Master's thesis

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

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Transmission investments under uncertainty

Assessment of how different European energy scenarios for 2030 influence the North Sea Offshore Grid

Master's thesis in Energy and Environmental Engineering
Supervisor: Hossein Farahmand
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Abstract

The North Sea Offshore Grid is considered being an important project towards more renewable power production and increased electricity market integration. The North Sea region has a significant potential for offshore wind production due to its favorable wind conditions. The wind power can be included in a way that ensures the security of supply by increasing the cross-border capacity between the North Sea bordering countries.

The main contribution of this thesis is the investigation of how investments in the North Sea Offshore Grid are affected by uncertainty. A stochastic two-stage model, formulated as a mixed integer linear program, is derived from the deterministic version of the transmission expansion model, PowerGIM. The model focuses on the expansion of three interconnectors; Great Britain to Norway, Germany to Norway, and Denmark to Great Britain. The model accounts for uncertainty, in terms of installed generation capacity, demand, and fuel and CO_2 prices, in the operation of the system in the year 2030. Two case studies are performed, and in total, seven scenarios for the year 2030 are applied. The input data and four scenarios in the first case study are collected from the Ten-Year Network Development Plan (TYNDP) from 2016 published by ENTSO-E, while the TYNDP 2018 is utilized in the three scenarios in the second case study.

The case studies demonstrate that more installed capacity from renewable energy sources (RES) and higher marginal costs of the generators result in a higher optimal capacity of the interconnectors in the model. Among other things, this occurs because the need for flexibility increases and interconnectors can contribute with that flexibility by transferring excess power produced by RES, from power surplus areas to power deficit areas. The two case studies have almost the same optimal capacity investment of the interconnectors. However, in the second case study, the model finds it optimal to invest 1000 MW less in the interconnector between Great Britain and Denmark due to the amount of installed solar capacity. Furthermore, the power generated from renewable energy sources in the system increases by 2% with optimal interconnector expansion. Consequently, the average area prices decrease.

A deterministic model is used, in addition to the stochastic model, to quantify metrics concerning the Expected Value of Perfect Information (EVPI) and the Value of the Stochastic Solution (VSS). With the given data and assumptions it is shown that a system planner is willing to pay a maximum between 0.17% to 0.22 % of the stochastic cost for perfect information about the future generation capacity, demand, and prices. The expected cost saving for a system planner by use of a stochastic program is 5.06% or 3.2 % of the stochastic cost, depending on the case, in comparison with a deterministic approach that copes with uncertainty.

Sammendrag

Nordsjønettet er ansett som et viktig prosjekt for å inkludere mer fornybar kraftproduksjon og øke integrasjon av kraftmarkeder. Nordsjøområdene har et stort potensial for offshore vindkraftproduksjon på grunn av de gunstige vindforholdene, med stabil, høy vindstyrke. Denne vindkraften kan inkluderes i kraftsystemet ved økt utbygging av handelskapasitet mellom Nordsjølandene.

Bidraget til denne oppgaven er undersøkelse av hvordan investeringene i Nordsjønettet påvirkes av usikkerhet. En stokastisk to-stegs modell, formulert som et blandet lineært heltallsproblem, er utledet fra den deterministiske versjonen av en modell for nettutbyggingsplanlegging, PowerGIM. Modellen benyttes til å evaluere utbygging av tre mellomlandsforbindelser, mellom Storbritannia og Norge, Storbritannia og Danmark og mellom Norge og Tyskland. Modellen inkluderer usikkerhet i form av installert generatorkapasitet, etterspørsel og drivstoff- og CO_2-priser for kraftsystemet i år 2030. To casestudier er utført, med totalt sju scenarioer for dette kraftsystemet i 2030. De fire scenarioene i det første casestudiet er basert på nettutviklingsplanen fra ENTSO-E, kalt TYNDP, fra 2016, mens de tre scenarioene i det andre casestudiet er basert på TYNDP 2018.

Casestudiene viser at mer installert fornybar energi kapasitet og høyere marginalkostnader på generatorene resulterer i en høyere optimal installert kapasitet på mellomlandsforbindelsene i modellen. Dette skjer blant annet fordi behovet for fleksibilitet øker, og mellomlandsforbindelsene kan bidra med denne fleksibiliteten ved å overføre overskuddsenergi produsert av fornybare energikilder i land med kraftoverskudd til land med kraftunderskudd. Optimal installert kapasitet i mellomlandsforbindelsene er nesten den samme i begge casestudiene, men modellen finner det optimalt å installere 1000 MW mindre kapasitet i forbindelsen mellom Storbritannia og Danmark i den andre casestudien. Dette skjer på grunn av mengden solceller installert. Videre vises det at generert energi fra fornybare energikilder øker 2% med utbygging av den optimale kapasiteten på mellomlandsforbindelsene. Som en konsekvens minker de gjennomsnittlige områdeprisene.

En deterministisk modell benyttes i tillegg til den stokastiske modellen for å bestemme den forventede verdien av perfekt informasjon (EVPI) og verdien av den stokastiske løsningen (VSS). Med den gitte inndataen og antakelsene, vises det at en systemplanlegger er maksimalt villig til å betale mellom 0.17% og 0.22% av den totale stokastiske kostnaden, for å få perfekt informasjon om fremtidig installert generatorkapasitet, etterspørsel og priser. Den forventede verdien en systemplanlegger kan spare ved å benytte en stokastisk modell, i stedet for en deterministisk me som inkluderer usikkerhet i form av forventningsverdier, er 5.06 % eller 3.2% av den totale stokastiske kostnaden, avhengig casestudiet.

Preface

This Master's Thesis is concluding my five year Master's degree in Energy and Environmental Engineering. My field of specialization has been Energy Analysis and Planning. The report is written at the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU).

I would like to express my sincere gratitude to my supervisors Associate Professor Hossein Farahmand and Ph.D candidate Simon Indrøy Risanger for their motivating guidance, interesting discussions and honest feedback.

The work with the thesis has been challenging with a lot of ups and downs. I have largely improved my programming skills by learning a new programming language, Python, and applying the optimization package Pyomo.

Gratitude is also given to Gurobi Optimization for enabling me to use their solver under the academic license. Finally, I am grateful for the love and support from my fellow students and my boyfriend.

Trondheim, June 2019

Mina Mathilde Grøterud

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Abbreviations

EEV	=	Expected Value of the Expected Cost Solution.
ENTSO-E	=	European Network Of Transmission System Operators For Electricity.
EVPI	=	Expected Value of Perfect Information.
GTEP	=	Generation And Transmission Expansion Planning.
LP	=	Linear Programming.
MILP	=	Mixed Integer Linear Programming.
NSOG	=	North Sea Offshore Grid.
OWP	=	Offshore Wind Production.
PowerGAMA	=	Power Grid And Market Analysis.
PowerGIM	=	Power Grid Investment Model.
PV	=	Photovoltaic.
RES	=	Renewable Energy Sources.
TEP	=	Transmission Expansion Planning.
TSO	=	Transmission System Operator.
TYNDP	=	Ten-Year Network Development Plan.
VSS	=	Value of the Stochastic Solution.

Chapter 1

Introduction

The 2030 Framework for climate and energy was adopted by the European Commission in October 2014. The framework has targets and policy objectives for the whole EU for the period between 2020 and 2030. It should help the progress towards a low-carbon economy and create an energy system which makes new opportunities for growth and jobs, increases the self-supply of energy and the security of supply, ensures affordable energy for all consumers, and brings environmental and health benefits. The main targets are to cut at least 40% in greenhouse gas emissions, have at least 32% renewable energy share and obtain an improvement of at least 32.5% in energy efficiency [1]. This puts pressure on today's power system as large-scale intermittent power production in remote areas is expected to be introduced to fulfill the goals, in addition to the introduction of Smart Grids and other radical changes on the demand and the supply side. Building more cross-border capacity is a cost-effective and simple way to maintain the security and flexibility of the power system when more variable and unpredictable renewables are integrated. Through high-voltage transmission lines, the system can obtain flexibility in such a way that the generation resources and demand spread across large geographical areas [2].

One of the five priorities within the European Commission's energy framework is to create a fully integrated European energy market. The strategy includes the target of having 15% interconnection capacity within the year 2030 [3]. This means that each member state should have interconnectors that allow transportation of 15% of the electricity produced in the country across its border to neighboring countries. The commission hopes that this ensure competitive energy prices, reduce the need for building new power plants, and increase the reliability and security of energy supply. Increased interconnection capacity makes it possible to transfer power from renewable energy sources (RES) in surplus areas to areas with a power deficit, which decreases the need for non-RES and maintain the security of supply. It is easier to balance the variability of intermittent energy generation, such as solar and wind production when having a large, connected area with weather differences.

The North Sea Offshore Grid (NSOG) has been identified as the number one strategic trans-European energy infrastructure corridor in the EU regulation No 347/2013[4]. The North Sea has enormous potential for offshore wind production (OWP) due to large offshore areas with favorable wind conditions. Additionally, Norway has a large amount of hydropower, which can store energy, and contribute by supplying power when other RES is unavailable. Consequently, the NSOG is an important transmission expansion project as it integrates OWP and increases cross-border trading [2, 5]. Such large-scale investments are challenging to implement since there is no centralized authority with the legal power to force countries to accept the proposed plan [6]. In order to cope with the changing energy mix and strategic outlines made by policymakers, it is essential to evaluate proper expansion planning models. The models should be able to evaluate multinational investments and cope with the increased uncertainty at the supply side in a future integrated market. By utilization of a stochastic model, uncertainty about the future operation can be incorporated. A stochastic model can give the optimal here-and-now investment, which is hedged against future market outcomes. Contrary to a deterministic model where the operational stage is given.

A specialization project prior to this Master's Thesis was conducted by the same author in the fall of 2018. The project investigated the profitability of three different interconnectors in the NSOG by use of a deterministic model. The investigation is continued in this thesis with the incorporation of uncertainty by the use of a stochastic model. Additionally, the study is expanded to evaluate a second case study with input data from the Ten-Year Network Development Plan (TYNDP) 2018. The thesis aims to answer the following research questions:

1. How does the stochastic model solution differ from its deterministic counterpart?
2. How are investments in the North Sea Offshore Grid affected by uncertainty in terms of installed generation capacity, fuel prices, and demand?
3. How do the optimal investments affect the generated energy and the average area prices?

1.1 Scope of the report

This thesis demonstrates the findings of a case study of the NSOG. Combinations of three different interconnectors are investigated, with the utilization of a stochastic optimization model which consider the uncertainty of the market operation in 2030 by the use of different scenarios. Two case studies are performed, where the scenarios are based on the four visions for 2030 in the TYNDP from 2016, and the three scenarios in the TYNDP 2018. TYNDP is a report published by European Network of Transmission System Operators for Electricity (ENTSO-E) biyearly which includes scenarios for the future European power system. The investigated interconnectors are from Norway to Great Britain (North Sea Link), from Denmark to Great Britain

(Viking Link) and from Norway to Germany (NordLink). These interconnectors represent well-planned projects which are expected to be commissioned in 2020-2022. The following bullet points represent the content of the report:

- Establish two input data sets for 2030 by use of TYNDP 2016 and TYNDP 2018.
- Compose a stochastic transmission expansion planning model.
- Analyze and compare the stochastic results with the deterministic investment decisions.
- Investigate how the investments respond to changes in the input data by a sensitivity analysis.

The transmission expansion planning (TEP) model is used to evaluate how uncertainties affect the optimal investment decision. An investment decision for large HVDC interconnectors is usually executed many years before the actual project implementation and installation, hence it is important to analyze the investments under different possible future market operations in term of scenarios to obtain the investment decision that minimizes the system's total cost. Due to the planning horizon and implementation times, the long-term scenarios must be employed to incorporate development pathways of the energy system, for instance, increased production from RES and offshore wind. Comparisons of model outputs from each scenario in the deterministic model and the stochastic model are important to quantify the significance of uncertainty, as well as indicate the importance of handling uncertainty in investment decisions.

1.2 Structure

The next chapter presents a literature review of research on the topics treated in this report regarding the North Sea offshore grid and TEP with uncertainty. Chapter 3 presents the background and theory with regards to transmission expansion planning and a description of ENTSO-E's Ten-Year Network Development Plan from 2016 and 2018. The methodology in Chapter 4 gives a presentation of the model, both the mathematical aspect and a thorough explanation of the model applied to the NSOG. Additionally, the methodology chapter includes an overview of the input data with assumptions and sources. Chapter 5 explains and discusses the model results, in addition to the limitations of the work. Finally, the conclusion and recommendations for further work are given in Chapter 6.

Chapter 2

Literature Review

The literature review presents an overview of previous work, existing methods, and studies regarding the topics in this report. The main focus is on previous studies and methods applied to the NSOG and TEP methods under uncertainty.

Chapter 2.1, about previous North Sea offshore grid studies, was written in the specialization project. However, some extensions with relevant articles are made. Some of the articles in Chapter 2.2 was included in the specialization project, but are included here with the aspect of uncertainty.

2.1 North Sea offshore grid studies

The background for the NSOG with an overview of the various proposals from different stakeholders and researchers by 2009 is presented in an article by De Decker and Woyte [5]. They state that the three main drivers for the development of offshore electricity interconnectors are the integration of high amount of new renewable energy, the requirement for security of supply, and the will to create a single European Energy Market. Four challenges for offshore grid development are presented in the article; *market challenges*, for instance, uncertainty of offshore wind farm development and financial risk, *technical challenges* such as bottlenecks in the onshore transmission system or challenges with operation and maintenance, *regulatory challenges* like differences in legislation and grid codes and *policy challenges* such as differences in allowed profit margins and unclear cost allocation. The Third Internal Electricity Market Package, which came into force in 2011 to improve the function of the internal European market and resolve structural problems, is expected to solve many of the mentioned challenges. A part of this is the establishment of the Agency of the Cooperation of Energy Regulators, which is essential to create a common regulatory framework, with the responsibilities of creating common network rules, coordinate and complement the work of national regulatory authorities [7].

Spro, Torres-Olguin, and Korpås [8] investigate the different aspects of the realization of a North Sea offshore grid. They focus on creating a meshed offshore grid with underwater storage that should contribute to the flexibility of the system. However, challenges of such a system exist, with regards to technology availability, standardization, cost-benefit sharing, and regulatory schemes of the surrounding countries. On the other hand, several studies have discovered profitability of investment in offshore grids in the North Sea. They conclude that future work should include techno-economical evaluations of different North Sea offshore grids with storage possibilities, to provide infrastructure that can balance the increased level of renewable energy in Europe.

Konstantelos et al. [2] present a study regarding the combination of cross-border link and the connection of offshore wind power plants. They analyze three particular interconnection cases in the North Sea concerning the quantification of costs and benefits. An optimization model for a pan-European wholesale electricity market is utilized to study both the conventional, point-to-point network and the integrated network design. Results from the analysis prove that the integrated network is most beneficial, in all three case studies. However, the model detects asymmetric cost-benefit allocation that can be found problematic. Some countries are found to be in a better position, while some countries are found to be in a worse position, despite the increase in total social welfare.

Doorman and Frøystad analyze the profitability of different interconnection alternatives between Norway and Great Britain for present and future scenarios [9]. The analysis is done from a merchant and a social welfare point of view. From the social welfare perspective, all the interconnectors are profitable under all sets of assumptions. In contrast, none of the interconnectors are profitable from the merchant viewpoint.

A literature review, written by Gorenstein Dedecca and Hakvoort [10] in 2016, declares the current and future research of the North Sea offshore grid modeling. The review analyzes the literature with a practical methodology that can be applied to other reviews of energy system models, and take into consideration the system characteristics, categories, and relevant indicators. The analysis points out that most of the studies focus on investment and operation of the grid by the use of optimization models, with little use of other research questions or different model approaches. However, the different studies present significant differences in methodology and assumptions, mostly due to the differences in installed generation capacities. As a consequence, the results vary significantly and complicate the comparability. Nevertheless, a common thread is that a meshed grid may increase the benefits, compared to a radial grid, due to the requirements of less investment and reduction in offshore wind curtailment. On the other hand, a meshed grid can probably create asymmetric distributions without adequate allocations of costs and benefits. Finally, some recommendations for furthers research are given. Future research should try to be thorough of the presentation and resolution of data, assumptions, and results, and consider grid characteristics relevant to the research question.

Gorstein Dedecca et al. expands the transmission expansion planning methods of the NSOG by including governance constraints in a study in 2018 [11]. Expansion planning in Europe usually occurs at the national level, and it does not consider integrated grids. ENTSO-E is an example of an association that promotes closer cooperation among TSOs in Europe, but there is still a lack of a governance framework for the offshore grid. Gorstein Dedecca et al. indicate that earlier studies have largely omitted governance barriers and kept it unaddressed, and model these barriers by using integrated governance constraints in a TEP model. The constraints are modeled by the use of Pareto welfare and integration constraints. In the Pareto welfare constraints, there is included the veto of a North Sea country to the investment in integrated lines, where a country which experiences decreased welfare can choose to not invest in the line. The results from the model, applied on a NSOG long-term case study, confirm that the offshore grid is beneficial to the society.

The need for cooperation and unfair cost-benefit allocation are assumed to be two significant challenges for the development of the NSOG. A NSOG study by Kristiansen, Munoz, Oren, and Korpås [12] utilizes the most ambitious TYNDP vision by ENTSO-E as input data in the open-source mixed integer linear programming (MILP) model in Python, PowerGIM. The main focus of their study is to investigate how of the Shapley Value can be used for the allocation of net benefit from transmission interconnectors under cooperation. [13] extends the former work. These cost-benefit allocation methods are beyond the scope of the case study, but they are mentioned due to their utilization of the same transmission expansion model, PowerGIM, and partly similar input data from ENTSO-E.

Kristiansen, Svendsen, Korpås, and Fleten [14] utilizes the same transmission expansion planning model, PowerGIM, in their study about uncertainty in transmission expansion planning models. The objective of the study is to incorporate uncertainty regarding future offshore wind deployment and allow two investment stages for grid expansion. The study uses a stochastic two-stage version of PowerGIM, with data from ENTOS-E's TYNDP 2016 vision 4, in addition to different offshore wind capacity scenarios. A deterministic program of the equivalent program is used to calculate the Expected Value of Perfect Information (EVPI), the Value of the Stochastic Solution (VSS), and the real option value. The study proves that a system planner can gain a maximum of 1.72 billion euros in terms of cost savings if having the perfect information about the future wind deployment. Additionally, a forward-looking system planner can save 22.3 million euros by using a stochastic program instead of a deterministic approach. The study provides useful information about key support tools available for TEP that cope with uncertainty and indicates economic profitability. However, a few assumptions and weaknesses are limiting the validity of the results, for instance, utilization of the ENTSO-E scenario with the strongest grid infrastructure and the most renewable capacity.

2.2 Transmission expansion planning under uncertainty

Hemmati, Hooshmand and Khodabakhshian [15] have prepared a comprehensive review of the state-of-the-art of transmission expansion planning until 2013. There is not a unique method which is the optimal in TEP, as it differs from one system to another. TEP is often faced with risk. Therefore, TEP methods should be incorporated to deal with uncertainties. The most common methods used to deal with uncertainties are Monte-Carlo Simulation and mathematical-statistical model. Monte-Carlo simulation is a numerical method based on iteration, while mathematical-statistical models, for instance, stochastic optimization, uses probabilistic models for considering uncertainty. Finally, the review concludes that there is still much work left with TEP methods which encompass, for instance, distributed generation, hydropower stations, generation expansion planning, and intermittent power production from PV and wind.

The study by Lumbreras and Ramos [6] is a comprehensive literature review of transmission planning as well, but it focuses on TEP in a European context. Challenges in transmission planning are analyzed, and different methods for solving the TEP problem are discussed. Treatment and scope of uncertainties is a part of TEP modeling. The study call attention to three main tools applied for the treatment of uncertainties in transmission expansion; stochastic optimization, robust optimization, and fuzzy decision analysis. It is recommended to identify and include the main uncertainties in transmission plans, as long as its incorporation does not result in an unmanageable problem. Stochastic optimization is appointed as the most reasonable method to treat short-term risk and uncertainties, for instance, demand and renewable energy production, while long-term uncertainties may be better approached by the use of robust optimization or fuzzy decision analysis.

Gacitua et al. present an up-to-date review on expansion planning models and their applications in the energy policy [16]. An overview of different optimization models used for expansion planning is included in the review, in addition to a comparison of their role as decision support tools for energy analysis. From the overview presented, mixed integer linear programming (MILP) appears as the most common optimization method in TEP. However, only a few of the investigated studies incorporate uncertainty with a stochastic programming approach. The authors indicate the importance of handling uncertainty in TEP due that the construction of new transmission lines is capital intensive and represents a strategic decision that can not be reversed. As stochastic optimization makes it possible to account for uncertainty in load growth and generation, scenario reduction techniques can be necessary to keep the optimization problem tractable.

One of the studies examined in the review by Gacitua et al. is by Munoz and Watson [17]. They propose a scalable decomposition algorithm to solve stochastic transmission planning problems, by considering discrete and continuous decision variables for transmission investments. This is a result of the currently limited stochastic modeling capabilities in the commercial software tools for TEP and the lack of practical solution techniques to solve stochastic models. Their resulting stochastic mixed integer linear optimization model is decomposed on a scenario basis and solved using a variant of the Progressive Hedging algorithm. As a result, a massive problem with uncertainty in load and RES power availability is solved to a high degree of accuracy in a reasonable time-frame.

Cedeño and Arora compare deterministic and stochastic TEP models in [18]. The performance of the models is measured as minimization of the total expected costs and the range of the operational costs over the set of the assumed scenarios. The paper shows that TEP plans which consider uncertainty perform better than plans with deterministic models, both in terms of minimization the total expected cost and the range of operational costs.

Flexible TEP with uncertainties in an electricity market is performed by Zao et al. in [19]. A mixed integer non-linear programming model is used to minimize the expansion investment cost, and maximizing the system reliability and security. The goal is to minimize the planning risk and obtain the most flexible expansion plan that has the least adaption cost.

Most of the existing literature on TEP under uncertainty, such as [18], [17] and [19], focus on one-time period investment problems. However, Van der Weijde and Hobbs [20] presents a stochastic optimization model for transmission planning, which allows two investment stages, applied on inter-regional grid reinforcements in Great Britain. In the model, investment decisions can be made in two periods, where each time is followed by market response, such that investment options can be delayed until more information is known, for instance, about renewables. Their results show that ignoring uncertainty in TEP has quantifiable economic consequences and that considering uncertainty can lead to decisions that have lower expected costs than traditional deterministic transmission planning methods.

2.3 Contributions

The literature review supports the contribution of this report regarding NSOG expansion planning. The main contribution is the application of input data consisting of four different scenarios from TYNDP 2016 and three different scenarios from TYNDP 2018 in a stochastic model, to evaluate how investments in the NSOG are affected by uncertainty. This study is a continuation of the work in the specialization project, *North Sea Offshore grid profitability in different 2030 scenarios*, where the four scenarios from TYNDP 2016 were used in a deterministic TEP model. Previous NSOG studies, for instance, [11], apply data from *e-highway 2050*'s five scenarios, besides, that the interconnection capacity is specified in the input data. This is a difference from this study, where the model decides the capacity. Furthermore, the literature review by Gorstein Dedecca and Hakvoort [10] emphasizes few NSOG studies with four scenarios have been accomplished. The study by Konstantelos et al. [2] utilizes four scenarios, but the input data is not open-source.

In this case study, a stochastic MILP model is applied for solving the TEP problem by an open source optimization model in Python, PowerGIM. As investigated by Gacitua et al. [16] MILP is the most common TEP model approach. Therefore, it can be considered as an acknowledged optimization method for TEP. [6], [16] and [15] indicate the importance of incorporating uncertainty in TEP, but prove that there is still much work left with stochastic TEP methods. [19], [18] and [17], are a selection of case studies that prove profitability of using stochastic programming. However, they are not applied to the NSOG, and some have a different modeling technique than stochastic MILP. The study by Kristiansen et al. [14] is probably the most similar existing study, as it uses the same model, the stochastic version of PowerGIM, but it does not apply more than one TYNDP 2016 scenario. The scenario is the most ambitious scenario, considering that the scenario is on track of the 2050 targets. Furthermore, Kristiansen et al. 's study only considers uncertainty in wind capacity, while this case study considers uncertainties in generation capacities, demand, and prices. However, the study has different scenarios for OWP, but they are not based on the same well-documented input data.

Sources, simplifications, and assumptions thoroughly document the input data in this study. Subsequently, the output data is analyzed from a natural allocation perspective. The results from the stochastic model are compared with the deterministic results, to identify the benefit of using a stochastic model. Consequently, the case study contributes to information regarding how a model can incorporate uncertainty to get the most profitable investments in the North Sea Offshore Grid.

Chapter 3

Background

The background chapter presents the concepts used in this report. The chapter covers theory on optimization under uncertainty through stochastic programming, transmission expansion planning (TEP), and an overview of the scenarios in the Ten-Year Network Development Plan (TYNDP) by ENTSO-E. Both the 2016 and 2018 version of TYNDP is included. The section concerning TEP was written in the specialization project. General knowledge of the components and operation in electric power systems and electricity markets is assumed to be known and will be not presented here. If desired, the reader is referred to [21] and [22] for an introduction to the topics. Optimization knowledge is not required to understand the results and discussion in the report but is necessary in order to understand the mathematical formulation of the TEP model. The basic theory on optimization is not presented here due to its scope but can be found in [23], while a further introduction to stochastic programming can be found in [24].

3.1 Transmission expansion planning

Generation and transmission are the main functions of the electricity network. The transmission network is a natural monopoly and is used by all producers and consumers to trade electric energy. Its impact on the functioning of the system is enormous. Line outages can threaten the stability of the whole system, and congestion can prevent the flow of cheap energy from production areas to consumption areas. Therefore, it is crucial to have a transmission network that, in most cases, is invisible to the system. Consequently, energy trading is carried out without the presence of the network being noticed.

TEP is the process of identifying optimal reinforcement for an electrical transmission network. TEP is performed from a social welfare and infrastructure viewpoint, and a TSO usually performs the work. The problem is multi-objective and should evaluate the trade of energy, provide reliability for all users, minimize cost, and maximize social welfare. In order to present the TEP theory [25] is investigated.

Uncertain parameters should be considered when performing TEP. In traditionally infrastructure planning, infrastructure is designed to operate correctly under the worst probable condition. However, the worst future condition is unknown when planning electricity transmission lines. It is important not to end up designing an expensive transmission network which is more robust than needed, but it is also important to invest sufficiently to be able to design a network that can withstand the worst possible condition. A transmission network should be able to handle the power flow and supply the demand even in the typical worst-case scenarios as peak demand and during generation unit failure.

The planning horizon for transmission expansion extends over a long period of time. As a result of this, many uncertainties exist concerning, for instance, availability of existing generation units, demand growth and investment in new generation. Generation investments are of particular importance because they are developed by private actors and have a shorter installation time than transmission investments. Generation and transmission are dependent upon each other, therefore, they usually are planned jointly, through generation and transmission expansion planning (GTEP). However, this is a simplification. As a matter of fact the TSO, for instance, Norway's TSO, Statnett, has no authority of deciding where generation expansion should happen since private actors perform generation investments. On the other hand, the regulator, for instance, NVE in Norway, creates incentives, legislation, and marked designs that coincide with the desired generations investments.

From a view where the TSO is facilitating the energy trading between the producers and consumers, the objective function of the problem is minimizing the generation and load-shedding costs. The transmission line investment cost for the TSO is also included. Two different approaches are developed to perform TEP, a deterministic approach, and an adaptive robust approach. In the latter, optimal transmission expansion plans are obtained by taking into account the uncertainty in the demand and the capacity of generating units. A deterministic approach considers the largest expected demand in the planning horizon to obtain the optimal transmission plans. Binary variables are used to determine whether a prospective transmission line is built, thus the TEP problem can be formulated as a mixed-integer nonlinear programming (MINLP) problem due to products of continuous and binary variables. It is possible that a MINLP problem does not converge, hence being hard to solve. However, it is possible to use a linearization procedure of the continuous variables, and reformulate the problem as a mixed-integer linear programming (MILP) problem [25]. The MILP problem is easy to solve by applying conventional branch-and-cut methods. At the same time as minimizing the costs, the TSO strives to maximize the welfare, if perfect competition is assumed. Hence, the MILP problem ends up as a co-optimizing problem.

3.2 Optimization and Stochastic Programming

3.2.1 MILP

MILP models are well suited for large operational models which have several hundred or thousand input parameters and processes, such as hourly load profile and wind profiles. The objective function in a MILP problem is linear. The problem has bounds and linear constraints, and all of the constraints must be linear functions. Some of the variables in MILP problems are required to take integer variables, while others are allowed to be non-integers [26], [27].

3.2.2 Uncertainty

Uncertainty in modeling means that a given value may or may not occur in the future [28]. There exists a difference between stochastic uncertainty and random uncertainty. Stochastic uncertainty is probabilistic variations in, for instance, observations over time, while the random uncertainty is unpredictable uncertainty that can not be described by previous observations [28]. When creating a long-term investment model, it is important to acknowledge how the future operations of the system will be affected by the investments. In electric power systems, the uncertainty in long-term expansion planning involves the following [25] :

- Future load by the consumers located throughout the transmission network.
- Future changes in the investment costs of different technologies, both transmission and generation units, and especially renewable generation units.
- Future changes in the operating costs of different production technologies.
- Future investment decisions in production facilities made by producers.

Utilization of a stochastic modeling approach is a way to account for uncertainty in modeling.

3.2.3 Stochastic programming

Contrary to deterministic programming, stochastic programming can account for uncertainty in input parameters or by having probabilistic constraints [24]. In a two-stage formulation, the first stage (investments) are separated from the second stage (operational) variables of the problem. The first stage is a here-and-now investment decision, and the uncertainty is in the second stage of the model. In multi-stage and multi-horizon formulations, these two stages can occur periodically multiple times. The number of scenarios is growing exponentially with the number of periods in such formulations [24].

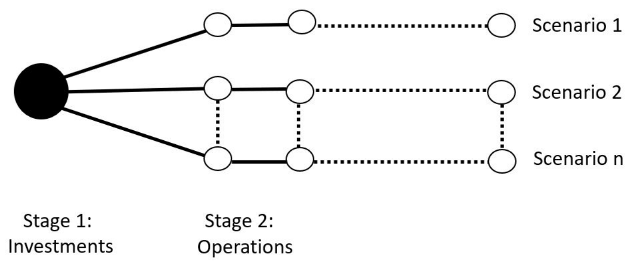


Figure 3.1: Scenario tree fro a two-stage stochastic model with one investment stage and multiple operation stages for each of the scenarios

Figure 3.1 displays the scenario tree of a two-stage stochastic model. The black circle represents the first stage, where the investment is made. This is also known as the strategic stage. The figure displays n scenarios of different operation outcomes, and each white circle represents a time step of the operation of the system. For instance, in the model utilized in this thesis, the operational time scale is hourly, and the model considers operation for a whole year. This gives 8760 white circles if one is not utilizing sampled sets. Figure 3.2 shows the deterministic equivalent model, which is a stochastic model of one scenario by the definition in [24]. The scenario trees are inspired by [29].

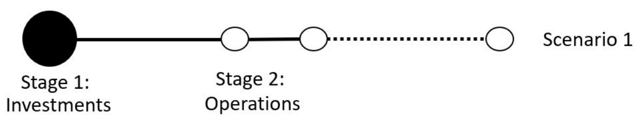


Figure 3.2: Deterministic equivalent scenario tree

The objective function of a two-stage model is divided into two parts, as given in 3.1. The two-stage stochastic programming problem below is a formulation of a generation and transmission expansion problem, concerning a single investment point in time.

$$\min_{\boldsymbol{x};\boldsymbol{y_\omega},\forall\omega} f^I(\boldsymbol{x}) + E_\omega\{f^O(\boldsymbol{y}_\omega)\} \tag{3.1}$$

$s.t$

$$\boldsymbol{h^I(x) = 0}$$

$$\boldsymbol{g^I(x) \leq 0}$$

$$\boldsymbol{x} \in X$$

$$\boldsymbol{h^O_\omega(x, y}_\omega) = 0 : \forall\omega \in \Omega$$

$$\boldsymbol{g^O_\omega(x, y}_\omega\boldsymbol{) \leq 0 :} \forall\omega \in \Omega$$

$$\boldsymbol{y}_\omega \in Y, \forall\omega \in \Omega$$

The problem in (3.1) attempts to minimize the total cost, consisting of the investment costs, $f^I(\boldsymbol{x})$, thereby investment variables $\boldsymbol{x}$ in transmission and generation facilities, and the expected operational costs, $E_\omega\{f^O(\boldsymbol{y}_\omega)\}$, thereby the operational variables $\boldsymbol{y}_\omega$ for all scenarios ω. The constraints $\boldsymbol{h^I}(\boldsymbol{x}) = \boldsymbol{0}$ and $\boldsymbol{g^I}(\boldsymbol{x}) \leq \boldsymbol{0}$ are related to the first stage investment decisions, while constraints $\boldsymbol{h^O_\omega}(\boldsymbol{x}, \boldsymbol{y}_\omega) = \boldsymbol{0}$ and $\boldsymbol{g^O_\omega}(\boldsymbol{x}, \boldsymbol{y}_\omega) \leq \boldsymbol{0}$ are related to the second stage operational decisions in scenario ω. The superscript "I" indicates the investment stage (first stage), while the superscript "O" indicates the operation stage (second stage). The subscript ω indicates the scenario, and Ω represents the set of all scenarios [25].

3.2.4 The Expected Value of Perfect Information

The quantity that a decision maker is willing to pay for obtaining perfect information about the future is called the expected value of perfect information (EVPI). EVPI is calculated as the difference between the expected value of the solutions based on perfect information and the objective value of the stochastic solution. For minimization problems, EVPI is computed as:

$$EVPI_{min} = z^{S*} - z^{P*} \tag{3.2}$$

Where z^{S*} is the stochastic problem's objective function's optimal value. z^{P*} is the expected value of all scenarios solved deterministic under perfect information [30].

3.2.5 The Value of the Stochastic Solution

The Value of the Stochastic Solution (VSS) is a measure of the value of the solution when using a stochastic model in place of a deterministic model. The authors of [24] explains the VSS as the *loss of profits due to the presence of uncertainty*. A small VSS indicates that the deterministic model is an accurate approximation of the problem and that there is little to gain from using a stochastic model. On the other hand, when having a large VSS, it may require the solution of a stochastic program to solve the problem accurately. The VSS is computed as:

$$VSS_{min} = z^{D*} - z^{S*} \tag{3.3}$$

Where z^{D*} is the value of the objective function in a deterministic model when replacing all the random, uncertainty variables by their expected values. z^{S*} is the value of the stochastic problem's objective function [30], [24].

3.3 TYNDP

ENTSO-E was established in 2009 as a result of EU's Third Legislative Package for the Internal Energy Market, which aims at liberalizing the electricity markets. ENTSO-E represents 43 TSOs from 36 countries across Europe. Together, they contribute to building the world's largest electricity market. This will affect the overall economy in Europe. A key principle for ENTSO-E is transparency, and this requires a strong interaction with the European institution and society.

The Ten-Year Network Development Plan, TYNDP, is published by ENTSO-E every other year. The plan presents ongoing investments in the grid and future needed grid project. In addition to data for the development project and market modeling data, TYNDP contains a scenario development report. This report explores different possible future scenarios of load and generation and how they interact with the pan-European electricity network. Stakeholders and public interaction are included in ENTSO-E's work with TYNDP by public workshops, stakeholder meetings, and public consultation. As a result, modeling data for the scenarios and simplified development plans are publicly available.

3.3.1 Scenarios for year 2030 - TYNDP 2016

TYNDP 2016 Scenario Development Report is divided into two separate stages, where the first stage is expected progress from 2016 towards 2020. This is a short period, and since most of the investments are already planned or under construction, the data is rather accurate. The second stage is set to 2030 and provides four scenarios for the year 2030, called visions [31]. All visions are developed from the expected progress in 2020, and they differ in terms of generation capacities and demand profiles. The visions are placed on two axes, where one axis is related to European targets of reducing CO_2 emissions in terms of if it is on track of the targets in 2050 Energy Strategy [32]. The second axis is related to how the decarbonization of the system should happen, either with a strong European framework or with a looser European framework resulting in parallel national schemes. Table 3.1 presents a summary of the visions.

3.3.1.1 Vision 1

Vision 1 is the least optimistic vision with a delay of the energy roadmap to 2050 and a loose European framework. Each country has its own policy and methodology for CO_2 emission reduction and development of new renewable solutions. Some economic growth is happening in this vision, but it has the least favorable conditions. Regarding demand, it is not implemented any ways of improving energy efficiency neither increased usage of electricity for transport. Due to the slightly economic growth, the annual electricity demand increases a bit.

As a result of the loose European framework, no new additional policies are implemented after the year 2020. Local subsidies are still a part of the system, which causes some additional local investments in renewable energy. There is not installed new thermal capacity, and some of the most polluting generators risk being shut down after 2030 to reach the 2050 target. The utilization of nuclear power is divided among the countries. In some countries where nuclear power is considered as a clean and affordable source, new power plants are built, while in other countries nuclear power plants are shut down. The baseload for electricity production is provided by hard coal, rather than gas.

3.3.1.2 Vision 2

Vision 2 is more optimistic than the first vision and has more favorable economic conditions. In this vision, the European framework is strong, and the markets focus on increasing energy efficiency and energy savings. However, there is still a limited willingness to invest in new RES and replace the most CO_2 emitting power plants, due to the low CO_2 price. Hence, Vision 2, as well as Vision 1, is looking to fail at reaching the 2050 climate targets. A breakthrough in energy efficiency development and usage of electricity in the transportation sector leads to a decrease in the electricity demand, compared to the year 2020.

Even though the vision is in the delay of reaching the goals of 2050, the share of renewable production is higher than for the previous one. Power system adequacy is ensured on a European level to optimize the costs for the society and decreases the need for backup capacity. Due to the introduction of only a few new policies and incentives to the system in 2020, the countries need to extend the lifetime of already operative conventional power plants. The baseload for electricity production is still delivered by hard coal rather than gas.

3.3.1.3 Vision 3

Vision 3 is called the *National Green Transition* and has even more favorable economic conditions than the previous ones, resulting in reinforcement in existing energy policies. These policies have a great impact on the CO_2 price, which causes a change in the baseload for electricity. Gas is now preferred to hard coal.

The demand in Vision 3 is stagnated compared to 2020, due to increased energy efficiency and flexible charging of electric vehicles in the transportation sector. Parallel national policy schemes determine the generation mix. Massive investments in RES bring electricity production from RES to a competitive level, and old generation units get decommissioned. The European network is weak, and the lack of cooperation results in a high cost for the total energy system. The RES are handled individually by each country, resulting in small investments in new energy storage. Investments in new nuclear power plants are unprofitable due to competitive RES prices. Therefore, only existing nuclear power plants are included in Vision 3.

3.3.1.4 Vision 4

Vision 4 is the most optimistic vision of all the visions and is called the *European Green Revolution*. It has the most favorable economic conditions, characterized by significant investments in renewable energy. Additionally, the European framework is strong, resulting in good cooperation across borders. Similar to Vision 3, gas is used as baseload electricity production. The energy efficiency is increased even more in this vision. However, the total electricity demand grows due to the electrification of the whole transportation sector.

Regarding the generation mix, this vision is strongly on track for the climate goals of 2050 at the lowest cost. The strong European framework ensures that RES is built and located in an optimal way around Europe. The countries cooperate with backup capacity, such that expanding hydro storage is more utilized than installing new gas power plants for backup. No new investments in nuclear power plants are made, and already existing plants are not flexible enough, this results in a phase-out of nuclear plants where the production from RES is high.

Table 3.1: Summary of the four visions in TYNDP 2016 [31]

	Vision 1	**Vision 2**	**Vision 3**	**Vision 4**
Economic conditions	Least favourable	Less favourable	More favourable	Most favourable
Energy policy focus	National	European	National	European
CO_2 price and fuel price	Low CO_2 price, high fuel price	Low CO_2 price, high fuel price	High CO_2 price, low fuel price	High CO_2 price, low fuel price
RES	Very low national	Between V1 and V3	High national	On track of 2050 target
Electricity demand	Increase	Decrease	Stagnation	Increase
Electric plug-in vehicles	No commercial break through	Flexible charging	Flexible charging	Flexible charging and generating
Storage	As planned today	As planned today	Decentralized	Centralized
Merit order	Coal before gas	Coal before gas	Gas before coal	Gas before coal

3.3.2 Scenarios for year 2030 - TYNDP 2018

TYNDP 2018 Scenario Report is a collaboration between ENTSO-E and ENTSOG, the European Network of Transmission System Operators for Gas, where their expertise within electricity and gas have been combined to establish a common set of scenarios [33]. TYNDP 2018 contains scenarios from 2020 to 2040, where the uncertainty increases with the time horizon. The scenarios for 2020 and 2025 are best estimate scenarios, which is based on the TSO perspective, reflecting all national and European regulation in place. The scenarios for 2030 and 2040 have been designed with the European 2050 targets as an objective. Three scenarios for the year 2040 and three scenarios for the year 2030 are presented, where one of the 2030 scenarios is an external scenario based on the European Commission's 2030 energy targets. As distinct from TYNDP 2016, all the scenarios for 2030 are on track for the 2030 EU targets in 2030. Table 3.2 presents a summary of the scenarios in TYNDP 2018.

3.3.2.1 Sustainable Transition

The Sustainable Transition scenario reaches its target through national regulation in terms of maximizing the use of the existing infrastructure and emission trading plans and subsidies. The scenario attempts to have a fast and economically sustainable CO_2 emission reduction by replacing lignite and coal by gas. The electrification of heat and transport happen at a slower pace than the other scenarios. To reach the EU goal of 80-95% CO_2 emission reduction in 2050, it is needed a rapid development during the 2040s through increased technological evolution. Hence, the scenario is slightly behind the track to the 2050 target.

3.3.2.2 Distributed Generation

The Distributed Generation scenario puts the prosumer at the center. More decentralized development happens, and end-user technology is in focus. Electrification of the transportation sector happens quickly, and there is a very high growth for the usage of electric vehicles. PV and batteries are widespread in buildings, which leads to a high level of demand-side response. Consequently, the scenario is slightly beyond the EU 2030 target and on track to the 2050 target.

3.3.2.3 The EUCO Scenario

The EUCO Scenario is an external scenario for the year 2030 by the European Commission. This scenario model the achievement of the 2030 climate and energy targets as agreed by the European Council in 2014, but including an energy efficiency target of 30%. EC determined that the EUCO Scenario was closest to the Global Climate Action scenario in terms of parameters that define the scenario. Consequently, the EUCO 30 scenario replaced the Global Climate Action scenario for 2030 in TYNDP.

The Global Climate Action scenario represents a global effort towards full speed decarbonization. The focus is to build large-scale renewables and even nuclear to produce power. Decarbonization of the transportation sector is achieved by an increase in both electric and gas vehicles. Energy efficiency is in focus and affects all sectors.

Table 3.2: Summary of the most relevant characteristics of the scenarios in TYNDP 2018 [33]

	Sustainable Transition	**Distributed Generation**	**EUCO 2030**
Economic conditions	Moderate growth	High growth	High growth
RES	Moderate growth	High/Very high growth	Moderate/High growth
Electricity demand	Stable	Moderate growth	Moderate growth
Electric vehicles	Moderate growth	Very high growth	High growth
Storage	Low growth	Very high growth	Moderate growth
Merit order	Gas before coal	Gas before coal	Gas before coal

Chapter 4

Methodology

The following chapter presents the Power Grid Investment Model (PowerGIM) and its application on the North Sea offshore grid. Both the representation of the NSOG model and the mathematical formulation of the stochastic TEP problem are included. Input data, assumptions, and simplifications are elaborated, while the complete input data are given in Appendix A. Finally, the configuration and method utilized to solve the stochastic version of PowerGIM are described.

4.1 Model representation

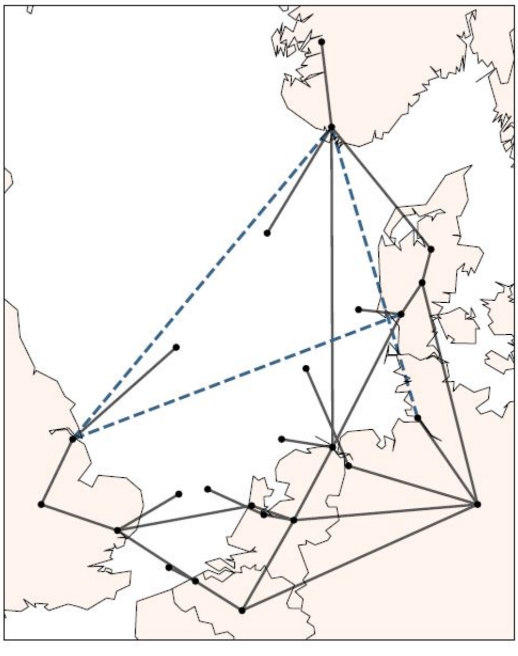


Figure 4.1: Representation of the North Sea offshore grid infrastructure for the case study [13]

The North Sea offshore grid model in this thesis is a simplification of the actual network. Norway (NO), Denmark (DK), Germany (DE), the Netherlands (NL) and Belgium (BE) are the considered countries in this model. They are all bordering to the North Sea and are closely connected to each other. The existing interconnectors between these countries and the planned interconnectors presented in this chapter are included in the model.

The system consists of 25 nodes. The demand and generation are aggregated in a single node for each country, except offshore wind generation, which is presented in 8 independent nodes connected to the countries. The remaining nodes represent the connecting hubs that connect the countries. The nodes are presented in Table A.1. All nodes are assumed existing in the case study, although this is not necessarily realistic due to the possibility of not having a great extension of offshore wind power.

Figure 4.1 is an illustration of the NSOG model. The solid lines represent the existing lines or lines that the model assumes to exist, while the dotted ones represent the interconnector investment options that the model considers. The user of the model needs to specify in the input data whether or not the model should invest in the respective lines. Hence, the investment options are given as Boolean values, 1 or 0, to indicate if the interconnector is open for expansion or not. Table 4.1 gives an overview of the possible interconnector investments. The three interconnectors are chosen because they represent well-planned interconnectors, under construction as of today, and are considered to be profitable. In reality, the interconnectors have a planned capacity of 1400 MW. However, this does not have an impact on the optimization process since the model chooses the optimal capacity below a maximum limit of 10 000 MW. This limit is chosen because the investment costs get significantly high when having a higher capacity than 10 000 MW, such that it would not be profitable to invest more.

Table 4.1: The possible interconnector investments [34, 35, 36]

Corridor	Investment alternative	Name	Expected commissioning
NO - GB	(1, -, -)	North Sea Link	2021
NO - DE	(-, 1, -)	NordLink	2020
DK - GB	(-, -, 1)	Viking Link	2022

The investment model used in this thesis is the Power Grid Investment Model (PowerGIM) described in [12]. The investment planning model is based on previous work by Trötcher and Korpås[37], Munoz et al.[38], and Svendsen and Spro [39], and it is a modification of the open-source Python package Power Grid and Market Analysis (PowerGAMA) by SINTEF Energy Research [40]. PowerGAMA is a deterministic linear programming (LP) problem, while PowerGIM is a mixed-integer linear programming (MILP) problem, which can handle binary and integer investment variables. Both models utilize the optimization modeling package Pyomo in Python [41, 42].

The model tries to maximize the total welfare for all countries in the region. It is assumed perfect competition in generation investments and operation and inelastic demand. The demand is assumed to be inelastic, which is a common assumption due that the elasticity is usually low for electricity consumers [43]. The system operators are normally regulated to provide an operation that maximizes welfare. Furthermore, perfect market conditions are hard to fulfill. However, if bidding is done according to marginal costs. The problem is a co-optimizing problem, which maximizes welfare and minimizes the total costs. Thus, it can be formulated as a MILP problem, where the objective is to minimize the total system cost.

In order to simplify the analysis of changes in profitability in different interconnector expansion along with different TYNDP scenarios for 2030, generation expansion, new nodes, and transmission line expansion are not considered beyond the three chosen interconnectors in this case study. This is specified in the chosen input data, where it is possible to choose different investment opportunities. However, the total formulation of the TEP problem is given. Another simplification is the aggregation of demand and generation for the countries, due to the importance of having an acceptable solution time and the difficulty of finding non-aggregated open-source data.

The model considers market clearing for each hour of a full year. Thus, random sampling is used to reduce the solution time. The same random sampling is used for all the scenarios to evaluate the same hours. Sampling and clustering techniques are investigated in [44, 45], where the same model, PowerGIM, is used on a similar NSOG system. By performing a deviation test of random samples of different sizes, it is concluded that a total of 200 sample steps are acceptable in [37]. Hence, 200 sample steps are used in this case study as well. However, one can never guarantee a good enough representation through random sampling, and therefore, it is crucial to evaluate the outcome of the model.

4.2 Mathematical formulation of the stochastic TEP problem

The mathematical problem formulation is derived from the deterministic problem formulation in [12] and the two-stage stochastic programming formulation in Equation (3.1). The model is presented as the deterministic equivalent, where the uncertainty regarding generation, demand, and prices are given in scenarios with equal probability. The model is actually a GTEP problem, which allows for investment in new generation capacity in addition to transmission capacity. However, only transmission capacity is considered in this thesis. The notation for the model is presented in Table 4.2.

Table 4.2: Notation for the transmission planning model (PowerGIM)

Sets and mappings		
$n \in N$	:	nodes
$i \in G$	:	generators
$b \in B$	:	branches
$l \in L$	:	loads, demand, consumers
$t \in T$	:	time steps, hours
$\omega \in \Omega$	:	scenarios
$i \in G_n, l \in L_n$	:	generators/load at node *n*
$n \in B_n^{in}, B_n^{out}$	:	branch in/out at node *n*
$n(i), n(l)$	:	node mapping to generator *i*/load unit *l*
Parameters		
FSC	:	first stage cost [EUR]
SSC_ω	:	second stage cost, scenario ω [EUR/yr]
a	:	annuity factor
w_t	:	weighting factor for hour *t* (number of hours in a sample/cluster) [h]
π_ω	:	probability, scenario ω
$VOLL$	:	value of lost load (cost of load shedding) [EUR/MWh]
MC_i	:	marginal cost of generation, generator *i* [EUR/MWh]
$CO2_i$	:	CO_2 emissions costs, generator *i* [EUR/MWh]
$D_{lt\omega}$	:	demand at load *l*, hour *t*, scenario ω
B, B^d, B^{dp}	:	branch mobilization [EUR], fixed cost [EUR/km] and variable cost [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]
CZ_n	:	onshore/offshore node costs (e.g platform costs), node *n* [EUR]
$P_{i\omega}^e$	:	existing generation capacity, generator *i* [MW], scenario ω
γ_{it}	:	factor for available generator capacity, generator *i*, hour *t*
F_b^e	:	existing branch capacity, branch *b* [MW]
$F_b^{n,max}$	:	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*
$E_{i\omega}$	:	yearly disposable energy (e.g. energy storage), generator *i* [MWh], scenario ω
M	:	a sufficiently large number
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*
x_i	:	new generation capacity, generator *i* [MW]
$g_{it\omega}$	:	power generation dispatch, generator *i*, hour *t* [MW], scenario ω
$f_{bt\omega}$	:	power flow, branch *b*, hour *t* [MW], scenario ω
$s_{nt\omega}$	:	load shedding, node *n*, hour *t* [MW], scenario ω

The equations and variables in (4.1) to (4.13) presents the mathematical model, where (4.1) is the objective function that minimizes total cost. The objective function is divided into two stages; first stage cost *FSC* and second stage cost *SSC*. The first stage cost is presented in (4.2) and is related to investments in infrastructure, thereby investments in new transmission lines, nodes, and generation capacity. (4.3) and 4.4 are the fixed and variable costs that are included in the investment cost of new lines, to give a realistic representation. The fixed cost is only dependent on the number of lines, while the variable cost is dependent on the capacity of the line. The second stage cost is the expected operational cost for one single year of market operation, dependent on a discrete set of scenarios, Ω. The notation *a* is the annuity factor that converts the future cash flows into present values, such that both the operational cost and the investment cost have the same unit and are represented as dependent of the financial lifetime in net present value.

The equations, (4.6) to (4.12), represent the constraints. (4.6) ensures energy balance, where the demand at a node is equal to own production, import, export, and load shedding. The importer pays for the transmission losses. Hence it is included. (4.7) limit the load shedding and make sure it is less or equal to the total load at a node. To make sure that the generation production levels are between the minimum and maximum limits, (4.8) is included as a constraint. The intermittent production from RES is represented by the availability factor $\gamma_{it\omega}$, where the availability is given as a range from 0 to 100%, for different nodes, time step, and scenario. (4.9) is the constraint that represents the yearly disposable energy and is relevant for generation methods that require storage. For instance, hydropower has a certain amount of storage capacity in dams, and the yearly generation must be less or equal to this energy amount. The flow limits, from both existing and new capacity, is fulfilled in (4.10). The upper and lower limits are the same in each corridor but have different signs. New branch capacity is restricted to be below the allowed capacity by (4.11). Finally, (4.12), ensures that a new node is available and developed if a corridor requests to use it.

The decision variables are defined in (4.13). The new transmission capacity y_b^{cap}, the power generation dispatch $g_{it\omega}$ and the load shedding $s_{nt\omega}$ are defined as non-negative real numbers, while power flow f_{bt}, in branch b for hour t in scenario ω, is defined as a real number. The number of new transmission lines y_b^{num} is a positive integer, and the number of new platforms z_n is a binary number.

$$\min_{x,y,z,g,s} FSC + a \sum_{\omega \in \Omega} \pi_\omega SSC_\omega \tag{4.1}$$

where

$$FSC = \sum_{b \in B} (C_b^{fix} y_b^{num} + C_b^{var} y_b^{cap}) + \sum_{n \in N} CZ_n z_n + \sum_{i \in G} CX_i x_i \tag{4.2}$$

$$C_b^{fix} = B + B^d D_b + 2CS_b \tag{4.3}$$

$$C_b^{var} = B^{dp} D_b + 2CS_b^p \tag{4.4}$$

$$SSC_\omega = \sum_{t \in T} w_t((\sum_{i \in G} (MC_i + CO2_i) g_{it\omega} + \sum_{n \in N} VOLL s_{nt\omega}) \tag{4.5}$$

subject to

$$\sum_{i \in G_n} g_{it\omega} + \sum_{b \in B_n^{in}} f_{bt\omega}(1 - l_b) - \sum_{b \in B_n^{out}} f_{bt\omega} + s_{nt\omega} = \sum_{l \in L_n} D_{lt\omega} \qquad \forall n \in N, t \in T, \omega \in \Omega \tag{4.6}$$

$$s_{nt\omega} \leq \sum_{l \in L_n} D_{lt\omega} \qquad \forall n \in N, t \in T, \omega \in \Omega \tag{4.7}$$

$$P_{i\omega}^{min} \leq g_{it\omega} \leq \gamma_{it}(P_{i\omega}^e + x_i) \qquad \forall i \in G, t \in T, \omega \in \Omega \tag{4.8}$$

$$\sum_{t \in T} w_t g_{it\omega} \leq E_{i\omega} \qquad \forall i \in G, \omega \in \Omega \tag{4.9}$$

$$-(F_b^e + y_b^{cap}) \leq f_{bt\omega} \leq (F_b^e + y_b^{cap}) \qquad \forall b \in B, t \in T, \omega \in \Omega \tag{4.10}$$

$$y_b^{cap} \leq F_b^{n,max} y_b^{num} \qquad \forall b \in B \tag{4.11}$$

$$\sum_{b \in B_n} y_b^{num} \leq M z_n \qquad \forall n \in N \tag{4.12}$$

$$x_i, y_b^{cap}, g_{it\omega}, s_{nt\omega} \in \mathbb{R}^+, f_{bt\omega} \in \mathbb{R}, y_b^{num} \in \mathbb{Z}^+, z_n \in \{0, 1\} \tag{4.13}$$

4.3 Input data to model

Usage of reliable open source data is the aim of the input data. Additionally, it is important to be consistent with sources and only supply with additional data sources if the main data is insufficient. Different motives and assumptions lie behind various sources. Thus it is important to be consistent with creating equal premises for all four scenarios. Comparison and analysis can then be made on the correct basis.

TYNDP 2016 [31] and TYNDP 2018 [33] are the main sources of the input data. If strictly necessary, other sources are added. The model uses a discount rate of 5% and 30 years, which is a neutral rate. Transmission lines have a long lifetime, and most likely, the infrastructure is used for more than 30 years. On the other hand, the investors would like to earn back their money in a reasonable time horizon. Therefore, a time horizon of 30 years is chosen.

The first case study has four scenarios based on the four visions TYNDP 2016, while the second case study contains the three scenarios from TYNDP 2018. Case 1 has scenarios named Scenario 1, Scenario 2, Scenario 3, and Scenario 4. Case 2 has scenarios with the original names, Scenario DG (Distributed Generation), Scenario ST (Sustainable Transition) and Scenario EUCO (European Commission scenario).

An overview of the installed generation capacity by source and scenario is given in Figure 4.2. One can observe that Scenario 3 has the highest total installed capacity, while Scenario 2 has the lowest installed capacity. The scenarios from TYNDP 2018 is between Scenario 1-2 and Scenario 3-4.

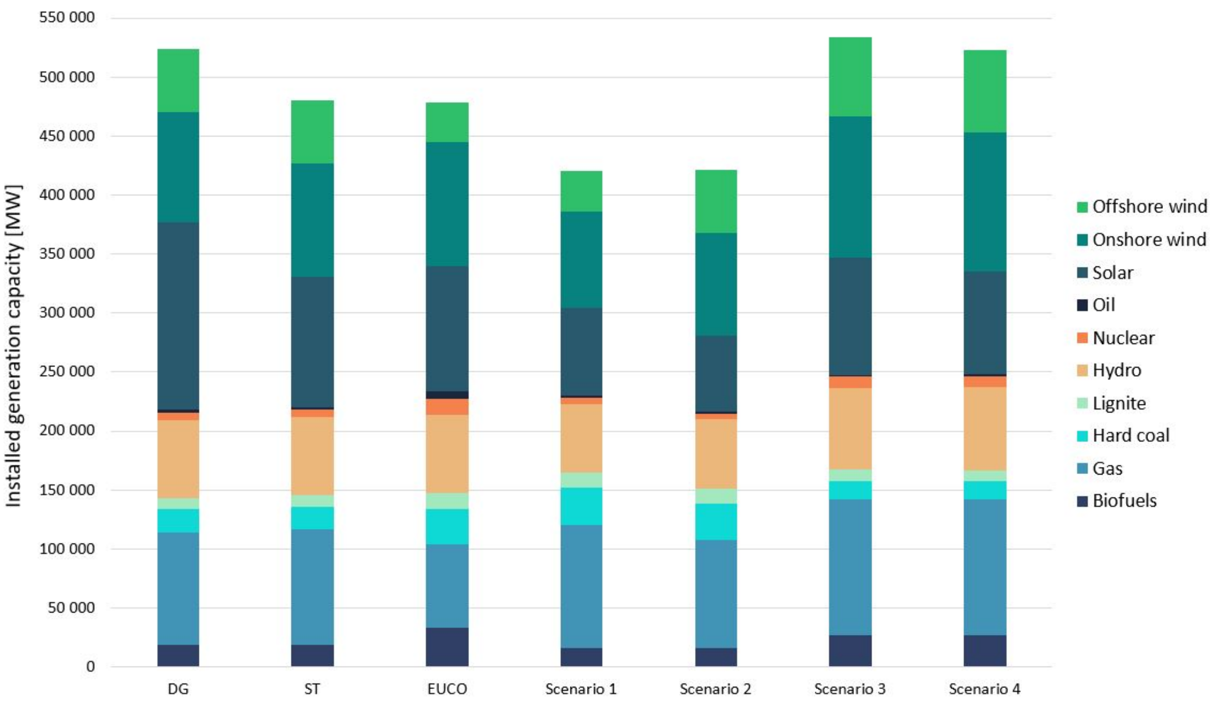


Figure 4.2: Installed generation capacity by source and scenario

4.3.1 Case 1: Input data from TYNDP 2016

4.3.1.1 Generation input

Installed generation capacity for all scenarios is retrieved from TYNDP 2016 [31]. In TYNDP, only the total amount of wind capacity is given. It is not divided into offshore and onshore wind production, which is important for this case study as one of its purposes is to analyze the effect of increased OWP in the power system. Hence WindEurope scenarios [46] are utilized to calculate the expected OWP. The total wind production differs between WindEurope and TYNDP. The WindEurope scenarios are generally more ambitious than the TYNDP scenarios. A reason for that can be that WindEurope is the association for wind energy in Europe, consisting of the entire value chain: developers, manufacturers, banks, and research institutes. The OWP for each country in each scenario is calculated by comparing the total wind production estimated by TYNDP for that country with the scenarios from WindEurope. The WindEurope scenario with the most similar total production to TYNDP for each country is chosen and then utilized to obtain the OWP percentage share. This percentage share is then used to calculate the OWP from the total wind production in TYNDP. ENTSO-E has foreseen the offshore wind generation to become increasingly significant in the future [47]. They assume that the total OWP in Vision 1 is 19%, while in Vision 4, it increases to approximately 29%.

In TYNDP 2016 there is two unclassified categories, *Others RES* and *Others non-RES*. *Others RES* consists of different types of renewable biofuel products. Therefore, it is assumed to be a part of the biofuel generation capacity in this case study. In TYNDP 2014 there exist an overview of the number of gas shares in the *Others non-RES*. Due to the noticeable amount of gas shares, the *Others non-RES* is added to the gas generation capacity.

Scenario 1's input data is from TYNDP Vision 1. The OWP for the countries is calculated by use of the low scenario in WindEurope, since the total amount of wind in TYNDP is closest to that scenario. There does not exist any data for Norway in WindEurope. Hence it is assumed to be 19% according to ENTSO-E [47].

Scenario 2 uses data from TYNDP Vision 2. This vision consists of more RES than Vision 1, but the total amount of wind production is still closest to the low scenario in WindEurope such that it is used to compute the offshore and onshore wind production. For Norway, the percentage of OWP is still assumed to be 19%.

Scenario 3's input data is from TYNDP Vision 3. Vision 3 has a high share of RES. Thus the high scenario in WindEurope is used to calculate the offshore and onshore wind in Germany and Great Britain. The central scenario is used to calculate the wind production in Denmark and Belgium, while the low scenario is used for the Netherlands. It is assumed a percentage share of 29% OWP in Norway, due to the ENSTO-E forecast.

Scenario 4 utilizes data from TYNDP Vision 4. The offshore wind share is calculated by us if the high scenario in WindEurope for all countries, except the Netherlands, which still has the total wind production closest to the low scenario. Norway has the same percentage as in Scenario 3.

The input generation capacities are given in Table A.2 in Appendix A.

4.3.1.2 Emission data

CO_2 emission estimates for electricity generation is taken from the International Energy Agency's report called *CO_2 Emissions From Fuel Combustion* [48]. It is assumed that the emission factor of *other bituminous coal* contains *hard coal*, which is used in TYNDP. The input emission rates are given in Table A.4

4.3.1.3 Cost of generation

The generation efficiencies and the fuel costs decide the costs of generation. TYNDP 2016 Market Modelling Data [49] presents the generation efficiencies and the fuel cost parameters. The generation efficiencies are presented as a range. Hence the average value is chosen. The efficiencies are given in Table A.5. The fuel prices are divided into four visions. The oil price is assumed to be the average value between light oil, heavy oil, and oil shale. The final input price of generation is calculated by (4.14).

$$p_g = \frac{3.6 * p_{fuel}}{n_{tech}} \tag{4.14}$$

Where p_{fuel} is the fuel cost and n_{tech} is the generation efficiency. The biomass fuel cost is not given in TYNDP 2016, and it usually has a wide cost range due to a large number of possible biomass types. A simplification is made, such that biomass is assumed to have the same price as gas. Hydropower is assumed to have a price of 10 EUR/MWh. The price is chosen because not all hydropower plants are run-of-river, without storage possibilities, and they have a marginal value that is not zero. If the price were zero, hydropower production would be competing against solar and wind production, which are intermittent. By setting the hydropower price equal the fossil fuel prices, it would also be misrepresenting because the marginal cost is much lower for hydropower. Thus, the hydropower price is set to be 10 EUR/MWh. The exception is Norway, which utilizes a production profile. The input data for the cost of generation is given in Table A.7

4.3.1.4 Renewable production and load profiles

Intermittent renewable production and load vary with time. Load profiles for each scenario are given in TYNDP 2016 Market Modelling Data [49]. There does not exist any data regarding solar and wind profiles in TYNDP. Hence open-source profiles are found by use of the *renewables.ninja* tool [50]. The *current onshore and offshore* simulation is used for wind profiles. Due to the differences in wind speed onshore and offshore, it is an advantage that the simulations are separated between onshore and offshore. This provides a more realistic approach. For creating solar profiles, the *MERRA-2* simulations are utilized, due that they have long-term stability and consistency.

In 2016, 96.3% of Norway's electrical power was produced by hydropower [51]. Consequently, the electricity prices in Norway are dependent on the calculated water value of the reservoirs. The water value is affected by reservoir levels, weather, and expected inflow and consumption. Therefore, it is necessary to have a price profile for Norway to depict the hydropower production. To represent the water value, prices from the power exchange Nord Pool [52] is used under the assumption of marginal cost bidding. The area with most interconnectors is Southern Norway, hence prices for that area is chosen.

4.3.1.5 Grid data

TYNDP 2016 Market Modelling Data[49] gives the transfer capacity between the countries in the model. Transfer capacities from a country to an offshore HVDC line, interconnection point, and offshore wind farm are chosen arbitrarily to have sufficient capacity. Consequently, the model only invests in new transfer capacity between the countries. The transfer capacities are presented in Table A.8.

Input data for demand is also collected from TYNDP 2016 Market Modelling Data [49]. Data for peak daily demand and annual demand is represented for each country for the four scenarios. The input values are given in Table A.9.

Table A.11-A.13 present the cost parameters data. The cost parameters are based on the cost model represented in [53]. The article presents a review of parameter costs given by various participants in the electricity market. The Electricity Ten Year Statement from National Grid was estimated to be the most accurate participant. Hence, the 2015 version of that is used as input data. In addition, some input data regarding power loss constant for converters and transmission power loss are calculated by the developers of PowerGAMA and are used with an allowance.

4.3.1.6 Quality of data

The TYNDP 2016 gives a good basis of the input data to the model, but it has the drawback of not providing all the necessary data. Mainly regarding the OWP, which creates dissimilarities between motivations and assumptions behind the data. When WindEurope is more ambitious than the TYNDP in their forecast for total wind production, it is challenging to compare and transfer WindEurope's scenarios to scenarios created by input data from the TYNDP. This is especially a problem when calculating the OWP in the Netherlands since WindEurope's forecasts are higher than the total wind productions in each of the scenarios in TYNDP. Consequently, the assumed OWP in the created scenarios can be a wrong presentation of the actual OWP in the power system in 2030. The wind profiles are divided into offshore and onshore, where the wind speed offshore is generally higher than onshore. The power produced can differ a lot if the share of OWP is different than expected. If the OWP is less than assumed, for instance, due to technology changes, and the onshore wind production share is higher, it can have a significant impact due to smaller wind speed onshore. However, it is possible to perform a sensitivity analysis to understand how the OWP contributes to the model result.

The content of *Others RES* and *Others non-RES* are not specified in the generation capacities in TYNDP 2016, and this is another drawback of the input data. Little documentation about their origin is provided in TYNDP 2016. Thus, they are hard to determine. It is documented that *Others non-RES* consist of gas shares, but the amount is not quantified. As a consequence, *Others non-RES* can actually contain other more CO_2 pollutive fossil fuels than gas, in addition to having a different price than gas, which results in an inaccurate representation of the amount of gas in the system. Moreover, the operational cost could change a lot if a significant enough share of *Others non-RES* are having a different price than the gas prices. Furthermore, price estimates of biofuels are not included in TYNDP 2016, such that a significant simplification is made when it is estimated that the biofuel price is equal to the gas price. As a result, the model can end up giving a higher or lower operational cost and different area prices, if the price differs. Also, the assumption that all biofuels and contents in *Others RES* have the same price would differ from reality. The marginal costs of some of the contents in *Others RES* may be small, for instance in a tidal or geothermal power plant.

Another shortcoming of the input data is the hydropower price in Norway. The data is from 2015, while the rest of the data is for 2030 scenarios. The hydropower price is, the same as the water value, which is derived from the system price. The share and localization of RES influence the price. So the assumption will not be precise and would not result in a complete representation of the power system in 2030. However, this is the chosen method due to the lack of reliable open-source data on future water values.

In TYNDP 2016, the technology efficiencies are given as a range. This is a weakness, due that the ranges are quite wide and difficulty if estimating how the efficiencies will change in each scenario. For instance, in some of the scenarios, technology breakthroughs can happen such that the efficiency would be higher. The technology efficiencies have an impact on the CO_2 emissions because there is a need for less fuel in the system to produce the same amount of power if the efficiency increases. Consequently, the results from the model will not be correct, and the model does not represent the real power system in 2030.

The weakness of the input data should always be examined when analyzing the results, as the input data is essential to obtain reliable results.

4.3.2 Case 2: Input data from TYNDP 2018

4.3.2.1 Generation input

The installed generation capacity is taken from the data set *ENTSO Scenario 2018 Generation Capacities* in [54] for all scenarios. The data set provides data for all generation technologies considered in the model, including wind capacity divided into onshore and offshore. The hydropower capacity is divided into hydro-pump, hydro-run, and hydro-turbine. In this case study, they are merged into one joint hydropower capacity for each country. Solar capacity is divided into PV and thermal, but are merged as well.

The two unclassified categories from TYNDP 2016, *Others RES* and *Others non-RES* are still included in TYNDP 2018. It is assumed that *Others RES* belongs to the biofuel capacity because they are merged in the Scenario Report 2018 [33]. For *Others non-RES*, the TYNDP report for 2014 includes an overview of the number of gas shares in the *Others non-RES*. It is shown a noticeable amount of gas shares, and hence the *Others non-RES* category is added to gas generation capacity. This is the same assumption that is made in Case 1 with input data from TYNDP 2016.

The generation input capacities are given in Table A.3 in Appendix A.

4.3.2.2 Emission data

Estimates for CO_2 emission from electricity generation is the same as in Case 1 and are discussed in 4.3.1.2. The emission input rates are given in Table A.4

4.3.2.3 Cost of generation

The cost of generation depends on two different factors, the generation efficiencies, and the fuel cost. The cost of generation is calculated in the same way as described in Case 1 Section 4.3.1.3. The generation efficiencies are the same as in Case 1, but fuel prices for Scenario DG, ST and EUCO are taken from TYNDP 2018 [33]. The fuel cost of biofuels is not given in TYNDP 2018 either, such that it is assumed to have the same price as the primary fuel type, gas. The hydropower price is still assumed to have a price of 10 EUR/MWh. The input data for the cost of generation for each scenario is given in Table A.6.

4.3.2.4 Renewable production and load profiles

Load and renewable production as wind and solar vary with time. Hence, profiles are needed to describe the variability over time. Load profiles are given as load series for each scenario in [54]. For some countries, for instance, Norway, the load is divided into the respective power market areas, not aggregated into one value. However, in the input data, the values are merged into one value for each country due to the need for comparable results with Case 1. The load series is built for climatic variations, but the load series for the normal year is chosen. ENTSO-E does not give profiles for wind and solar, hence the same open-source profiles as in Case 1 from the *renewables.ninja* tool [50] are utilized.

The hydropower price profile for Norway is updated to the power price in southern Norway for the year 2018 [52]. A thorough description of this assumption is given in Section 4.3.1.4.

4.3.2.5 Grid data

The existing line capacities and the cost parameters are the same as in Case 1. The data is further discussed in Section 4.3.1.5. The full overview of transmission capacities is given in Table A.8, while the cost parameters are given in Table A.11 - A.13.

The input demand data is calculated by use of the load series. The peak daily demand is the maximum load value, and the annual demand is the sum of the load series. The input demand data is calculated for each country. Table A.10 displays the input demand data.

4.3.2.6 Quality of data

The TYNDP 2018 has the advantage of providing almost all necessary input data to the model. Wind power capacity is divided into onshore and offshore wind capacity in TYNDP 2018. Thus it prevents wrong representation of the wind power in the scenarios for 2030. The contents of *Others RES* and *Others non-RES* are still not specified in the generation capacities given in TYNDP 2018. ENTSO-E provides scarce documentation regarding their origin in TYNDP 2018, and they are hard to determine. *Other non-RES* is still assumed to be consisting of gas shares, and is added to the gas capacity. However, this is a great simplification because it may be that *Other non-RES* actually contains other more CO_2 pollutive fossil fuels than gas, in addition to having a higher or lower price than the gas price. This results in an inaccurate representation of the amount of gas in the power system. Additionally, the operational cost could have been different if a great enough share of *Other non-RES* having a different price than the gas price. Moreover, TYNDP 2018 does not give any price estimate of biofuels. Hence, a great simplification is made when it is decided that the biofuel price is equal to the gas price. It can result in that the model gives a higher or lower operational cost if the price is different. The average price from the results could differ as well. Additionally, the assumption of all biofuels and contents in Other RES having the same price, would differ from reality. The marginal costs of the contents in *Other RES* actually may be small, for instance in a geothermal or a tidal power plant, which ends up in this category.

Another disadvantage of the input data from TYNDP 2018, which is found in TYNDP 2016 as well, is that the efficiency for each generation technology is given as a range. It is difficult to foresee how the efficiencies change along with the different scenarios. The technology efficiencies have an impact on the operational costs and the CO_2 emissions due to the need for less fuel in the system to produce the same amount of power if the efficiency is higher.

The hydropower price in Norway is updated with values from 2018. Still, there exists a mismatch because the demand and generation are different in 2030. The water value is derived from the system price, which is influenced by the share and localization of RES. Therefore, this assumption is not precise and would not result in a complete representation of the NSOG grid in 2030. However, due to the lack of reliable open-source data on water values, this is the chosen method.

In total, the TYNDP 2018 provides more data than the model is capable of utilizing. Generation capacities, as well as load series, are divided into the respective power market areas. This makes it possible for the model to give a more realistic a correct simulation of the power market in terms of area prices. This is further discussed in Section 5.5 about limitations.

4.4 Model configuration and method

The input data for the investment model is divided into five different CSV files; *Generation*, *Branches*, *Nodes*, *Consumers* and *Profiles*. Each scenario has its input files, in addition to an XML file that describes the financial parameters. These input files are directly read into the deterministic PowerGIM model, but to solve the stochastic PowerGIM model, a different approach is necessary.

Pyomo Stochastic Programming (PySP) [55] recommend the creation of a file structure that consists of an abstract model for the deterministic problem in a file called *Referencemodel.py*, specifications of the stochastic variables and parameters in a file called *ScenarioStructure.dat* and scenario data specification in .dat files. The full data for each scenario is specified in the .dat files. The files differ from each other, and the names are specified in the ScenarioStructure.dat file. The PowerGIM package contains functions that can create .dat scenario files, from input data formulated as a Pyomo data model in dictionary format.

To find the solution for the stochastic PowerGIM model, the command *!runef -m models -i scenariodata – solver=gurobi –solve –solution-writer=pyomo.pysp.plugins.csvsolutionwriter* is applied in the IPython console. This command puts together the extensive form solution of the model, so it creates a large model that has constraints to ensure that variables at a node have the same value. In this case, the investment variables (the new branch capacity and the number of new branches) must have the same value regardless of which scenario is realized. The objective is then the expected value of the objective function, and the solution is written to CSV files. One file contains the scenario stage cost, with the optimal values for the first stage investment and each scenario. The second file contains the corresponding optimal values for the variables; for instance, the number of new transmission lines, new line capacity, generation dispatch, and load shedding.

Chapter 5

Results and analysis

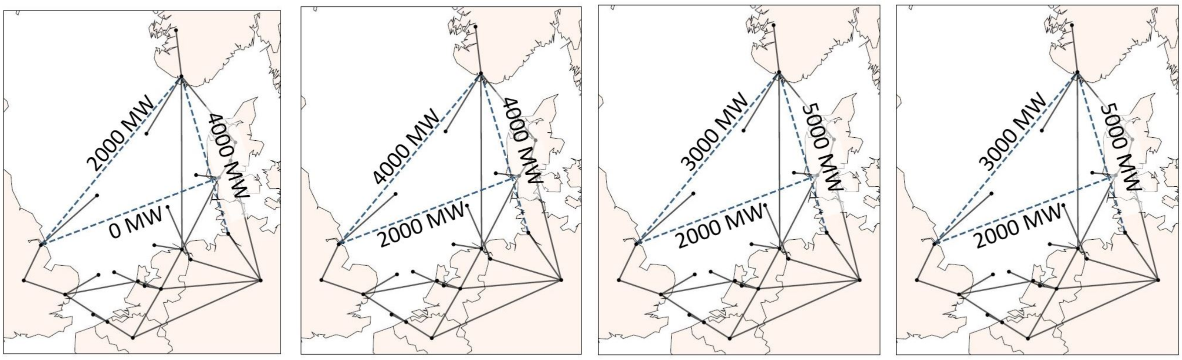
The objective of the PowerGIM model is to minimize the total cost of the system, thereby the investment cost and the operating cost. From the specialization project, there were concluded that the total cost is lowest when having the possibility to expand all the interconnectors. Thus, this study focus on obtaining the optimal capacity of the three interconnectors. The results are divided into two case studies, Case 1 and Case 2. Case 1 has input data based on TYNDP 2016, whereas Case 2 has input data based on TYNDP 2018. To begin with, an overview of the results from the deterministic model and the EEV solution, a method to account for uncertainty in a deterministic model, are presented. Then, the results from the stochastic model are presented, and the VSS and EVPI are calculated. After that, the results from the stochastic model is utilized to compute the generated energy by each generator type, and then calculate the average area prices.

Furthermore, a sensitivity analysis is performed by solving the stochastic model with different scenario probabilities, CO_2 prices, and OWP capacity to investigate how sensitive the investments are to changes in the input values. In order to find the optimal capacity expansion investment, a discussion section is included. Finally, the limitations of the model and analysis are presented.

5.1 Results from Case 1: TYNDP 2016

5.1.1 Deterministic solution and EEV

Figure 5.1 shows the optimal investment capacity from the deterministic results of the four different scenarios. More transmission capacity is required when the scenarios contain more RES. The installed OWP in Scenario 2 is almost three times as much as in Scenario 1. Consequently, more transmission capacity is needed to transfer the excess energy from Great Britain to Norway and Denmark. The flexible hydropower in Norway makes it possible to utilize more RES capacity in both Great Britain and Germany, which is the reason for the overall higher transmission capacity in NO-DE and NO-GB, compared to the capacity or the interconnector between Great Britain and Denmark. The investment costs and total cost occurring in each deterministic scenario are displayed in Table 5.1, where the total new transmission capacity is ranging from 6000 MW to 10000 MW.



(a) Scenario 1 **(b)** Scenario 2 **(c)** Scenario 3 **(d)** Scenario 4

Figure 5.1: Optimal capacity of line investments in the deterministic solutions (a)-(d)

A system planner that only considers scenario analysis would probably argue that the optimal investment decision is the investments that occur in all scenarios [14]. In such a case, the interconnectors, GB-NO and NO-DE, would score highest under those criteria as they occur in the four scenarios.

Table 5.1: Total cost and investment cost of the deterministic solution and the expected cost of expected value solution. Assuming equal probability. Given in [bEUR].

	S1	S2	S3	S4	Expected value
Deterministic solution	719.109	442.694	424.660	541.262	531.932
→ Investment cost	10.433	18.158	17.746	17.746	16.020
Expected value solution					559.793
→ Investment cost					16.722

To obtain the expected cost of the expected value solution (EEV), the deterministic model is solved by setting the uncertain parameters to its expected values. In this case, it is done by setting the uncertain parameters, including average demand, demand profile, generation capacity, cost of generation, max load shedding and CO_2 price, to the average value of the values in the four scenarios, and then the deterministic model is solved. The distribution of the optimal transmission capacity installed is given in Figure 5.2.

The capacity between Great Britain and Norway is 5000 MW, so it is higher in this case than in every deterministic scenario. This can be a result of a deviation of 40% in the total installed generation capacity in Great Britain between Scenario 1 and Scenario 4, where a large amount of wind power has been included in Great Britain in Scenario 4. The interconnector between Great Britain and Norway becomes essential to transfer excess power from Great Britain to Norway, where Norway has a large amount of flexible hydropower. There is still a relatively high amount of wind power in Great Britain in Scenario 1, such that the expansion of the interconnector from Great Britain to Norway represents a profitable investment. Great Britain and Denmark have a more similar generation mix, which is why the transmission capacity between those countries is smaller than between the other countries. The capacity between Great Britain and Denmark is 1000 MW, which is the same as the average value of capacity in the deterministic scenarios.

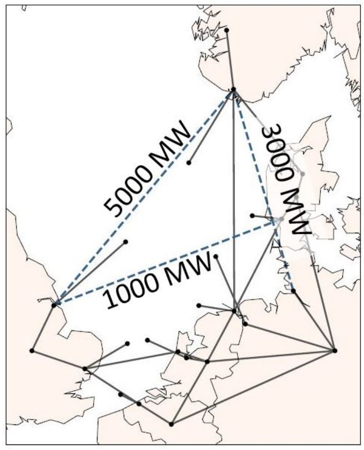


Figure 5.2: Optimal capacity of line investments in the EEV solution

If the system planner decides to use the investments based on the EEV solution, the cost would be higher than in the deterministic solution with perfect information. The increased cost is representing the costs of uncertainty. The cost of the expected value solution is given in Table 5.1. As the EEV solution represents the expected cost of using a method that copes with uncertainty in a deterministic case, it can be used to quantify the gap to the stochastic solution. This is known as the value of the stochastic solution, VSS, and is the value of using a stochastic program instead of a deterministic one.

5.1.2 Stochastic solution

Table 5.2: The stochastic solution results in [bEUR]

	Investment cost	Total cost
Stochastic solution	17.746	532.851

The problem is solved with a classical two-stage formulation, where market operations under four different scenarios directly follow the investments. The stochastic model makes it possible to hedge against different future market operation situations, but the investment cannot be postponed to minimize risk. The optimal transmission capacity for the different interconnectors in the stochastic solution is given in Figure 5.3. The stochastic model finds it optimal to invest in all the interconnectors. The stochastic investment strategy ensures that the system has enough grid capacity to cope with the most ambitious RES scenario, Scenario 4, at the same time, it aims to minimize the loss if the expansion of RES and OWP ends up being small. The stochastic solution is given in Table 5.2. The investment cost is higher than the average investment cost of the deterministic solutions, but it is similar as the investment cost in Scenario 3 and 4, which is a result of investment in the same interconnector capacity.

A stochastic program might be a good way to include as much information as possible in a decision model. The maximum amount one is willing to pay for perfect information about the future must be equal to the expected cost saving between the stochastic solution and perfect foresight. Hence, the expected value of the deterministic solution is subtracted from the stochastic solution to calculate the EVPI. Table 5.3 shows that the EVPI is 0.17 % of the stochastic cost. This is a small value, therefore, a system planner would not gain much in terms of cost savings with perfect information about the future in this case.

Table 5.3: EVPI and VSS

	bEUR	% of stochastic cost
EVPI	0.920	0.17%
VSS	26.942	5.06 %

The VSS can be calculated by looking at the expected value of the decision, based on expected value and the stochastic solution. The EEV is more costly than the stochastic, and the deviation between them is the VSS. The calculated value is displayed in 5.3. The result of 26.942 bEUR indicates the expected cost savings of using a stochastic strategy, instead of trying to incorporate uncertainty in a deterministic model. This is a significant cost saving. Therefore, it indicates that the EEV approach is a sparse approximation of incorporating uncertainty in the model. In the EEV solution, the first stage cannot react to the risk of different scenarios to evolve. Hence, it is advised to solve the stochastic model with the proposed scenarios to get a more exactly decision basis.

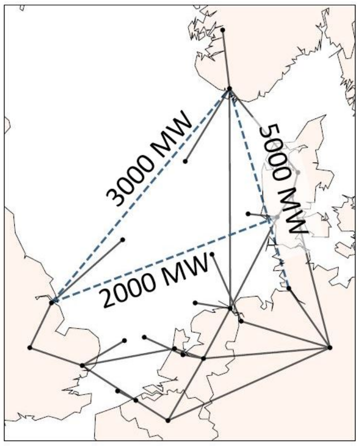
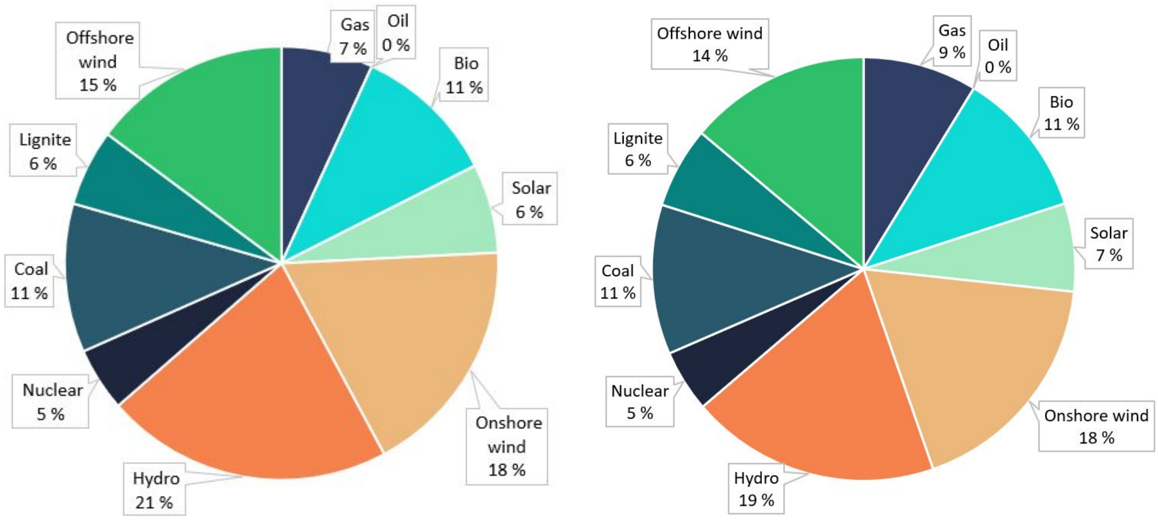


Figure 5.3: Optimal transmission investment capacity in the stochastic solution

5.1.3 Energy mix

In addition to deciding the optimal expansion of the interconnectors, the model gives information about the optimal generated power by each generator in the system for each time step. The total energy mix in the NSOG area is displayed in Figure 5.4 (a), while the total generated energy for a year of operation in each country is shown in Figure 5.5. The figures are overviews of the results from the stochastic model, where the energy displayed is the average of the four possible operational scenarios for a year of operating the NSOG system. Additionally, Figure 5.4 (b) and Figure 5.6 present the energy mix without investment in interconnectors. They are included to give a better insight into how investment in interconnectors affects the generation of energy and RES-share. Table B.1 and Table B.2 in Appendix B display the complete energy mix.

The total energy mix consists of 21% hydropower, 18% onshore wind, and 15% offshore wind. In total, RES generates 71 % of the energy. Hence, 29 % of the total generated energy is from non-RES. This is mainly due to the marginal cost of the generation technologies, which consist of fuel price and the CO_2 price. Oil has the highest price in all of the scenarios. In fact, the marginal cost of oil is so high that it is unprofitable to generate power from oil. The RES such as solar and wind produces regardless of whether it is profitable or not. Thus, they always start to cover the demand before non-RES.



(a) Investment in interconnectors **(b)** No investment in interconnectors

Figure 5.4: Shares of the different generation technologies in the total energy mix in NSOG area.

In the case without investment in interconnectors, the generated energy from RES has decreased to 69%. The power produced by hydropower and offshore wind has decreased, and the power from bio and gas has increased. This indicates that some countries need to start up gas or bio power plants instead of import excess power from offshore wind or cheap hydropower, for instance from Norway.

In Figure 5.5 can it be observed that Germany is the largest producer, as expected due to the high installed total capacity and the great demand. Onshore wind, coal, lignite, and hydro are the four greatest generation technologies in terms of generating the most energy. Surprisingly, gas is not one of the technologies that produce much, as it is one of the generation technologies with one of the most installed capacity. Gas power plants do only generate 2.3 TWh or 1% of the total generated power in Germany. This is mainly due to the high marginal cost of gas, compared to the other generator types such as lignite and coal. Great Britain is the second largest producer, where offshore wind is the generation technology that generates the most, followed by gas, nuclear, and onshore wind. Two of the scenarios do not have any installed capacity in coal and lignite, such that producing power from gas is necessary to cover the demand, even though it is more expensive. Consequently, the area price gets higher.

Norway is the third largest producer and produces almost all energy from hydropower. This is expected due to the installed capacities and the low cost of hydropower. Few generator types can compete with the marginal price of hydropower, except intermittent RES such as onshore and offshore wind, which also contributes to the Norwegian electricity mix.

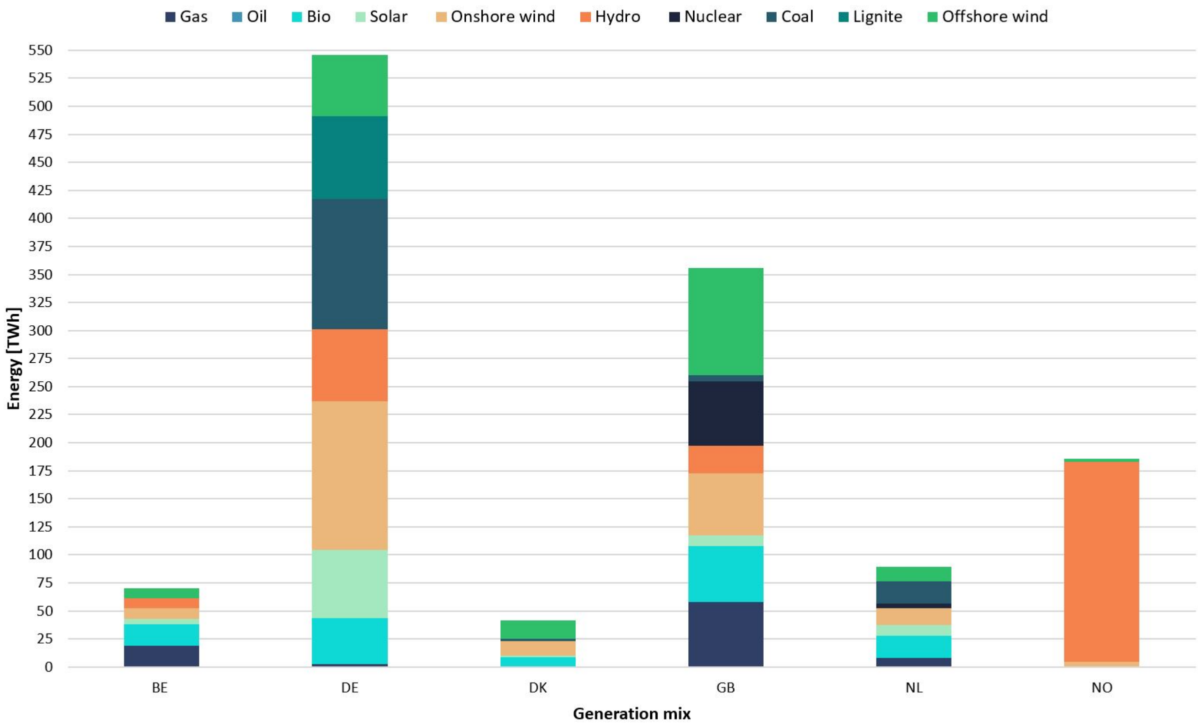


Figure 5.5: The amount of energy generated by each generation technology in each country with optimal investment in interconnectors.

The Netherlands, Belgium, and Denmark are relatively small power producers, with a yearly production between 40 and 89 TWh. The Netherlands generates the most power from bio, coal, and wind power (onshore and offshore). In Belgium, most of the generated power is from gas and bio, while in Denmark most the power is from wind power.

If one compares the annual generation in Figure 5.5 with the annual demand in Table A.9, it can be observed that Denmark, Germany, Great Britain, and Norway cover its demand. The Netherlands and Belgium generate less than the annual demand. Therefore, they are dependent on import of power from other countries, for instance, from Norway, which experiences a power surplus.

Figure 5.6 displays that the generation mix in each country is quite similar in the case without interconnector investments to the previous case with investments. However, the hydropower production in Norway has decreased by about 30 TWh due to less export capacity from Norway. Consequently, the other countries must compensate by producing more power from gas and bio to cover their power demand.

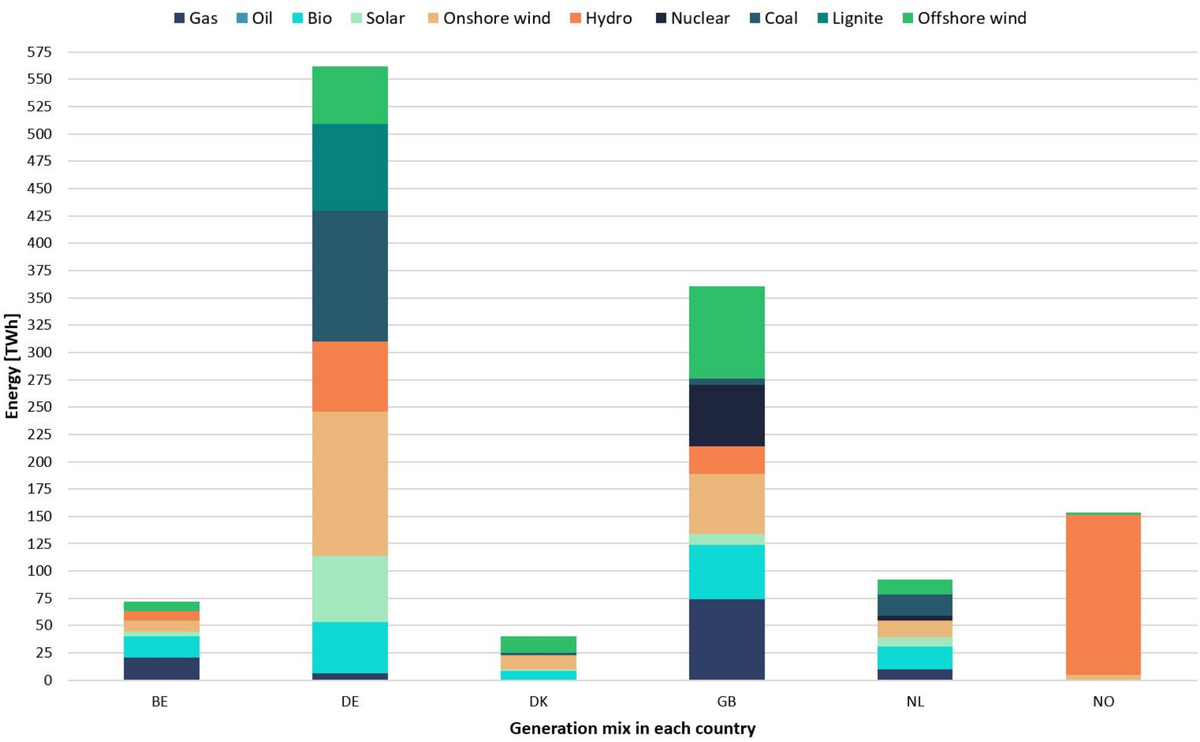


Figure 5.6: The amount of energy generated by each generation technology in each country without investment in interconnectors.

5.1.4 Average area price

The area prices can be calculated from the generated power in each area by use of the marginal costs of each generation technology. Then, the area price is equal to the marginal cost of the generator, which produces at that time step with the highest marginal cost. This is a simplified method, since the last dispatched generator unit may cover demand in other countries, but it gives the approximate area price. Table 5.4 (a) presents the prices for the scenarios in the optimal stochastic solution, when the transmission investment capacity in GB-NO, NO-DE, and GB-DK are 3000, 5000, and 2000 MW. The average value is the expected area price in the stochastic model when assuming uniform probability. Table 5.4 (b) presents the prices when there is no investment in new transmission capacity.

The area price reflects the generation mix in the countries. Belgium has the highest area price because of a significant share of power generated from gas and bio with a relatively high marginal cost. While Norway has the lowest area price due to the price of hydropower. The price was collected from the system price in Norway in 2015. Thus, it is not customized to the power system in 2030 and can be fallacious. The price in The Netherlands is attached to the price of coal and biofuels, and the combination of nuclear, gas and bio create an approximately equal price for Great Britain as for The Netherlands. Denmark has a lot of wind power, but the area price is affected by the power generation from biofuels in hours with insufficient amount of wind. Germany has an area price above Denmark and below Great Britain and The Netherlands. This is because Germany has a lot of RES combined with coal and lignite.

The NSOG area price is the average price of all the average prices in different areas. The average price for one area is the average of the prices in all the time steps. From the tables, it can be observed that the NSOG area price decreases as the renewables share increase, along with the different scenarios. In Scenario 4, the price decreases a little less because of the high CO_2 price.

Table 5.4: Average area prices

(a) Optimal interconnector investments

	Price [EUR/MWh]				
Area	S1	S2	S3	S4	**Average**
BE	91.68	88.95	66.92	81.16	**82.18**
DE	58.33	54.01	67.99	74.41	**63.68**
DK	73.60	44.47	65.20	43.93	**56.80**
GB	91.82	73.19	67.28	71.27	**75.89**
NL	83.84	73.18	65.91	66.10	**72.26**
NO	20.36	20.01	20.11	20.11	**20.15**
NSOG	69.94	58.97	58.90	59.50	**61.82**

(b) Without interconnector investments

	Price [EUR/MWh]				
Area	S1	S2	S3	S4	**Average**
BE	91.64	89.08	68.43	81.81	**82.74**
DE	64.62	62.95	69.42	62.93	**64.98**
DK	93.25	52.31	48.45	52.44	**61.61**
GB	91.89	74.16	69.10	76.35	**77.87**
NL	83.50	71.91	71.07	68.85	**73.83**
NO	20.11	20.11	20.11	20.11	**20.11**
NSOG	74.17	61.75	57.76	60.41	**63.52**

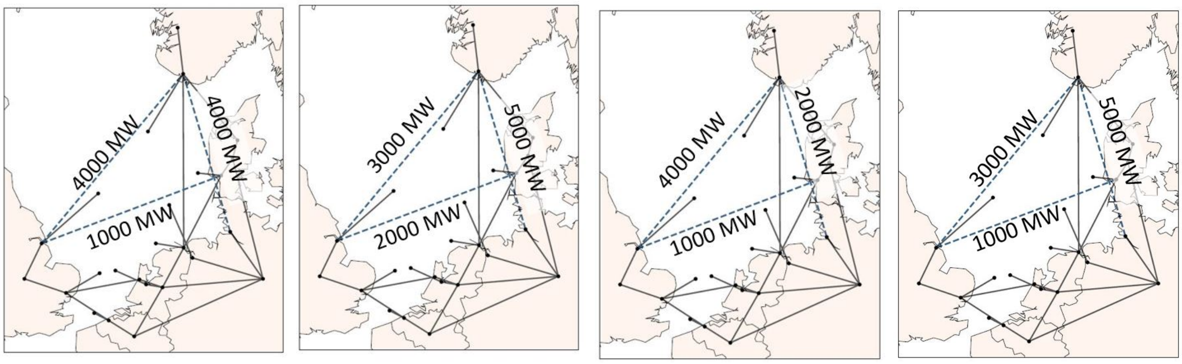
It can be observed from the table that NSOG average area price is lower in the case with interconnector capacity than in the case without interconnector capacity. This is due to decreased prices in almost every area, except NO. NO gets a small increase in the price due to one hour of gas production in one of the scenarios. Gas has a quite high marginal cost, such that it pulls up the area price. A reason for this can be that a country connected to Norway, for instance, Great Britain, experiences high demand and at the same time low RES-production due to low wind speed. Thus, Norway exports much hydropower and needs to compensate with gas to cover its demand.

In the case with optimal interconnector investments, the other countries get lower prices due to an increased amount of RES. The RES can be transferred to where it is needed, to a greater extent than without the interconnector investments. The countries which were highly dependent of non-RES as coal or gas earlier can cut its cost by producing more power from RES and import when the demand is high or if there is lack of, for instance, wind resources. The risk of having a power system with a high amount of RES gets diversified with increased integration, due to the possibility of transferring excess power from RES over large areas to where it is needed. It is unlikely that such broad areas as the North Sea areas do have the same correlation of RES, for instance, that there is a lack of wind resources in both Great Britain and Denmark at the same time.

5.2 Results from Case 2: TYNDP 2018

5.2.1 Deterministic solution and EEV

The optimal capacity of the interconnectors in the different scenarios is given in Figure 5.7. Scenario ST is the scenario with the most installed capacity, a total of 10 000 MW capacity. Scenario DG has a total of 9 000 MW installed capacity, while the EUCO Scenario has 7 000 MW capacity as the optimal investment. The range in the total installed capacity between the scenarios is lower than in Case 1, which reflects that the total installed capacity in the scenarios is more similar.



(a) DG **(b)** ST **(c)** EUCO **(d)** EEV solution

Figure 5.7: Optimal capacity of line investments in the deterministic solutions (a)-(c), and the EEV solution (d).

Table 5.5 displays the costs of the deterministic solutions. Scenario ST is a scenario which reaches its RES target by national regulations and subsidies. The results show that high interconnection capacity is recommended to minimize the total costs in the scenario. The scenario has the highest operational costs and investment cost, due to the high CO_2 price, but the operational costs would have been even higher without investment in new transmission capacity.

Table 5.5: Total cost and investment cost of the deterministic solution and the expected cost of expected value solution. Assuming uniform probability. The cost is given in [bEUR].

	DG	ST	EUCO	Expected value
Deterministic solution	215.446	256.169	223.476	231.697
→ Investment cost	16.309	17.746	13.106	15.721
Expected value solution				239.628
→ Investment cost				15.897

Scenario DG has the lowest total costs. The scenario has a generation mix consisting of much decentralized production, such as solar and wind power. This is cheap power production, as they have zero marginal costs. As a result, the operational cost gets low. Energy storage in batteries and flexible charging of electric vehicles are widespread. This is reflected in the demand profile, in the input data to the model. Consequently, the need for flexibility decreases.

Scenario EUCO has total costs between Scenario ST and Scenario DG. However, the investment cost in the scenario is low. This can be because of changes in the generation mix in the countries and changed input prices. The CO_2 cost, for instance, is quite low compared to Scenario ST and DG. Germany has lower OWP than in the other scenarios, and a higher share of other generation technologies. In addition, Norway has a more diversified, dispatched generation mix in this scenario, consisting of offshore wind, solar, bio and some coal. As a result, the need for flexibility is decreased, and the optimal capacity between Germany and Norway gets lower. The interconnector between Great Britain and Norway maintain a high capacity because it is cheaper to produce power from hydro, bio and coal in Norway than to produce from gas in Great Britain.

The interconnector capacity between Great Britain and Norway is relatively high in all scenarios and does not fluctuate much. This is due to the almost uniform amount of total installed generation capacity in all scenarios in Great Britain. Great Britain has overall a high amount of offshore wind installed, and Norway has a high share of flexible hydropower, such that increased interconnector capacity provides valuable flexibility. However, in Scenario ST, there is more profitable to invest in 1000 MW more in the interconnector between Germany and Norway, and the capacity in Great Britain to Norway interconnector decreases. This might happen due to the high marginal cost of coal in Germany, such that the operational cost decrease more when the coal is replaced by hydropower, than when the gas in Great Britain is replaced by hydropower. The interconnector capacity between Great Britain and Denmark is quite stable in all the scenarios because of the generation mix in Great Britain, and Denmark remains quite similar in all scenarios.

The EEV solution is given in Table 5.5 and the optimal interconnector capacities are displayed in Figure 5.7 (d). The investment cost is approximately equal to the average investment cost of the deterministic solution, but the operational cost is higher. This is due to the replacement of the uncertain values with the expected values, and the increased operational cost reflects the cost of the uncertainty.

5.2.2 Stochastic solution

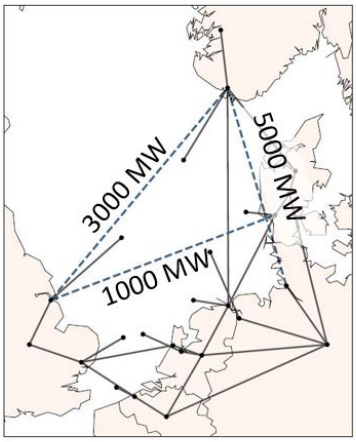


Figure 5.8: Optimal transmission investment capacity in the stochastic solution

Figure 5.8 displays the optimal transmission capacity investments in the stochastic solution, while Table 5.6 gives the stochastic solution's costs. It can be observed that the investment cost capacity is equal to the investment capacity in the EEV solution.

The maximum amount one is willing to pay for perfect information about the future is equal to the EVPI. The EVPI is shown in Table 5.7 and has a value of 0.504 billion euros in this case study. This indicates that a system planner could save maximum 0.22% of the total stochastic cost by having perfect information about the future. This is a quite small cost saving. Consequently, the expected cost of the uncertainty is low, and there is less likely that the system player makes the wrong decision about the investment.

Table 5.6: Results from the stochastic model with input data from TYNDP 2018 given in [bEUR].

	Investment cost	Total cost
Stochastic solution	15.897	232.201

The VSS is calculated to quantify the value of using a stochastic model instead of a deterministic model. It is the difference between the EEV solution and the stochastic solution. The VSS for this case is displayed in Table 5.7. It has a value of 3.22% of the total stochastic cost, which implies that there is a lot to gain by using a stochastic approach. The VSS in Case 1 is 5.06 % of the total stochastic cost, which is even higher than the VSS in Case 2. This may imply that the EEV approach performs better and is a less costly approach in Case 2. This may be because the scenarios in Case 2 are more similar to each other, in terms of installed generation capacity, compared to the scenarios in Case 1.

Table 5.7: EVPI and VSS for the model with input data from TYNDP 2018.

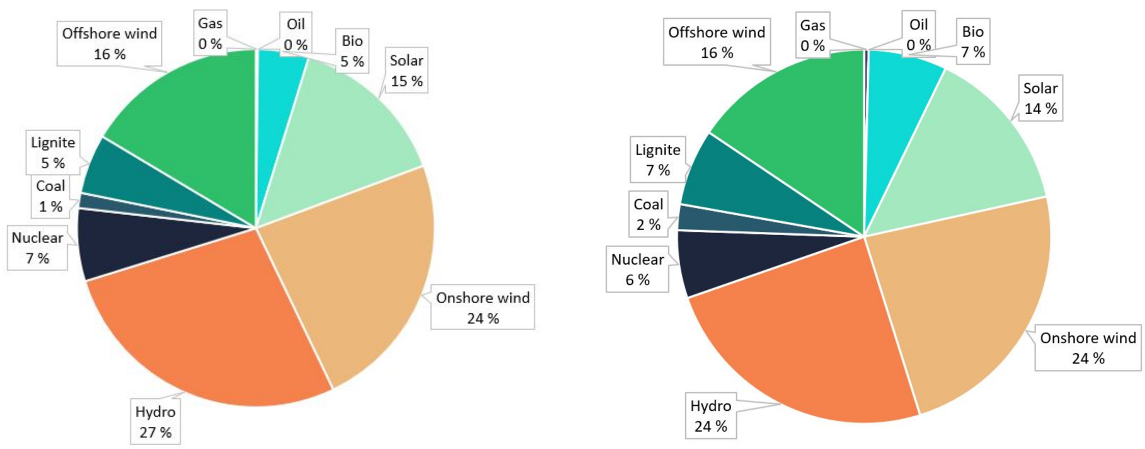
	bEUR	% of stochastic costs
EVPI	0.504	0.22%
VSS	7.427	3.20%

Furthermore, the investment cost in the EEV solution and the stochastic solution are equal. Thus, the increased cost of the EEV solution is related to operational costs, and the stochastic model incorporates this uncertainty better. On the other hand, in this case, it has no impact if the model is used to find the optimal transmission investment decision.

5.2.3 Energy mix

To obtain information about the energy mix, the generation output for each generator type in each country for each time step in each scenario from the stochastic model results is added up. Subsequently, the actual generation from the stochastic solution is the average of the generation from the three scenarios. Figure 5.9 (a) displays the total energy mix for the total NSOG area in the case with optimal capacity investment, while Figure 5.10 displays the generated energy in each country. Additionally, Figure 5.9 (b) and Figure 5.11 are included to present the energy mix without investment in interconnectors. Table B.3 and Table B.4 in Appendix B display the complete energy mix.

The total energy mix in the case with optimal interconnector investments consists of 27 % hydropower and 40% wind power. In total, RES generate 87% of the total energy in the NSOG area. Only 6% of the energy mix is from CO_2 emitting power plants. This is due to the high amount of installed RES capacity combined with overall high fuel prices and CO_2 prices in the three scenarios. Due to decreased transmission capacity in the case without investments in interconnectors, the total RES share decreases to 85% in Figure 5.9 (b). The power produced from hydro and solar is decreased, while power generated by bio, coal, and lignite has increased. This implies that some of the countries need to start up bio or coal power plants instead of import excess solar power or cheap hydropower, to cover their demand.



(a) Investment in interconnectors **(b)** No investment in interconnectors

Figure 5.9: Shares of the different generation technologies in the total energy mix in the NSOG area.

From Figure 5.10, it can be observed that Germany is the most significant power producer as expected due to its high demand and installed capacity. Germany's greatest generation technologies are wind power, which produces in total 152 TWh, followed by hydropower and solar. Lignite is the only non-RES which produces a significant amount of power. Nevertheless, the installed capacity of lignite is less than the installed capacity of gas and coal. A reason for this can be that the marginal cost of lignite is lower than coal and gas, such that it is more profitable to produce from lignite. Accordingly, the CO_2 price is not high enough to out lignite. The second largest power producer is Great Britain, which has an energy mix dominated by wind, both onshore and offshore, and nuclear. Consequently, the area price gets low. Norway is the third largest producer and produces almost all of the energy from hydropower.

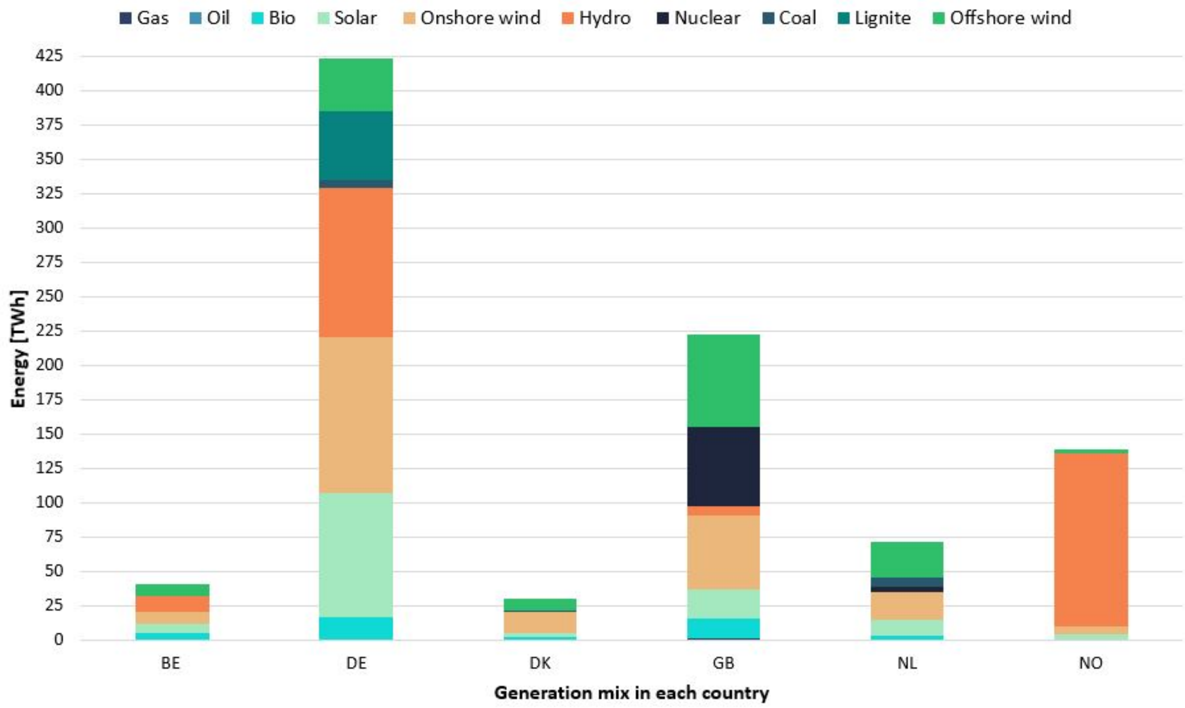


Figure 5.10: Generated energy by each generation technology in each area with optimal interconnector investment.

Belgium, Denmark, and The Netherlands are relatively small power producers. Denmark generates its power mainly from wind power, both onshore and offshore, in addition to some biofuels. The Netherlands has an energy mix consisting of mainly wind power, solar and coal, while Belgium's energy mix is consisting of mainly renewables such as wind, hydro, solar and biofuel.

By comparison of Figure 5.10 and Figure 5.11, it is observed that Germany generates more energy, and Norway generates less energy in the case without interconnector investments. This implies that Norway has a role of contributing Germany with hydropower at times with low RES production. Without interconnector capacity between Norway and Germany, Germany must cover its demand by producing more power from lignite and coal. Consequently, the

North seas area gets a lower RES-share and emits more CO_2. However, the generation mix in the other countries remains quite the same as in the case with interconnectors.

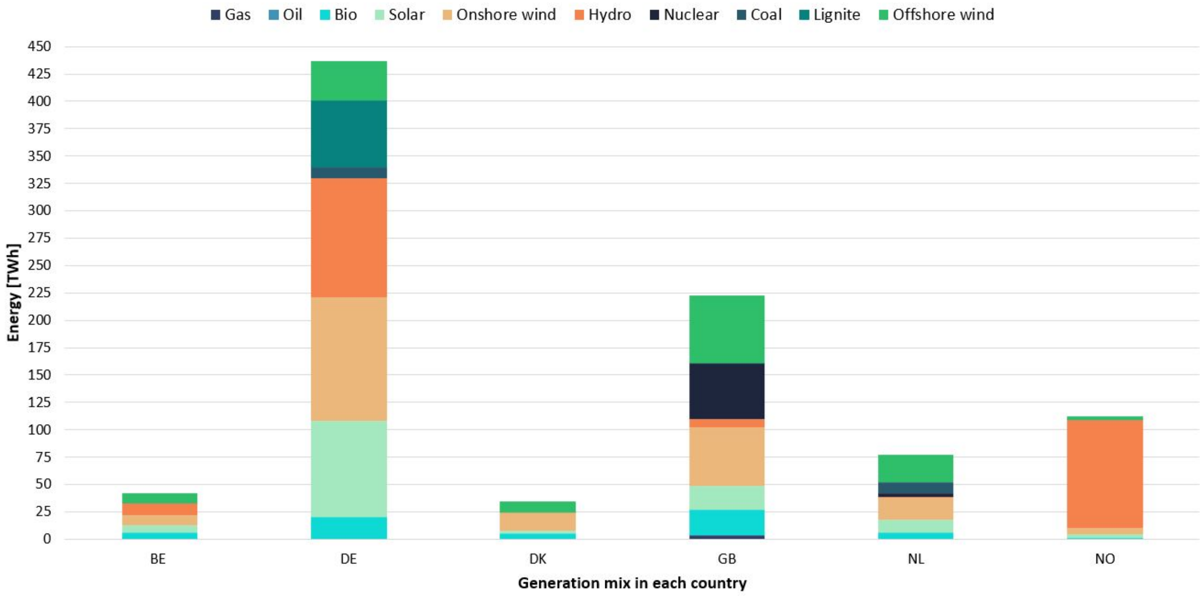


Figure 5.11: Generated energy by each generation technology in each area without interconnector investment.

5.2.4 Average area price

The area price is calculated in the same way as in Case 1. The area prices for Case 2 are displayed in Table 5.8. Table 5.8 (a) presents the prices for the scenarios in the optimal stochastic solution, where the investment capacity is 3000 MW in GB-NO, 5000 MW in NO-DE and 1000 MW in GB-DK. Table 5.8 (b) presents the prices in the case without interconnector investments.

Table 5.8: Average area prices

(a) Optimal interconnector investments

	Price [EUR/MWh]			
Area	DG	EUCO	ST	**Average**
BE	22.75	42.90	66.49	**44.04**
DE	45.20	43.51	63.05	**50.59**
DK	16.89	11.76	31.59	**20.08**
GB	34.63	22.36	37.97	**31.65**
NL	27.90	28.37	55.21	**37.16**
NO	60.30	40.49	41.14	**47.31**
NSOG area	34.61	31.56	49.24	**38.47**

(b) Without interconnector investments

	Price [EUR/MWh]			
Area	DG	EUCO	ST	**Average**
BE	25.37	51.32	70.21	**48.96**
DE	50.54	45.51	72.93	**56.32**
DK	26.88	20.86	57.59	**35.11**
GB	42.22	28.34	52.60	**41.05**
NL	48.02	48.99	65.82	**54.27**
NO	60.55	43.25	42.97	**48.93**
NSOG	42.26	39.71	60.35	**47.44**

The area price is strongly related to the generation mix in the areas. Germany has the highest price in both of the cases, due to the need for power to cover the peak demand for many of the hours. The coal power does not produce a considerable amount of power, but it is necessary to cover the peak demand. Thus, the prices get affected because it is the generator type with the highest marginal costs. By investing in an interconnector between Germany and Norway, the prices decrease. This is due to the possibility of transferring cheap hydropower from Norway at the times when Germany ordinarily is dependent on covering the load with coal power due to high demand or low availability of RES. Additionally, Norway can import cheap power from RES in Germany at times when there is a power surplus in Germany. This will decrease the prices in Norway because the marginal cost of solar and wind is lower than the hydropower cost in Norway. The most significant decrease in the area price happens in the Netherlands. The area price decrease with 17.11 EUR/MWh when having the optimal capacity in the assessed interconnectors. The Netherlands is not even one of the countries where the evaluated interconnectors are located. Thus, it must have strong connections to the other countries evaluated in the model. In Appendix A, Table A.8, it is displayed that The Netherlands is connected to Great Britain through the interconnector BritNed of 1000 MW, connected to Norway through NordNed of 700 MW and has interconnectors of 5000 MW to Germany. Accordingly, The Netherlands is connected to the surrounding countries, such that when they are producing more power from RES, it affects the Netherlands. The Netherlands can import cheap excess power from RES, from the surrounding countries, hence reduce its own more expensive production of power from coal when there is lack of wind resources in the Netherlands.

Belgium experiences the same as the Netherlands when having increased interconnector capacity in the North Sea area. Belgium is not directly affected by increased interconnector capacity but is affected by the increased power from RES in the surrounding countries through already existing interconnectors. Belgium covers its peak load by gas and can reduce this occurrence by import cheap excess power. Consequently, the area price in Belgium gets lower.

Denmark produces much of its power from wind power but is dependent on power from bio or coal at the times when having high demand or low wind speed. This sets the area price. Therefore, Denmark experiences a large decrease in the area price with an interconnector to Great Britain. Instead of producing power from coal and bio, Denmark can import excess renewable energy from Great Britain. Due to such large areas, it is unusual that both Denmark and Great Britain experiences the same low wind speed at the same time. Consequently, Denmark can export excess wind power at times with low wind in Great Britain. Great Britain has a much higher total demand and more installed wind capacity than Denmark, such that the import of excess power from Denmark is a smaller share of the total generation mix. Thus the price in Great Britain decreases less. Great Britain is still dependent on some power production from gas to cover the load but to less extent. The interconnector from Great Britain to Norway enhance the cost reduction such that the area price in Great Britain decreases by 9.4 EUR/MWh.

In both cases, with and without interconnector expansion, there exist significant differences in the area prices between the scenarios. Scenario ST has the highest average area prices in most of the areas because it is the scenario with the highest marginal costs. Besides, it indicates that generation from power plants with high marginal costs are necessary to cover the peak demand. The marginal costs in the EUCO scenario are lower, such that the average area prices become lower compared to Scenario ST. Scenario DG has lower marginal costs than Scenario ST, due to a lower CO_2 price. Additionally, Scenario DG produces more power from solar, which does not have any marginal costs, and at the same time, cut its power produced from biofuels.

5.3 Sensitivity analysis

5.3.1 Probability distribution

In the case studies, a uniform probability distribution is assumed. The probabilities are changed to observe how the different scenarios affect the results and especially the investment decision.

The main focus of the sensitivity analysis of Case 1, with input data from TYNDP 2016, is to investigate how the results change when the probability for Scenario 1 and Scenario 4 is different from the others. They are chosen as they represent the most extreme scenarios, in terms of emission goal achievement. Scenario 1 is the least optimistic one, and Scenario 4 is the most optimistic.

Table 5.9: Case 1: Overview of the results when the probabilities for the scenarios are changed. Total cost (TC) and investment cost (IC) are displayed for the stochastic, deterministic and EEV solution, in addition to the resulting EVPI and VSS. Values given in [bEUR].

Probability	Stochastic		Deterministic		EEV			
S1 S2 S3 S4	TC	IC	TC	IC	TC	IC	EVPI	VSS
70% 10% 10% 10%	645.597	13.883	644.238	12.668	658.517	12.446	1.360	12.919
40% 20% 20% 20%	570.586	15.897	569.367	14.903	593.338	16.722	1.219	22.751
25% 25% 25% 25%	532.851	17.746	531.932	16.020	559.793	16.722	0.920	26.942
10% 30% 30% 30%	495.007	17.746	494.496	17.138	526.422	18.158	0.511	31.415
30% 30% 30% 10%	531.169	17.746	530.065	15.657	556.327	16.722	1.104	25.159
20% 20% 20% 40%	534.534	17.746	533.798	16.366	560.922	18.158	0.736	26.388
10 % 10% 10% 70%	537.898	17.746	537.530	17.056	554.269	17.746	0.368	16.738

Table 5.9 presents an overview of the results from the sensitivity analysis of Case 1. It can be observed that the investment cost of the stochastic model is the same as the base case, with uniform probabilities when increasing the probability of Scenario 4. The investment cost is also the same when reducing only the probability of Scenario 1 or Scenario 4. This is because the optimal investment of Scenario 3 and 4 in the deterministic model is the same as the optimal investment in the stochastic model. However, when increasing the probability of Scenario 1, the

investment cost decreases. The optimal investment cost of Scenario 1 in a deterministic model is 10.433 billion euros. Thus, it converges towards this value in the stochastic model when the probability of Scenario 1 is increased.

The VSS is higher when having a more uniform probability distribution. In other words, when none of the scenarios have a significantly higher probability than the rest. This is due to increased uncertainty. Similarly, when having one scenario with high probability, the uncertainty is less. There is more probable to reach that specific scenario, and there is less value for a system planner to solve the problem with a stochastic approach rather than an EEV approach.

Table 5.10 presents an overview of the results from the sensitivity analysis of Case 2, input data from 2018. The main focus of the sensitivity analysis is to observe how the results change when adjusting the probabilities for all the three scenarios in terms of having one scenario with high probability and two with low probability, and one scenario with low probability and two with high probability.

Table 5.10: Case 2: Overview of the results when the probabilities for the scenarios are changed. Total cost (TC) and investment cost (IC) are displayed for the stochastic, deterministic and EEV solution, in addition to the resulting EVPI and VSS. Values in [bEUR].

Probability	Stochastic		Deterministic		EEV			
DG EUCO ST	TC	IC	TC	IC	TC	IC	EVPI	VSS
1/3 1/3 1/3	231.201	15.897	231.697	15.721	239.628	15.897	0.504	7.427
2/3 1/6 1/6	223.878	16.309	223.571	16.014	230.285	15.897	0.307	6.407
1/6 2/3 1/6	228.111	16.309	227.586	14.414	233.112	16.309	0.524	5.001
1/6 1/6 2/3	244.191	17.746	243.933	16.733	250.096	17.746	0.258	5.905
5/12 5/12 1/6	225.994	16.309	225.579	15.214	231.950	15.897	0.415	5.956
5/12 1/6 5/12	234.104	15.897	233.752	16.374	242.560	17.746	0.352	8.456
1/6 5/12 5/12	236.292	17.746	235.760	15.574	244.111	17.746	0.532	7.819

When Scenario DG has a low probability, and Scenario ST has a high probability, the investment capacity increases to 17.746 billion euros. This is the same capacity as the optimal capacity in Case 1. Scenario ST has higher input prices such that the operational costs get high. To compensate and reduce the total costs, the model finds it optimal to increase the investment capacity to be able to utilize more RES in the system.

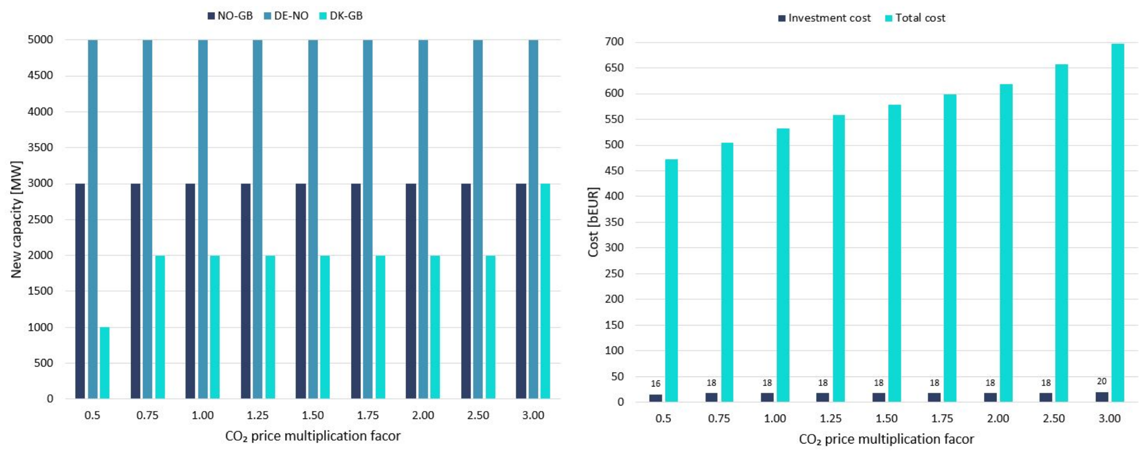
The VSS is highest in the case with equal probabilities for the scenarios and when there are two scenarios with high probability and one with low probability. The VSS is lowest when having one scenario with high probability. This implies that the VSS gets lower because the value of considering investments that are valuable for all scenarios decreases compared to EEV. Both methods make investments that align towards the scenarios with most probability, which, therefore, also has the most weight in the objective function.

From the sensitivity analysis of the probabilities of the scenarios, it is observed that the most repeatedly optimal investment cost is 17.746 billion euros. This is the highest investment cost that appears when adjusting the probabilities; hence, it may be natural to assume that this is the highest profitable investment capacity in this problem. The lowest investment cost is 13.883 billion euros in the sensitivity analysis of Case 1, where Scenario 1 has the highest probability. This is a scenario with low RES capacity and low CO_2 price, much lower than all the scenarios from TYNDP 2018. Based on the new scenarios from TYNDP 2018 one can assume that the North Seas areas have a higher installed RES capacity and different input prices in 2030 than proposed in Scenario 1. Hence, the lowest optimal investment capacity becomes 15.897 billion euros, which is the optimal capacity of the stochastic model in Case 2. Consequently, a good investment decision is to have an interconnector between Norway and Great Britain of 3000 MW, an interconnector of 5000 MW between Germany and Norway and an interconnector of either 2000 MW or 1000 MW between Great Britain and Denmark.

5.3.2 CO_2 price

A sensitivity analysis of the CO_2 price is performed for both case studies, to obtain information about the uncertainty in the CO_2 price and how it affects the optimal investment decision.

Figure 5.12 shows the behavior when the CO_2 price for all scenarios is gradually increased from half of its original value to three times its original value in Case 1 with input data based on TYNDP 2016. From the figure, it can be observed that the total cost increases when the CO_2 price is increased. This is because of the operational cost increases when the CO_2 price is increased. When the CO_2 price is from 0.75 to 2.5 times its original value, the investment cost is the same as in the base case, because the total cost does not increase so much that it is profitable to increase the transmission capacity. However, when the CO_2 price is three times its original value, the optimal solution is to increase the capacity on the interconnector between Denmark and Great Britain to 3000 MW. In this case, it is more profitable to invest in more interconnector capacity in order to reduce the costs in the system. Both Denmark and Great Britain have installed biofuel capacity. By the definition in this model, the biofuel price is not affected by the CO_2 price. Thus is the power produced from biofuels reasonable priced compared to the non-RES, and the countries with a lot of installed biofuel capacity would export this power. When the CO_2 price is half its original value, the new transmission capacity between Denmark and Great Britain is decreased to 1000 MW. Here, it is more profitable to produce a little extra power from non-RES than transfer excess power from OWP between the countries. The other interconnectors, NO-GB and DE-NO, remain at the same capacity in all cases.



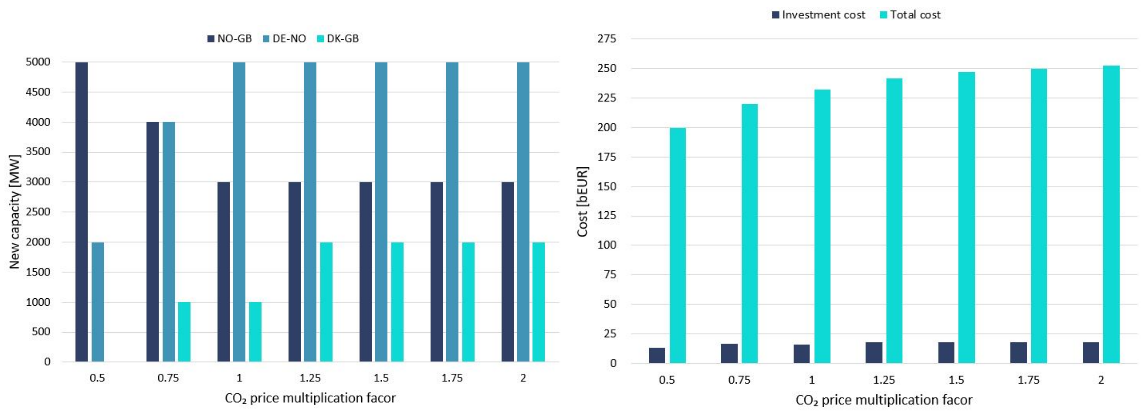
(a) Capacity expansion **(b)** Total cost and investment cost

Figure 5.12: Case 1: Results from the model when the CO_2 price is decreased and increased.

Figure 5.13 displays the behavior when the CO_2 price is changed in Case 2, based on input data from TYNDP 2018. From Figure 5.13 (b) it is observed a trend of increasing total cost when the CO_2 price increases. This is because of the operational cost in terms of marginal cost for the CO_2 emitting generator types increases when the CO_2 price increases. To compensate for this and reduce the total cost, the model wants to invest in more transmission capacity. In that way, more RES can be utilized by transferring surplus power to where it is needed. Hence, it gives reduced operational cost. Figure 5.13 (a) presents that the model finds it profitable to increase the capacity on the interconnector between Denmark and Great Britain to 2000 MW the CO_2 price is 25% more than in the original case. This is the same capacity as the optimal investment capacity in the stochastic solution in Case 1.

When the CO_2 price is half its original value, it is only profitable to invest in the interconnectors connected to Norway. In this case, the interconnector to Great Britain has an optimal capacity of 5000 MW, while the interconnector to Germany has a capacity of 2000 MW. This implies that there is more to gain from building the interconnector to Great Britain than to Germany. Great Britain has much power produced from gas, in addition to RES and nuclear, while Germany has a generation mix consisting of coal power plants, in addition to RES. A low CO_2 price does not affect the marginal cost of gas, as much as it decreases the cost of coal. Therefore, it is more cost saving to increase the power exchange between Norway and Great Britain instead of Germany. In that way, Norway can contribute with flexible hydropower, at times when Great Britain usually would be forced to increase its gas power production to cover the demand. Similar to Germany, Denmark supplements its wind power production by power from coal. It is not profitable to build an interconnector between Great Britain and Denmark because of the resultant low marginal cost for coal power plants.

In the case where the CO_2 price is reduced with 25% from the original case, there is profitable to invest in just as much capacity in the interconnector between Germany and Norway, as in the interconnector between Norway and Great Britain. Norway can contribute with flexible hydropower at times when there is less solar or wind resources in Germany or Great Britain. Additionally, Norway can by cheap power produced by wind at especially the night if there are high wind speed and low demand. Investment in 1000 MW between Denmark and Great Britain is profitable as well. This implies that the marginal cost of coal has increased, such that it is more profitable to build interconnectors to transfer excess power from RES, such as wind and solar, besides, to share the biofuel power capacity installed in the countries to keep the costs low.



(a) Capacity expansion

(b) Total cost and investment cost

Figure 5.13: Case 2: Results from the model when the CO_2 price is decreased and increased.

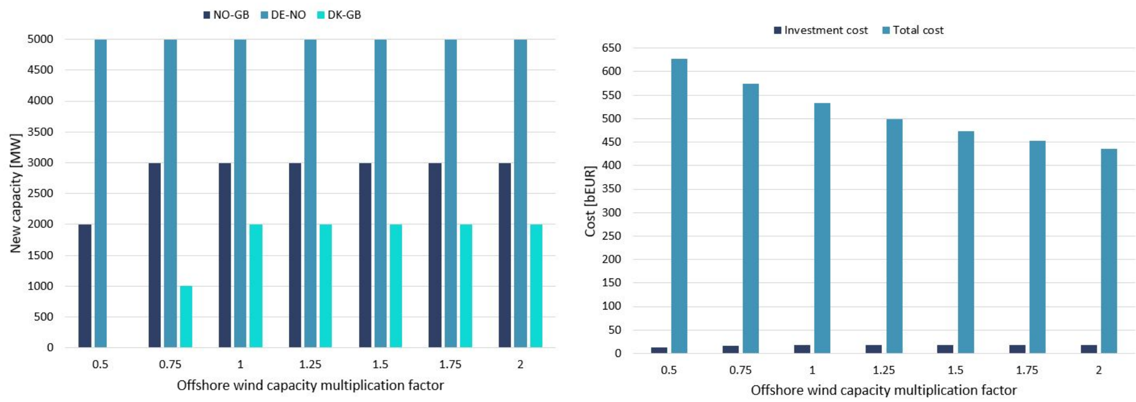
5.3.3 OWP capacity

A sensitivity analysis of the OWP capacity is performed for both case studies, to obtain information about how the OWP capacity affects the optimal investment decision.

Figure 5.14 displays the behavior when the OWP capacity in all scenarios is changed from half its original value until twice its original value in Case 1. It can be observed that the total cost decreases with increased OWP capacity. This is because the offshore wind has zero operational cost, and outs the power produced from non-RES. In the case where the OWP capacity is half its original value, the investment costs are low, and there is no new capacity between Denmark and Great Britain. The capacity between Norway and Great Britain is also reduced compared with the base case. The production capacity in Great Britain consists of a lot of OWP in all scenarios. Therefore, when the OWP is reduced, it is less profitable to transfer power from Great Britain because a higher amount of the produced power is from more expensive, non-RES, such as gas. Denmark and Great Britain have a similar generation mix, such that there is no need for transmission capacity between the countries when OWP is low. In that case, it is more profitable to produce their own power from fossil fuels.

The interconnector between Germany and Norway has a capacity of 5000 MW in all the cases.

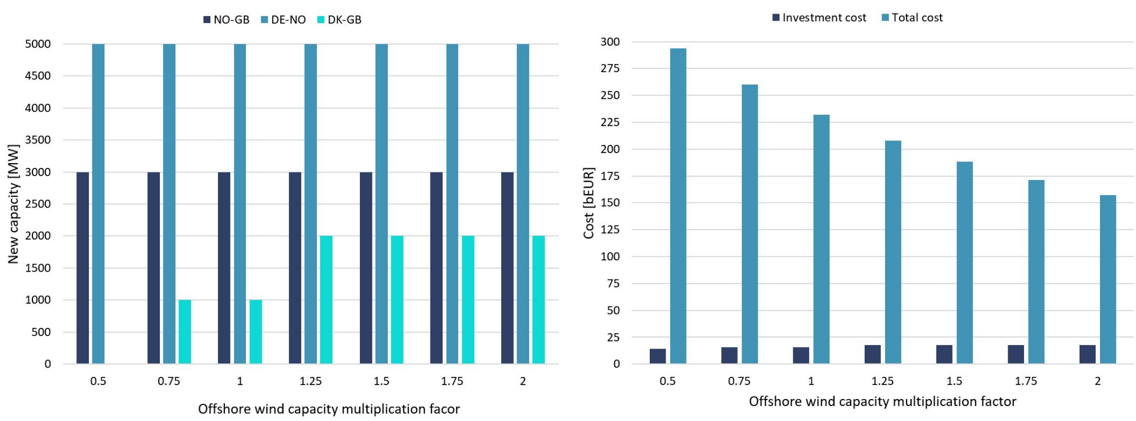
Hence, it appears as the most robust interconnector. The generation capacity in DE consists of more solar than OWP in all the scenarios, such that the need for flexibility is still high. An interconnector to Norway, a country with much flexible hydropower, can contribute to that.



(a) Capacity expansion **(b)** Total cost and investment cost

Figure 5.14: Case 1: Results from the model when the offshore wind capacity is decreased and increased.

Figure 5.15 presents the behavior of the model when the OWP capacity is adjusted from half to twice its original value in Case 2. From 5.15 (b) it is observed that the total cost decrease approximately linearly with the increased OWP capacity. OWP reduces the operational costs due to zero marginal cost, and outs more expensive power production from coal and gas. The need for interconnector capacity increases due to the need for maintaining the security of supply, and the possibility of transfer excess power from OWP to countries which experiences high demand or have low wind resources at that moment. The total installed interconnector capacity varies from 8000 MW to 10 000 MW. The interconnectors from Norway generally have a larger capacity than the interconnector between Denmark and Great Britain due to the possibility of supplying Great Britain and Germany with flexible hydropower from Norway and transfer excess power from OWP to Norway.



(a) Capacity expansion **(b)** Total cost and investment cost

Figure 5.15: Case 2: Results from the model when the offshore wind capacity is decreased and increased.

5.4 Discussion

5.4.1 Optimal investment decision

Case 1 has more capacity expansion than Case 2. The interconnector between Great Britain and Denmark has a 1000 MW higher capacity in Case 1 than Case 2. In Case 2, both Great Britain and Denmark have twice as much power produced from solar compared to Case 1. Therefore, both countries have more solar in addition to wind power with zero marginal cost to cover the load. Consequently, the operational cost does not get any lower when increasing the interconnector capacity. Additionally, it is observed that the total cost in Case 1 is more than doubled compared to Case 2. The operational cost in Case 1 is higher because Case 1 produces more energy than Case 2. Germany produces much power from coal, and the other countries generally produce more power from gas, than in Case 2. Moreover, Case 1 has overall higher marginal costs than Case 2. To reduce the total costs in Case 1, it is profitable to invest in more capacity, such that Denmark and Great Britain can transfer more of its surplus power. The difference in total cost is reflected in the average area prices, where the total NSOG area in Case 1 has an average price, which is 22.89 EUR/MWh higher than in Case 2, due to the higher marginal costs.

However, when the CO_2 price or the OWP capacity is increased with 25% in Case 2, the model finds it optimal to invest in the same capacity as in Case 1. Then it is more profitable to invest in more transmission capacity and increase the production of wind power in Denmark and Great Britain, instead of covering the demand with power from coal or gas. Additionally, the most common investment capacity across the scenarios in the sensitivity analysis of the scenario probabilities is the optimal capacity from Case 1. Thus, this capacity may imply as the upper boundary of the optimal investment, based on the input data in this model. The CO_2 price in Case 1 needs to be increased three times for it to be optimal to invest in more capacity, while in Case 2 the CO_2 price must be increased even more. The optimal investment capacity neither increases if the OWP capacity increases to twice its original value in both cases. From the deterministic solutions of the cases, it can be observed that the model never wants a higher total capacity than 10 000 MW, and the allocation is 3000 MW between Great Britain and Norway, 5000 MW between Norway and Germany, and 2000 MW between Great Britain and Denmark. Consequently, uncertainty is mainly regarding the lower boundary of the optimal investment capacity. If Scenario 1 is more likely to occur, the investment capacity decrease and similarly, if Scenario EUCO is more likely to occur. Scenario EUCO and Scenario 1 has relatively low fuel and CO_2 prices; additionally, Scenario 1 has low installed capacity from RES. Hence, it seems like the fuel and CO_2 price, and installed RES capacity affects the investments if they are lower than expected. Due to the 2050 goals of the EC of reducing CO_2 emissions with 80-95 % by 2050, it may be more profitable from a long-term perspective to invest the sufficient capacity now to meet the year 2050. However, some investigation of the optimal capacity in 2050 based on scenarios for 2040 and 2050 may be required to obtain the optimal grid structure.

5.4.2 Other observations

Five of the scenarios are stated in TYNDP 2016 and 2018 to have a merit order of gas before coal. From the case studies, it appears that there is more profitable to produce power from coal than gas. The input price of coal, inclusive fuel, and CO_2 cost, is lower than gas in all the scenarios. Hence, this has an impact on the area prices. Since the input prices to the model are calculated by use of the generation technology efficiencies, the selection of the generation efficiencies may have an impact on the merit order. Additionally, the CO_2 emission factors are a part of the calculation of the final marginal cost of each generation technology.

A general trend is that the utilization of RES increases with increased interconnector capacity. Consequently, the average area price becomes lower. However, the price an end-user needs to pay for power may not decrease due to the possibility of increased grid-tariff to cover the transmission line expansion costs. The end-users require that the revenue from the power exchange, in terms of congestion rents, are utilized to decrease the grid-tariff. There is a possibility for a change in the welfare distribution in the investigated countries, even though the total system costs decrease. Some countries may experience that the producers earn more, and the consumers must pay more.

5.5 Limitations

Limitations of the work are mainly related to the model and the input data. The model has the potential to be more realistic. Hence, less aggregation would describe a more realistic system and give more exhaustive results of the NSOG case study. TYNDP 2018 presents non-aggregated data on demand and generation capacity for the countries. It is possible to include that in the model, but it may be at the sacrifice of the computational time. Moreover, the use of full-time periods or a better sampling technique using another method than random sampling may give more exact results. Then the model would be able to use the actual data for a whole year, not just random data samples which may not represent the reality. Different sampling and clustering techniques with appurtenant sensitivity analysis applied to the NSOG are investigated in [44] and [45]. They propose that a sample size of 200 sample steps as utilized in this model is sufficient.

Investment in offshore node and new generation capacity are not considered in this model. The offshore nodes are assumed to exist in all scenarios, which is not realistic in Scenario 1 and Scenario 2, as they have low OWP capacity compared to the rest of the scenarios. Such that the investment costs could have increased in the model if it appeared necessary to expand some of the nodes in Scenario 1 or 2. The total generation capacity in the model is assumed to exist when the modeling year starts, to simplify the problem. However, in real life, some generation expansion might be profitable to decrease the total cost. Nevertheless, these assumptions enable a comparison on an equal basis. Cost parameters for branch expansion are the same in all scenarios, and this is necessarily not realistic due to the difference in the financial conditions and new technology breakthroughs. However, it simplifies the comparison. Additional assumptions and simplifications are made when preparing the generator input data and fuel prices. Mainly regarding the unspecified categories *Others RES* and *Others non-RES*, and OWP in Case 1. It is difficult to find a complete, reliable open-source data set that can be used in the model since it is important that the data is built on the same basis. Section 4.3.2.6 and Section 4.3.1.6 give a detailed explanation of assumptions in the input data.

The assumption regarding the hydropower price is discussed in the chapter about input data but is mentioned here as well due to its conspicuity in the area price calculations. The hydropower price for Case 1 is from the system price in south Norway in 2015, while hydropower price in Case 2 is from the system price in 2018. 2018 was a very dry year with high temperatures and drought in southern Norway. This caused a high power price and a high water value due to less water in the reservoirs than in a mean year. Additionally, the CO_2 price increased a lot during 2018, from 8 EUR/tCO_2 at the beginning of the year to 24 EUR/tCO_2 at the end of the year. In 2015, the CO_2 price was between 7 and 8 EUR/tCO_2. The CO_2 price affects the system price in Norway because the price of raw materials such as gas, coal, and CO_2 are the factors that mainly decide the market price. Hence, the hydropower price is decided on the basis of this and the water level in the reservoirs. Therefore, it may be a wrong approach to utilize the system price in Norway from 2015 and 2018 in this model to represent the hydropower price for 2030. However, due to the lack of open-source data on water values for 2030, this is the chosen approach.

Furthermore, the calculation of the average area prices is a simplification. To obtain the correct area prices, the dual variables of the model should be calculated, but since the optimization problem contain binary variables, this information is not reliable. The chosen method is, therefore, the method where the marginal cost of the last dispatched generation type is used as the area price. The change in the area price is used as an estimation of how the interconnector expansions decreased the costs. However, cost-benefit allocation in terms of socio-economic measures such as a change in the consumer and producer surplus should have been calculated to give a better knowledge of how the interconnector expansions affect the areas. This was not performed due to lack of time and difficulties with handling the output results from the stochastic model by the existing PowerGIM functions.

Chapter 6

Conclusion

6.1 Conclusion

The main objective of this thesis is to investigate how investments in the North Sea Offshore Grid (NSOG) are affected by uncertainty. A stochastic two-stage model, formulated as a mixed integer linear program, is utilized and applied on two case studies. The model separates the first stage investment variables from the second stage operational variables, accounting for the uncertainty through in total seven scenarios, divided into two cases. The scenarios in the first case are conducted by input data from the Ten-Year Network Development Plan (TYNDP) 2016, while the second case utilizes the scenarios in TYNDP 2018 as input data. The uncertainty in the operational stage is the differences between the scenarios and is mainly regarding fuel and CO_2 prices, installed generation capacity of the different generation technologies and demand at the consumer side. A deterministic program of the equivalent problem is used to quantify metrics concerning the Expected Value of Perfect Information (EVPI) and the Value of the Stochastic Solution (VSS).

The first research question is about how the stochastic model solution differs from the deterministic counterpart. The EVPI and the VSS are employed as a measure of the stochastic model performance compared to the model's deterministic counterpart. The first case obtain an EVPI of 920 million euros (0.17% of the stochastic cost) and a VSS of 26.942 billion euros (5.06% stochastic cost), while the second case get an EVPI of 504 million euros (0.22% of the stochastic cost) and a VSS of 7.427 billion euros (3.2% of the stochastic cost). The results indicate that a system planner is willing to pay 920 million euros in the first case, and 504 million euros in the second case for perfect information about the future prices, generation capacities, and demand. Besides, the system planner can save 26.942 billion euros in the first case and 7.427 billion euros in the second case, by accounting for uncertainty in a stochastic model compared to an approach which copes with uncertainty in a deterministic model.

The second research question was to find out how investments in the NSOG are affected by uncertainty. Generally, it is observed that more installed capacity from renewable energy sources (RES) and higher marginal costs of the generators result in higher investment capacity. Increased investment capacity makes it possible to transfer surplus power produced by RES to where it is needed. In such a way, there is less need for covering the demand with CO_2 emitting generator types. Hence, the operational costs decrease.

The optimal investment in the first case is 3000 MW in the interconnector between Great Britain and Norway, 5000 MW in the interconnector between Germany and Norway, and 2000 MW between Great Britain and Denmark. This is the same capacity as the optimal capacity in the two most ambitious scenarios in the case when solving the deterministic model. From this, it seems like the model is willing to invest in too much capacity instead of too little, such that it can cover the most ambitious scenario.

The optimal investment capacity in the second case is 3000 MW in the interconnector between Great Britain and Norway, 5000 MW in the interconnector between Germany and Norway, and 1000 MW in the interconnector between Great Britain and Denmark. This is 1000 MW less than the optimal capacity in the first case. The main reason for this is that there is more installed solar capacity to supplement the wind capacity in the countries in the case. Thus, the marginal cost of coal and gas is not high enough to make it profitable to transfer more power between the countries. However, the sensitivity analysis of the second case indicates that an increase of 25% in the CO_2 price or installed offshore wind capacity made it optimal to invest in 1000 MW more in the interconnector between Great Britain and Denmark.

The third and final research question is concerning how the energy mix and average area prices are affected by optimal investments. In the first case, the generated energy from RES is 71% with optimal interconnector expansion and 69% without interconnector expansions. In the second case, the generated energy from RES is 87 % with interconnector expansion and 85 % without interconnector expansions. The increase of 2% is an acceptable increase considering that the model is not replacing any fossil fuel plants neither invests in new generation from RES. Furthermore, changes can be seen in the average area prices. The NSOG area average price in the first case decreased from 63.52 to 61.82 EUR/MWh, and in the second case, the price decreased from 47.44 to 38.47 EUR/MWh. In both cases, RES are covering the base-load in the areas, and non-RES such as coal and gas cover peak-load. With increased interconnector capacity, there is less need for power production from coal and gas, and one can instead import excess power from RES. Thus, the area price decrease.

6.2 Further work

This study considers a two-stage stochastic optimization model. A natural way of further work would be to apply the input data to a multistage stochastic optimization model. A model having two investment stages for grid expansion, contributes with valuable flexibility for a system planner. This flexibility or the option value of an investment can be quantified by comparing the results from the multistage model with the one-step here-and-now investment decision. A study, utilizing the multistage stochastic model, is already performed in [14]. However, it only considers uncertainty in offshore wind development. Therefore, it could be interesting to investigate other uncertainties in the same multistage model, such as the ones investigated in this thesis. Some extensions of the model are recommended in [29] for future work. The recommendations are mainly regarding the introduction of lead time; for instance, the construction time after the decision is made and how this affects the optimal investment decision. There is also suggested to perform a study to quantify managerial characteristics of the different investment options by varying the number of investment stages and lead time.

Another way to extend the work is to allow for generation expansion in the model. Thus, the countries can respond to the transmission investments, and maybe increase the power produced by RES.

Finally, improvement and work with the limitations mentioned in Section 5.5 is beneficial to obtain more accurate results since the main limitations of this study are related to the input data. Recommended further work are, for instance, elaboration of a method to estimate the hydropower price in Norway in 2030, specification of the unspecified generation categories, or usage of less aggregation. Additionally, an interesting upgrade of the input data could be to perform a study that utilizes the scenarios for the year 2040 from TYNDP 2018. They are natural extensions of the applied 2030 scenarios from TYNDP 2018, in addition to the fact that few studies with the approach of the year 2040 exist.

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Appendix A

Table A.1: Overview of nodes in the case study

Node	Country	Latitude	Longitude	Offshore	Type	Function
1	BE	51.45	2.45	Yes	DC	OWP
2	DE	54.68	6.16	Yes	DC	OWP
3	DK	55.59	7.58	Yes	DC	OWP
4	GB	55.01	2.65	Yes	DC	OWP
5	GB	52.67	2.72	Yes	DC	OWP
6	NL	52.75	3.5	Yes	DC	OWP
7	NL	53.56	5.5	Yes	DC	OWP
8	NO	56.74	5.11	Yes	DC	OWP
21	BE	51.22	3.17	No	AC	Connecting hub
22	DE	53.13	7.31	No	AC	Connecting hub
23	DK	55.52	8.73	No	AC	Connecting hub
24	GB	53.56	-0.15	No	AC	Connecting hub
25	GB	52.07	1.06	No	AC	Connecting hub
26	NL	52.33	5.02	No	AC	Connecting hub
27	NO	58.28	6.85	No	AC	Connecting hub
28	DE	53.9	9.18	No	AC	Connecting hub
29	DK	56.5	9.54	No	AC	Connecting hub
30	NL	53.43	6.88	No	AC	Connecting hub
31	NL	52.48	4.69	No	AC	Connecting hub
91	NO	59.47	6.58	No	AC	Aggregated country
92	DK	56.0	9.3	No	AC	Aggregated country
93	DE	52.5	10.8	No	AC	Aggregated country
94	NL	52.24	5.83	No	AC	Aggregated country
95	BE	50.72	4.43	No	AC	Aggregated country
96	GB	52.5	-1	No	AC	Aggregated country

Table A.2: Input generation data for Scenario 1-4, mainly from TYNDP 2016 visions for 2030 [49]. Offshore wind calculated by use of data from WindEurope [46].

		Installed capacity [MW]						
	Generation tech.	**BE**	**DE**	**DK**	**GB**	**NL**	**NO**	**Total**
Scenario 1	Biofuels	1700	6960	1720	5450	300	0	16130
	Gas	10570	29788	2604	47377	13837	425	104601
	Hard coal	0	23365	410	2897	4610	0	31282
	Hydro	1438	13257	9	4754	38	38900	58396
	Lignite	0	12610	0	0	0	0	12610
	Nuclear	0	0	0	4552	486	0	5038
	Oil	0	1026	735	109	0	0	1870
	Solar	4050	57240	840	8270	4000	0	74400
	Onshore wind	3332	60041	3205	9171	4480	1685	81913
	Offshore wind	1568	14009	3985	12699	2520	395	34177
	Total	22658	218296	12508	95279	30271	41405	420417
Scenario 2	Biofuels	1700	6960	1720	5450	300	0	16130
	Gas	10570	24113	2604	40786	12856	425	91354
	Hard coal	0	23365	410	2897	4610	0	31282
	Hydro	1438	13257	9	4754	38	38900	58396
	Lignite	0	12610	0	0	0	0	12610
	Nuclear	0	0	0	4552	486	0	5038
	Oil	0	1026	735	109	0	0	1870
	Solar	4050	46869	840	7460	5100	0	64319
	Onshore wind	3332	49633	4356	24009	3942	1685	86957
	Offshore wind	1568	11567	4054	33291	2218	395	53093
	Total	22658	189400	14728	123 308	29550	41405	421049
Scenario 3	Biofuels	2500	9340	1720	8420	5080	0	27060
	Gas	10040	45059	3746	40726	14438	855	114864
	Hard coal	0	14940	410	0	0	0	15350
	Hydro	2730	17637	9	7682	38	40800	68896
	Lignite	0	10209	0	0	0	0	10209
	Nuclear	0	0	0	9022	486	0	9508
	Oil	0	871	735	75	0	0	1681
	Solar	5800	60740	1970	15560	15400	0	99470
	Onshore wind	4452	78607	5780	20436	8128	2066	119469
	Offshore wind	4048	22143	4970	30654	4572	844	67231
	Total	29 570	259546	19340	132575	48142	44565	533738
Scenario 4	Biofuels	2500	9340	1720	8420	5080	0	27060
	Gas	10040	45059	3746	40726	14438	855	114864
	Hard coal	0	14940	410	0	0	0	15350
	Hydro	2226	14505	9	5470	38	48700	70948
	Lignite	0	9026	0	0	0	0	9026
	Nuclear	0	0	0	9022	486	0	9508
	Oil	0	871	735	75	0	0	1681
	Solar	4925	58990	1405	11915	9700	0	86935
	Onshore wind	3938	75656	6600	23160	6397	1771	117523
	Offshore wind	3580	21311	6225	34741	3598	724	70178
	Total	27209	249698	20850	133529	39737	52050	523073

Table A.3: Input generation data for Scenario DG, ST and EUCO from TYNDP 2018 [33].

		Installed capacity [MW]						
	Generation tech.	**BE**	**DE**	**DK**	**GB**	**NL**	**NO**	**Total**
DG	Biofuels	1370	6631	1885	8142	507	76	18548
	Gas	7509	39379	99	36863	11132	435	95417
	Hard coal	0	14727	410	0	4608	0	19745
	Hydro	2575	24908	7	1695	38	36931	66154
	Lignite	0	9368	0	0	0	0	9368
	Nuclear	0	0	0	5686	486	0	6172
	Oil	500	835	817	695	0	0	2847
	Solar	6851	94574	5113	34663	14084	2972	158257
	Onshore wind	3298	58500	5596	16125	6723	3330	93572
	Offshore wind	2310	14664	2905	22182	11500	0	53561
	Total	24350	263586	16832	126051	49078	43744	523641
ST	Biofuels	1307	6631	1885	8142	507	76	18548
	Gas	7509	41334	529	36863	11132	435	97802
	Hard coal	0	14727	410	0	4608	0	19745
	Hydro	2575	24909	7	1695	38	36931	66155
	Lignite	0	9368	0	0	0	0	9368
	Nuclear	0	0	0	5686	486	0	6172
	Oil	0	835	817	195	0	0	1847
	Solar	5051	66300	2939	24494	11439	400	110623
	Onshore wind	3298	58500	5596	16125	9723	3330	96572
	Offshore wind	2310	14664	2905	22182	11500	0	53561
	Total	22050	237268	15088	115382	49433	41172	480393
EUCO	Biofuels	810	8567	2872	17760	2690	140	32839
	Gas	9688	18752	788	29487	10812	1879	71406
	Hard coal	16	22930	1471	501	4429	4	29351
	Hydro	2575	24704	7	1695	38	36931	65950
	Lignite	0	13782	0	0	0	0	13782
	Nuclear	0	0	0	13107	485	0	13592
	Oil	218	1247	218	2579	2066	2	6330
	Solar	6907	81501	838	10860	5933	800	106839
	Onshore wind	4146	59902	5271	24335	7674	3700	105028
	Offshore wind	3240	9547	2834	13326	2561	1840	33348
	Total	27600	240932	14299	113650	36688	45296	478465

Table A.4: CO_2 emission factors for fuel combustion given by IEA [48], used as emission data input.

Fuel	**Emission factor [tC02/MWh]**
Hard coal(Other bituminous coal)	0,87
Lignite	1,03
Natural gas	0,405
Fuel oil	0,67

Table A.5: Efficiencies for each technology, from ENTSO-E market modelling data [49].

Technology	Efficiency range	Assumed efficiency
Nuclear	0.3 - 0.35	0.33
Lignite	0.3 - 0.46	0.38
Hard coal	0,3 - 0,46	0.38
Gas conventional	0.25 - 0.42	
Gas CCGT	0.33 - 0.60	
Gas OCGT	0.35 - 0.44	
Estimated gas mix		0.4
Light oil	0.32 - 0.38	
Heavy oil	0.25 - 0.43	
Oil shale	0.28 - 0.39	
Estimated oil mix		0.34

Table A.6: Cost of generation for the different generation technologies in scenario 1-4 . Calculated from fuel prices [33] and technology efficiency in Table A.5.

	Product	Fuel price [EUR/net GJ]	Assumed efficiency	Input price [EUR/MWh]
DG	Nuclear	0.47	0.33	5
	Lignite	1.1	0.38	10
	Hard coal	2.7	0.38	26
	Gas	8.8	0.40	79
	Oil	12.9	0.34	137
	Hydro (except NO)			10
	CO2	50		50
ST	Nuclear	0.47	0.33	5
	Lignite	1.1	0.38	10
	Hard coal	2.7	0.38	26
	Gas	8.8	0.40	79
	Oil	12.9	0.34	137
	Hydro (except NO)			10
	CO2	84.3		84.3
EUCO	Nuclear	0.47	0.33	5
	Lignite	2.3	0.38	22
	Hard coal	4.3	0.38	41
	Gas	6.9	0.40	62
	Oil	12.47	0.34	132
	Hydro (except NO)			10
	CO2	27		27

Table A.7: Cost of generation for the different generation technologies in scenario 1-4 . Calculated from fuel prices [49] and technology efficiency in Table A.5.

	Product	Fuel price [EUR/net GJ]	Assumed efficiency	Input price [EUR/MWh]
	Nuclear	0.46	0.33	5
	Lignite	1.10	0.38	10
	Hard coal	3.01	0.38	29
Scenario 1	Gas	9.49	0.40	85
	Oil	11.11	0.34	118
	Hydro (except NO)			10
	CO2	17		17
	Nuclear	0,46	0,33	5
	Lignite	1,1	0,38	10
	Hard coal	3,01	0,38	29
Scenario 2	Gas	9,49	0,4	85
	Oil	11,11	0,34	118
	Hydro (except NO)			10
	CO2	17		17
	Nuclear	0,46	0,33	5
	Lignite	1,1	0,38	10
	Hard coal	2,8	0,38	21
Scenario 3	Gas	7,23	0,4	65
	Oil	8,48	0,34	90
	Hydro (except NO)			10
	CO2	71		71
	Nuclear	0,46	0,33	5
	Lignite	1,1	0,38	10
	Hard coal	2,8	0,38	21
Scenario 4	Gas	7,23	0,4	65
	Oil	8,48	0,34	90
	Hydro (except NO)			10
	CO2	76		76

Table A.8: Capacity between nodes. Capacity between countries from TYNDP 2016 Market Modelling Data [49]. Capacity from countries to connection hub and offshore wind farms are arbitrarily chosen to be sufficient

Node from	Node to	Capacity [MW]	Corridor name
21, BE	95, BE	5000	
22, DE	93, DE	15000	
23, DK	92, DK	5000	
24, GB	96, GB	10000	
25, GB	96, GB	5000	
26, NL	94, NL	5000	
27, NO	91, NO	10000	
28, DE	93, DE	5000	
29, DK	92, DK	5000	
30, NL	94, NL	5000	
31, NL	94, NL	5000	
93, DE	94, NL	5000	
93, DE	92, DK	3000	
93, DE	95, BE	1000	
94, NL	95, BE	2400	
1, BE	21, BE	100000	
2, DE	22, DE	100000	
3, DK	23, DK	100000	
4, GB	24, GB	100000	
5, GB	25, GB	100000	
6, NL	26, NL	100000	
7, NL	30, NL	100000	
8, NO	27, NO	100000	
27, NO	24, GB	From model	North Sea Link
27, NO	28, DE	From model	NordLink
27, NO	29, DK	1700	Skagerakk
27, NO	30, NL	700	NordNed
23, DK	30, NL	700	COBRA
23, DK	24, GB	From model	Viking
31, NL	25, GB	1000	BritNed
21, BE	25, GB	1000	NEMO

Table A.9: Input demand data for vision 1 - 4 from TYNDP 2016 Scenario Development Report and TYNDP 2016 Market Modelling Data [31, 49].

		Country					
		BE	**DE**	**DK**	**GB**	**NL**	**NO**
Annual demand [GWh]	Scenario 1	93 152	546 765	38 853	329 349	122 012	131 506
	Scenario 2	87 862	518 757	36 776	310 117	114 551	124 907
	Scenario 3	86 184	508 708	39 810	354 408	116 399	140 384
	Scenario 4	93 247	547 178	41 219	368 084	122 577	145 806
Peak daily demand [MW]	Scenario 1	14 067	86 425	6 971	58 340	19 518	23 840
	Scenario 2	12 851	79 794	6 194	52 701	17 860	21 655
	Scenario 3	12 612	78 298	7 107	63 840	19 032	25 342
	Scenario 4	13 486	81 369	6 623	59 578	18 751	24 468

Table A.10: Input demand data for Scenario DG, ST and EUCO from TYNDP 2018 Scenario Development Report [33] and *Joint scenarios data: Load Series 2030 DG - ST - EUCO* [54].

		Country					
		BE	**DE**	**DK**	**GB**	**NL**	**NO**
Annual demand [GWh]	DG	89 247	561 963	50 236	337 470	129 426	149 951
	ST	89 312	551 505	46 982	324 794	119 067	149 211
	EUCO	96 477	580 788	39 315	376 515	118 990	151 509
Peak daily demand [MW]	DG	13 816	86 729	8 111	63 937	21 150	25 844
	ST	13 870	84 598	7 600	60 646	18 684	25 760
	EUCO	15 233	90 853	6 354	70 717	18 811	26 446

Table A.11: Parameters for cost per branch for new transmission corridors

Type	B_d [kEUR/km]	B_{dp} [kEUR/kmMW]	B [kEUR]
AC	1193	1.416	312
DC-mesh	1236	0.578	312
DC-direct	1236	0.578	312
Converter	0	0	0
AC overhead line	1187	0.394	0

Table A.12: Cost per branch endpoint parameters for new transmission corridors

Type	C_p^L [kEUR/MW]	C^L [kEUR]	C_p^S [kEUR/MW]	C^S [kEUR]
AC	0	1562	0	5437
DC-mesh	1562	0	5437	
DC-direct	93.2	58209	107.8	453123
Converter	46.6	28323	53.9	20843
AC overhead line	0	1562		

Table A.13: Cost parameters for new nodes

Type	N^L [kEUR]	N^S [kEUR]
AC node	1	50000
DC node	1	406000

Appendix B

Table B.1: Case 1: Energy mix from the stochastic results with optimal interconnector investments capacity. Values given in GWh.

Area	Gas	Oil	Bio	Solar	Wind	OWP	Hydro	Nuclear	Coal	Lignite
BE	19 268	0	18 894	4 872	9 734	8 800	8 576	0	0	0
DE	2 831	0	40 808	60 589	133 004	54 347	64 228	0	116 074	73 583
DK	453	0	8 139	1 179	13 470	16 155	39	0	1 904	0
GB	57 985	0	49 736	9 851	55 100	95 744	24 813	57 166	5 331	0
NL	7 689	0	20 342	9 231	14 880	13 215	166	4 123	19 796	0
NO	5	0	0	0	4 704	2 720	178 276	0	0	0
Total	88 229	0	137 920	85 722	230 893	190 982	276 099	61 289	143 105	73 583

Table B.2: Case 1: Energy mix from the stochastic results without interconnector expansions. Values given in GWh

Area	Gas	Oil	Bio	Solar	Wind	OWP	Hydro	Nuclear	Coal	Lignite
BE	20 883	0	18 969	4 874	9 732	8 829	8 576	0	0	0
DE	6 239	0	46 773	60 989	131 963	52 883	64 228	0	119 526	79 367
DK	546	0	7 905	1 189	13 512	15 475	39	0	1 785	0
GB	73 926	0	50 141	9 851	55 143	84 999	24 813	56 659	5 332	0
NL	10 209	0	20 380	9 231	14 880	13 171	166	4 101	19 708	0
NO	0	0	0	0	4 731	2 519	146 359	0	0	0
Total	111 802	0	144 168	86 134	229 961	177 876	244 182	60 761	146 352	79 367

Table B.3: Case 2: Energy mix from the stochastic results with optimal interconnector investments capacity. Values given in GWh.

Area	Gas	Oil	Bio	Solar	Wind	OWP	Hydro	Nuclear	Coal	Lignite
BE	389	0	4 945	6 493	9 258	8 662	11 279	0	9	0
DE	0	0	16 405	90 385	113 646	38 169	108 801	0	6 094	50 114
DK	0	0	2 315	2 703	15 954	9 425	31	0	263	0
GB	1 302	0	14 953	21 106	53 266	67 548	7 424	57 537	0	0
NL	0	0	3 446	11 103	20 799	26 107	166	3 737	6 424	0
NO	0	0	794	3 328	6 011	2 836	126 318	0	6	0
Total	1 691	0	42 858	135 117	218 934	152 747	254 018	61 274	12 796	50 114

Table B.4: Case 2: Energy mix from the stochastic results without interconnector expansions. Values given in GWh.

Area	Gas	Oil	Bio	Solar	Wind	OWP	Hydro	Nuclear	Coal	Lignite
BE	424	0	5 807	6 485	9 257	8 677	11 279	10	0	0
DE	0	0	20 512	87 950	112 267	36 269	108 801	0	10 073	61 325
DK	0	0	5 225	2 776	16 169	9 883	31	0	416	0
GB	3 238	0	24 049	21 174	54 069	61 698	7 424	50 670	7	0
NL	0	0	6 406	11 205	20 678	24 752	166	3 663	10 261	0
NO	0	0	794	3 328	6 011	2 836	99 138	0	6	0
Total	3 662	0	62 793	132 918	218 451	144 116	226 839	54 343	20 763	61 325

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