
coal	0,06	-	0,08	-	0,00	0,03	-
gas_CCGT	23,91	38,72	21,68	0,34	10,57	27,18	-
gas_conventional	0,23	0,39	0,46	-	0,00	-	-
gas_OCGT	0,32	0,56	-	0,10	0,00	0,27	-
hydro	30,00	30,00	-	30,00	30,00	-	31,07
nuclear	-	-	-	80,00	80,00	-	-
oil	0,03	0,04	0,05	-	0,00	-	-
other_non_RES	1,14	3,38	3,13	1,44	0,01	0,91	0,09
other_RES	68,89	67,51	68,48	48,18	72,00	66,55	80,00
run_of_river	40,00	40,00	-	40,00	40,00	40,00	-
solar_pv	11,82	11,84	11,26	13,82	11,39	11,65	9,87
wind	30,35	28,09	31,84	33,08	37,53	28,68	44,66
wind_offshore	37,32	36,24	35,03	29,64	36,97	38,51	60,85

Table 33: Capacity factor GEP&TEP scenario

	BE	DE	DK	FR	GB	NL	NO
battery	9,30	11,60	11,00	7,30	9,30	13,60	-
coal	0,03	-	0,00	-	0,00	0,00	-
gas_CCGT	17,98	28,42	6,57	0,24	6,39	18,30	-
gas_conventional	0,11	0,06	0,05	-	0,00	-	-
gas_OCGT	0,14	0,22	-	0,07	0,00	0,06	-
hydro	30,00	30,00	-	30,00	30,00	-	34,76
nuclear	-	-	-	80,00	80,00	-	-
oil	0,01	0,00	0,00	-	0,00	-	-
other_non_RES	0,88	2,00	0,55	1,25	0,00	0,56	0,09
other_RES	68,01	67,71	67,93	46,58	65,60	66,11	80,00
run_of_river	40,00	40,00	-	40,00	40,00	40,00	-
solar_pv	11,82	11,84	11,26	13,82	11,39	11,65	9,87
wind	30,35	28,21	31,84	33,12	37,53	28,68	44,66
wind_offshore	37,46	36,73	49,36	28,98	41,11	42,45	60,01

Table 34: Capacity factor flexible demand scenario

	BE	DE	DK	FR	GB	NL	NO
battery	9,30	11,60	11,00	7,30	9,30	13,60	-
coal	0,00	-	0,00	-	0,00	0,00	-
gas_CCGT	0,68	3,63	0,88	0,00	0,19	2,67	-
gas_conventional	0,00	0,00	0,00	-	0,00	-	-
gas_OCGT	0,00	0,00	-	0,00	0,00	0,00	-
hydro	30,00	30,00	-	30,00	30,00	-	21,41
nuclear	-	-	-	80,00	80,00	-	-
oil	0,00	0,00	0,00	-	0,00	-	-
other_non_RES	0,00	0,03	0,00	0,00	0,00	0,00	0,09
other_RES	67,46	66,18	65,99	49,01	68,85	65,33	80,00
run_of_river	40,00	40,00	-	40,00	40,00	40,00	-
solar_pv	11,82	11,84	11,26	13,82	11,39	11,65	9,87
wind	30,35	28,18	31,84	33,37	37,53	28,68	44,66
wind_offshore	37,91	36,47	46,33	30,88	40,40	38,44	60,79

Table 35: Emissions reference scenario [tCO2]

	BE	DE	DK	FR	GB	NL	NO
coal	3006	0	4527	0	0	6978	0
gas	6382169	20858311	335047	79868	12956518	8245064	0
oil	320	552	1112	0	0	0	0
other_non_RES	52676	2433271	54469	329675	1505	119889	806
Total	6438170	23292133	395156	409544	12958023	8371931	806

Table 36: Emissions GEP&TEP scenario [tCO2]

	BE	DE	DK	FR	GB	NL	NO
coal	1406	0		0	0		0
gas	4795270	15266797	99889	55111	7832809	5549797	0
oil	107	0	0	0	0	0	0
other_non_RES	41036	1442956	9536	286226	0	74404	806
Total	4837819	16709753	109424	341336	7832809	5624201	806

Table 37: Emissions flexible demand scenario [tCO2]

	BE	DE	DK	FR	GB	NL	NO
coal	0	0		0	0		0
gas	181234	1945167	13255	0	235066	805772	0
oil	0	0	0	0	0	0	0
other_non_RES	0	20139	0	0	0	0	806
Total	181234	1965306	13255	0	235066	805772	806

B.1 Net-zero emission results

Table 38: Annual production configuration with Ncl&FL [TWh]

	BE	DE	DK	FR	GB	NL	NO
coal	0.000	0.000	0.000	0.000	0.000	0.000	0.000
gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000
hydro	4.185	43.928	0.000	78.402	17.422	0.161	73.823
nuclear	0.000	0.000	0.000	260.971	130.012	0.000	0.000
oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_non_RES	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_RES	1.229	31.216	3.795	12.102	28.617	3.209	0.533
solar_pv	12.759	108.970	1.825	49.869	27.174	19.847	0.047
wind	18.959	236.588	17.650	128.778	50.990	25.374	31.095
wind_offshore	19.698	78.118	54.790	35.588	135.379	60.148	12.788
Total:	56.831	498.821	78.059	565.711	389.596	108.738	118.285

Table 39: Annual production configuration with FL and without Ncl [TWh]

	BE	DE	DK	FR	GB	NL	NO
coal	0.000	0.000	0.000	0.000	0.000	0.000	0.000
gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000
hydro	4.185	43.928	0.000	78.402	17.422	0.161	82.236
nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000
oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_non_RES	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_RES	1.332	31.556	3.746	17.004	29.514	3.295	0.533
solar_pv	12.759	108.970	1.825	49.869	27.174	19.847	0.047
wind	27.653	236.752	21.657	217.748	149.621	25.374	31.095
wind_offshore	27.530	79.112	49.363	86.337	135.629	61.285	46.075
Total:	73.459	500.318	76.590	449.396	359.360	109.962	159.985

Table 40: Annual production configuration with Ncl and without FL [TWh]

	BE	DE	DK	FR	GB	NL	NO
coal	0.000	0.000	0.000	0.000	0.000	0.000	0.000
gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000
hydro	4.185	43.928	0.000	69.514	16.823	0.161	55.504
nuclear	0.000	0.000	0.000	260.971	130.012	0.000	0.000
oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_non_RES	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_RES	0.717	20.229	2.336	7.096	15.147	2.033	0.425
solar_pv	12.759	108.970	1.825	49.869	27.174	19.847	0.047
wind	18.941	235.095	36.171	205.091	146.066	25.361	31.095
wind_offshore	17.669	84.217	50.247	20.721	73.809	45.550	69.774
Total:	54.271	492.440	90.578	613.262	409.032	92.952	156.844

Table 41: Annual production configuration without Ncl&FL [TWh]

	BE	DE	DK	FR	GB	NL	NO
coal	0.000	0.000	0.000	0.000	0.000	0.000	0.000
gas	0.000	0.000	0.000	0.000	0.000	0.000	0.000
hydro	3.958	41.959	0.000	78.402	17.422	0.161	47.179
nuclear	0.000	0.000	0.000	0.000	0.000	0.000	0.000
oil	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_non_RES	0.000	0.000	0.000	0.000	0.000	0.000	0.000
other_RES	0.606	16.212	1.774	9.063	19.007	1.592	0.390
solar_pv	12.759	108.970	1.825	49.869	27.174	19.847	0.047
wind	89.400	279.603	59.449	217.473	149.336	25.374	31.095
wind_offshore	31.418	91.139	48.617	130.473	147.199	59.645	80.125
Total:	138.141	537.884	111.665	485.280	360.138	106.619	158.836

B.2 Sensitivity results

Table 42: Capacity factors of the different cliimate years [%]

	BE	DE	DK	FR	GB	NL	NO
solar PV, 1982	12.10	12.42	11.58	13.58	10.74	12.17	10.03
Solar PV, 1984	11.82	11.84	11.25	13.82	11.39	11.65	9.87
Solar PV, 2007	12.41	12.61	11.53	14.18	11.03	12.27	9.68
Onshore wind, 1982	31.35	25.43	28.61	33.19	38.93	29.65	41.29
Onshore wind, 1984	30.35	28.09	31.84	33.08	37.53	28.68	44.66
Onshore wind, 2007	33.53	29.73	34.18	34.24	39.72	31.93	41.58
Offshore wind, 1982	37.32	36.24	35.03	29.64	36.98	38.51	60.85
Offshore wind, 1984	37.76	33.56	32.19	28.89	37.19	35.82	58.70
Offshore wind, 2007	38.56	32.99	31.39	30.31	36.28	36.79	58.19

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