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Assessing the economic benefits and power grid impacts of the power link island project

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Abstract

Increasing penetration of renewable energy production bring new and tougher challenges for power systems and transmission system operators. This master's thesis includes three different case studies of a futuristic offshore power grid project including an artificial island in the North Sea named the power link island project. The idea behind the project is to use this island for transnational power exchange as well as a power distribution hub for offshore wind power. The purpose of this thesis is to assess the economic benefits of this type of grid expansion, as well as its impact on the power grid in its entirety.

The transmission expansion model PowerGIM is used for optimizing grid investments and it includes six countries, all bordering the North Sea. These countries are Great Britain, Belgium, the Netherlands, Germany, Denmark and Norway. The first case study includes three different degrees of offshore power grid development. In the second case study, three predetermined percentages of the onshore renewable energy production are moved from onshore to offshore nodes in the power system. In the last case study, the placement of additional offshore wind power prediction was researched. The data sets used in the investment model are based on futuristic visions for the European power system collected from the TYNDP 2016 published by ENTSO-E. All case studies include two sets of simulations, one for the least optimistic vision, and one for the most optimistic vision. The thesis assesses the economic benefits of the power link island project, as well as the impacts the project has on the power system, investigating central attributes like project costs, transmission line expansions, transmission investments in areas, power exchange through the island as well as area prices.

It was an economic advantage to invest in the power link island for all simulated scenarios which allowed the power link island to be built, independent of futuristic vision. When examining different degree of power grid development in case 1, the project was even more profitable for simulations with futuristic scenarios having higher penetration of renewable energy production. The movement of predetermined percentages of renewable energy production from onshore to offshore nodes had a positive effect on the total costs of the project up to a certain extent. Combining the most promising results from the simulations done in the first two case studies gave a reduction of 12.56% and 15.85% in total costs for vision 1 and vision 4 respectively. This included a fully developed power grid with 25% of the renewable generation moved to offshore nodes.

Installing new offshore wind capacity in association with the power link island gave a reduction in total costs, compared to distributing the same capacity between offshore nodes of each area. An uneven distribution of transmission investment costs, different impacts on area prices in countries and the amount of capacity upgrades needed demands a strong cooperation between all participant countries regarding maritime spatial planning and development of incentive schemes.

Sammendrag

Økende andel fornybar energiproduksjon gir nye og tøffere utfordringer for kraftnett og transmisjonssystemoperatører. Denne mastergradsoppgaven inneholder tre ulike studier av et futuristisk, offshore strømnettprosjekt, som inkluderer byggingen av en kunstig øy i Nordsjøen kalt power link island prosjektet. Tanken bak prosjektet er å bruke denne øya både for internasjonal kraftutveksling, samt som et kraftdistributionssenter for offshore vindkraft. Formålet med denne oppgaven er å vurdere de økonomiske fordelene ved dette prosjektet, samt prosjektets innvirkning på kraftnettet i sin helhet.

Overføringsutvidelsesmodellen PowerGIM brukes til å optimalisere nettinvesteringer og omfatter seks land som alle grenser til Nordsjøen. Disse landene er Storbritannia, Belgia, Nederland, Tyskland, Danmark og Norge. Den første casestudien omfatter tre forskjellige grader av offshore nettverksutvikling. I den andre casestudien flyttes tre forhåndsbestemte prosentandeler av fornybar energiproduksjon fra land til offshorenoder i kraftsystemet. I den siste casestudien ble plasseringen av ny vindkraftkapasitet undersøkt. Datasettene som brukes i investeringsmodellen er basert på futuristiske visjoner for det europeiske kraftsystemet innhentet fra TYNDP 2016 utgitt av ENTSO-E. Alle casestudier omfatter to sett med simuleringer, en for den minst optimistiske visjonen, og en for den mest optimistiske visjonen. Denne avhandlingen analyserer de økonomiske fordelene av prosjektet, samt virkningen prosjektet har på kraftsystemet i sin helhet. Oppgaven undersøker sentrale attributter som prosjektkostnader, overføringslinjeutvidelser, overføringsinvesteringer fordelt på områder, kraftutveksling gjennom øya samt områdepriser.

Det var en økonomisk fordel å investere i øya for alle simulerte scenarier som tillot øya å bli bygd, uavhengig av futuristisk visjon. Ved å undersøke forskjellig grad av nettverksutbygging i studie 1, var det mulig å se at prosjektet var enda mer lønnsomt for simuleringer med futuristiske scenarier med høyere andel fornybar energiproduksjon. Forflyttingen av forhåndsbestemte prosentandeler av den fornybare energiproduksjonen fra land til offshorenoder har til en viss grad påvirket prosjektets totale kostnader positivt. Resultatene fra de to første case-studiene kombinert ga en reduksjon på henholdsvis 12,56% og 15,85% i totale kostnader for visjon 1 og visjon 4. Dette inkluderte et fullt utviklet kraftnett med 25% forflytting av den fornybare generasjonen fra land til offshore noder.

Ved å installere ny offshore vindkraftkapasitet sammen med øya var det mulig å redusere de totale kostnadene, sammenlignet med å fordele samme kapasitet mellom offshore noder for hvert område. En ujevn fordeling av investeringskostnadene mellom deltagende land, prosjektets ulike påvirkning på områdepriser og de totale kapasitetsoppgraderingene som må til for å få prosjektet levedyktig, krever et sterkt samarbeid innen maritim områdeplanlegging og utvikling av nye insentivordninger.

Preface

This master's thesis was written at the Department of Electric Power Engineering at the Norwegian University of Science and Technology(NTNU) during the spring semester of 2017.

Sincere thanks to Prof. Magnus Korpås at NTNU, for great guidance, professional input and discussions throughout the semester. I would also like to give a big thanks to PhD candidate Martin Kristiansen for essential help and counselling regarding the functionality of the transmission expansion model, PowerGIM.

Trondheim, June 11th, 2017

Erik Solli

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Abbreviations

TSO – Transmission system operator

RES – Renewable energy sources

TYNDP – Ten Year Network Development Plan

PowerGIM – Power Grid Investment Model

PowerGAMA – Power Grid And Market Analysis

MILP – Mixed integer linear programming

NPV – Net present value

VOLL – Value of lost load

HVDC – High voltage direct current

BE – Belgium

DE – Germany

DK – Denmark

GB – Great Britain

NL – The Netherlands

NO – Norway

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1 Introduction – North Seas Offshore Grid Development

New and sharpened climate goals bring major challenges for power systems and transmission system operators. These strict ambitions give a strong desire to phase out old, ineffective and polluting power generators running on coal or gas for the benefit of new non-polluting generators running on renewable energy sources like wind, solar or hydro. Norway has tall mountains, multiple lakes and therefore perfect conditions for exploiting hydro power. This is not the case for many of the remaining European countries. The most popular solutions nowadays are generators running on solar or wind power which are resources available for everyone, of course in a varying degree.

The interaction between availability of renewables and the power grid load is of great worry for transmission system operators. Producing power from more than one energy source is vital to obtain a sustainable and secure power supply. If an area in the power system has poor conditions for producing energy from multiple resources, good interconnections between areas or countries are crucial as well. Building trans-border power connections requires regional cooperation on a higher level than to day.

In Luxembourg on the 6th of June in 2016 the North Sea region countries agreed on a closer energy cooperation by signing a political declaration. This declaration was signed by Belgium, Germany, France, Ireland, Luxembourg, Norway, Sweden, Denmark and the Netherlands. The purpose of this cooperation has roots in the treaty signed in Paris in 2015. The Paris agreement is the first legally binding climate agreement ever made and the aim of the agreement is to reduce to greenhouse gas emissions by 80-95% by 2050, compared to the levels from 1990. The council of the EU stated in November 2015 that regional cooperation is of great importance to achieve an optimal power market and power trade[1].

By signing the declaration in Luxembourg, the participant countries agree to try and create good conditions for integration of offshore wind energy in the power system. The declaration has four different focus areas. The first focus area is optimization of the sea areas. Increasing traffic out at sea limits the areas that may be used for offshore wind farms, interconnections et cetera. The participant countries will find the best way to utilize the space. The second focus area is on power grid development. The power grid must be able to handle large imports from offshore wind farms and be able to distribute this electricity in the transnational power market[2].

The countries will work together to find the best ways to expand and develop the power grid. The third focus area regards information sharing. Every country must share their need for infrastructure upgrades to cope with increasing offshore power production. By sharing this information, it is possible to find the best investments for the power grid and to find the joint projects to optimize social economic benefits. Lastly, the political declaration will bring focus to the development of national standards for offshore generation facilities. This will hopefully help to reduce costs in future offshore power grid projects[2].

1.1 Contributions

This master's thesis assesses one of the hottest offshore projects nowadays, namely the power link island project. It is intended for the North Sea Region and includes the construction of an artificial island in the Dogger Bank area with associated transmission lines connecting all participating countries. In this thesis, a transmission expansion model named PowerGIM is used. Three different case studies were developed during this research with the aim of finding the economic benefits of the power link island project, what impact this project may have on the future power situation in Europe, and possible ways to make it even more attractive for future investors.

The transmission expansion model PowerGIM is used for optimizing grid investments and it includes six countries, all bordering the North Sea. These countries are Great Britain, Belgium, the Netherlands, Germany, Denmark and Norway. The first case study includes three different degrees of offshore power grid development. In the second case study, three predetermined percentages of the onshore renewable energy production are moved from onshore to offshore nodes in the power system. In the last case study, the placement of additional offshore wind power prediction was researched. The data sets used in the investment model are based on futuristic visions for the European power system collected from the TYNDP 2016 published by ENTSO-E. TYNDP includes four different visions for the power system situation in Europe in year 2030. All case studies include two sets of simulations, one for the least optimistic vision, and one for the most optimistic vision.

2 Power grid expansion

This section presents a selection of previous studied offshore grid projects in Europe as well as a more comprehensive description of the power link island project and the idea behind it.

2.1 Offshore grid projects in Europe

The North Sea already has some interconnectors installed and more to come, but building a stabile offshore power grid in Europe has proven to be difficult. Regulations, financial aspects and little political support are only some of the aspects for this. There are however multiple examples of projects concerning offshore grid development. Some of them are North Sea Countries' Offshore Grid Initiative (NSCOGI), Ten Year Network Development Plan(TYNDP), NORTHSEAGRID, SEANERGY2020 and the power link island. This subchapter will present some of the key findings in previous offshore grid projects.

SEANERGY2020 was a project with focus on marine spatial planning. The project took place between May 2010 and June 2012, had many participating parties and was coordinated by Wind Europe (former EWEA). It was discovered that the marine spatial planning was of great variance from nation to nation and with a lack of transnational planning and consultation. The difficulty to create a framework perfect for every participating country was one of the main obstacles. In addition, the project participants discovered that the international marine spatial planning tools and instruments had trouble implementing the increase of offshore renewables[3].

The final report did however conclude that improved maritime spatial planning on a transnational level could improve decision making and enable the development of clean offshore energy by creating more investment opportunities as well as lower the risk of investments offshore. They also concluded that transnational cooperation on the topic would give good opportunities to develop cross-border infrastructure such as an offshore power grid with reduced transaction costs for maritime activities. Additional information of the project may be found in [3].

The final report of another offshore grid project was released in March 2015. The NorthSeaGrid was a study of three different expansion cases for offshore wind power and offshore transmission interconnections between North Sea countries. One case was a two-wind farm project with connections between Germany, Denmark and the Netherlands, the second case study was offshore wind farms in Belgium and the Netherlands connecting these countries as well as the UK. The last case included a large offshore wind farm in the UK interconnecting the UK and Norway. Previous reports concluded that all of these cases had environmental, economic and technical advantages for the power system in Europe so the aim of NorthSeaGrid project was to reveal why they never were realised[4].

Key findings in the NorthSeaGrid confirmed that each case would lower costs and reduce the amount of materials needed in the future European power system. An increase in trans-border connections would provide increased availability and stability as well as better utilization of the power system. The level of benefits from each case is very sensitive to the abilities of the next generation European power system. A higher implementation of renewable production would increase benefits, while lower fuel- and carbon prices on the other hand would reduce them. Some of the solutions mentioned to make these projects more attractive for North Sea countries include incentive schemes from the country in which the generator is build independent of which country receives the power flow from the wind farm. Another aspect was to make renewable energy targets international instead of the national targets to day. This would give the ability to give increased incentives to participant countries with strong contribution to the common cause. Lastly a fair way of dividing costs between countries participating in such a project must be established[4].

2.2 Power link island

In June 2016, the Dutch TSO TenneT unveiled their vision of the power link island project. Their ambition is to build an artificial island at the Dogger Bank in the middle of the North Sea. TenneT intend to connect the island directly to Great Britain, Germany, Belgium, Denmark, Norway and the Netherlands. According to the vision, the island will have housing accommodations, a port for naval traffic and even an air strip[5]. The power link island will cover 6 km^2 and it will cost approximately 1.5 billion EUR only in sand and stone[6]. An overview image of TenneTs vision is showed in Figure 2.1

Figure 2.1: An overview image of the planned power link island[5]

2.2.1 Objective and benefits of the power link island

The power link island will be a very important part of the future North Sea power grid. The island will have two main purposes. Firstly, it will serve as a power interconnection between North Sea countries. The island is supposed to be connected via direct current cables to many of the North Sea countries and these cables may be used for transnational power exchange. Secondly, the island may be seen upon as a wind power distribution hub for offshore wind power in the Dogger Bank area. The Dogger Bank is a shallow area with good wind conditions, making it very suitable for offshore wind investments.

There are many benefits with building an artificial island like this at the Dogger Bank with the main driver being the economic side of future far shore wind investments. Wind conditions are good in the middle of the North Sea and nearby wind farms are expected to produce more power in more hours than regular wind turbines. In addition, the shallow water is causing the investments costs of the offshore wind turbines to drop.

Other savings are made when using alternating current technology between wind farms and the island, instead of more expensive direct current technology from each wind farm to shore. In addition, the island gives shelter for personnel, equipment and other resources, which brings transportation, operation and maintenance costs down[5].

2.2.2 The idea behind the power link island

With increasing penetration of renewables in the power system, sufficient trans-border interconnections are crucial for a stable and secure power supply. Building transnational offshore interconnections can be done in a wide variation of ways. If the goal is to build transmission lines between all countries boarding an ocean, Figure 2.2 shows four different sketches with different solutions. The upper left sketch represents a power grid with interconnections between each area, without offshore wind power. The upper right sketch also has offshore wind nodes added to the grid. The lower left sketch illustrates the principle of an offshore island implemented in the power grid, while the lower right sketch has the same principle, but offshore wind nodes added as well. The circle in each corner of a sketch indicates land areas, while transmission lines are offshore interconnections. In this thesis, these lines are interconnections extending across the North Sea.

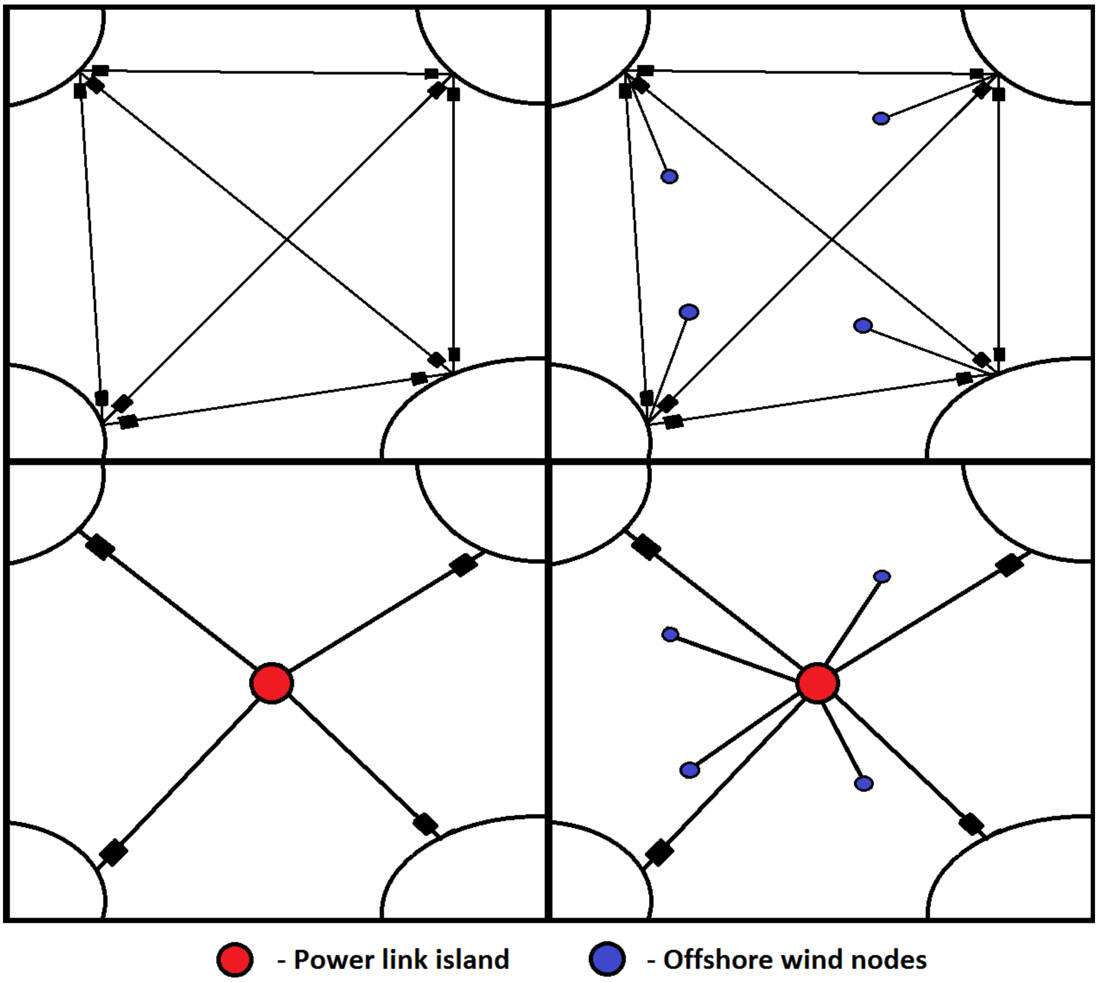

Figure 2.2: Sketches of four different ways of expanding an offshore power grid, with and without offshore wind nodes

Disregarding the offshore nodes, the power link island may reduce the amount of transmission lines and converters needed to get a fully connected offshore power grid. Another important aspect is the exclusion of transmission lines going all the way across the sea. These lines are now split in two by the power link island. A power grid with offshore wind nodes will gain additional benefits with a power link island. It is now possible to connect the offshore nodes directly to the island, as shown in the lower right sketch in Figure 2.2. This makes it is easier to distribute offshore energy production from surplus to deficit areas. Power production at offshore nodes no longer need to be transmitted back to the shore of the owner before being sent to other areas, reducing the distance and transfer losses for power trading.

3 An expansion planning model – PowerGIM

In this chapter, the expansion planning model used for optimizing grid investments is presented both theoretically and mathematically. The investment model used in this thesis is called PowerGIM. PowerGIM or Power Grid Investment Model is a mixed-integer linear program used in association with the power market model PowerGAMA. PowerGAMA is an open source software made by SINTEF Energy Research. It is a simulation tool based on Python used for analysing large power systems with high penetration of renewable energy[7]. While PowerGAMA is deterministic linear program optimization problem, PowerGIM on the other hand is a mixed-integer linear program (MILP). PowerGIM is formulated as a MILP to be able to handle binary and integer investment variables. [8] Transmission expansion planning problems have been studied for several years and the formulation used in PowerGIM is only one of many formulations of the grid expansion problem. Examples of other formulations of transmission expansion problems include the ones made by Latorre *et al.*[9] and Alguical *et al.* [10].

A lot of investments must be made regarding the European power system to reach the climate goals for the future. Increasing investments in offshore wind power in Europe will bring huge challenges to transmission system operators. Hence the focus when developing PowerGIM was offshore wind power[11]. There is much to gain in finding the best way to connect new offshore wind power and transnational subsea cables to increase transfer capacity. PowerGIM was created to find the solution which gives maximum social economic benefits in a transnational power grid. The transnational power grid is represented by multiple offshore wind power nodes as well as onshore nodes. The goal is to connect these nodes in a way that gives perfect balance between investment costs, connection to new generation units and the possibility to strengthen the power trading markets[11].

The solutions to obtain the most favourable social economic benefit includes reduced losses, shortened down-time and an improved market for power trade. To improve the energy market, sufficient branch capacity between surplus and deficit areas are crucial. This allows areas with low marginal costs to produce surplus power for sale at the power market. PowerGIM is as mentioned focused on offshore wind power. The placement of offshore wind farms depends on a lot of circumstances, but to simplify the optimisation, they are fixed in term of location and generation in the investment model. This limits the optimization problem, and allows PowerGIM to optimize scenarios with given generation in the system[11].

3.1 Model structure

The objective function of the investment model maximizes social economic benefits. Demand and supply of electricity as well as transmission constraints from the already existing power grid are found in the model. Generators are represented in the model by their maximum and minimum production along with their marginal cost of generation.

Generation and imports will always be equal to load and imports at each node in the system. The demand in the system is inelastic and the amount of transferred electricity in a branch may never exceed its capacity. Transmission losses in branches will vary linearly with the amount of power transmitted at each moment[11].

The power system has large variation in demand and generation, meaning that the state of the power system is rarely the same. Variations in demand and generation need to be considered in the model. This is handled by implementing multiple time series in the model. These profiles tell how much wind, solar or hydro power the power system has available in each node for every hour. The investment model must take many states into consideration when planning the optimal solution. The time series are created from historical data and future expectations[11].

The model takes all input data into consideration, but is also able to plan which grid expansions that are needed to obtain the optimal solution. This includes investing in new nodes and branches as well as upgrading existing branches. The investment costs of new cables are not only dependent of the cable capacity, there are also large fixed costs per cable. These costs include transportation, trenching, laying and individual components for each cable. With limited capacity per cable, these costs may be added several times for the same expansion as more than one cable may be needed. These costs are also implemented in the objective function. There are also some aspects that are not included in the model. Generators in the system will not have reduced efficiency when not working at full load. The model does not take ramp rates, reservoir limits and minimum up or down time of generators into consideration[11]. As shown in the task flow chart in Figure 3.1, it is possible to get both deterministic and stochastic solutions after collecting input data and formulation the abstract model.

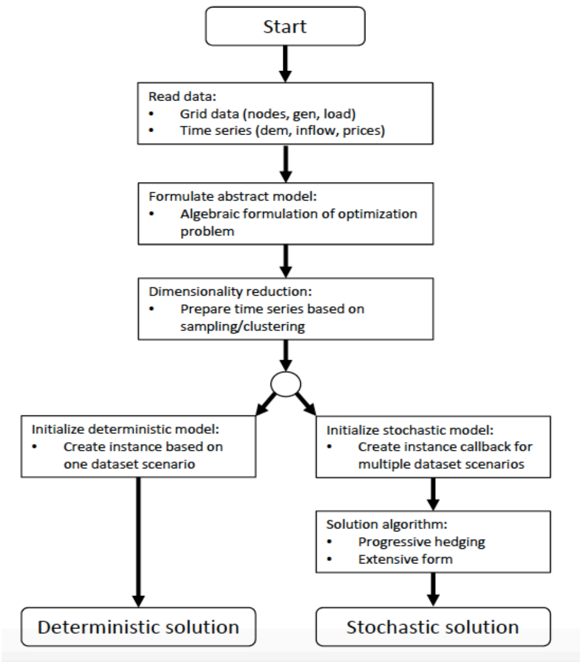

Figure 3.1: Task flow chart for the transmission expansion model PowerGIM[8]

3.2 Mathematical formulation

The following subchapter presents the deterministic formulation for the optimization problem. The formulation and enclosed description are obtained from [12]. The investment model is to minimize total cost (3a) consisting of investment costs (3b) and operational costs (3c). The annual operational costs are converted into NPV by being multiplied with an annuity factor a. Equations (3d) and (3e) represent the fixed and variable costs of transmission investments. The fixed costs are dependent on mobilization costs (B), cable distance ($B^{d}D_{b}$) and voltage transformers and/or power electronics needed at each end of a cable. The fixed costs are multiplied with an integer variable (y_{b}^{num}), which represents the number of cables. The variable costs in (3e) include a power-distance parameter ($B^{dp}D_{b}$), as well as a power dependent cost parameter ($2CL^{p}/CS^{p}$) which is multiplied by the new branch capacity parameter y_{b}^{cap} in equation (3b). The CL/CS notation is an indication if the end stations are land or offshore based[12].

The installation costs of non-existing nodes are reflected by the binary variable z_{n} if the non-existing node is forced to be implemented by equation (3l). The investment model ignores Kirchhoff's voltage laws because most the power system are represented by fully controllable HVDC branches which gives a transport model with no loops as show in equations (3j) and (3k). The linear losses for power flows (f_{b}) reflects both transmission distance and use of necessary voltage transformers and power electronics in (3f)[12].

Variations in availability of renewable energy resources such as wind, solar and hydro as well as the system load are represented by full-year hourly profiles collected from both historical and numerical weather data. The hourly profiles are reflected with a factor, γ_{it} which varies from 0 to 100% in availability and is multiplied with existing capacity represented by P_{i}^{e}, in addition to other new capacity investments x_{i}.The hourly profiles used in the investment model are reduced from 8760 hours to 548 hours by using a clustering technique. Each hour of a profile is weighted by ω_{t}, the number of hours in a cluster in (3c) and (3i), while maintaining the multi-variating correlations between different technologies and geographical coordinates[12].

The generators in the power system are represented by installed capacities (g_{it}), marginal costs (MC_{i}) and lastly the fossil fuel driven generators also have emission costs ($CO2_{i}$). Load shedding ($\mathrm{s_{n}}$) is allowed at a cost equal to the value of lost load ($VOLL$). The energy balance of the power system investigated for each time step is represented by equation (3f), where D_{lt} represents the estimated demand profile and is derived externally and can be met at the marginal cost. As shown in equation (3c), these operational costs include the operational costs from the objective function[12].

Table 3.1 shows the notation used for describing the deterministic formulation.

Table 3.1: The nomenclature for the deterministic model of PowerGIM[12]

Sets & Mappings	
$n \in N$	: nodes
$i \in G$	: generators
$b \in B$	: branches
$l \in L$	: loads, demand, consumers
$t \in T$	: time steps, hour
$i \in G_n, l \in L_n$	: 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	
a	: annuity factor
ω_t	: weighting factor for hour t (numbers of hours in a sample/cluster[h]
$VOLL$	: value of lost load [€/MWh]
MC_i	: marginal cost of generation, generator i
$CO2_i$	: CO_2 emission costs, generator i
D_{lt}	: demand at load l, hour t [MW]
B, B^d, B^{dp}	: branch mobilization, fixed and variable cost [€, €/km, €/MW]
CL, CL^p	: onshore switchgear, fixed and variable cost [€, €/MW]
CS, CS^p	: offshore switchgear, fixed and variable cost [€, €/MW]
CX_i	: capital cost for generator capacity, generator i [€/MW]
NL, NS	: onshore/offshore node costs [€]
P_i^e	: existing generator capacity for generator i
γ_{it}	: factor for available generator capacity for generator i in hour h
P_b^e	: existing branch capacity for branch b [MW]
$P_b^{n,max}$	: maximum new branch capacity for branch b [MW]
D_b	: length of branch b [km]
l_j	: transmission losses, fixed and variable, branch b
E_i	: yearly disposable energy (energy storage) for generator i [MWh]
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}	: power generation dispatch, generator i, hour t [MW]
f_{bt}	: power flow, branch b, hour t [MW]
s_{nt}	: load shedding, node n, hour t [MW]

$$\min_{x,y,z,g,f,s} IC + a \cdot OC \tag{3a}$$

Where

$$IC = \sum_{b \in B} (C_b^{fix} y_b^{num} + C_b^{var} y_b^{cap}) + \sum_{n \in N} C_n^{bus} z_n + \sum_{i \in G} CX_i x_i \tag{3b}$$

$$OC = \sum_{t \in T} \omega_t (\sum_{i \in G} MC_i + CO2_i) g_{it} + \sum_{n \in N} VOLL s_{nt} \tag{3c}$$

$$C_b^{fix} = B + B^d D_b + 2CL/CS \qquad \forall b \in B \tag{3d}$$

$$C_b^{var} = B^{dp} D_b + 2CL^p/CS^p \qquad \forall b \in B \tag{3e}$$

Subject to

$$\sum_{i \in G_n} g_{it} + \sum_{b \in B_n^{in}} f_{bt}(1 - l_b) - \sum_{b \in B_n^{out}} f_{bt} + s_{nt} = \sum_{l \in L_n} D_{lt} \qquad \forall n, t \in N, T \tag{3f}$$

$$s_{nt} \leq \sum_{l \in L_n} D_{lt} \qquad \forall b \in N, T \tag{3g}$$

$$P_i^{min} \leq g_{it} \leq \gamma_{it}(P_i^e + x_i) \qquad \forall i, t \in G, T \tag{3h}$$

$$\sum_{t \in T} \omega_t g_{it} \leq E_i \qquad \forall i \in G \tag{3i}$$

$$-(P_b^e + y_b^{cap}) \leq f_{bt} \leq (P_b^e + y_b^{cap}) \qquad \forall b, t \in B, T \tag{3j}$$

$$y_b^{cap} \leq P_b^{n,max} y_b^{num} \qquad \forall b \in B \tag{3k}$$

$$\sum_{b \in B_n} y_b^{num} \leq M z_n \qquad \forall n \in N \tag{3l}$$

$$x_i, y_b^{cap}, g_{it}, f_{bt}, s_{nt} \geq 0, \qquad y_b^{num} \in \mathbb{Z}^+, \qquad z_n \in \{1,0\}$$

3.3 Offshore grid expansion

Development of an offshore grid differs greatly from onshore grid development. Subsea cables add both costs and constraints for the network optimization, and there are most commonly no existing nodes to connect to far out sea. A future offshore grid should have two functionalities. It should both export power from future wind farms as well as serve as a hub for power exchange between different areas. When optimizing the development of a power grid the costs of transmission line upgrades and new nodes are central. A single branch expansion has both fixed and variable costs. The costs are also dependent on where the endpoints of the cable are located, whether they are onshore or offshore. The total cost of a branch can be described as in equation 2.1 using the parameters from Table 3.2[13].

Table 3.2: Parameters used to describe branch costs[13]

Parameter	**Description**
B_d	Cost per distance (installation and cable)
B_{dp}	Cost per power rating and distance (cable)
B	Mobilisation cost (installation vessel)
$C^L{}_p$	Cost per power rating for branch endpoint on land (onshore switchgear)
C^L	Fixed cost for branch endpoint on land
$C^S{}_P$	Cost per power rating for branch endpoint at sea (switchgear on offshore platform)
C^S	Fixed cost for branch endpoint at sea

The equation below represents the total costs of a branch expansion

$$Cost = \left(B + B_d \cdot D + B_{dp} \cdot D \cdot P\right) + (C^{S/L} + C_p^{S/L} \cdot P) + (C^{S/L} + +C_p^{S/L} \cdot P) \tag{2.1}$$

D equals the distance of the cable, and P is the cables rated power. The first part of the equation is directly linked to the cable, with manufacturing and installation costs, while the last two parts represent each endpoint for the cable. The upper indexes S and L indicates if an endpoint of a cable is onshore or offshore. The cost of new cables is presented in Figure 3.2, and for the DC branches the converter and platform costs are included. The losses in a cable are proportional to power flow and linearly dependent on distance.

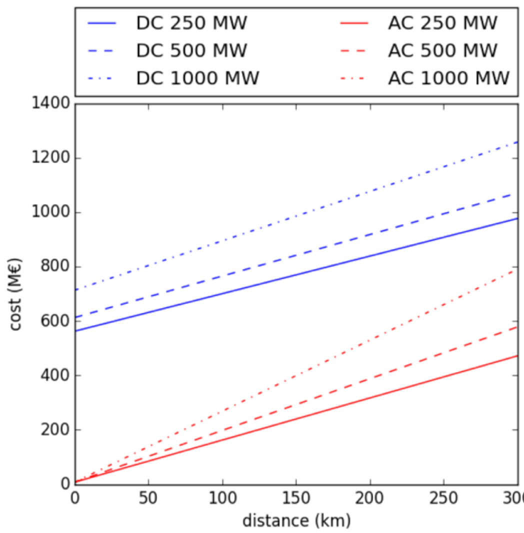

Figure 3.2: Branch cost versus distance, including converter and platform costs for DC branches[13]

4 Scenarios for year 2030 - TYNDP

Working towards a greener future in Europe, ENTSO-E releases a ten-year network development plan also known as TYNDP every two years. The report tells which power system developments are needed in Europe to reach the climate goals for 2030. The latest version of TYNDP was released in 2016 and it builds heavily on the report from 2014. The TYNDP report is divided in two separate stages. The first stage is an expected progress from today and towards 2020. This is a relatively short time span and since most of the investments are already planned or under construction the projection is rather accurate. The next stage is set to 2030 and consists of four different visions. All visions are developed from the expected progress in 2020 and they differ in terms of consumption profiles and generation capacities. The visions may be seen upon as different paths to reach the climate goals of the European Union. This chapter presents and compares the visions of TYNDP 2016.

4.1 Presentation of visions - TYNDP

Vision 1

The first vision is the least optimistic vision with a loose European framework and a delay of the energy roadmap to 2050. In this scenario, each European country work for themselves with individual ways of dealing with CO_2-emissions and development of new renewable solutions. The scenario has some economic growth, but is the least favourable of all the scenarios in this term as well. When it comes to demand, this vision has no new way of improving energy efficiency nor the usage of electricity for transport.

Because there is a slight economic growth, the annual demand increase some. No new additional policies are implemented after year 2020 due to a loose European framework. The system still has local subsidies, which causes some additional investments in renewable energy production locally. The vision has little new thermal energy and some of the generators with the worst pollution risk being shut down after year 2030 to reach the 2050 target. Nuclear power is a national issue, and some countries see nuclear power as clean power and these countries are investing in new nuclear plants before year 2030. In this vision, the baseload for electricity production is provided by hard coal rather than gas[14].

Vision 2

The second vision is more optimistic than vision one with better economic growth. In this vision, the European framework is strong, and the markets have a focus on increasing the energy efficiency and savings. There is however a limited willingness to invest in low carbon emitting sources. The lack of willingness means that this vision equal to vision 1 is looking to fail at reaching the 2050 climate targets. A significant development in energy efficiency and usage of electricity for transport leads to a decrease in electricity demand compared to the previous vision. In this vision, there is also a better demand response potential, making it possible to adjust energy consumption according to production.

When it comes to generation, there is still some delay in the roadmap to reach the goals for 2050. The delay is not as significant as in vision one, and the share of renewable production is higher for this vision than the previous one. Still, only a few new policies and intensives are being introduced to the system in year 2020, causing countries to extend the lifetime of already operative conventional power plants. The baseload for electricity production is still delivered by hard coal rather than gas[14].

Vision 3

Vision 3 is referred to as «national green transition» and has even better economic conditions than the previous two. The vision relies on member states having more financial power and willingness to amplify existing energy policies. These policies have a crucial impact on carbon pricing, which again causes a change in the baseload for electricity. Gas is now preferred to hard coal unlike the two previous visions.

The demand in this vision is decreased compared to vision 1. This is a benefit due to increased energy efficiency and a lot of electrification in the transport sector. Large investments in the RES section brings electricity production form RES to a competitive level. The European network is weak and therefore the cost of the electricity system will be higher than in vision two which had a strong framework. The RES are handled individually by each country and this results in little investments in new energy storage. The extra investments in storage are only made on a national basis. Participating countries are not cooperating to reach the climate goals but the good economic conditions let countries invest in new conventional power plants. Investing in new nuclear power plants are no longer profitable, and therefore only existing nuclear power plants are included here[14].

Vision 4

This is the most optimistic vision of all the visions and may be seen upon as a green revolution. The vision has the best financial conditions of all the visions and gives participating countries even better opportunities to expand their existing energy policies. In addition to favourable financial conditions the European framework is strong, and the cooperation across borders are good. Like vision 3, gas is used for baseload electricity production. Vision 4 also has the most promising prospects when it comes to energy efficient solutions and electrification of transport and heating. Regarding the mix of generation, this vision is strongly on track to reach the climate goals for 2050. The strong European framework makes it possible for countries to invest heavily in RES, and it becomes a way to increase social surplus. Participants also cooperate with backup capacity, giving the possibility to build hydro storage rather than gas power plants for backup. No new investments in nuclear power plants are made, and already existing plants are being phased out where the production from RES is high[14].

4.2 Comparison of the four visions

Table 4.1 is derived from the scenario development report given by ENTSO-E[14].

Table 4.1: Comparison between the four different visions found in the TYNDP [14]

	Vision 1	**Vision 2**	**Vision 3**	**Vision 4**
Economical and financial conditions	Least favourable	Less favourable	More favourable	Most favourable
Focus of energy policies	National	European	National	European
Focus of R&D	National	European	National	European
CO_2 and primary fuel prices	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	Low national RES	Between vision 1 and vision 3	High national RES	On track to 2050
Electricity demand	Increase	Decrease compared to 2020(small growth but higher energy efficiency)	Stagnation compared to 2020	Increase (growth in demand)
Demand response (smart grids)	As today	Partially used	Partially used	Fully used
Electric vehicles	No commercial break through	Electric plug-in vehicles (flexible charging)	Electric plug-in vehicles (flexible charging)	Electric plug-in vehicles (flexible charging and generating)
Heat pumps	Minimum level	Intermediate level	Intermediate level	Maximum level
Adequacy	National – not autonomous limited back-up capacity	European – less back-up capacity than vision 1	National – autonomous high back-up capacity	European – less back-up capacity than vision 3
Merit order	Coal before gas	Coal before gas	Gas before coal	Gas before coal
Storage	As planned today	As planned today	Decentralized	Decentralized

5 Methodology

The configuration of input data used in the expansion planning model, case study setup as well as organization of results are presented in this chapter.

5.1 Configuration of the expansion planning model

In the PowerGIM model most of the original input data originated from TYNDP 2014. To make the model work with the most recent numbers, all input data were updated to match TYNDP 2016. This sub chapter deals with the basic setup which was used in PowerGIM and any modifications made underway are presented in the «presentation of cases» sub chapter.

The input data in the investment model is divided into four different .csv files named «nodes», «branches», «generators» and «consumers». The PowerGIM investment model has its focus area on the North Sea, where the countries represented are the Netherlands, Germany, Belgium, Great Britain, Denmark and Norway.

5.1.1 Nodes

The power grid is represented by 25 nodes, where each participating country is represented by at least 3 nodes. The nodes have three main placements. If a country is represented by three nodes, the first node is found in the load/generation centre of the country. The second node lies on the coastline of the country in association with the last node which is in the North Sea, representing the offshore generation of the country.

Instead of creating a node for each offshore wind farm, all countries have offshore nodes which represents a simplification of all the offshore energy produced by a country. Each country has at least one offshore node. The Netherlands and Great Britain are represented by two offshore nodes each. The offshore nodes are non-existing when starting a simulation, meaning they need to be invested in for a country to be able to produce offshore power. The nodes representing the power grid and their associated country are presented in Table 5.1. The geographical location of the nodes is presented in Figure 5.1. Node number 1-8 indicates offshore nodes, nodes with numbers from 21-31 are coastal nodes, and finally nodes numbered from 91 to 96 are located at the generation centre of each country. Nodes 91 to 96 are the only nodes programmed with a demand.

Table 5.1: Node ID and associated country in PowerGIM

Node ID	**Country**	25	GB
1	BE	26	NL
2	DE	27	NO
3	DK	28	DE
4	GB	29	DK
5	GB	30	NL
6	NL	31	NL
7	NL	91	NO
8	NO	92	DK
21	BE	93	DE
22	DE	94	NL
23	DK	95	BE
24	GB	96	GB

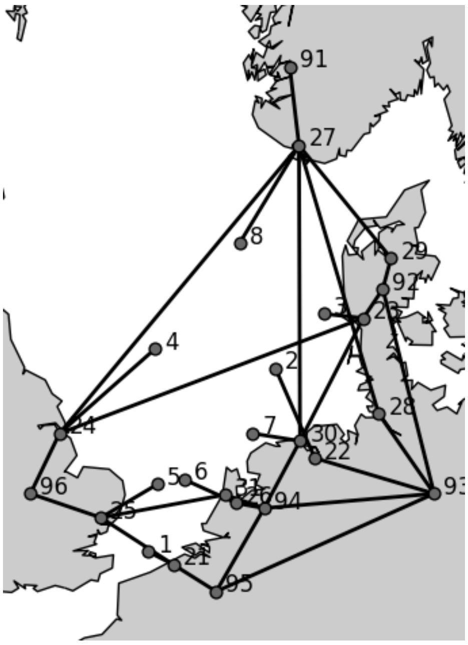

Figure 5.1: Graphical representation of the original North Sea grid in PowerGIM

5.1.2 Branches

All nodes in the system are interconnected with at least one other node except the offshore nodes, which are still not invested in. The branch capacities in PowerGIM match the capacities obtained in TYNDP 2016 and include projects planned or under construction from this day and until the end of year 2030. The capacities are the same for both directions of power flow in the PowerGIM model. All possible connections to the offshore nodes are set to zero, but the model is programmed to expand capacities between offshore and coastal nodes to utilize offshore power production. This is caused by the non-existing offshore nodes, which are only invested in when the simulations start. Capacities needed from offshore to coastal nodes are calculated during simulations. Transfer capacities between all nodes in the system before a simulation takes place are presented in Table 5.2.

Table 5.2: Existing branch capacities between nodes in the original setup

Node ID		Capacity[MW]			
From	**To**		1	21	0
21	95	5000	2	22	0
22	93	15000	3	23	0
23	92	5000	4	24	0
24	96	10000	5	25	0
25	96	5000	6	26	0
26	94	5000	7	30	0
27	91	10000	8	27	0
28	93	5000	27	24	1400
29	92	5000	27	28	1400
30	94	5000	27	29	1700
31	94	5000	27	30	700
93	94	5000	23	30	700
93	92	3000	23	24	1400
93	95	1000	31	25	1000
94	95	2400	21	25	1000

5.1.3 Generators

Each vision of TYNDP have a corresponding «generators» data input file. In this thesis visions 1 and 4 were used. In the previous version of TYNDP the generator types were divided into gas, oil, bio-mass, solar, wind, hydro, nuclear and lignite & hard coal. The latest version however was divided into bio, gas, coal, hydro, lignite, nuclear, oil, others RES, others NON-RES, solar and wind. The «generators» file was updated to match the most recent data. TYNDP 2016 did not separate offshore from onshore wind. This was solved by calculating the percentage of offshore wind power from total wind power in TYNDP 2014. These percentages were again used to calculate the new shares of offshore wind from the total wind power production in the latest version of TYNDP.

All existing generator types were represented by their maximum and minimum generation capacity. All generators were also set to non-expandable, because investing in new generator capacity was not the focus of this thesis. The installed capacities of all generator types for every participating country for vision 1 and 4 are figuratively made in Figure 5.2 and Figure 5.3.

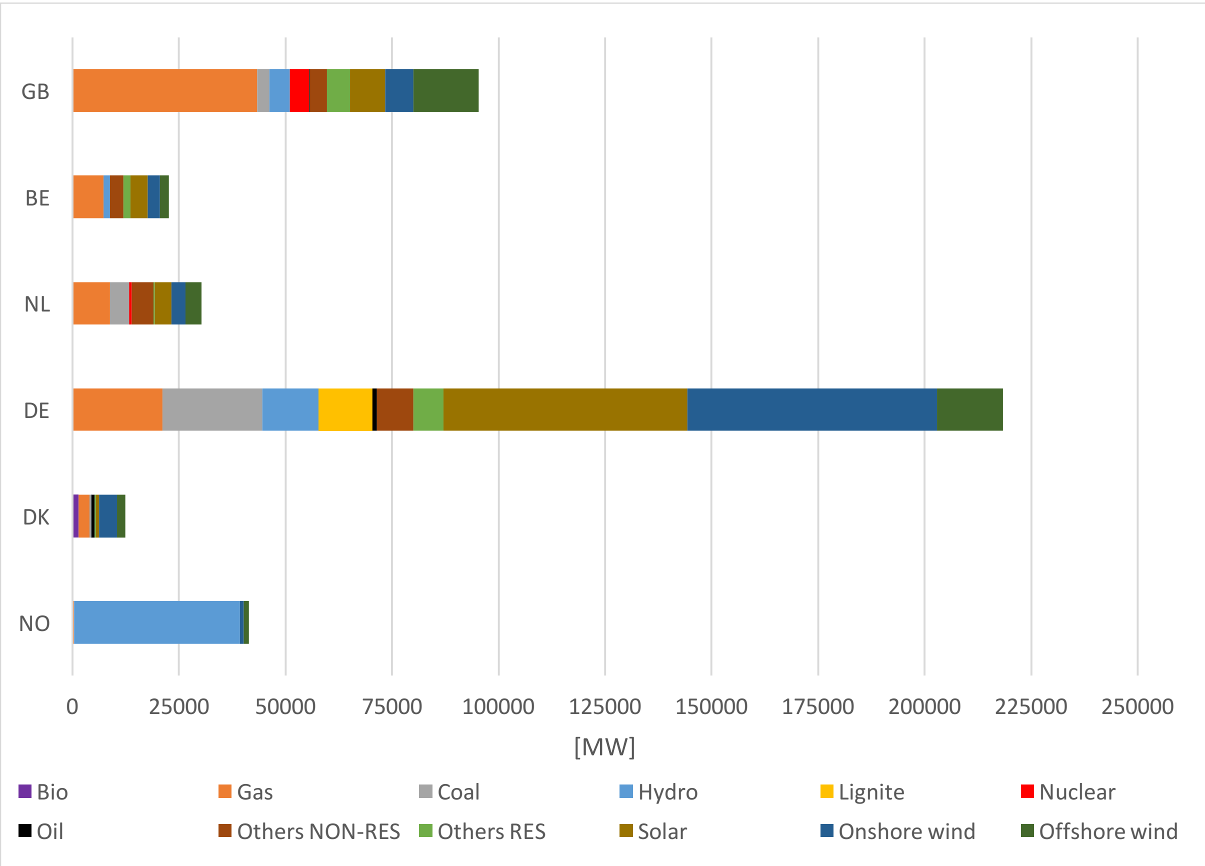

Figure 5.2: Installed capacities for generator types in vision 1

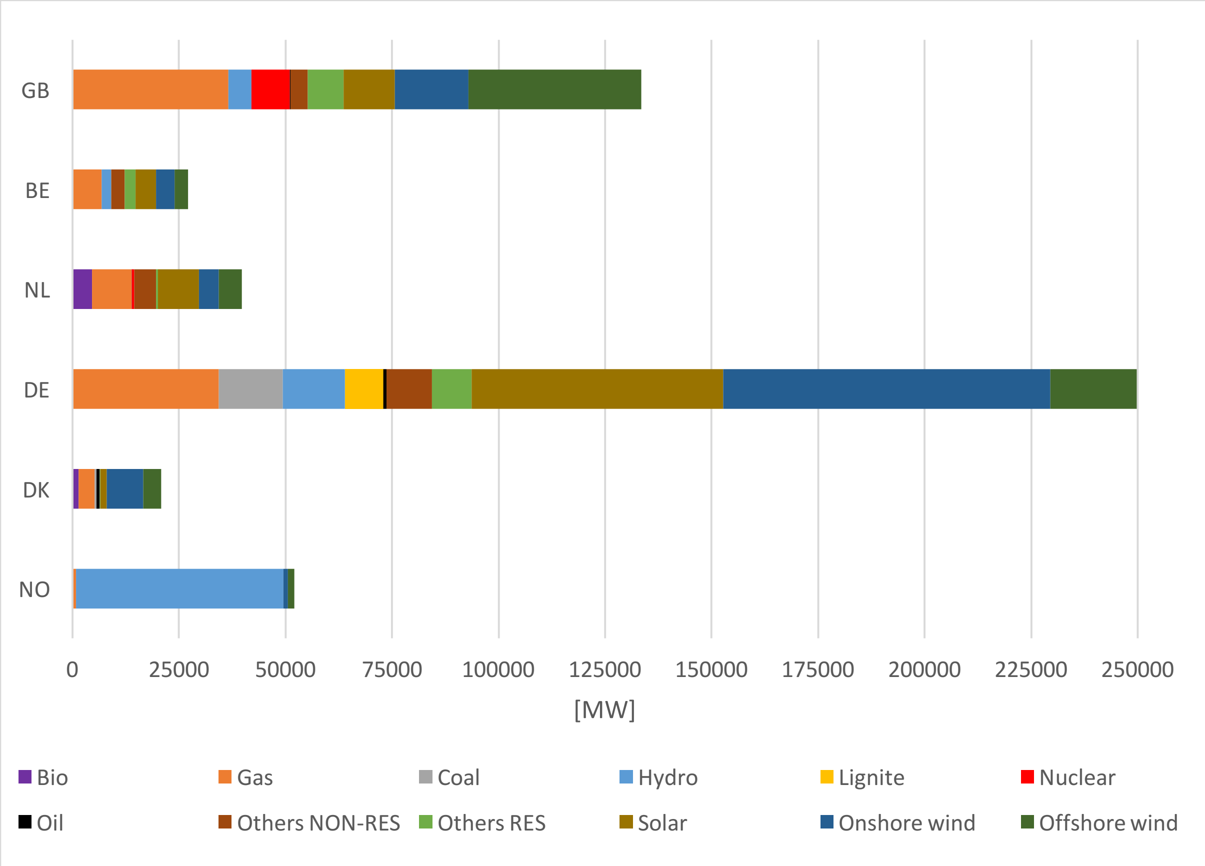

Figure 5.3: Installed capacities for generators in vision 4

5.1.4 Consumers

The «consumers» data input file is also varying with each vision. The load centre nodes are the only nodes in the power system with consumption. They represent all the demand in a country. The input data is only the demand in MW during the most extreme hour of a year. This data is then used in conjunction with time series to create a consumption profile for each country. The maximum consumption for participating countries for vision 1 and vision 4 is visualized in Figure 5.4 and Figure 5.5

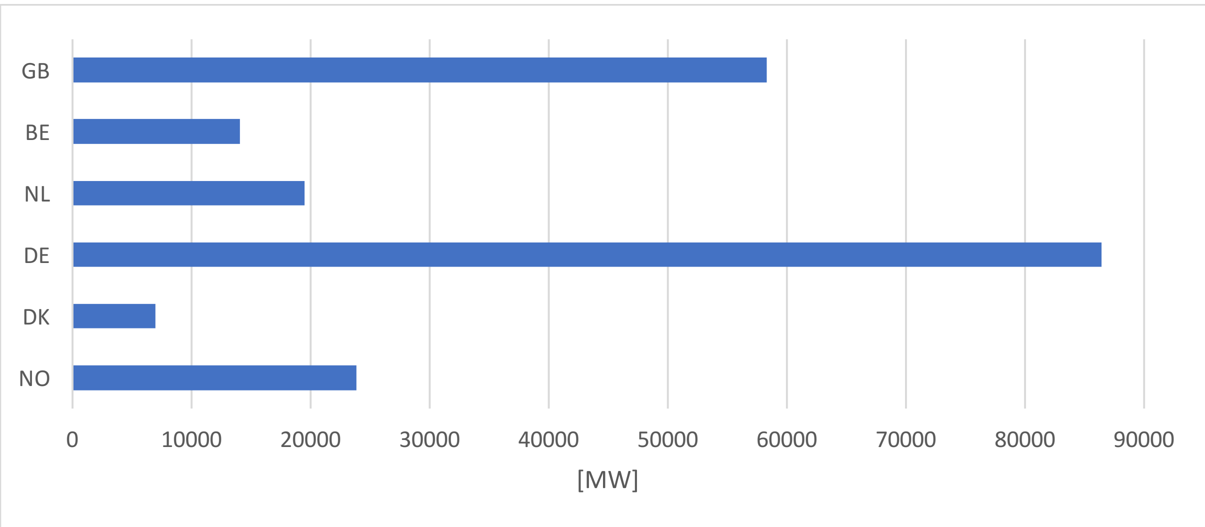

Figure 5.4: Maximum consumption for each area in vision 1

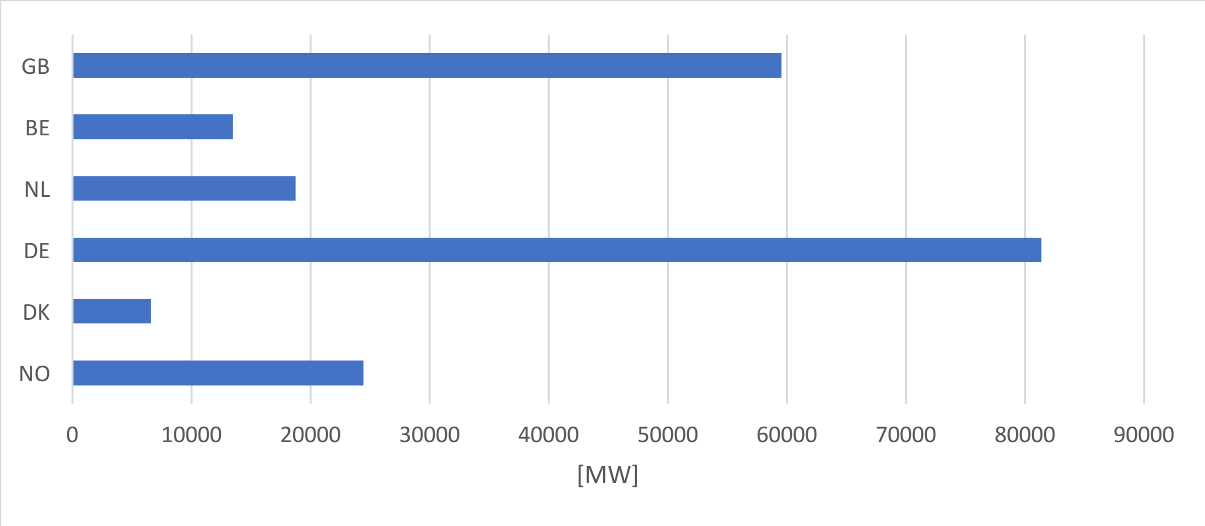

Figure 5.5: Maximum consumption for each area in vision 4

5.1.5 Time series

Time series is an important part of the uploaded data in PowerGIM. The investment model needs profiles for wind, solar and hydro conditions as well as the consumption for each area in the system. Generation of hydro power in Norway is strongly dependent of electricity price, and the model therefore has an own profile for electricity prices in Norway. There is also a significant difference between offshore and onshore wind conditions, leading to two different condition profiles for the two.

All these profiles bring huge amount of data into the optimization problem. To simplify the network expansion problem, it is possible to use sampling and clustering techniques on these profiles. All simulations in this thesis were made with a dimension reduction on time series. Instead of using data for a full year, 8760 hours, the data was compromised to 548 hours using a clustering technique named «k-means». This technique creates subsets of the complete time series and the centroid of each subset equals the mean value of all values in that specific subset.[15]

5.1.6 Fuel and CO_2 prices

The prices for gas, hard coal, lignite, nuclear and oil respectively had to be recalculated from EUR/GJ to EUR/MWh since this is the denomination used in PowerGIM. The recalculation was done by using the heat rate of each resource, except for biofuels. The fuel price for biofuels is hard to predict, but it is estimated somewhere between hard coal and gas. In this thesis, it was determined to be 50€/MWh. All fuel prices used during the simulations in this thesis are presented in Table 5.3.

Table 5.3: Fuel prices used during simulation for vision 1 and 4. CO_2 prices were excluded

Fuel	Vision 1 [€/MWH]	Vision 4 [€/MWh]
Biofuels	50	50
Gas	104.21	79.39
Hard coal	32.01	23.29
Lignite	11.70	11.70
Nuclear	5.08	5.08
Oil	147.39	106.29

The emission cap for CO_2 emissions was set very high for all generating nodes to keep the emissions from being a binding constraint during simulations. CO_2 pricing and emissions was not the issue of this thesis, and disregarding these issues simplified the investment model.

5.2 Case study setup

The purpose of the thesis was to find scenarios which gave an increase of social economic benefits by developing an offshore power grid in the North Sea with focus on the power link island project. The simulations done in PowerGIM was divided into three different case studies. All scenarios in each case study were simulated for the two extremes of the TYNDP, namely vision 1 and vision 4. This was done to get a better picture of what impact increasing penetration of renewables may have on the future offshore power grid.

The three cases have different focus areas, but they also have some similarities. To be able to detect impacts from different adjustments in the investment model only a few changes were made at the time. For all simulations in this thesis the input data in the file named «parameters» stayed the same. This file includes data such as interest rate, investment costs of branches, nodes and generators, emission rates and so on. The financial data in «parameters» may be found in appendix A. For all simulations including the power link island, the investment cost was set to $1.5 \cdot 10^9$ €. This equals the estimated costs for the island only in stone and sand. The electrical plant on the island was hard to estimate because of its unknown extent. This was handled by disregarding these costs during simulations and then taking them into account when analysing the results.

5.2.1 Case 1 – Offshore grid development

Case 1 was divided into three scenarios. Each scenario was simulated with a varying degree of offshore power grid development. The first scenario was simulated with the power grid equal to the original power grid described in the previous chapter. In scenario B, the investment model was given the opportunity to invest in a new offshore node, namely the power link island. This node was given random geographical coordinates within the Dogger Bank area. It was also given the same offshore wind conditions as the offshore nodes of Great Britain, because node 4 was the closest to the island. The model was also given the possibility to invest in new branches between the power link island and the coastal nodes of each participating country. The last scenario included the option to build interconnections between the power link island and the offshore nodes as well as the coastal nodes for each country granting the investment model even more freedom. Modifications made in the original investment model in each scenario are shown in Table 5.4.

Table 5.4: Deviations from original input data in case 1

Input data	Nodes	Branches	Generators	Consumers
Scenario A	Standard	Standard	Standard	Standard
Scenario B	+ power link island node	+ option to build branches from island to coastal nodes	Standard	Standard
Scenario C	+ power link island node	+ option to build branches from island to coastal and offshore nodes	Standard	Standard

5.2.2 Case 2 – Onshore versus offshore generation

In the second case study predetermined percentages of the onshore renewable generation were moved to offshore nodes. This was done by calculating the total of «hydro», «solar», «wind» and «others RES» generation in the onshore generation node of each country and thereafter transferring a percentage of this generation to the offshore node. All three scenarios where simulated with the offshore grid configuration equal to scenario C in case 1. Scenario D was simulated with a 10% renewable generation shift from onshore to offshore. Scenario E had 25%, and lastly scenario F had 50% generation shift. Changes made in the input data from the basic setup of PowerGIM are presented in Table 5.5

Table 5.5: Deviations form original input data in case 2

Input data	Nodes	Branches	Generators	Consumers
Scenario D	+ power link island node	+ option to build branches from island to coastal and offshore nodes	Shifted 10 % of RES generation from onshore to offshore nodes	Standard
Scenario E	+ power link island node	+ option to build branches from island to coastal and offshore nodes	Shifted 25 % of RES generation from onshore to offshore nodes	Standard
Scenario F	+ power link island node	+ option to build branches from island to coastal and offshore nodes	Shifted 50 % of RES generation from onshore to offshore nodes	Standard

5.2.3 Case 3 – Implementation of additional wind power

TenneT envisioned at least one wind farm cluster with a total installed capacity of 30GW directly connected to the island. The aim of the last case study was to see what impact the placement of these 30GW had on the offshore power grid. The 30GW of extra wind energy was added to the investment model in three different ways. In scenario G, the extra installed wind capacity was distributed between the offshore nodes of each country.

This was done by calculating the total offshore production in all nodes and then adding a percentage of the 30GW equal to the percentage of total production to each node. In this way, countries with a larger share of offshore production got a bigger piece of the extra 30GW. In scenario H, the all the extra production was added directly to node 4, one of Great Britain's offshore nodes. In the last scenario, the 30GW of extra wind power was added directly to the power link island. For every scenario in case 3, the offshore grid expansion possibilities equalled scenario C in case 1. The adjustments made from the original investment model are shown in Table 5.6.

Table 5.6: Deviations from original input data in case 3

Input data	Nodes	Branches	Generators	Consumers
Scenario G	+ power link island node	+ option to build branches from island to coastal and offshore nodes	+ 30GW wind energy distributed between offshore nodes	Standard
Scenario H	+ power link island node	+ option to build branches from island to coastal and offshore nodes	+ 30GW wind energy added to a Great Britain offshore node	Standard
Scenario I	+ power link island node	+ option to build branches from island to coastal and offshore nodes	+ 30GW wind energy on power link island node	Standard

5.3 Organization of results

This subchapter gives a brief description of the structure of the presented case studies. All cases have the same result organization with focus on the same grid topologies.

Project costs

The project costs include the total cost for expanding and operating the North Sea power grid for 30 years. In addition to investment costs, operational costs and total costs the new transmission costs were included. The new transmission costs are the share of investment costs used for building or expanding transmission lines in the power grid. Project costs will be illustrated by a figure, making it easier to spot variations between the different scenarios. A table of the exact project costs will also be presented, to get more accurate numbers. The power link island was programmed with only the costs in stone and sand, meaning that the electrical plant and other facilities needed on the island were not accounted for in the project costs.

Capacity expansions

This subchapter will have a focus on the transmission lines upgraded by the optimal solution. All scenarios will be represented with a map plot, showing only the branches in the system that are upgraded by the investment model. The map plot uses different colouring for size of expansions, and the denomination used was MW for all expansions.

Transmission investments

The transmission investments were summed up for each area. If a country owned a node at one or two ends of a transmission line, the total cost of this line was added to the transmission investments for a country. This was done to be able to see which areas had the highest share of investment costs when expanding the power grid. The subchapter will include a figure showing transmission investments for each area for all scenarios simulated, as well as a table containing the exact numbers. It should also be noted that these costs includes operation and maintanace of the transmission lines as well.

Island power flow

All transmission lines with direct connection to the power link island will be presented with their percentage utilization in this subchapter. This allows an insight in the power flow between the island and the participating countries. All nodes with direct connection to the island are gathered in a plot, showing if the specific node uses its line utilization for imports or exports.

Average area prices

The changes in area prices are presented with a figure, including all areas and scenarios. This was done to see what direction the area prices took when doing changes from scenario to scenario and to see the context between transmission investments and area prices.

6 Case 1 – Offshore grid development

This case study is divided into three different scenarios with varying degree of offshore grid investment possibilities. The results presented consist of project costs, branch capacity expansions, transmission investments distributed among participant countries, power line utilization for transmission lines directly connected to the power link island in the scenarios including the possibility to invest in such an island and the effect the adjustment has on area prices in the system.

6.1 Simulations with vision 1

Vision 1 is the least optimistic vision for year 2030. The following results were all obtained when simulating scenarios with input data associated with vision 1.

6.1.1 Project costs

Table 6.1 and Figure 6.1 show the variations in project costs for the scenarios in case 1 simulated with input data from vision 1. It was very clear that allowing investments in new branches as well as the power link island had a positive effect on the power systems total costs. Both investment and operational costs of the simulated scenarios progressively decreased with increasing grid development, giving a positive development of the total costs. They started at €659.74bn for scenario A, decreased to €648.56bn for scenario B and ended up at €622.94bn for scenario C. This equalled a total reduction of €36.80bn from scenario A to scenario C. The decline in new transmission costs accounted for €18.81bn of this amount.

Table 6.1: Project costs for all scenarios in case 1, vision 1

Vision 1	Scenario A	Scenario B	Scenario C
Investment costs [10^9 €]	113.23	109.22	96.38
New transmission costs [10^9 €]	108.98	103.01	90.17
Operational costs [10^9 €]	546.52	539.34	526.56
Total costs [10^9 €]	659.74	648.56	622.94

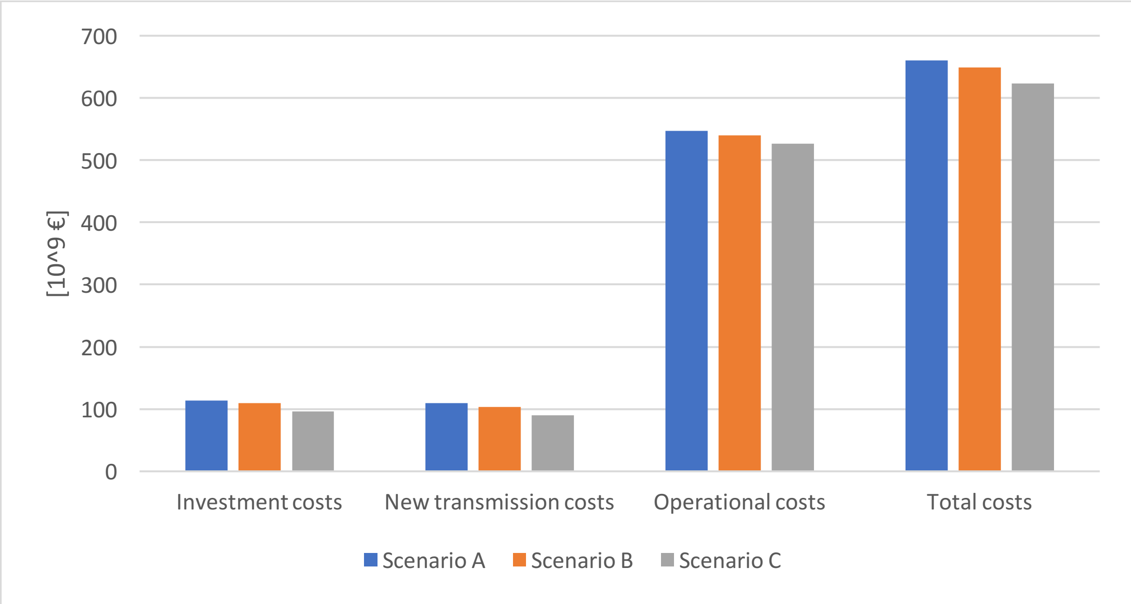

Figure 6.1: Project costs for all scenarios in case 1, vision 1

6.1.2 Capacity expansions

Figure 6.2, Figure 6.3 and Figure 6.4 shows the investments made in new capacity from the three scenarios in case 1. The coastal node of Norway, node 27 became some sort of power distribution midpoint for the power grid in scenario A. The largest capacity expansion found place between node 91 and node 27 and was an upgrade of 16,000MW. A branch expansion of 15,000MW was built between node 27 of Norway and node 24 of Great Britain. All offshore nodes were connected to their corresponding coastal node in the first scenario.

The optimal solution in scenario B was to invest in the offshore island and invest in multiple new transmission lines. All participating countries except Denmark were connected directly to the island via coastal nodes. The transmission line with the biggest capacity was built from the island and to the coastal node of Norway, and had a capacity of 20,000MW. The power grid midpoint now became the power link island and all offshore nodes were still connected directly to their corresponding coastal nodes.

When allowing offshore nodes to be connected directly to the power link island in scenario C, most of them did exactly that. The offshore nodes of Denmark (3) and the Netherlands (7) were connected to both the island and their coastal nodes. A small transmission line was built between the island and node 3 of Denmark as well, leading to a direct island connection for all participating countries. Great Britain was again involved with the biggest expansion with a 20,000MW transmission capacity between their coastal node 24 and the power link island.

Installed capacity for generators at some of the offshore nodes exceeded the transmission line capacity quite much for scenario A and B. When allowing the offshore nodes to be connected directly to the island in scenario C, the transmission line expansions for the optimal solution made it possible to utilize more of the produced power at offshore nodes.

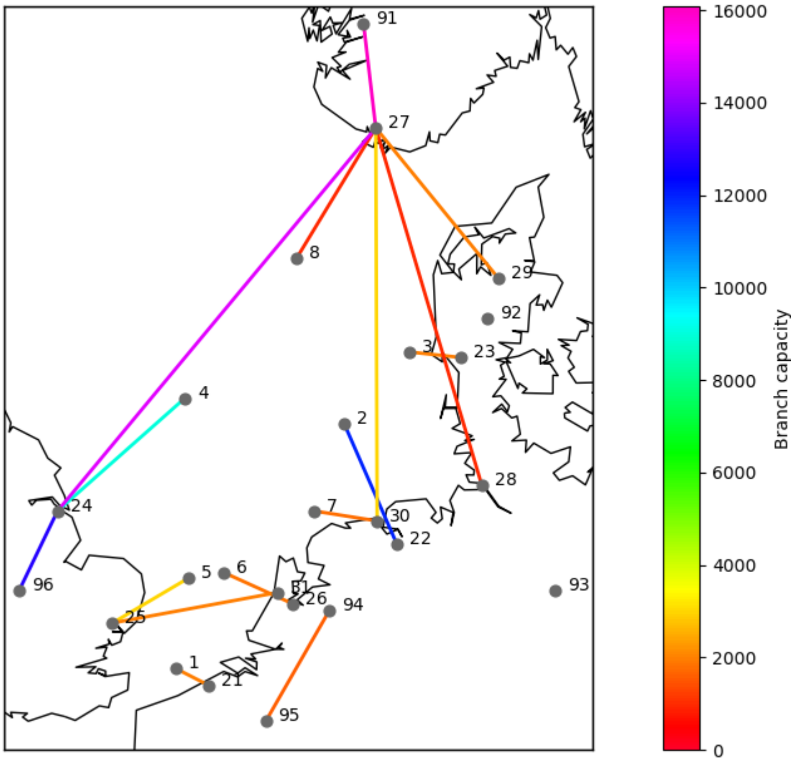

Figure 6.2: Branch capacity expansions in MW for Scenario A, vision 1

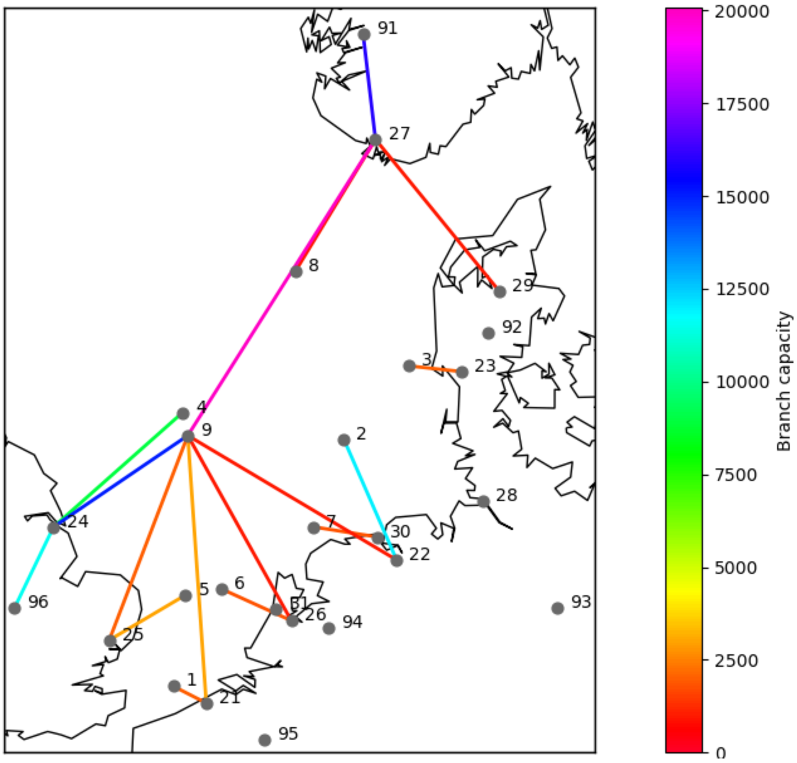

Figure 6.3: Branch capacity expansions in MW for Scenario B, vision 1

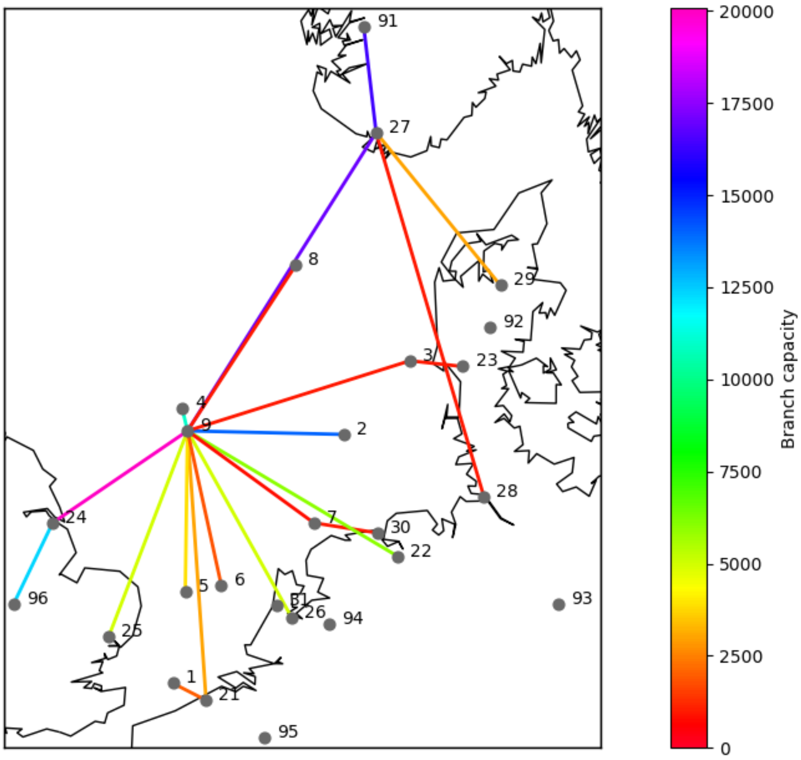

Figure 6.4: Branch capacity expansions in MW for scenario C, vision 1

6.1.3 Transmission investments

In Table 6.2 and Figure 6.5 the transmission investments for the simulated scenarios are presented. The costs were distributed among areas and the investment costs for each area represent all branch investments made in conjunction with a node of that certain area.

Norway and Great Britain had direct relation to most of the costs in scenario A with €59.26bn and €52.69bn respectively. The length and capacity of the transmission line linking these two countries accounted for a large part of these costs. In general, the transmission investment costs had a high spread in this scenario. Denmark and Belgium got away cheaply compared to the above-mentioned countries with investment costs of €3.94bn and €4.20.

Scenario B gave a major cutback in transmission investments for both Norway and Great Britain. The equivalent numbers from scenario A was now reduced to €35.99bn and €37.22bn. This was mainly due to the replacement of the power line linking the two countries with separate lines coupled via the island. Belgium was the only country with an increase in transmission investment costs when moving from scenario A to scenario B from €3.94bn to €4.93bn. Most of this amount was related to their connection with the power link island.

The final step from scenario B to scenario C gave little impact on transmission investments in Norway and Belgium. The Netherlands and Denmark had an increase in costs, while Great Britain and Germany had declining transmission investment costs throughout all scenarios. In fact, Great Britain had a reduction from €59.26bn to €27.55bn in total from scenario A to scenario C.

Table 6.2: Transmission investments for case 1 scenarios, vision 1

Area	Branch investments Scenario A [10^9 €]	Branch investments Scenario B [10^9 €]	Branch investment Scenario C [10^9 €]
BE	3.94	4.93	4.93
DE	18.13	17.36	14.00
DK	4.20	3.20	4.88
GB	59.26	35.99	27.55
NL	13.40	5.31	6.39
NO	52.69	37.22	37.02

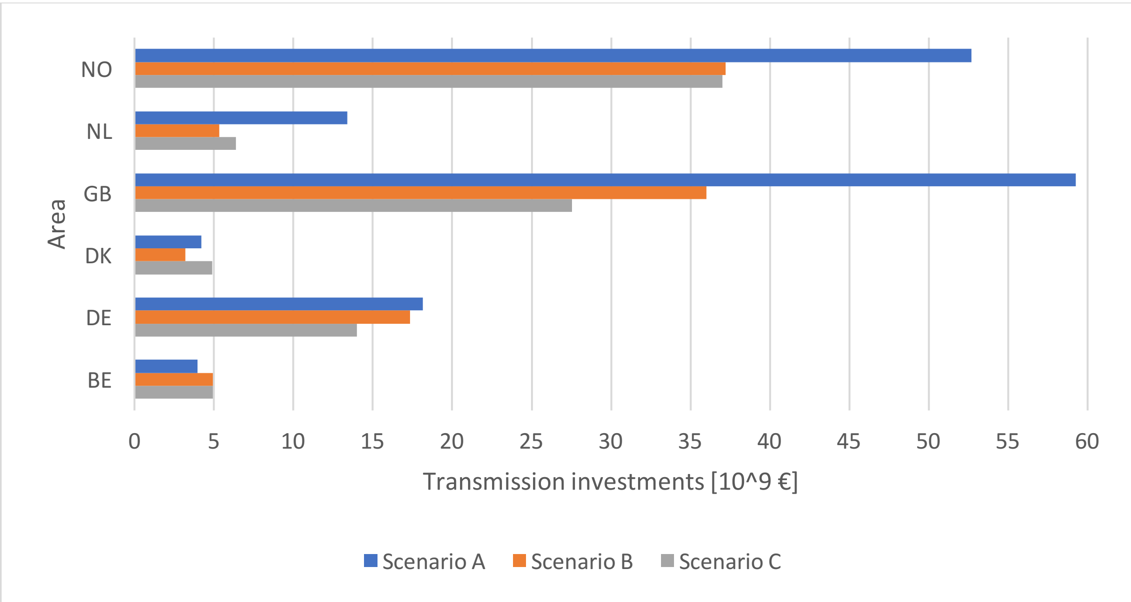

Figure 6.5: Transmission investments by area for scenarios in case 1, vision 1

6.1.4 Island power flow

The island transmission line utilizations presented in Figure 6.6 and Figure 6.7 was the average line utilization in percentage for nodes directly connected to the island. Scenario A had no power link island implemented in the power grid and therefore had no relevance in this subchapter. All participating countries except Denmark had an island connection via their coastal nodes in scenario B. The only pure export country in this scenario was Norway. The average line utilization for export from node 27 of Norway was 91.81%. On the other hand, Great Britain was the only pure import country with two transmission lines utilizing 89.87% (24) and 65.92% (25) for imports from the island. It was the island connections with nodes 27 and 94 that had the highest capacity as well, indicating that Great Britain had high imports from Norway.

The optimal solution included building high capacity branches for export of cheap hydro power from Norway to Great Britain instead of generating expensive power from gas generators at node 94. Germany had nearly the same average export/import utilization on their island transmission line, while the Netherlands imported a far bigger share of power than they exported. Scenario C more than doubled the amount of island interconnections. All offshore nodes except node 1, belonging to Belgium, were connected to the island and worked as export nodes to the island. Only a few of the offshore nodes had a tiny share of imports in this scenario. They were all offshore nodes with connections to both the island and their respective coastal nodes, transmitting power back to their load centre.

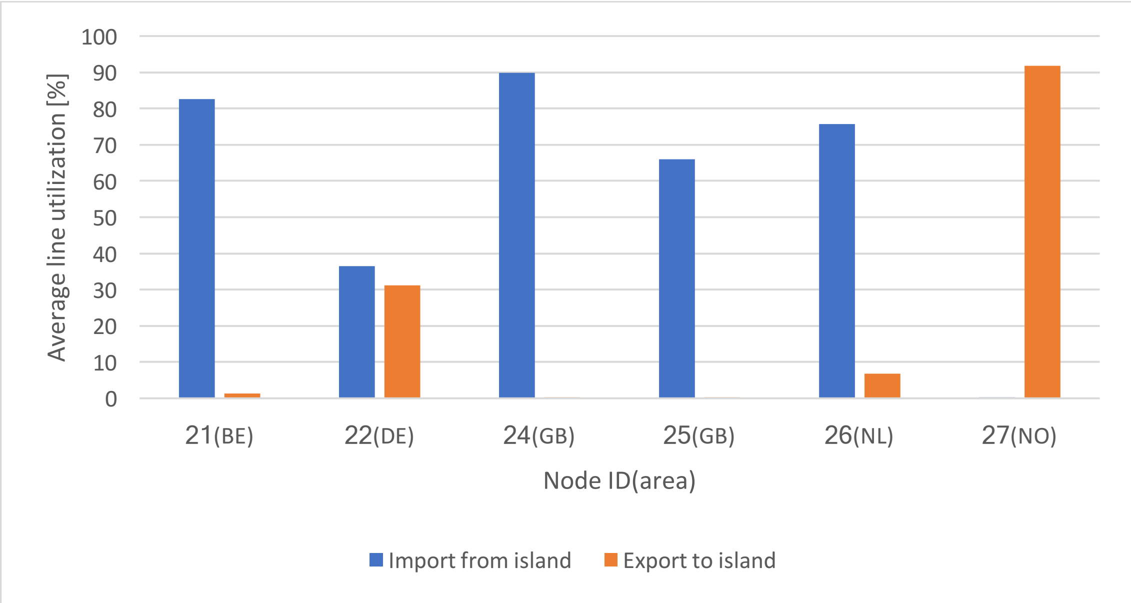

Figure 6.6: Average island transmission line utilization for scenario B, vision 1

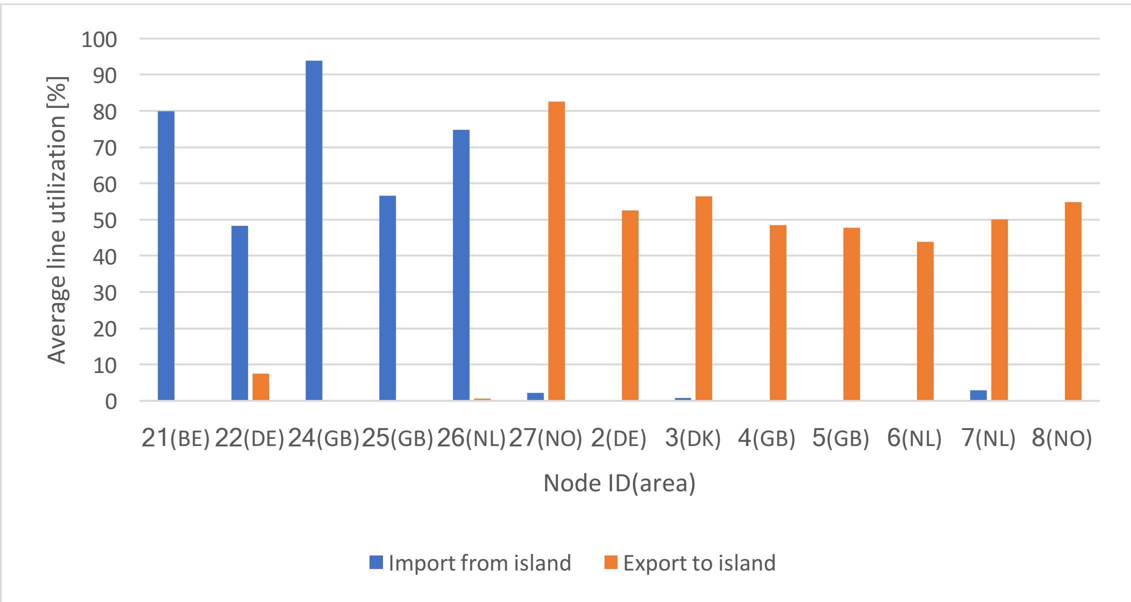

Figure 6.7: Average island transmission line utilization for scenario C, vision 1

6.1.5 Average area prices

Expanding the offshore power grid had an impact on the area prices of the system. These variations are shown in Figure 6.8. Norway had the most stabile electricity price (around 30€/MWh) throughout all scenarios in this case. Germany was the only country with a slight gradual increase in area price. Denmark and the Netherlands got a price increase from scenario A to scenario B, but then a decrease again from scenario B to scenario C. Denmark ended up with a higher area price in scenario C compared to scenario C, while the Netherlands had a reduction. Great Britain and Belgium had price drops in each step of the development. The biggest price reduction from scenario A to the fully developed offshore grid found place in Belgium. Their average area price was reduced from 63.24€/MWh to 49.28€/MWh.

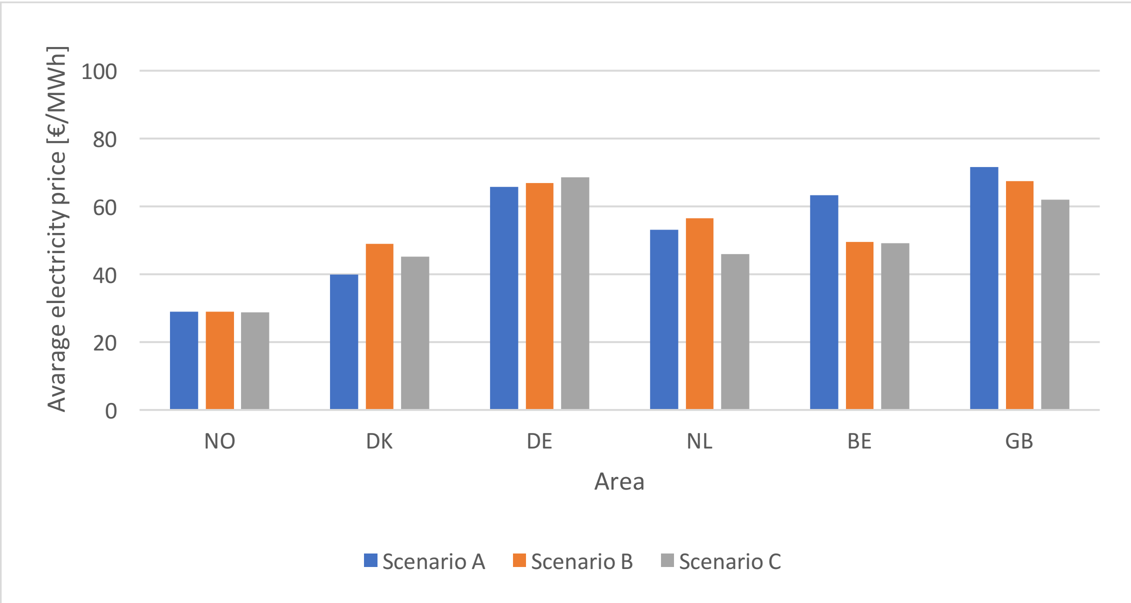

Figure 6.8: Average area price for all scenarios in case 1, vision 1

6.2 Simulations with vision 4

Vision 4 has the most favourable economic conditions and a much higher penetration of renewable energy than vision 1. The following results were obtained when simulating scenarios in case 1 with vision 4 conditions.

6.2.1 Project costs

Table 6.3 and Figure 6.9 shows project costs for case 1 with vision 4 conditions. As for the simulations with the previous vision, the total costs declined with increasing degree of power grid development. However, the investment costs had an increase from scenario A to scenario B, which was unlike the equivalent results for the previous simulations. The increase in investment costs was mainly due to higher transmission costs. The total costs started ad €420.89bn for scenario A, had a slight decline to €414,18bn to scenario B, and ended up at €370.20bn for scenario C. This was a total project cost reduction of €50.69bn.

Table 6.3: Project costs for all scenarios in case 1, vision 4

Vision 4	Scenario A	Scenario B	Scenario C
Investment costs [10^9 €]	124.56	131.44	107.81
New transmission costs [10^9 €]	120.31	125.23	101.60
Operational costs [10^9 €]	296.33	282.74	262.39
Total costs [10^9 €]	420.89	414.18	370.20

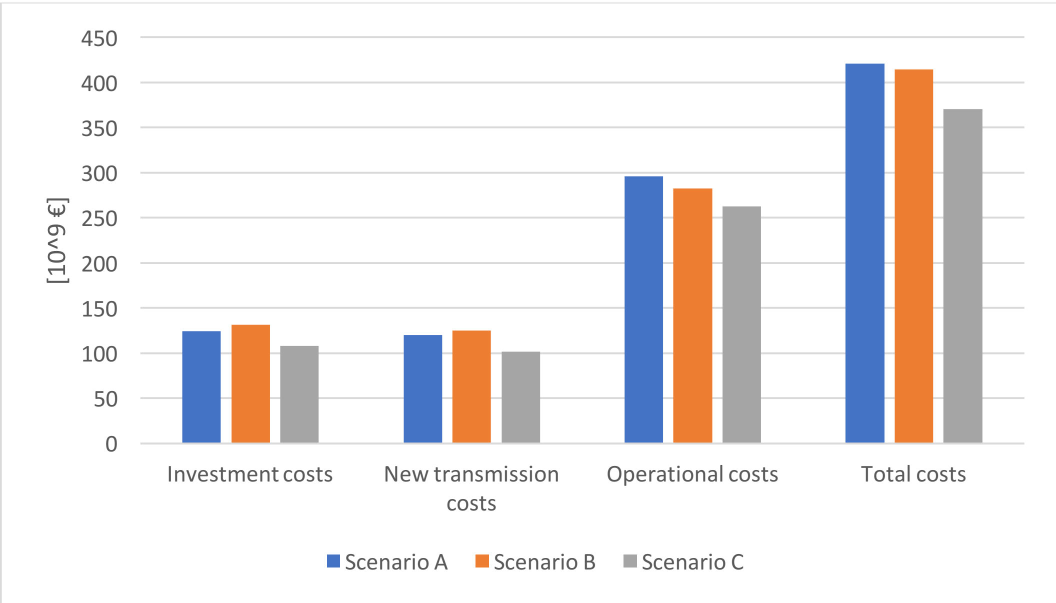

Figure 6.9: Project costs for all scenarios in case 1, vision 4

6.2.2 Capacity expansions

Transmission expansions for scenarios in case 1 simulated with vision 4 conditions are illustrated in Figure 6.10, Figure 6.11 and Figure 6.12. For scenario A, the power grid had one extra transmission line with increased capacity compared to similar results from vision 1 simulations. This line went from node 25 of Great Britain to node 21 of Belgium. When comparing to vision 1 conditions, the branch upgrade between Norway and Great Britain was reduced for these conditions, implying a reduction of power exchange between the two countries compared to the previous conditions.

The optimal solution in scenario B was to invest in the island and build interconnections with all countries except Denmark. Lines expanded were the same as for vision 1 conditions, except for a small upgrade between Great Britain (25) and the Netherlands (31). In scenario C, the power grid had two extra upgrades when comparing to vision 1 conditions. These upgrades were between offshore and coastal nodes of Great Britain (5 and 25) and the Netherlands.

A few extra transmission lines were invested in when moving from vision 1 to vision 4 conditions. The higher penetration of renewable energy in vision 4 was triggering the investment of a few extra transmission lines to increase power exchange between areas. The power grid development in scenario C still offered additional utilization of offshore power production compared to the other two scenarios. The biggest capacity expansion in scenario C was between the power link island and node 4 of Great Britain and equalled a total of 29000MW. This was much higher than the largest expansions for vision 1 conditions, but the offshore generator capacities were higher in this case.

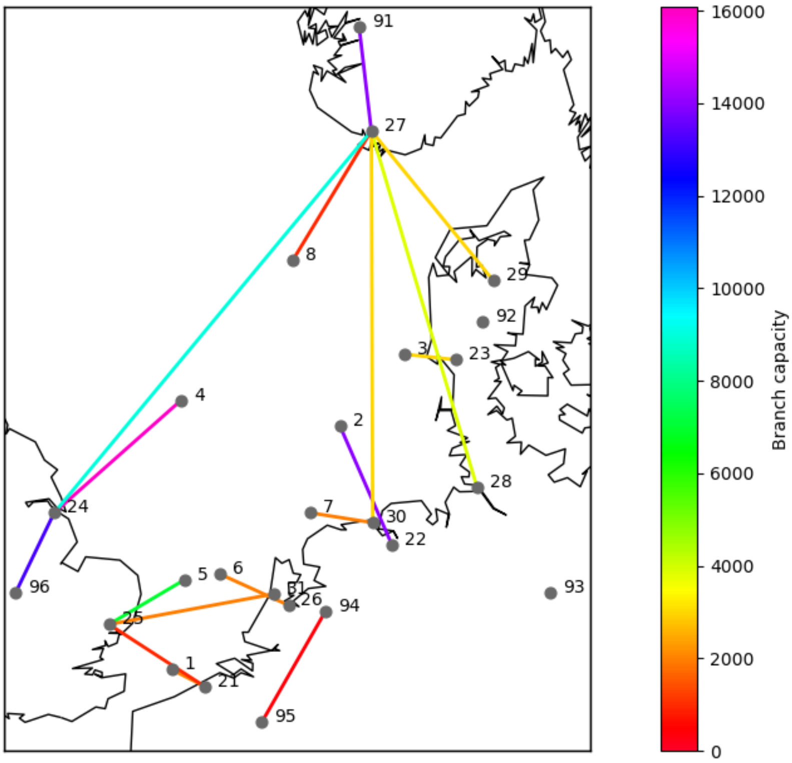

Figure 6.10: Branch capacity expansions in MW for scenario A, vision 4

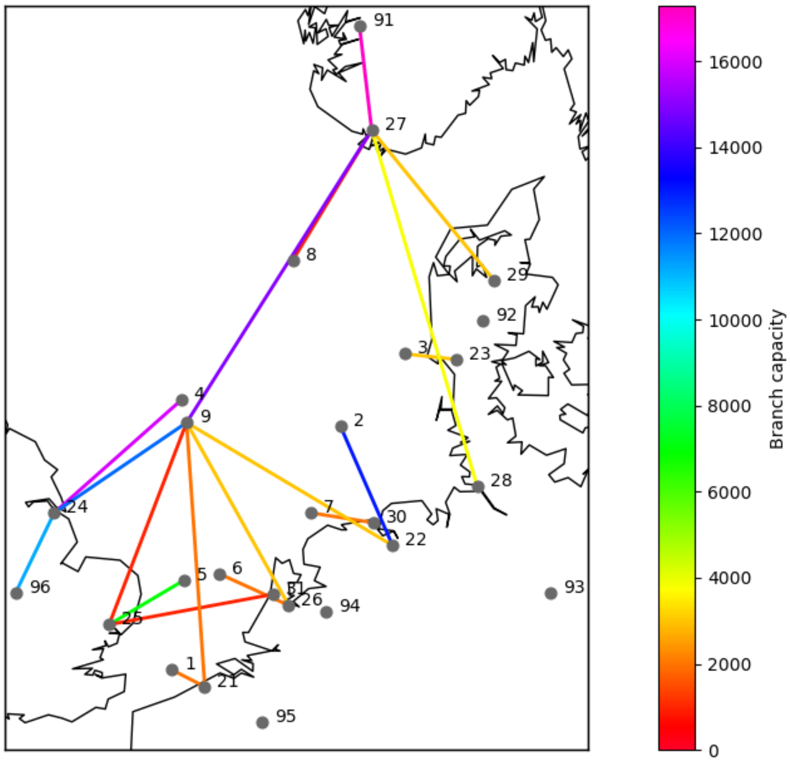

Figure 6.11: Branch capacity expansions in MW for scenario B, vision 4

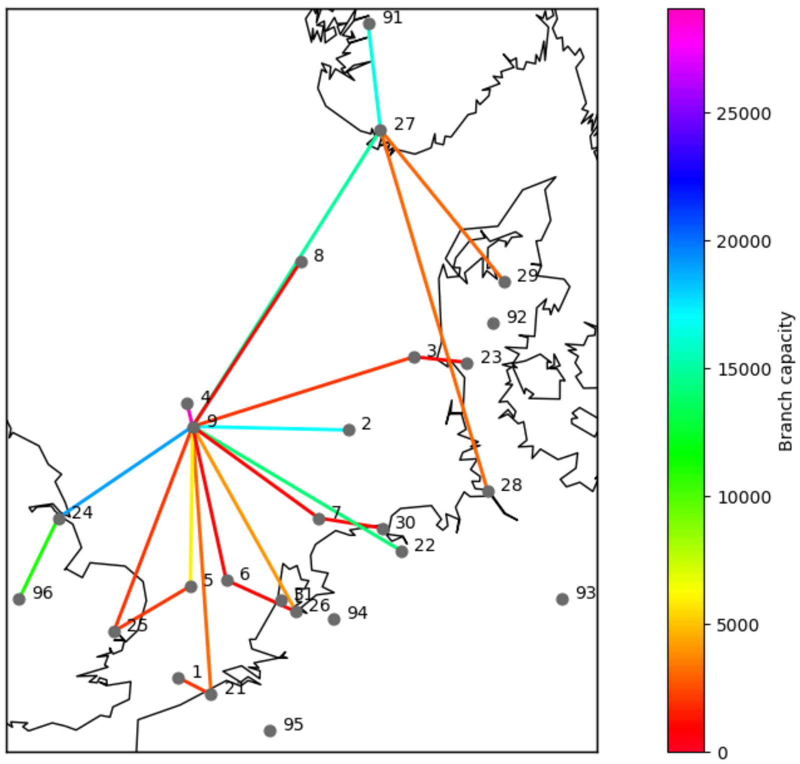

Figure 6.12: Branch capacity expansions in MW for scenario C, vision 4

6.2.3 Transmission investments

Transmission investments for case 1 with vision 4 conditions are presented in Table 6.4 and Figure 6.13. Great Britain was directly involved in €63.81bn of the transmission investment costs for scenario A. This equalled 53% of the total transmission costs of the scenario. The trend of investment costs was decreasing for Norway, the Netherlands and Great Britain throughout all simulations with these input data. In Denmark, the branch expansion costs stayed the same when moving from scenario A to scenario B, but was reduced when moving from scenario B to scenario C. Germany had an increase in costs from scenario A to scenario B, but a modest reduction in costs when comparing scenario A and C. Belgium was the only country with an increase in investment costs throughout the scenarios, going from €3.39bn to €4.93bn, which was still the smallest amount of all areas.

Great Britain got the biggest financial advantage when moving from no island to a fully developed offshore grid. Their total transmission investments costs went from €63.81bn to €29.04bn. A large part of this reduction was due to the big branch expansion between Norway and Great Britain which only was a part of the optimal solution for scenario A. Scenario C allowed direct connection between offshore nodes and the power link island, which saved lots of investment costs, compared with building two separate lines from the coastal nodes to both the offshore nodes and the power link island in scenario B.

Table 6.4: Transmission investments by area for scenarios in case 1, vision 4

Area	Branch investment Scenario A [10^9 €]	Branch investment Scenario B [10^9 €]	Branch investment Scenario C [10^9 €]
BE	3.39	4.00	4.93
DE	25.59	26.70	25.43
DK	6.32	6.32	5.66
GB	63.81	49.77	29.04
NL	12.16	7.89	6.36
NO	44.76	40.87	37.98

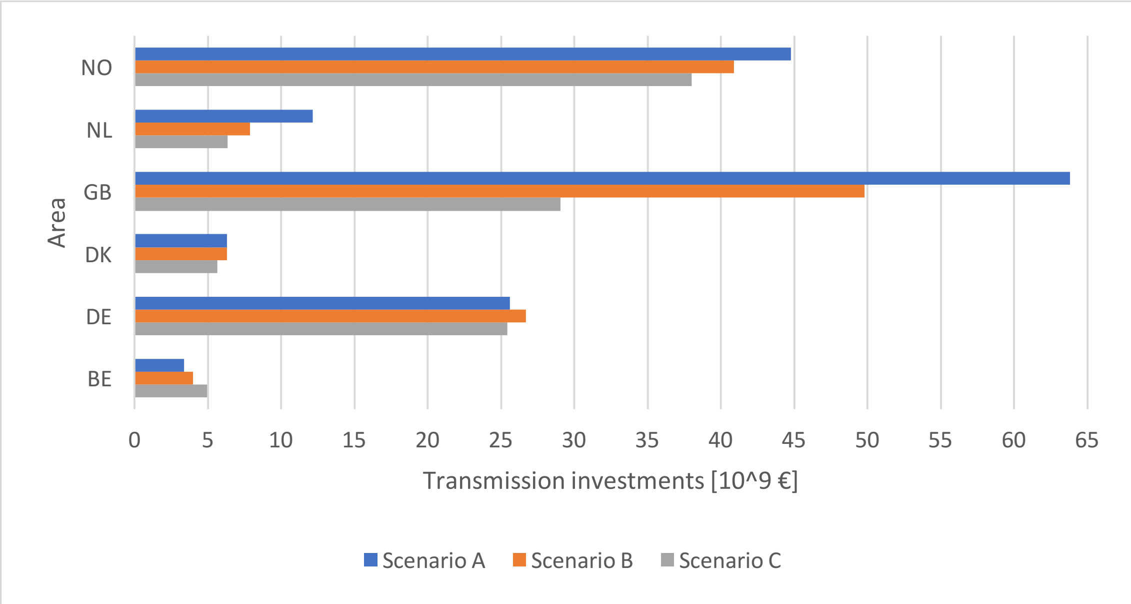

Figure 6.13: Transmission investments by area for scenarios in case 1, vision 4

6.2.4 Island power flow

Island transmission line utilization reveals that scenario B had no pure import/export nodes for vision 4 conditions. Even Norway imported some power from the power link island for this simulation. Belgium had the smallest line utilization for exports to the island with approximately 2%. Germany had again quite similar export/import shares for this scenario. The two nodes of Great Britain as well as node 26 of the Netherlands had a larger share of imports than exports from the island, while Norway was the only country with higher exports than imports. Germany and Norway were the only areas with exports at coastal nodes in scenario C. The coastal node of Norway even had a larger share of export than import for this scenario. The offshore nodes had most utilization for island exports, and only a minor part for imports. A very small part of the line utilization between the power link island and offshore node 2 of Germany was used for island imports in scenario C. This node had no coastal connection or load, meaning that this was excessive power in the offshore grid. All transmission line utilizations are illustrated in Figure 6.14 and Figure 6.15.

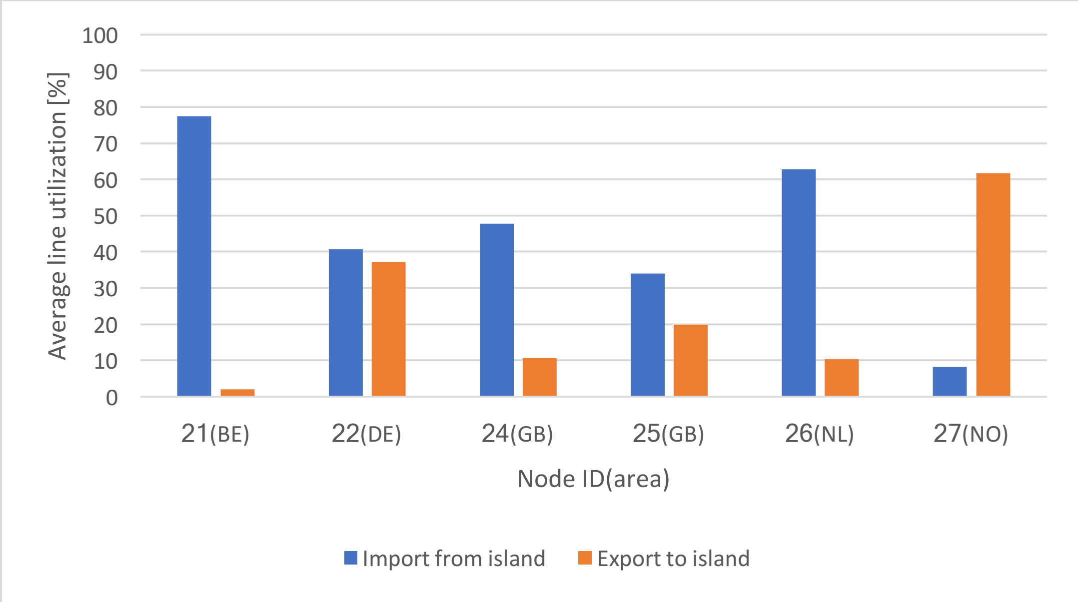

Figure 6.14: Average island transmission line utilization for scenario B, vision 4

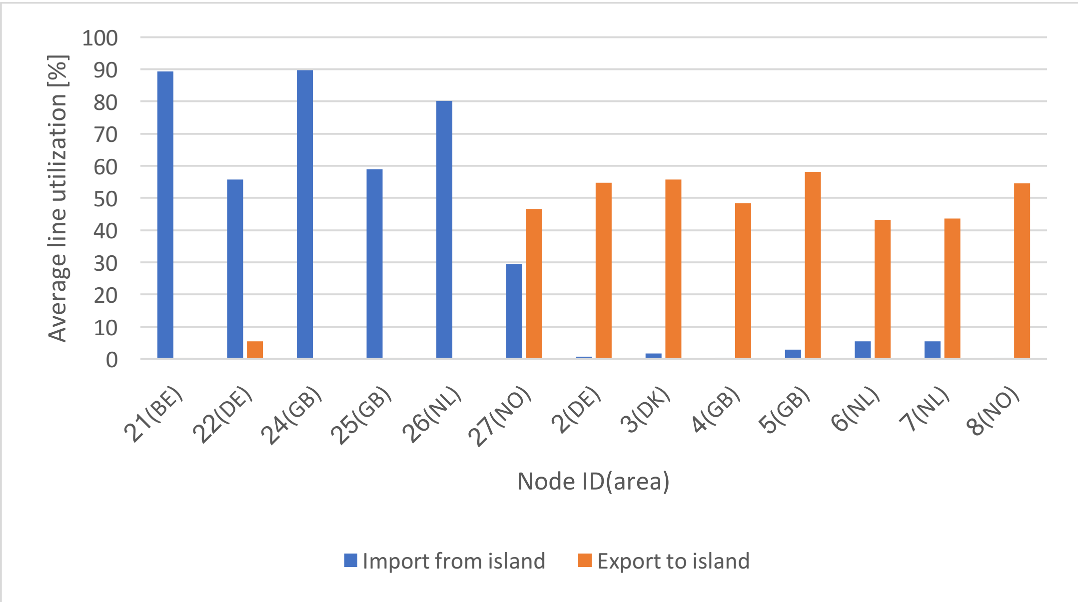

Figure 6.15: Average island transmission line utilization for scenario C, vision 4

6.2.5 Average area prices

The average area prices are presented in Figure 6.16. The areas with decreasing electricity price throughout the scenarios were Norway, the Netherlands, Belgium and Great Britain. The reduction from 39.31€/MWh to 26.14€/MWh made Belgium the economic winner when moving from scenario A to scenario C. Denmark and Germany on the other hand had a small reduction in electricity prices when going from scenario A to scenario B, but their prices went up when going the final step. Denmark was the only country ending up with a higher electricity price in scenario C compared to their starting price in scenario A, moving from 13.37€/MWh to 14.30€/MWh.

Germany had the most expensive electricity price while the cheapest area was Denmark for all scenarios. In scenario A, the area prices varied from 41.50€/MWh to 13.37€/MWh between the areas. The same variation was from 39.21€/MWh to 12.56€/MWh in scenario B, and ended up form 40.19€/MWh to 14.30€/MWh in scenario C.

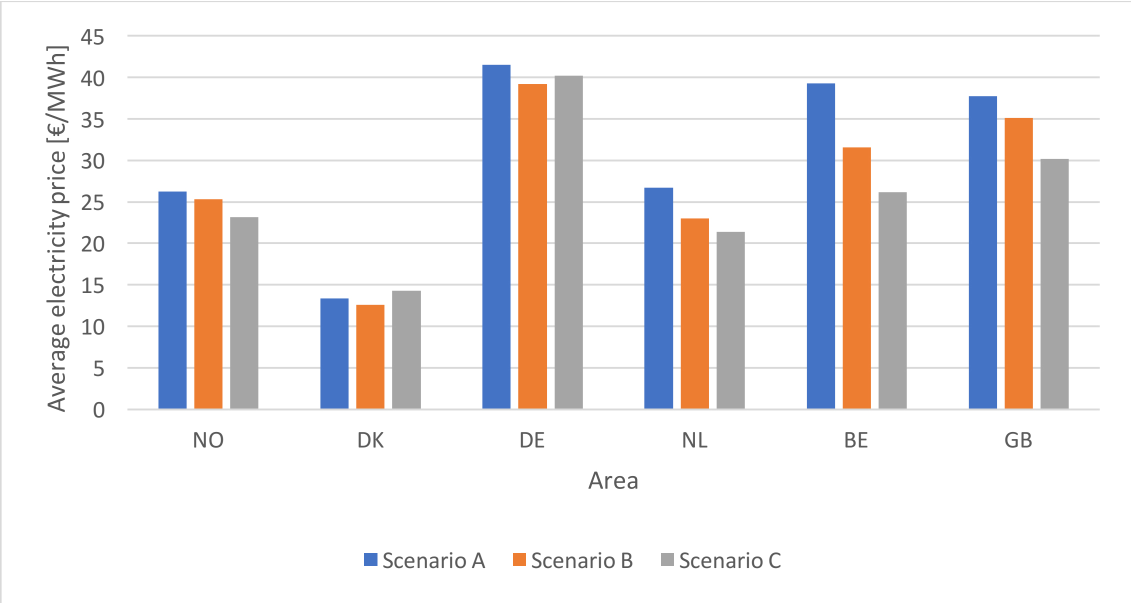

Figure 6.16: Average area prices for all scenarios in case 1, vision 4

7 Case 2 – Onshore versus offshore generation

The aim of this case study was to research to which extent the power grid was influenced by moving the renewable energy production from onshore to offshore nodes. The amount renewable energy moved from onshore to offshore was 10%, 25% and 50%. Scenario C in case 1 was chosen as a reference scenario for simulations in this case, and the power grid was granted the same power grid expansion possibilities as for the reference scenario in all simulations presented in this case study.

7.1 Simulations with vision 1

All simulations presented in this subchapter were obtained during simulations with vision 1 standards. Results from Scenario C in case 1 was added as a reference scenario.

7.1.1 Project costs

Moving power production from onshore to offshore nodes caused a gradual increase in investment costs but had a positive impact on operational costs. The results are presented in Table 7.1 and Figure 7.1. At one point the additional power grid investments exceeded the savings associated with operational costs and from this point on, the total costs increased.

The total costs of the reference case started at €622.94bn, was reduced to €596.38bn in scenario D, further reduced to €570.75bn in scenario E, before increasing slightly to €576.11bn in scenario F. By moving 25% of the energy production from onshore to offshore nodes it was possible to save an extra €52.19bn compared to the reference scenario with power system development equal to vision 1 standards.

Table 7.1: Project costs for all scenarios in case 2, vision 1

Vision 1	Reference	Scenario D	Scenario E	Scenario F
Investment costs [10^9 €]	96.38	106.68	121.01	147.87
New transmission costs [10^9 €]	90.17	100.48	114.81	141.66
Operational costs [10^9 €]	526.56	489.70	449.74	428.24
Total costs [10^9 €]	622.94	596.38	570.75	576.11

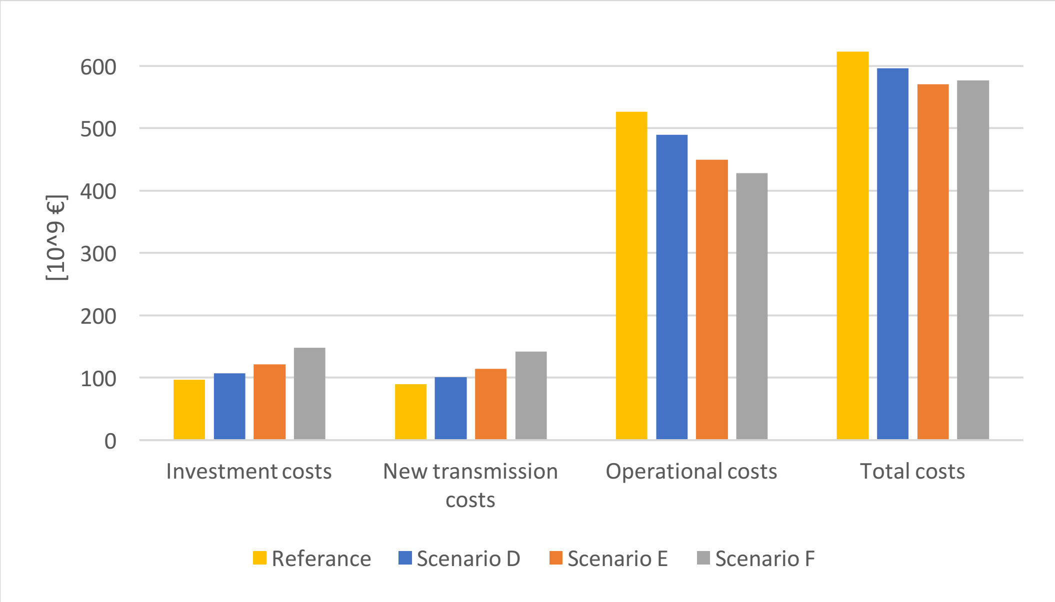

Figure 7.1: Project costs for all scenarios in case 2, vision 1

7.1.2 Capacity expansions

The branch capacity expansions for scenarios in case 2 with vision 1 conditions are presented in Figure 7.2, Figure 7.3 and Figure 7.4. Comparing to the reference scenario, three extra transmission lines were built in scenario D. The offshore node of Norway was connected to its corresponding coastal node. The last two new lines were built from the island and on to node 1 and 21 respectively.

Moving from scenario D to scenario E caused a lot of changes in the offshore power grid. Transmission lines were expanded from offshore node to coastal node and then from coastal node to generation centre node in Belgium. A new line was also constructed between the offshore and coastal node of Great Britain (5 to 25). Lastly the coastal node of Germany was connected to the power link island. The transmission line between Norway (27) and Denmark (29) was removed, as well the branch from the power link island to the offshore node of Denmark. Denmark was now the only country without a direct connection to the island. The transmission expansion between Norway (27) and Germany (28) was not invested in during this evolution.

The final step from scenario E to scenario F required even more adjustments to the power grid. Denmark was again connected to the island. This time with two transmission lines connected to nodes 23 and 29. Moving this amount of generation offshore caused a need for multiple grid expansions between coastal nodes and generation centre nodes. Germany got additional capacities from nodes 22 and 28 into their generation centre, node 93. This also applied to Belgium, investing in additional capacity from node 21 to 95. The Norwegian branch expansion between generation centre and coastal nodes was no longer necessary, nor was the expansion in cable capacity between Norway (27) and Germany (28).

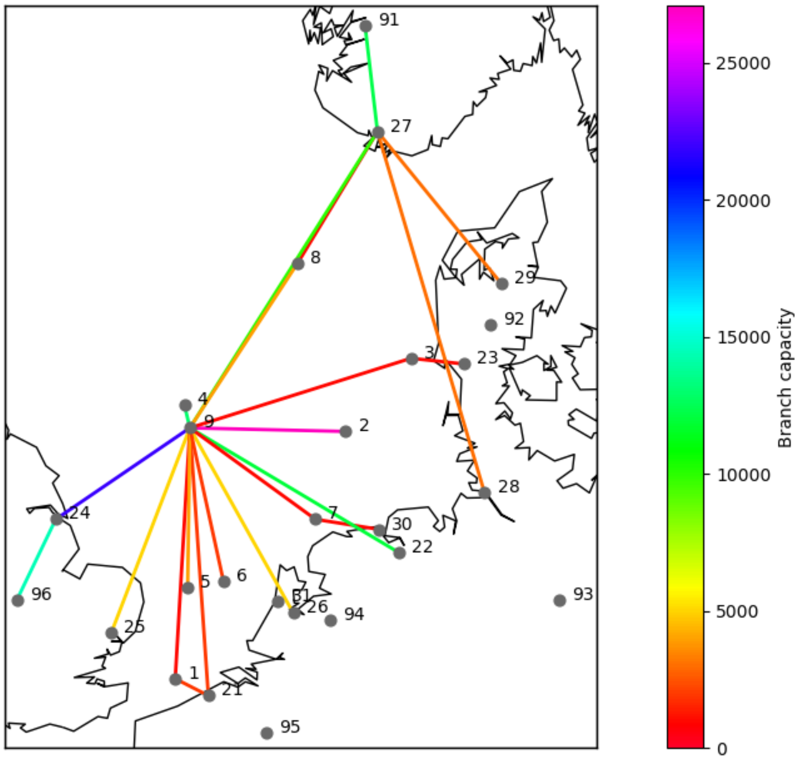

Figure 7.2: Branch capacity expansions in MW for scenario D, vision 1

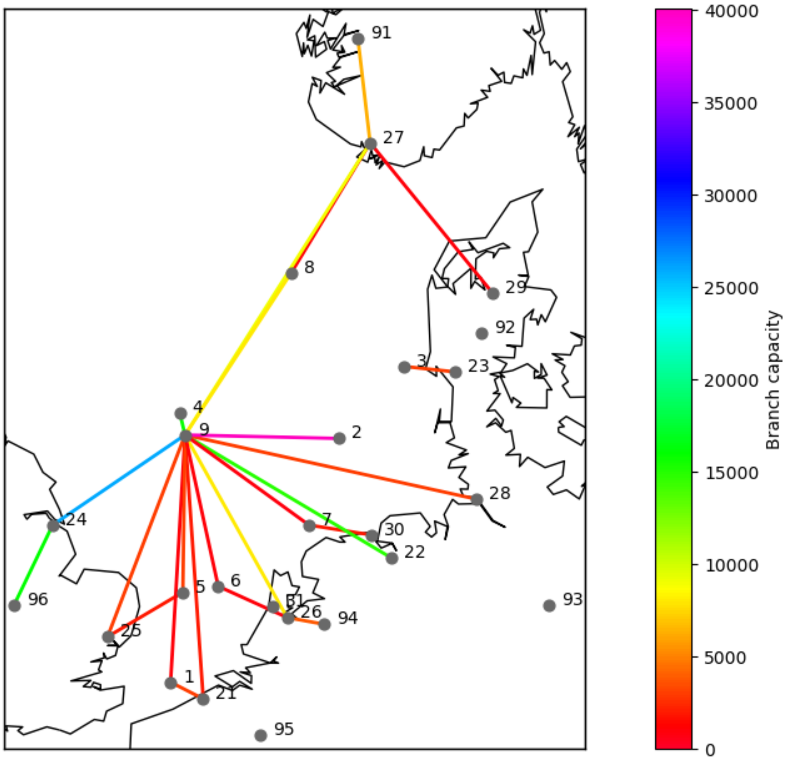

Figure 7.3: Branch capacity expansions in MW for scenario E, vision 1

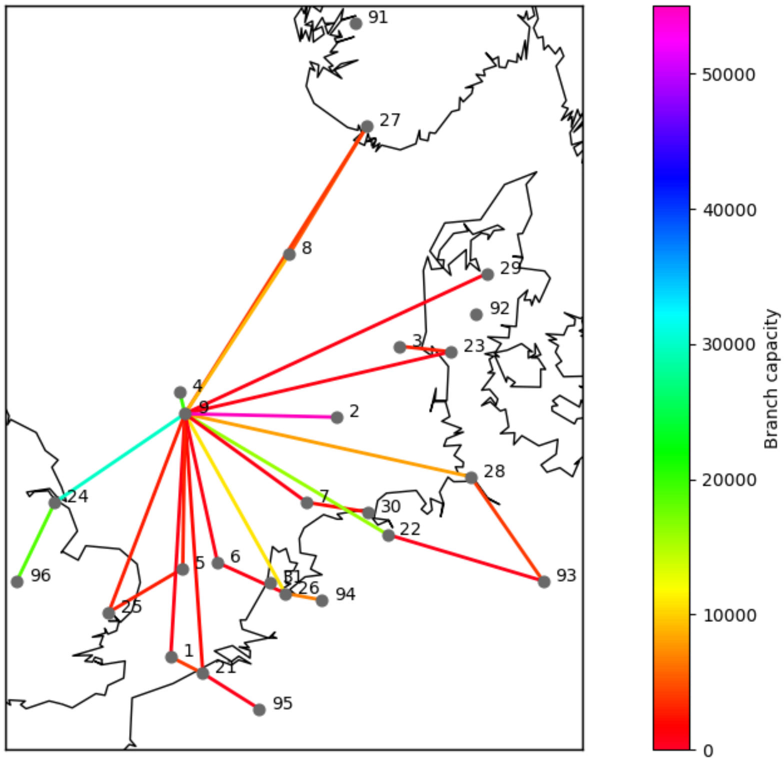

Figure 7.4: Branch capacity expansions in MW for scenario F, vision 1

7.1.3 Transmission investments

The transmission investments divided by area for scenarios in case 2 with vision 1 standards are presented in Table 7.2 and Figure 7.5 Norway got a smaller part of the total transmission investment costs for each step of generation shifting. Norway started at €37.02bn and ended up at €17.34bn in scenario F. Norway was an exporting country, and their investment costs were reduced by moving their energy production closer to the power link island.

Germany was on the other side of the scale with increasing investment costs in all steps. They started at €14.00bn and ended up at €56.11bn. Germany was also the country with highest renewable production, leading to a great amount of power being transferred to their offshore node, and again creating a need for a gigantic branch expansion between this node and the power link island. Other countries with increasing transmission costs were the Netherlands, Great Britain and Belgium. Denmark had varying transmission investment costs that were very dependent of their connection to the island.

Table 7.2: Transmission investments by area for scenarios in case 2, vision 1

Area	Branch investments Reference [10^9€]	Branch investments Scenario D [10^9 €]	Branch investments Scenario E [10^9 €]	Branch investments Scenario F [10^9 €]
BE	4.93	4.88	5.94	7.50
DE	14.00	29.07	36.71	56.11
DK	4.88	4.88	4.31	5.36
GB	27.55	30.39	34.51	40.47
NL	6.39	6.44	11.73	14.89
NO	37.02	32.63	22.62	17.34

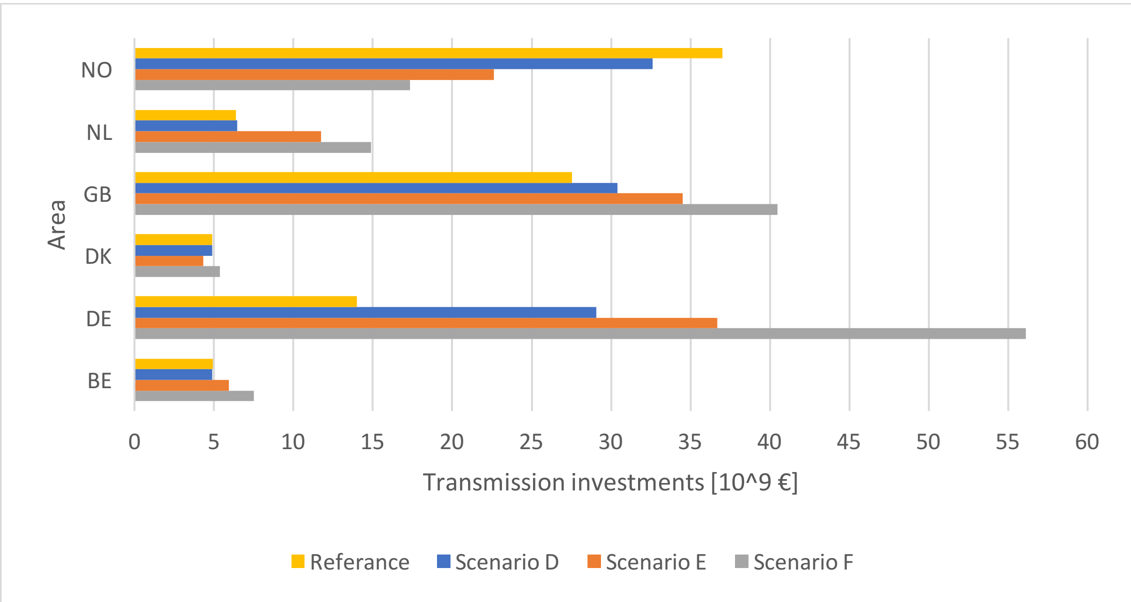

Figure 7.5: Transmission investments by area for scenarios in case 2, vision 1

7.1.4 Island power flow

Figure 7.6, Figure 7.7 and Figure 7.8 shows transmission line utilization for lines connected to the island. Germany and Norway had a decreasing share of export utilization from their coastal nodes, and in the final scenario the coastal node of Norway was the only coastal node still exporting to the island. Offshore nodes with branches to both coastal nodes and the power link island got increasing share of imports from the island, meaning that some of the power distributed from the island were transported via offshore nodes. There were no cases of island export to offshore nodes with connection to coastal nodes.

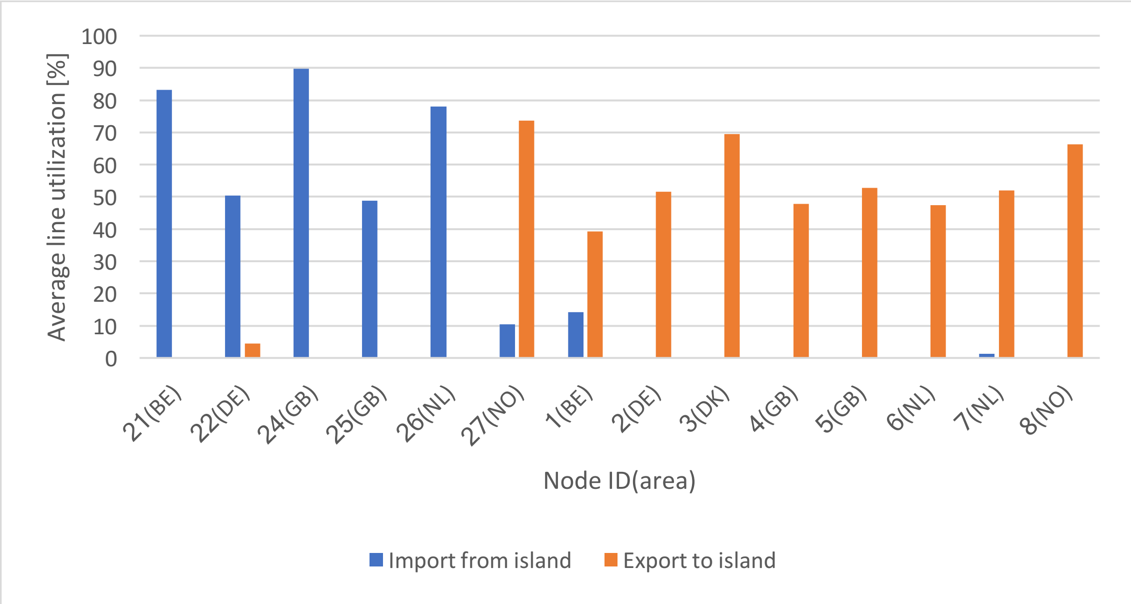

Figure 7.6: Average island transmission line utilization for scenario D, vision 1

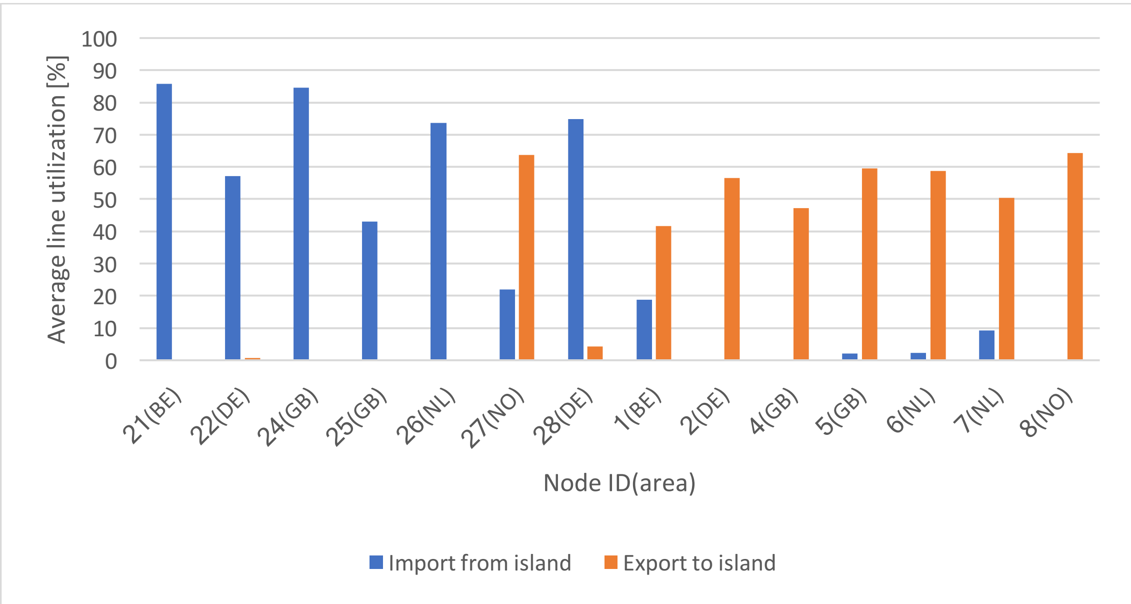

Figure 7.7: Average island transmission line utilization for scenario E, vision 1

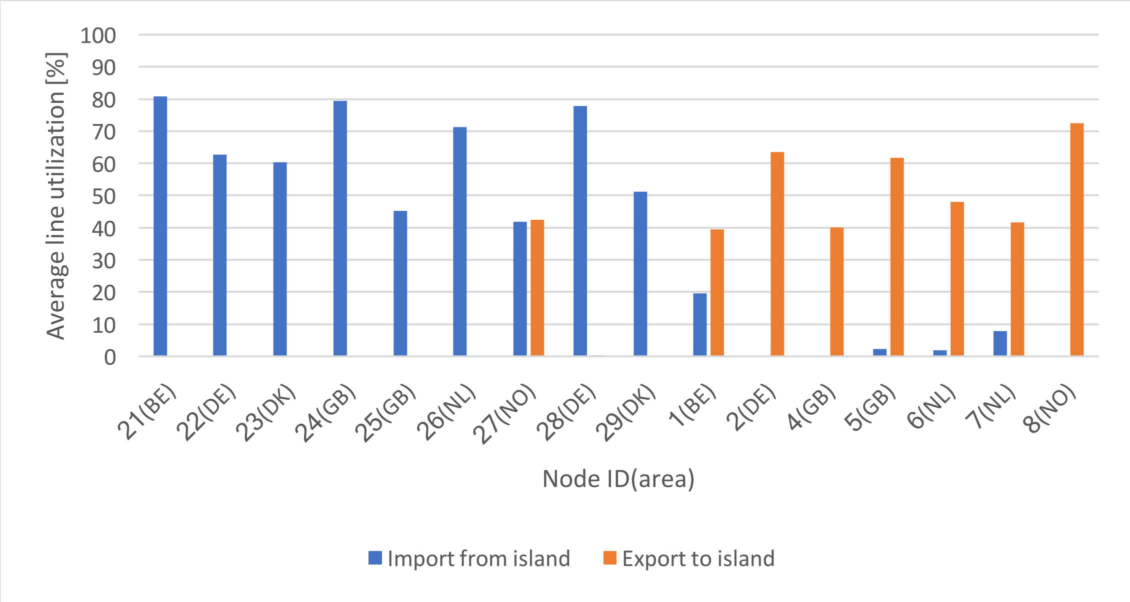

Figure 7.8: Average island transmission line utilization for scenario F, vision 1

7.1.5 Average area prices

The effect on area prices are shown in Figure 7.9. Belgium and Great Britain were the only two countries that had decreasing area prices throughout all scenarios. The average area price in Norway was unaffected until scenario F. Moving this amount of production caused an increase in area price compared to the reference scenario. The area price in Germany got reduced in scenario D and E, but then increased again in scenario F. Scenario E gave the biggest reduction in total project costs, and it was worth noticing that the all the area prices where reduced when comparing scenario E with the reference scenario. The Netherlands had the biggest reduction from the reference scenario to scenario E, moving from an area price of 46.06€/MWh to 32.34€/MWh.

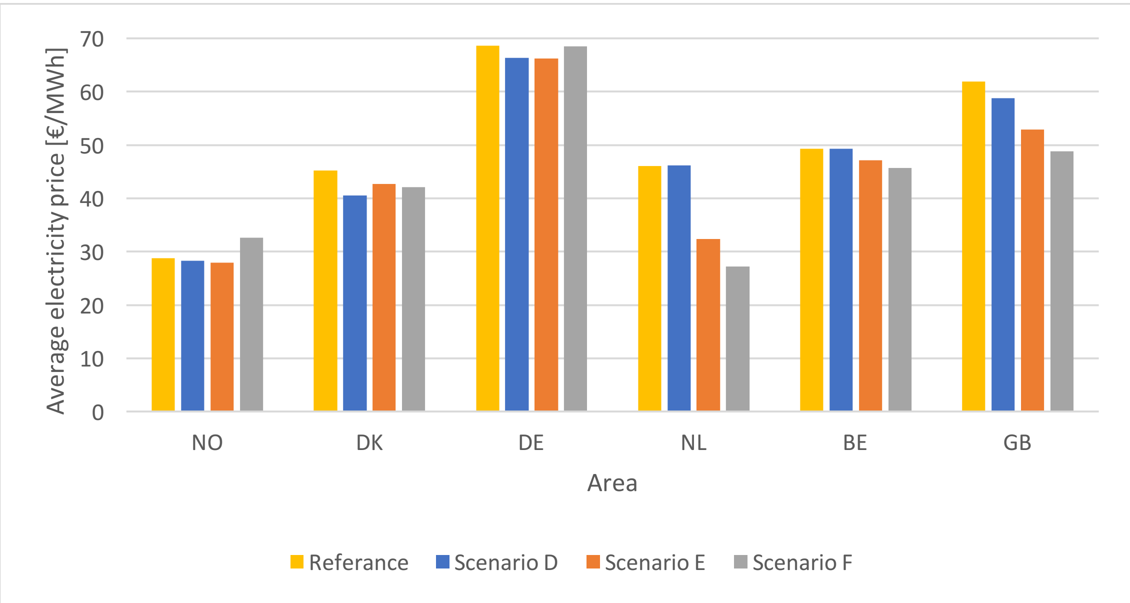

Figure 7.9: Average area prices for scenarios in case 2, vision 1

7.2 Simulations with vision 4

The following results were obtained when adjusting system conditions from vision 1 to vision 4 standards.

7.2.1 Project costs

The trend of increasing transmission investment costs and decreasing operational costs was still present for simulations done with vision 4 conditions, but this time the operational costs also started to increase for scenario F. The point where savings in operational costs was less than transmission expenditure seemed to occur for a smaller percentage of generation shifting from onshore to offshore nodes. The projects total cost started at €370.20bn for the reference scenario and were at its lowest for scenario E with an amount of €354.18bn. This equalled a total cost reduction of €16.02bn. Scenario F had an increase of €9.36bn in total costs compared to the reference scenario. Other key numbers for these simulations is found in Table 7.3 and Figure 7.10.

Table 7.3: Project costs for all scenarios in case 2, vision 4

Vision 4	Reference	Scenario D	Scenario E	Scenario F
Investment costs [10^9 €]	107.81	120.11	128.16	149.95
New transmission costs [10^9 €]	101.60	113.90	121.95	143.74
Operational costs [10^9 €]	262.39	237.75	226.02	229.61
Total costs [10^9 €]	370.20	357.86	354.18	379.56

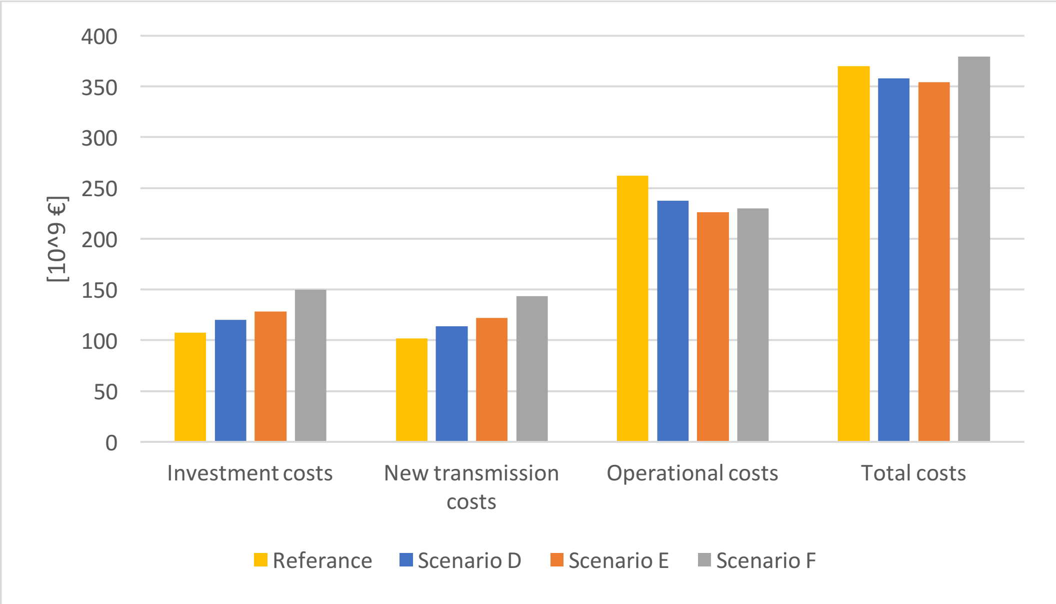

Figure 7.10: Project costs for scenarios in case 2, vision 4

7.2.2 Capacity expansions

When comparing grid expansions between the reference scenario and scenario D, three additional transmission lines were upgraded. The first line was expanded between the coastal and offshore nodes of Norway. The other two additional line upgrades were done between the power link island and the coastal nodes of Belgium and Germany. The transmission line expansion between node 27 of Norway and node 28 of Germany was the only one no longer needed. The transfer from scenario D to scenario E removed the upgrade of capacity between the power link island and the offshore nodes of Denmark (3) and Belgium (1). The line upgrade from node 27 of Norway to node 29 of Denmark no longer needed an upgrade for the optimal solution. The only addition line upgrade was made between the costal and generation centre nodes of Belgium.

The last step of these simulations was moving from 25% to 50% generation shift. This lead to three additional line upgrades, all from coastal nodes to generation centres. The affected countries were Denmark, with an upgrade from node 23 to node 92, and Germany with upgrades from both 28 and 22 into their generation centre node, 93.

All capacity expansions for the different scenarios are depicted in Figure 7.11, Figure 7.12 and Figure 7.13

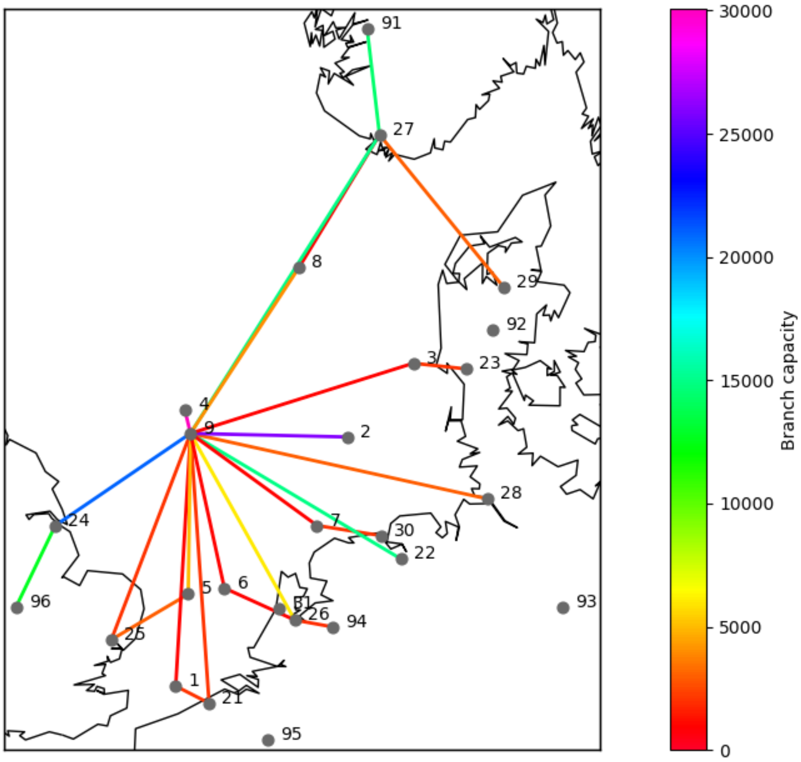

Figure 7.11: Branch capacity expansions in MW for scenario D, vision 4

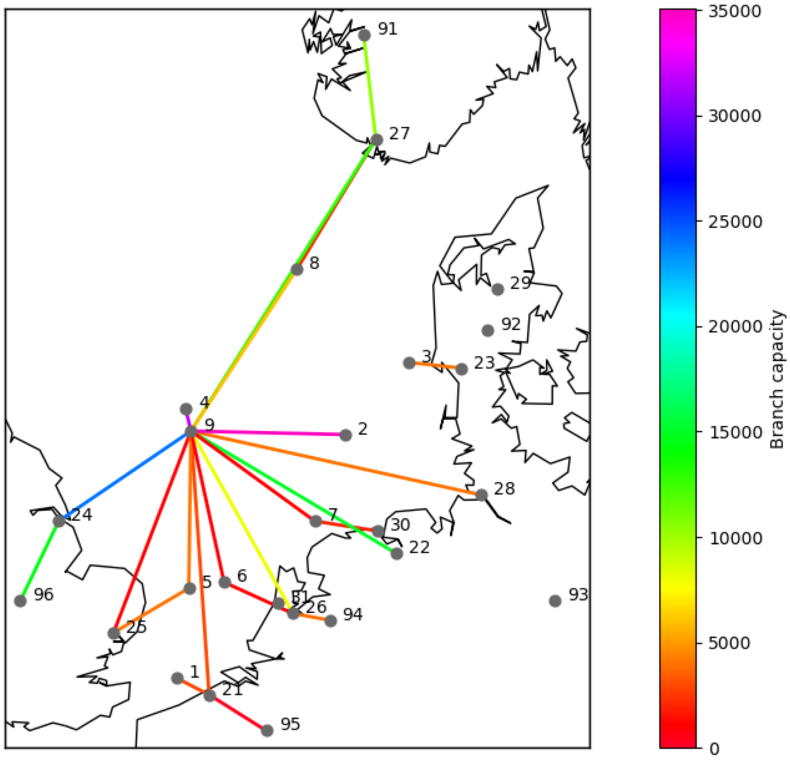

Figure 7.12: Branch capacity expansions in MW for scenario E, vision 4

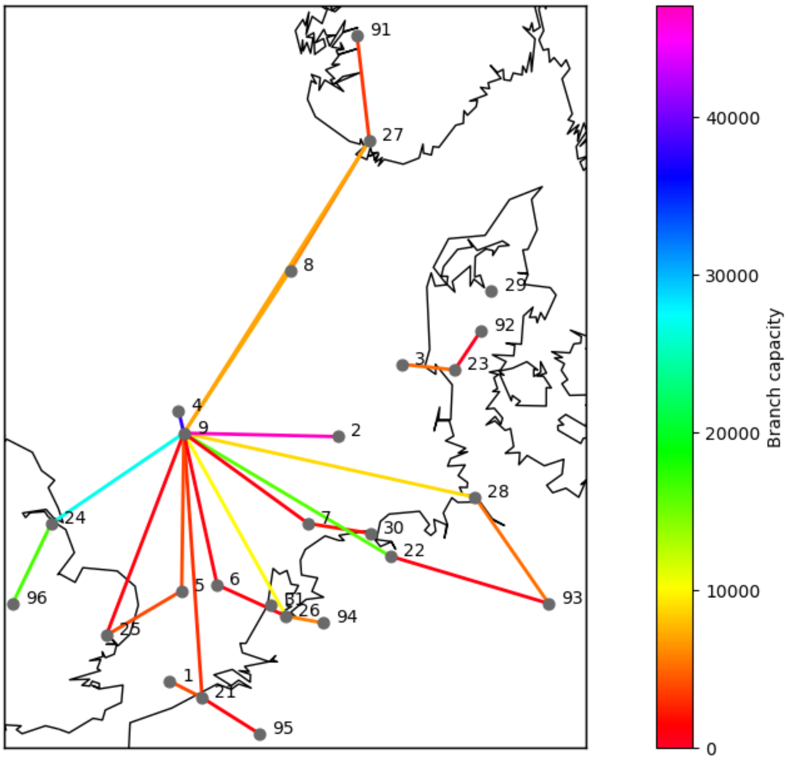

Figure 7.13:Branch Capacity expansions in MW for scenario F, vision 4

7.2.3 Transmission investments

As for vision 1 conditions, Norway was again the only country with a progressive decrease in transmission investments costs. Starting at €37.98bn for the reference scenario and ending up at €23.29bn for scenario F. The Netherlands, Great Britain and Germany got increasing transmission investments following the amount of power produced offshore instead of onshore. Belgium had a slight investment decrease in scenario D, but ended up with higher branch investment costs for the last two scenarios compared to the reference scenario. The most favourable economic scenario for Denmark was scenario E, which led to a decrease compared to the reference scenario. Both scenario D and F gave an increase in investment costs for Denmark.

The country with the highest costs for scenario D was Norway, closely followed by Great Britain and Germany. All remaining areas were directly involved in much less costs than the abovementioned areas. Great Britain and Germany went a little past Norway regarding transmission investment costs in scenario E, but those three countries still had a large share of the costs. The biggest contributor in the final scenario was again without doubt Germany, being directly involved in €54.21bn of the total €143.74bn. All transmission investment costs for every scenario are shown in Table 7.4 and Figure 7.14

Table 7.4: Transmission investments by area for scenarios in case 2, vision 4

Area	Branch investments Reference	Branch investments Scenario D [10^9 €]	Branch investments Scenario E [10^9 €]	Branch investments Scenario F [10^9 €]
BE	4.93	4.88	6.24	7.80
DE	25.43	29.29	35.07	54.21
DK	5.66	5.99	4.41	5.67
GB	29.04	32.15	35.14	38.88
NL	6.36	9.63	11.76	13.89
NO	37.98	34.97	29.32	23.29

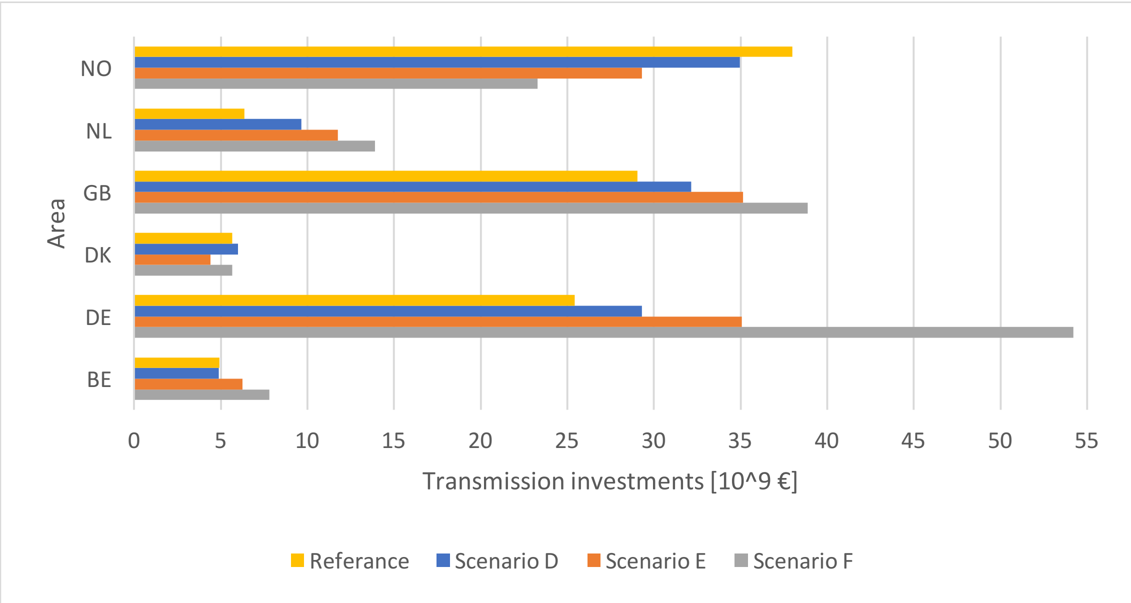

Figure 7.14: Transmission investments by area for scenarios in case 2, vision 4

7.2.4 Island power flow

Norway and Germany were still exporting power from their coastal nodes to the power link island for scenario D. Of those two countries only Norway had higher export than import utilization in scenario D, but the tables turned in scenario E and F. In scenario F, Norway was the only country exporting from their coastal node to the island. The line connected with the coastal node of Belgium had the highest line utilization for imports. All offshore nodes were mainly export nodes, with Belgium and the Netherlands having the biggest share of island power imports to their offshore nodes. All transmission line utilizations for lines connected to the power link island is shown in Figure 7.15, Figure 7.16 and Figure 7.17.

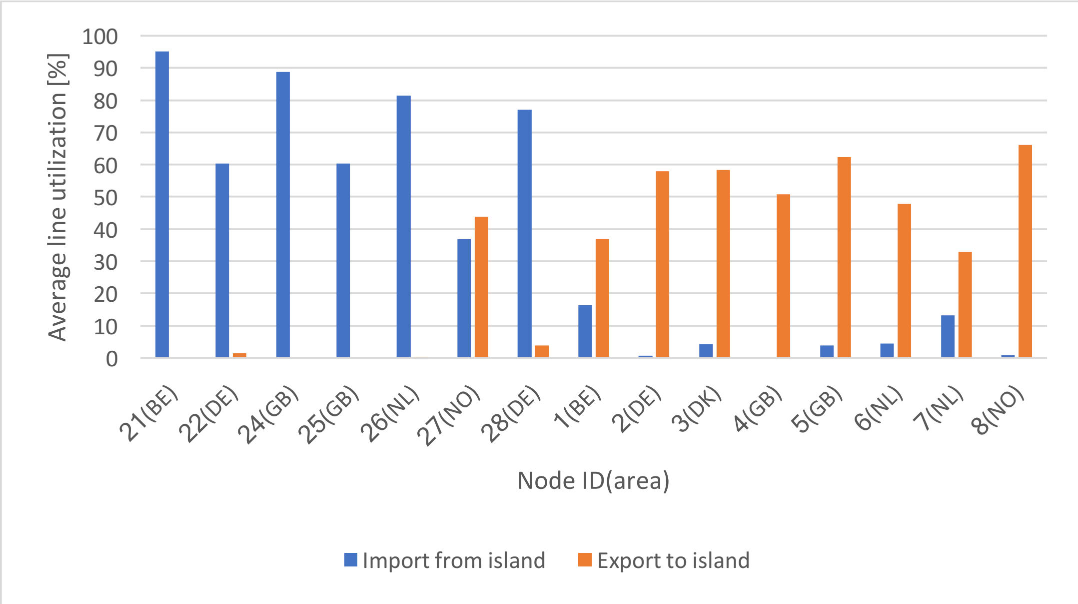

Figure 7.15: Average island transmission line utilization for scenario D, vision 4

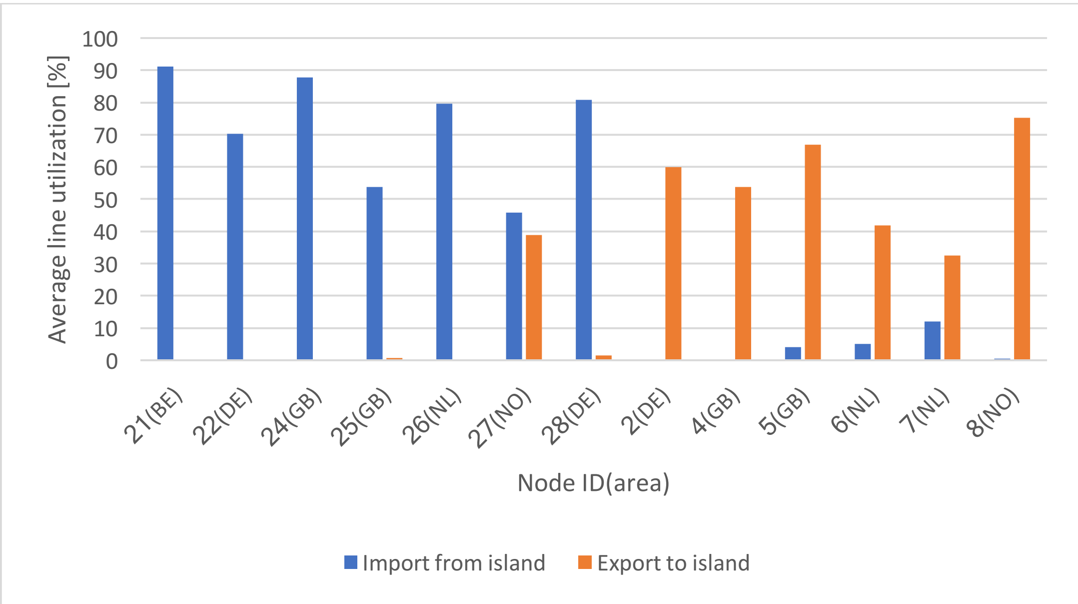

Figure 7.16: Average island transmission line utilization for scenario E, vision 4

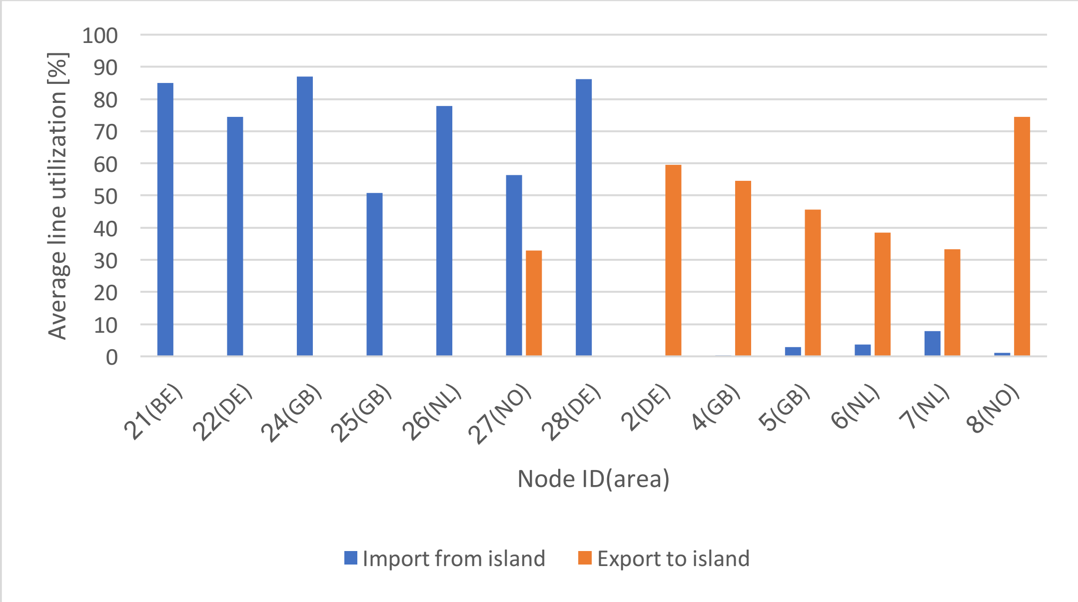

Figure 7.17: Average island transmission line utilization for scenario F, vision 4

7.2.5 Average area prices

All area prices decreased when moving from the reference scenario to scenario D. The second step from scenario D to scenario E gave additional decreases in Norway, Belgium and Great Britain, while Denmark, Germany and the Netherlands got increased area prices. Moving from 25% to 50% lead to increased area prices in Norway, Denmark and Germany and price reductions in the Netherlands, Belgium and Great Britain. Germany had the highest area prices by far, always finding themselves around 40-45€/MWh for all scenarios. For scenario D, Denmark had the lowest area price with 13.66€/MWh respectively. The Netherlands had this honour in scenario E and F with 18.70€/MWh and 18.64€/MWh. These and the rest of the area prices for scenarios in case 2 with vision 4 conditions are illustrated in Figure 7.18

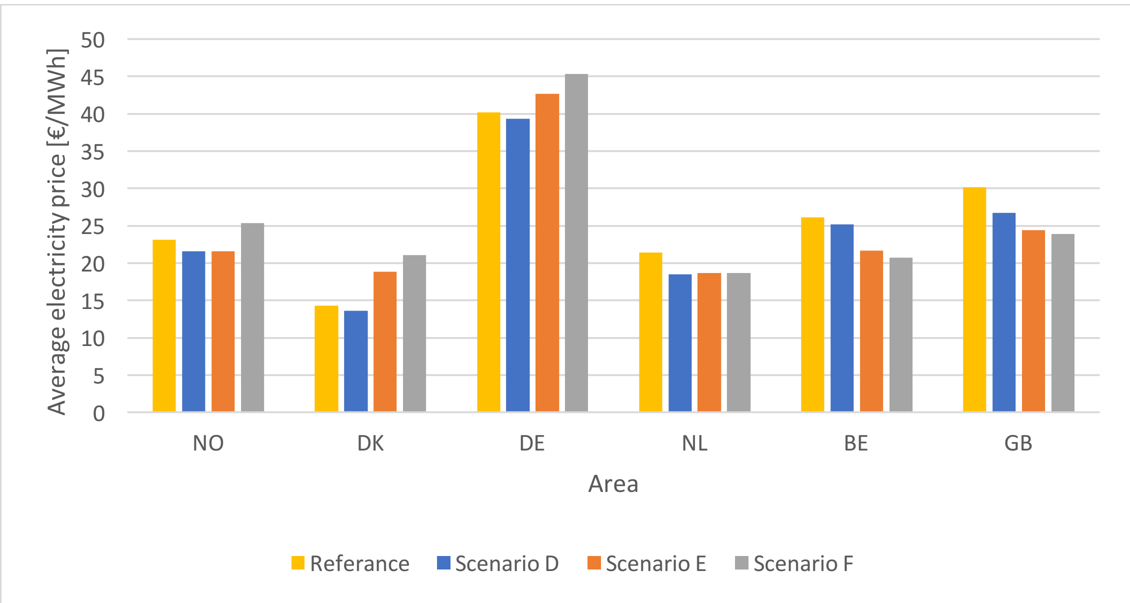

Figure 7.18: Average area prices for scenarios in case 2, vision 4

8 Case 3 – Implementation of additional wind power

The third and last case study disclosed the placement of additional offshore wind power production in the power grid system. Three different placements were used, including a distribution of new wind power between offshore nodes by percentage, placement on a single existing offshore node (4), and finally placing the new capacity directly on the power link island.

8.1 Simulations with vision 1

The first part of this case study was done with vision 1 conditions, which was the least favourable economic future prediction.

8.1.1 Project costs

Figure 8.1 makes it clear that distributing the extra wind power by percentage gave both the highest investment and operational costs, and was therefore the most expensive solution in this case. Scenario H and I had nearly the same operational costs with only €0.05bn difference in favour of scenario I. Scenario I also had the lowest investment costs, bringing the total costs of the optimal economic scenario down to €530.03bn. For scenario G, the total costs ended up at €540.72bn leading to a total cost difference of €10.69bn between the least and most favourable economic scenarios. Accurate system costs for all scenarios with vision 1 conditions are shown in Table 8.1 and Figure 8.1.

Table 8.1: Project costs for all scenarios in case 3, vision 1

Vision 1	Scenario G	Scenario H	Scenario I
Investment costs [10^9 €]	114.03	107.51	104.80
New transmission costs [10^9 €]	107.83	101.30	98.59
Operational costs [10^9 €]	426.68	425.29	425.24
Total costs [10^9 €]	540.72	532.80	530.03

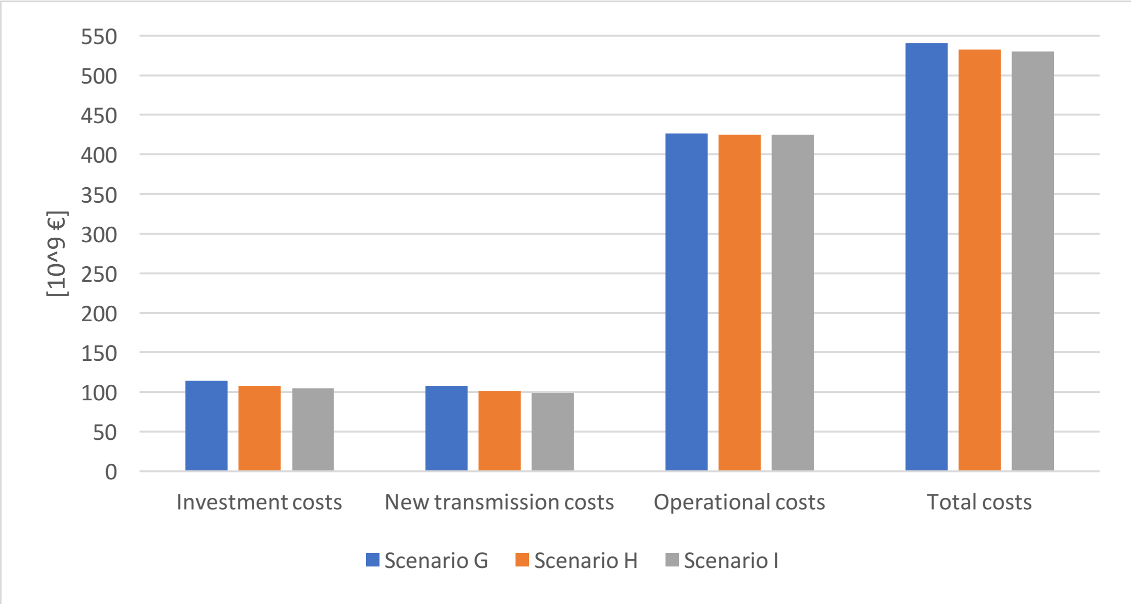

Figure 8.1: Project costs for all scenarios in case 3, vision 1

8.1.2 Capacity expansions

The investment model was given the same grid expansion possibilities for all scenarios in case 3. Even though placing the additional wind power in different locations, the power grid development ended up nearly the same for all three scenarios. The size of the transmission line upgrades did however vary. All offshore nodes got direct connection to the power link island in scenario G. Offshore nodes 1, 3 and 7 also got transmission capacities to their respective coastal nodes. All scenarios had two expansions of power lines directly between areas, both starting in node 27 of Norway and ending up in node 29 of Denmark and node 28 of Germany. The biggest branch expansion for scenario G was between the offshore node of Germany and the power link island. The upgraded capacity equalled 25000MW. In scenario H, a tremendous branch expansion occurred between node 4 of Great Britain and the island. This expansion equalled 41000MW. For the last scenario, the size of expansions had a friendlier distribution with the biggest one going from the island and on to node 24 of Great Britain with an upgrade equal to 22000MW. Figure 8.2, Figure 8.3 and Figure 8.4 show all branches with upgraded capacities for the scenarios in case 3 with vision 1 conditions.

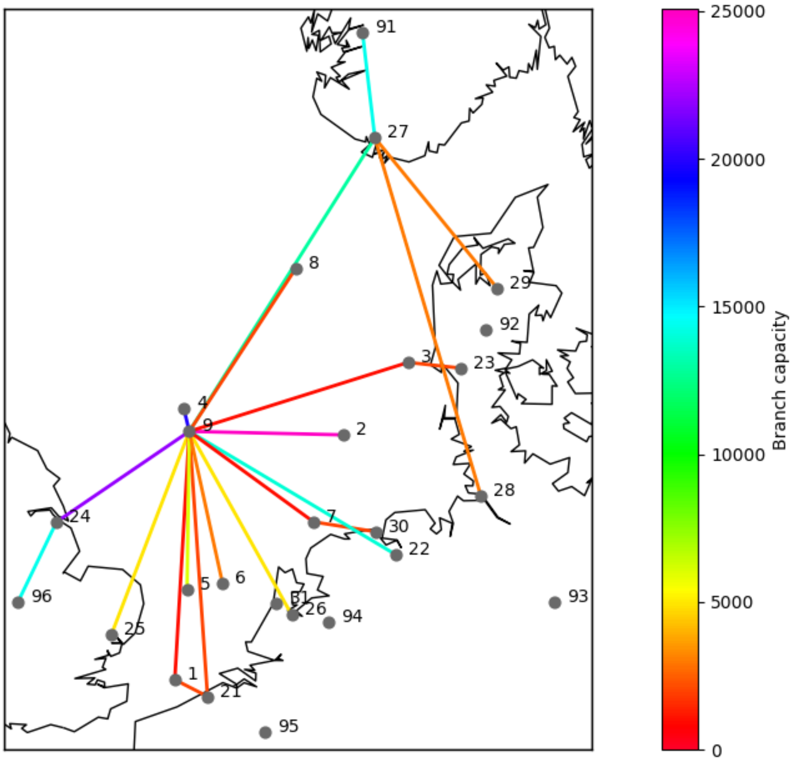

Figure 8.2: Branch capacity expansions in MW for scenario G, vision 1

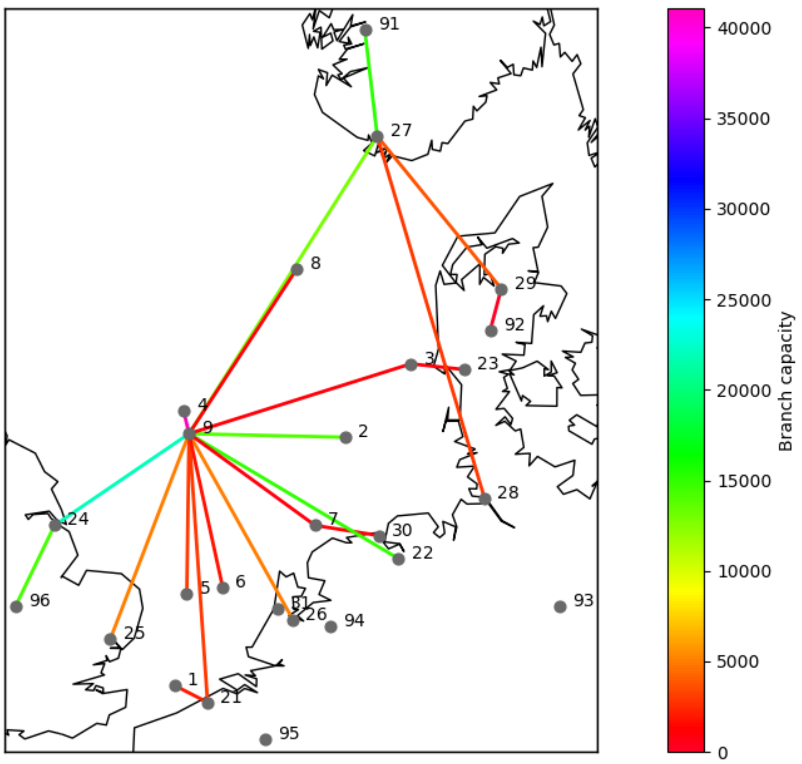

Figure 8.3: Branch capacity expansions in MW for scenario H, vision 1

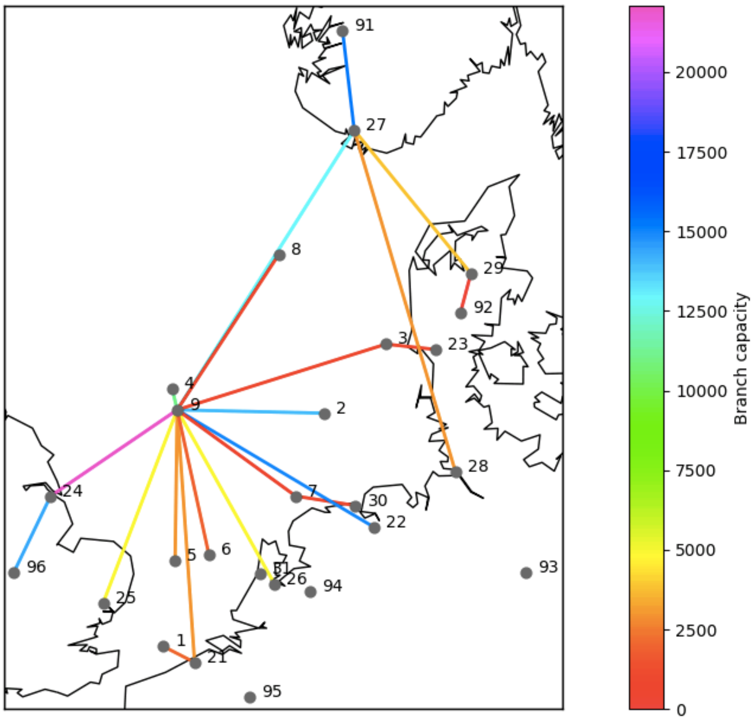

Figure 8.4: Branch capacity expansions in MW for scenario I, vision 1

8.1.3 Transmission investments

Starting with the biggest contributor in all scenarios, the transmission costs for Norway were most favourable for scenario G. The second biggest investor for these scenarios was Great Britain, and they gained most by adding the extra wind power capacity directly to the power link island. Germany along with the Netherlands and Denmark would prefer one of the last scenarios. All countries had the same transmission investments in both scenario H and I, except Great Britain who had larger transmission investment costs for scenario H. Belgium had only a slight increase in costs in the two latter scenarios, compared to scenario G. All transmission investments for the presented scenarios are shown in Table 8.2 and Figure 8.5.

Table 8.2: Transmission investments by area for scenarios in case 3, vision 1

Area	Branch investment Scenario G [10^9 €]	Branch investment Scenario H [10^9 €]	Branch investment Scenario I [10^9 €]
BE	4.88	4.93	4.93
DE	29.67	24.67	24.67
DK	5.99	5.94	5.94
GB	32.13	32.36	29.65
NL	8.14	6.39	6.39
NO	34.84	35.75	35.75

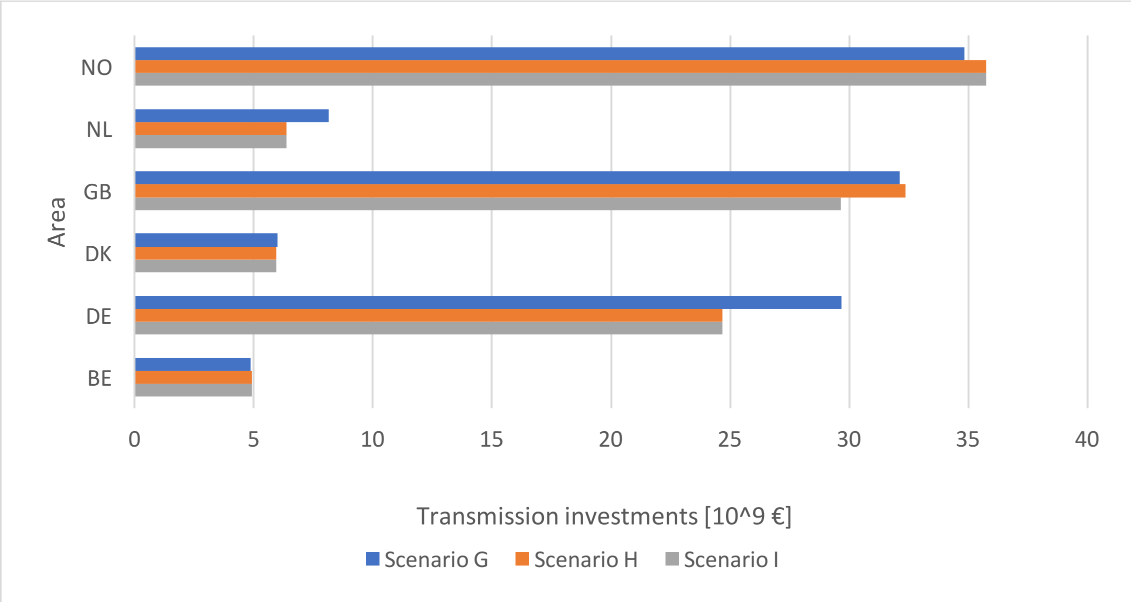

Figure 8.5: Transmission investments by area for scenarios in case 3, vision 1

8.1.4 Island power flow

Two coastal nodes were used for export to the island for all scenarios. These two where linked to nodes 22 in Germany and node 27 in Norway. Norway had a significant share of exports compared to imports. The offshore nodes were mainly exporting power to the power link island. Belgium, Denmark and the Netherlands also had some power imports to their offshore nodes. For Belgium, this was only the case in scenario G because the interconnection between the island and their offshore node was not invested in for the last two scenarios. Disregarding Belgium, the power line utilization was nearly the same for the other areas in all scenarios. The average line utilization for all cables connected to the island are shown for in Figure 8.6 for scenario G. Similar figures for scenario H and I are found in appendix B.

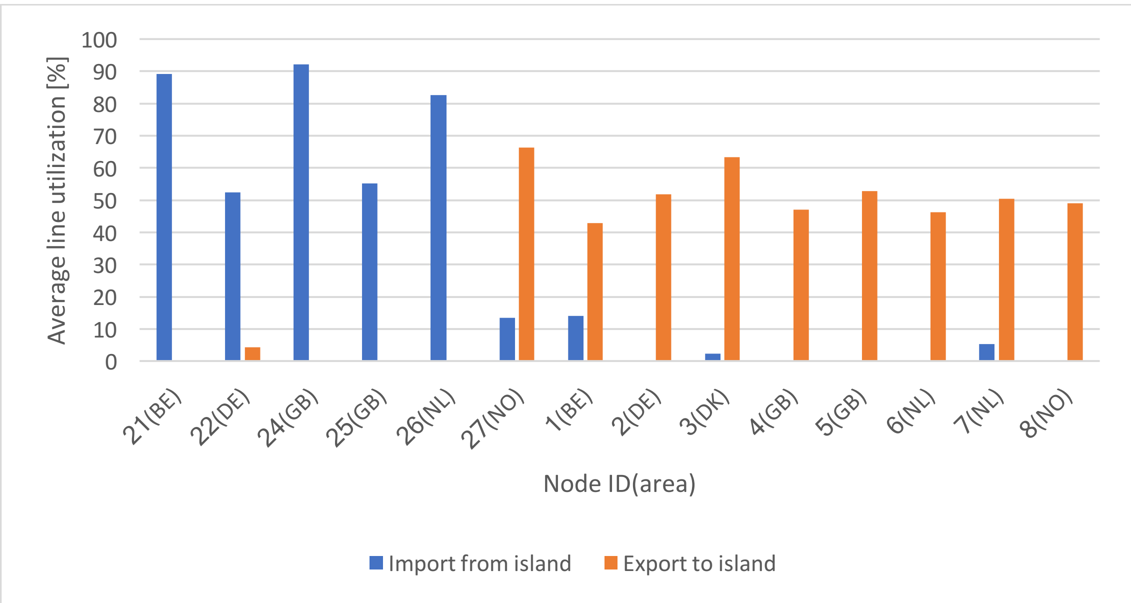

Figure 8.6: Average island transmission line utilization for scenario G, vision 1

8.1.5 Average area prices

The location of the extra wind power had little impact on area prices. The Netherlands had the biggest variation in area price which equalled 1.23€/MWh from 39.26€/MWh in scenario G to 40.40€/MWh in scenario H. Germany had the highest prices just below 60€/MWh, followed by Great Britain with a price around 51€/MWh. Belgium and the Netherlands both got price levels at approximately 40€/MWh. Denmark was not far behind the two with an area price of approximately 35€/MWh, while Norway had the lowest area price, an area price of around 27€/MWh. All area prices and variations between scenarios with vision 1 conditions are illustrated in Figure 8.7.

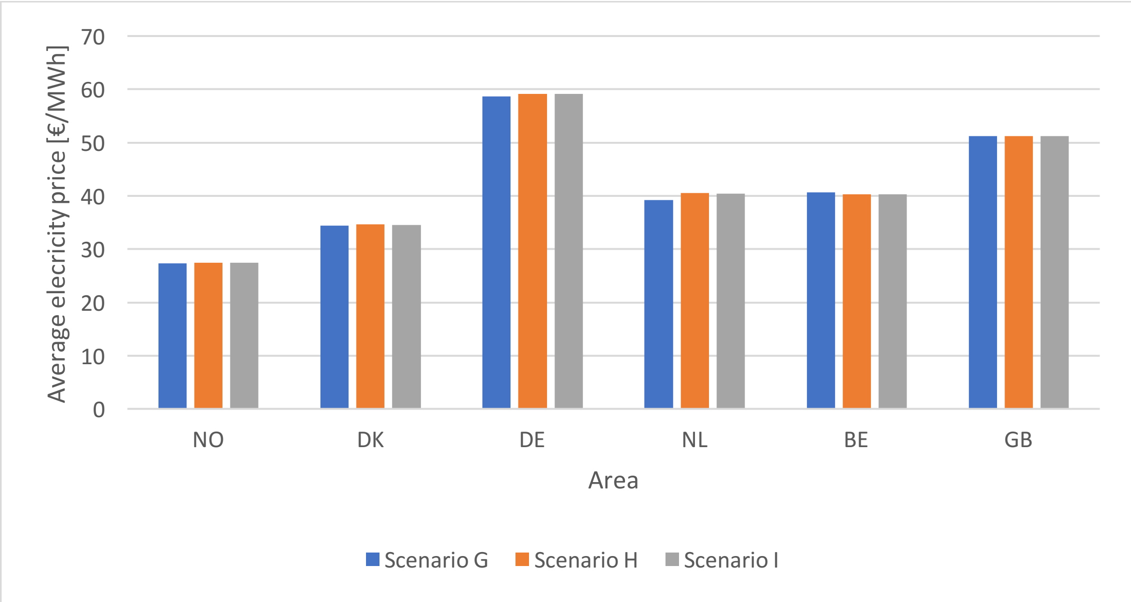

Figure 8.7: Average area prices for scenarios in case 3, vision 1

8.2 Simulations with vision 4

The following results were obtained by varying the additional wind power location with a power system that had a higher penetration of renewables than vision 1.

8.2.1 Project costs

As shown in Table 8.3 and Figure 8.8, choosing the optimal location for the extra wind power capacity would lead to a €6.95bn reduction in total costs from €335.71bn in scenario G to €328.76bn in scenario I. As for simulations with vision 1 conditions, the optimal location was at the power link island, while the least favourable option was distributing the extra wind power between all offshore nodes. Scenario H and I had nearly €6bn cheaper operational costs than scenario G, and because the investment costs were lowest for scenario I this was the most economically attractive solution.

Table 8.3: Project costs for all scenarios in case 3, vision 4

Vision 4	Scenario G	Scenario H	Scenario I
Investment costs [10^9 €]	115.00	116.30	113.95
New transmission costs [10^9 €]	108.79	110.10	107.75
Operational costs [10^9 €]	220.71	214.89	214.81
Total costs [10^9 €]	335.71	331.19	328.76

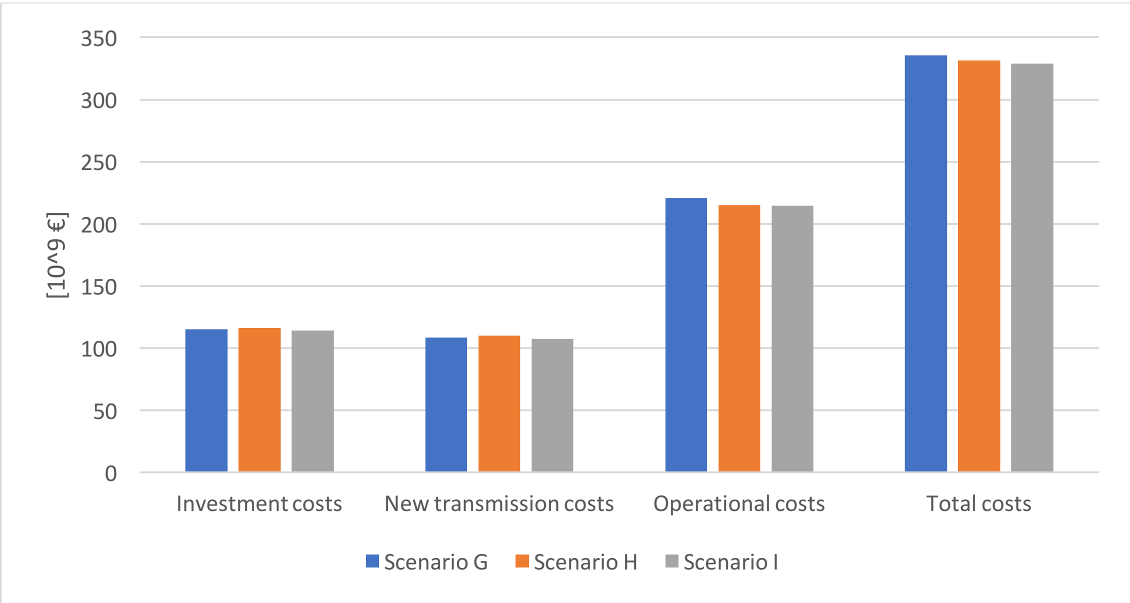

Figure 8.8: Project costs for all scenarios in case 3, vision 4

8.2.2 Capacity expansions

The branches expanded were as shown in Figure 8.9, Figure 8.10 and Figure 8.11 nearly the same for all scenarios. Scenario G did however differ with two less branches being upgraded. These two went between the island and node 25 of Great Britain, and between the coastal node 26 of the Netherlands to their generation centre node. The biggest capacity expansion was between Great Britain's offshore node 4 and the power link island for all scenarios. The placement of the extra wind power did however have a substantial impact when optimizing the upgrade of this line. For scenario G, the line was built with a capacity of 37,000MW, when moving extra capacity to node 4 in scenario H, the same figure was 50,000MW, before ending up at 24,000MW in scenario I.

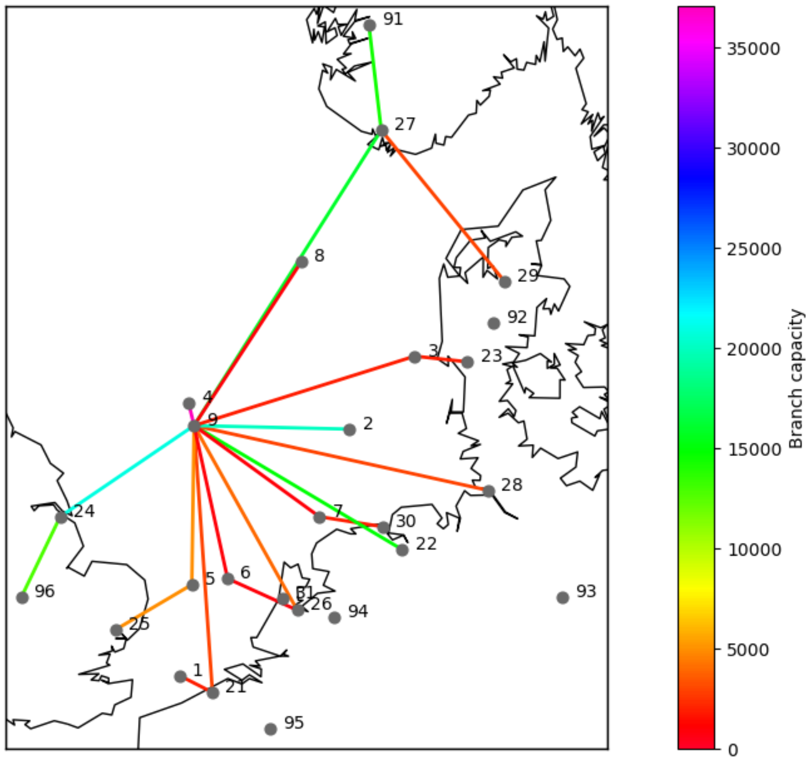

Figure 8.9: Branch capacity expansions in MW for scenario G, vision 4

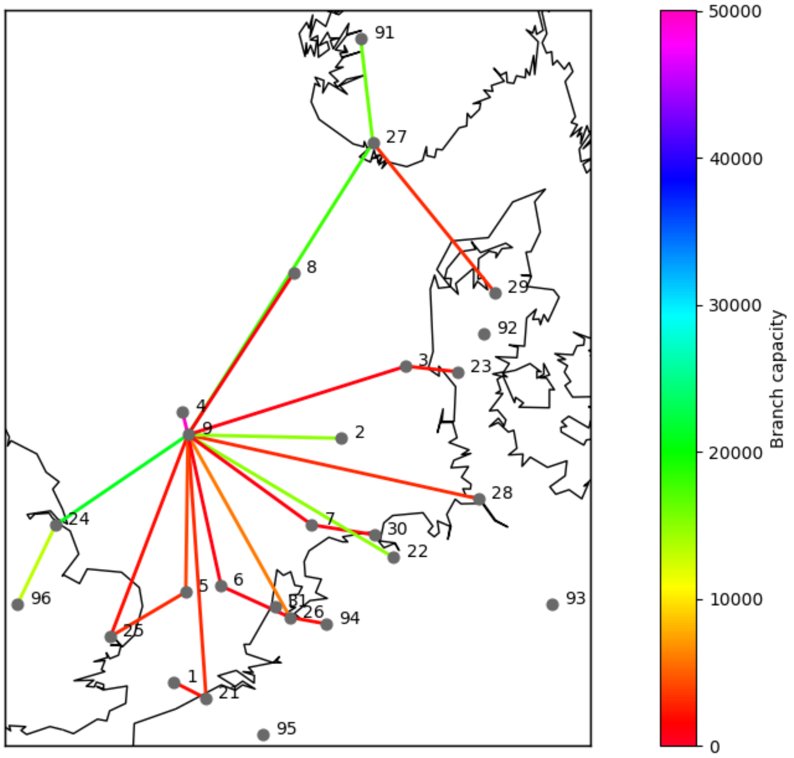

Figure 8.10: Branch capacity expansions in MW for scenario H, vision 4

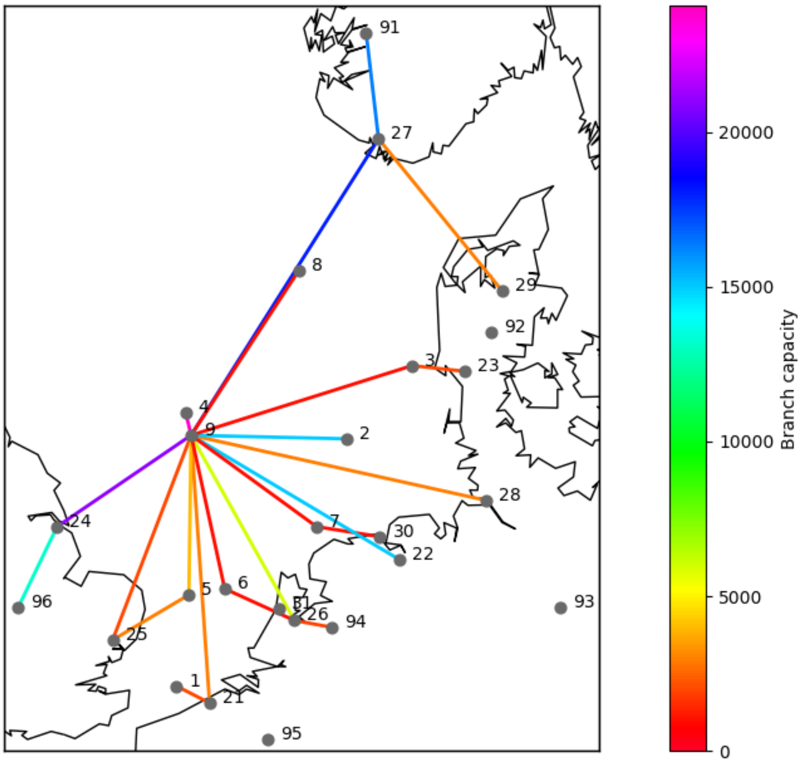

Figure 8.11: Branch capacity expansions in MW for scenario I, vision 4

8.2.3 Transmission investments

The distribution of transmission investments had many similarities with the previous simulations in this case. Belgium was the only country with transmission investments independent of the placement of the extra offshore capacity. For Norway and the Netherlands, a percentage distribution between offshore nodes would give the lowest transmission costs. The remaining areas would prefer scenario H or I over scenario G, and Great Britain would even prefer scenario H over scenario I as well.

The areas were in twofold when regarding the size of investment costs, with Norway, Great Britain and Germany being the main contributors to the offshore grid expansions. The biggest contributor in scenario G was Great Britain, with transmission investments equal to €33.75bn. Norway had to the biggest share with €36.54bn in both remaining scenarios. Remaining transmission investment costs are found in Table 8.4 and Figure 8.12.

Table 8.4: Transmission investments by area for scenarios in case 3, vision 4

Area	Branch investment Scenario G [10^9 €]	Branch investment Scenario H [10^9 €]	Branch investment Scenario I [10^9 €]
BE	4.93	4.93	4.93
DE	26.10	23.45	23.45
DK	6.76	5.99	5.99
GB	33.75	33.71	31.36
NL	7.51	8.48	8.48
NO	32.74	36.54	36.54

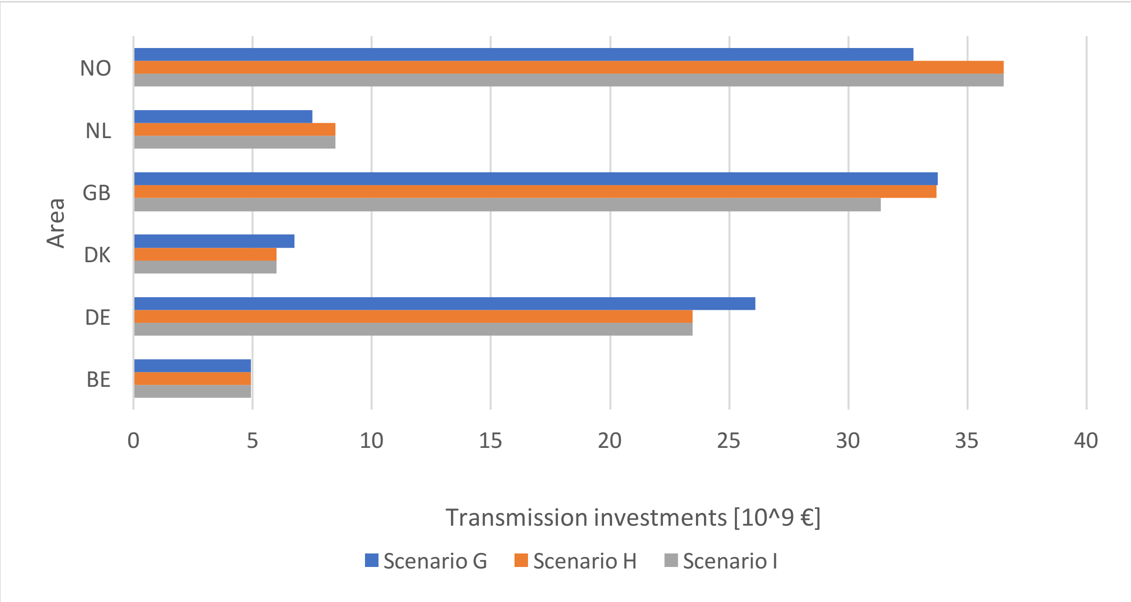

Figure 8.12: Transmission investments by area for scenarios in case 3, vision 4

8.2.4 Island power flow

All countries except Denmark had at least one direct connection to the power link island via their coastal nodes in all scenarios and the only offshore node not connected to the island was node 1 of Belgium. The interconnection between the power link island and node 28 of Germany was the only line not present in all scenarios. Scenario H and I had this expansion, while scenario G did not. Norway and Germany were still the only countries exporting power to the power link island from their coastal nodes. Germany was exporting from both of their coastal nodes in scenario H and I, and only from node 22 in scenario G. The transmission line utilization figures for these simulations were very similar. The line utilization for scenario H is shown in Figure 8.13, for similar figures of the remaining scenarios see appendix B.

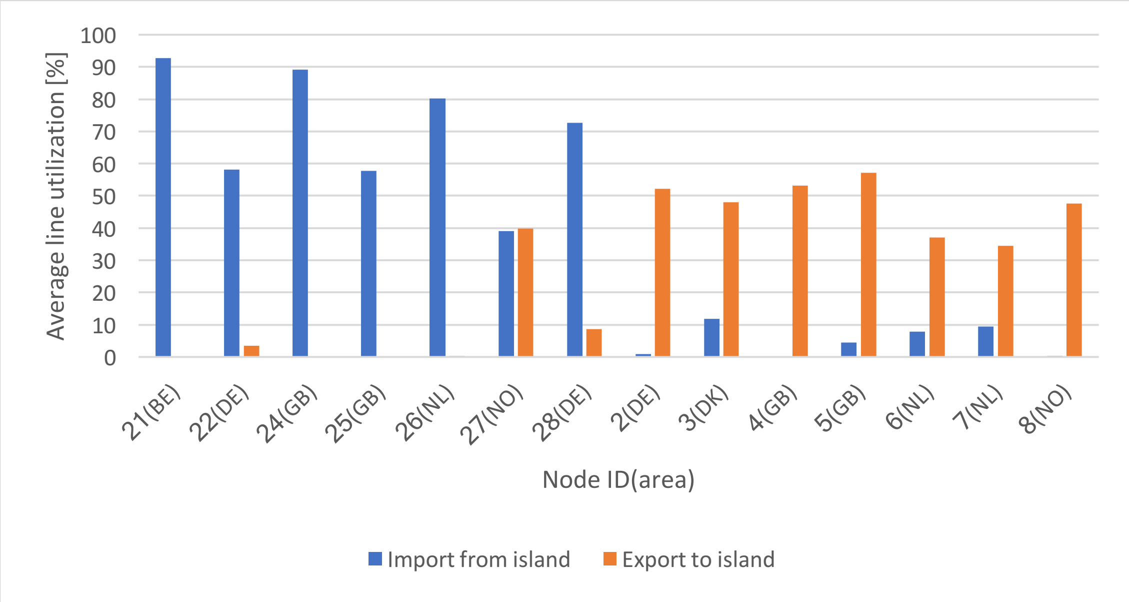

Figure 8.13:Average island transmission line utilization for scenario H, vision 4

8.2.5 Average area prices

Figure 8.14 shows that there were little disparities in area prices between the scenarios. The only noteworthy changes arose when comparing scenario G with the other two scenarios. Great Britain had the largest variation of 1.80€/MWh comparing scenario H and I with scenario G. Norway, Germany and the Netherlands were the other countries with a small reduction in area price when comparing scenario G with the remaining two. Belgium on the other hand had a higher area price for the last two scenarios.

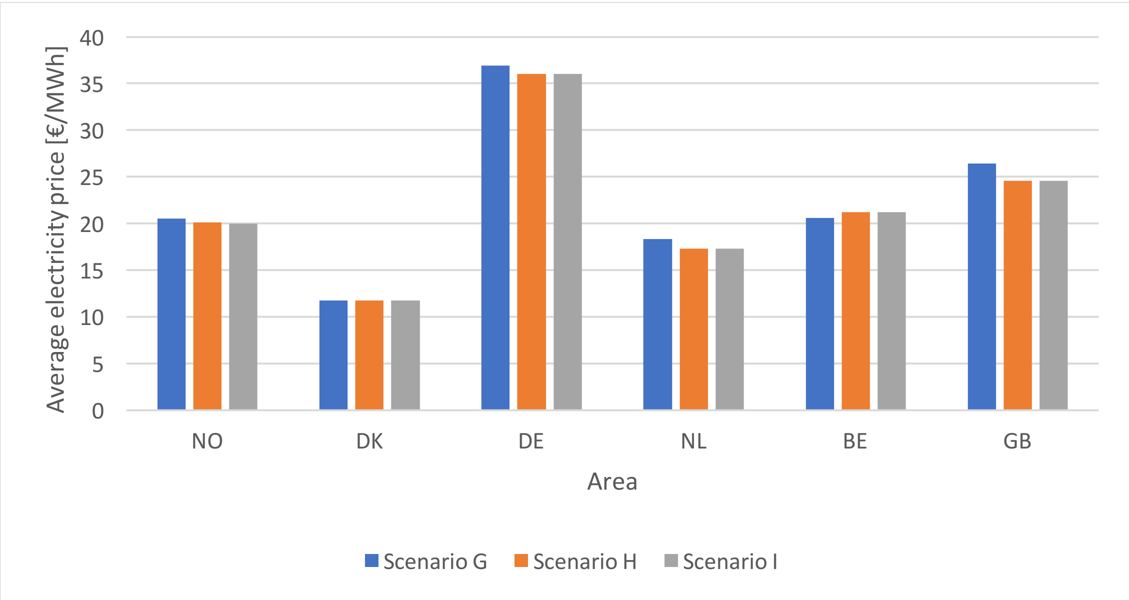

Figure 8.14: Average area prices for scenarios in case 3, vision 4

9 Discussion

This chapter sums up the discussion from all cases and includes discussion across the case studies

9.1 Varying degree of power grid development

Simulations done in conjunction with case 1 showed that Vision 1 standards gave higher operational costs than vision 4, but for investment costs it was the other way around. The total costs of the project were progressively decreasing with regards to offshore grid development for both sets of input data, but the reduction in total costs was highest for vision 4 standards. This phenomenon can be explained by the higher penetration of renewable energy for vision 4 compared to vision 1. The energy production from renewable energy sources gave both cheaper but also more weather and condition dependent energy generation. When the power production on a higher level depends on unpredictable energy resources, the need for grid expansions increases. This was also causing the need for extra expansions when comparing capacity expansions between vision 1 and vision 4 simulations.

The largest drop in operational costs found place when moving from scenario B to scenario C in both sets of simulations. When linking offshore generation nodes to the power link island in scenario C, the utilization of offshore wind power production increased, causing the operational costs to decline. This also explained why the drop in operational costs were higher for vision 4 than vision 1 standards, since the production at offshore nodes were higher for vision 4 standards. The transmission investments were also heavily reduced from scenario B to scenario C for both sets of simulations. This was due to the possibility of connecting offshore nodes directly to the island. In scenario B, the offshore nodes had to transmit their production back to its respective country, before optionally sending it back out to the power link island. In scenario C, this power production could be sent directly to the island for distribution between all areas. The reduction in total costs when comparing the original power grid with the fully developed grid equalled €36.80bn for vision 1 conditions and €50.69bn for vision 4 conditions.

Great Britain and Norway were both involved in large transmission line expansions in all scenarios for this case regardless of futuristic vision. High gas prices led the investment model to invest in branches capable of transferring surplus energy from hydro production in Norway to Great Britain. This required transmission lines all the way from the generation centre node of Great Britain over to the generation centre node of Norway, bringing tremendous costs for the two countries. When the share of renewable energy increased in vision 4 these lines were still expanded greatly, but not as much as for vision 1 conditions. With vision 4 conditions the offshore production at node 4 of Great Britain was so high that they ended up with large expansions for these sets of simulations as well. Germany was also a country in need of large capacity expansion to utilize their installed offshore capacity. Belgium, Denmark and the Netherlands had for comparison very little production of offshore wind power, giving them less capacity expansions and smaller amounts of the transmission investment costs.

9.2 Moving renewable generation

Moving some of the generation from onshore to offshore nodes was proven profitable for the projects total costs. At first the savings in operational costs exceeded the extra expenses in transmission investments causing the total cost to decline. At a certain percentage, the total cost started to increase again, because of big grid expansion costs to cope with the increased decentralized energy production. When moving more than a certain percentage of the power production offshore, a power deficit occurred at some of the central area nodes. The imports needed from the power link island to cover the load at central area nodes started exceeding the capacities in the already existing onshore transmission lines. This forced the investment model to expand these lines in addition to the already large expansions associated with the power link island which had a huge negative effect of the projects total costs.

In both sets of simulations the savings in total costs were highest for scenario E, which involved moving 25% of the renewable generation. The exact percentages were not calculated, but the results indicated that it was possible to move a higher percentage of renewable energy production for vision 1 standards than for vision 4. The share of renewable production was considerably higher for vision 4 standards, meaning that moving a higher percentage not necessarily meant moving more energy production. For scenario E, the reduction in total cost compared to the reference scenario was €52.19bn for vision 1 conditions, and €16.02bn for vision 4 conditions.

The moving of renewable energy production had a large impact on the distribution of transmission costs, with Norway and Germany being the two extremes for this case. In the reference case, Norway was the biggest contributor regarding transmission investments for both futuristic visions in the reference scenario, with large branch expansions all the way from the central area node, to the power link island. This was done to export hydro power to the European power grid. When moving the renewable production from the central area node to the offshore node, the export transportation length was sharply reduced, leading to a reduction in transmission investments for Norway.

For Germany, it was the other way around. They already had a large share of offshore production, and the largest share of renewable generation at their central node as well. Moving for instance 10% of the renewable generation offshore equalled a significant larger amount for Germany, compared to the Netherlands or Belgium for instance. This lead to a huge increase in power production at the offshore node of Germany, demanding a corresponding upgrade of the transmission line from this node to the power link island. In addition, they also needed to expand their onshore transmission lines to be able to import enough power to their central area node which now had a significant power deficit.

9.3 Adding new offshore wind power

Compared with the two previous case studies, case 3 had little impact on the projects total cost, transmission investments distribution and area prices of the system. The additional wind power was placed three different places during simulations, but the optimal solution included the power link island and nearly the same offshore grid development independent of placement. The optimal financial solution was scenario I, where the capacity was placed directly at the island. The difference between scenario H and I was mainly the additional transmission line expansion between node 4 where the extra wind power was added in scenario H, and the power link island. The optimal solution in scenario H was to produce wind power at node 4 and export everything straight to the island for distribution, while Scenario I already produced the extra power at the island.

The biggest difference in total cost appeared between case G and I for both sets of simulations. If all participating countries joined forces and invested in the extra wind capacity in accordance with the power link island instead of expanding their own capacity, the total project costs would be reduced. By placing the extra offshore production directly at the distribution center of the offshore power grid, there was no longer a need for additional expansions from offshore nodes to the power link island, lowering the transmission investment costs compared to the two other placements. In addition, the power produced was now easier to distribute between the participating countries, allowing better utilization of the offshore power production. This helped bringing the operational costs for the project down. The difference in total costs between worst and best case scenario equalled €10.69bn for vision 1 conditions and €6.95bn for vision 4 conditions.

9.4 Cross-case discussion

9.4.1 Combination of case 1 and case 2

The optimal combination of the two first case studies would include a fully developed power grid and 25% renewable production moved from onshore to offshore. This would lead to a total reduction of €82.88bn in project costs for vision 1 conditions, and a total reduction of €66.71bn for vision 4 conditions. Vision 1 gave the biggest cost reduction with the optimal solution, however the project costs for vision 1 were higher than the project costs for vision 4. The total project costs when simulating with vision 1 standards were always higher than when simulating with vision 4 standards. Vision 4 standards had higher penetration of renewable energy production, leading to lower average marginal costs of generation and therefore lower operational costs in the entire power system.

The reduction in total project costs from the original power grid to a fully developed power grid with 25% onshore to offshore generation shift in percentage equalled 12.56% for vision 1 and 15.85% for vision 4 standards. If participating countries were to invest in extra offshore wind capacitates, the results from case 3 indicated that it would be most profitable to install this in the immediate vicinity of the power link island. As mentioned earlier, these numbers did not include the costs of the electrical components or facilities needed for the island to be fully functional. Some benefits were also not included in these numbers, like reduced maintenance costs due the possibility of storing personnel and equipment at the island, as well as reduced investment costs for future wind projects with association to the power link island.

9.4.2 Transmission line utilization

Disregarding scenario B and the import of hydro power from Norway, and a very small percentage of utilization from Germany in some of the simulations, the interconnection between the power link island and the coastal nodes were mainly used for importing power from the power link island. The transmission lines from offshore nodes all had higher utilization for exporting power to the power link island regardless of whether they had connections to their respective coastal nodes or not. This indicates that the power link island imported hydro power from Norway, a small portion of renewable production from Germany in surplus periods and offshore wind production from most of the areas before distributing this power to deficit areas, or areas dependent on expensive power production. This could for example be a replacement for expensive gas power production in Great Britain, leading to some of the reduction in the operational costs of the European power grid in the optimal solution.

Some of the offshore nodes only connected to the power link island had a very small line utilization for imports form the power link island in a few simulations. The offshore nodes were not programmed with loads, meaning that power transported to such nodes could be excessive power in the power grid for time periods where some of the offshore power production was redundant.

9.4.3 Variation of area prices

The biggest winners in form of area price reduction for the two first cases were Great Britain and Belgium. They had decreasing area prices throughout all scenarios in case 1 and 2 for both visions. These two countries were also the countries with the highest share of gas power production, and the power distribution from the island helped reduce their average gas power production considerably. A country like Germany also had a fair reduction in gas power production, but this did not make up much of their total, and therefore their area prices were less affected than the prices of the abovementioned countries.

9.4.4 Transmission investments versus area prices

There were big differences in variations of area prices in the first two cases, but it was hard to find a specific relation between transmission investment costs and area prices. When comparing multiple simulations of a case study, one area could have decreasing transmission investments and area prices, while other areas could have decreasing investment costs and increasing area prices and so on. The participating countries had very different degree of utilization when it came to the power link island, but the best economic solutions included a huge development of the offshore grid, as well as a cooperation between participating countries to build offshore wind power capacities in accordance with the power link island.

The distribution of transmission investments was quite uneven for many of the simulations. Norway, Great Britain and Germany had much larger shares than the remaining countries in most of the simulations. Germany had on average large shares of the transmission investments for all scenarios. In addition, the development of their area price was not very positive in most of the simulations. What on the other hand could not be measured was the increase in stability and security of power supply obtained by realising this project. Germany had the highest maximum demand of all participating countries, combined with a large share of power production from unpredictable renewable energy resources. The gain in terms a stabile power delivery may be higher than the costs shown in the results of this thesis.

In addition, it was clear that a stronger cooperation between participating countries when it comes to maritime spatial planning was crucial. The offshore power grid in the North Sea area need lots of upgrades for the power link island project to achieve its full potential, and a closer cooperation would make it easier to distribute costs and agree on different incentive schemes for project investors.

9.4.5 Sources of errors

This was the very first economic analysis of the power link island project, and the possibility to compare with corresponding projects was therefore absent. No related projects make it harder to find possible sources of errors having a negative impact on the simulated results.

Time series was an important part of the investment model. The time series used had been simplified using a clustering technique, meaning that the 8760 hours of the year were represented by only 548 hours. Even though the clustering technique used mean values from the full profiles, it was hard to say how accurate the simplified representation was. The optimal solutions from the investment model equalled 30 years of operating and investment costs, all calculated with data from 548hours, which was a source of error on its own.

The input data used in the power investment model were not data from current power grid situation in Europe, but visions for the power grid in 2030, based on different developments from the planned grid in 2020. Even though some of the transmission lines and generator capacities already were planned when TYNDP.

10 Conclusion

Three different case studies regarding the possibility of building an artificial island in the North Sea have been examined during this master's thesis. Each case study involved three individual scenarios which were simulated with two different visions for the futuristic European power grid. The visions used during simulations were collected from the TYNDP 2016 released by ENTSO-E. The three scenarios in the first case study had a varying degree of power grid development possibilities. In the second case study, each scenario had a certain percentage of the renewable production relocated from onshore to offshore nodes. The final case study involved three different ways of implementing additional offshore wind power in a fully developed offshore power grid. All simulations started with the same initial representation of the European Power grid. Any deviations from the initial power grid in optimal solutions were investments done by the investment model.

The investment model ended up investing in the power link island for all scenarios allowing this investment to be done, independent of what futuristic vision that was used during the simulations. Further development of the offshore power grid, including the construction of an artificial island and corresponding transmission lines was proven cost effective for the future European power grid in case 1. The power link island was even more profitable for futuristic scenarios with a higher penetration of renewable energy. The maximum savings in total cost when moving from the original power grid to a fully expanded grid excluding the costs of electrical components and facilities on the island equalled €36.80bn for vision 1 conditions and €50.69bn for vision 4 conditions.

The results from the second case study made it clear that it was possible to increase the savings in total cost for the power link island project by moving a percentage of the renewable power production from onshore to offshore nodes, thus increasing the share of offshore wind power. This gave a further reduction in operational costs, but also caused a need for more investments in the offshore power grid, because of the decentralised generation. In both sets of simulations the savings in total cost were highest for scenario E, which involved moving 25% of the renewable generation to offshore nodes. Even though the exact percentages were not calculated, the results indicated that it was possible to move a higher percentage of renewable energy production for vision 1 standards than for vision 4. For scenario E, the reduction in total cost were €52.19bn for vision 1 conditions, and €16.02bn for vision 4 conditions.

The last case study made the least impact on project total costs. An interesting observation was that the optimal economic solution included a cooperation between participating countries which placed additional wind power directly at the power link island node, instead of distributing the extra capacity between all offshore nodes in the system. The difference in total costs between worst and best case scenario equalled €10.69bn for vision 1 conditions and €6.95bn for vision 4 conditions.

Combining the best economic results with a fully developed power grid and 25% renewable production moved from onshore to offshore lead to a reduction of €82.88bn for vision 1 conditions, and a total of €66.71bn for vision 4 conditions. This equalled 12.56% and 15.85% of the total costs. The last case study also proved that the power link island could reduce project total costs even further when used as an offshore base for future offshore wind power. Benefits not included in this numbers are reduced maintenance cost due the possibilities of storing personnel and equipment at the island, as well as reduced investment costs for future wind projects with association to the power link island.

An uneven distribution of transmission investment costs, different impacts on area prices in countries and the amount of capacity upgrades needed demands a strong cooperation between all participant countries regarding maritime spatial planning and development of incentive schemes.

10.1 Shortcomings and further work

During all case studies in this thesis, the power link island had the same geographical location. This was not a planned location, but chosen randomly in the Dogger Bank area. Further simulations could include different placements of the power link island to see what impact the placement of the island has on total project costs. When adding wind power production to the node in scenario I, the hourly profile used to describe the availiabilty of wind belonged to Great Britain. By obtaining similar measurements for the Dogger Bank area, even more accurate results may be achieved.

The offshore wind capacities were recalculated by percentage based on data from the previous TYNDP report. An improvement of the final results may be achieved by researching the actual installed capacities planned and installed in the North Sea area. To simplify the transmission expansion planning model, it was not possible to expand existing generator capacities during simulations. The cost of biofuel was predetermined randomly by professional consultation, and the CO_2 emission caps at generating nodes were set extremely high. All these parameters could be optimized and implemented in the model to get more accurate results.

During simulations, the two extremes of the visions in the TYNDP 2016 report were used. These two visions did not necessarily represent the most realistic future European power grid. Redoing the simulations with visions 2 and 3 could give a wider aspect of results. In addition, it could be possible to find similar input data sets from other reports than the TYNDP as well, with different views of the future.

Finding the optimal percentage of renewable production to be moved offshore could be done in the future. A proposed adjustment could be moving different percentages from each country to avoid cases like the one in Germany for the results in this thesis. A case study combining the varying degree of network development with the placement of new offshore wind production will possibly give more realistic results with more variations than achieved in this study, because the power link island was constructed for all scenarios. This might not have been the case if for instance Great Britain was to invest in 30GW of extra wind power capacity by themselves.

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Appendix A – Financial parameters used in PowerGIM


```xml
<?xml version="1.0" encoding="utf-8"?>
<powergim>

<!-- Fixed investment costs for nodes -->
<nodetype>
  <item name="ac" L="1" S="50e6" />
  <item name="dc" L="1" S="406e6" />
  <item name="il" L="1" S="150e7" />
</nodetype>

<!-- Investment costs for branches -->
<branchtype>
  <item name="ac"      B="312e3"  Bdp="1.416e3"  Bd="1193e3" CL="1562e3"     CLp="0"      CS="4813e3"    CSp="0"        maxCap="400" lossFix="0" lossSlope="5e-5" />
  <item name="dcmesh"  B="312e3"  Bdp="0.578e3"  Bd="1236e3" CL="1562e3"     CLp="0"      CS="4813e3"    CSp="0"        maxCap="1000" lossFix="0" lossSlope="3e-5" />
  <item name="dc"      B="312e3"  Bdp="0.578e3"  Bd="1236e3" CL="58209e3" CLp="93.2e3"  CS="452499e3"  CSp="107.8e3"  maxCap="1000" lossFix="0.032" lossSlope="3e-5" />
  <item name="conv"    B="0"      Bdp="0"        Bd="0"      CL="28323e3" CLp="46.6e3"  CS="20843e3"   CSp="53.9e3"   maxCap="2000" lossFix="0.016" lossSlope="0" />
  <item name="ac_ohl"  B="0"      Bdp="0.394e3"  Bd="1187e3" CL="1562e3"     CLp="0"      CS="0"         CSp="0"        maxCap="4000" lossFix="0" lossSlope="3e-5" />
</branchtype>

<!-- Investment costs and emissions for generator types -->
<gentype>
  <item name="wind_offshore"   CX="156000"    CO2="0"/>
  <item name="wind"            CX="84205"     CO2="0"/>
  <item name="solar_pv"        CX="76983"     CO2="0"/>
  <item name="hydro"           CX="109250"    CO2="0"/>
  <item name="bio"             CX="124150"    CO2="0"/>
  <item name="nuclear"         CX="233503"    CO2="0"/>
  <item name="gas"             CX="35025"     CO2="0.4215"/>
  <item name="coal"            CX="93401"     CO2="0.8605"/>
  <item name="oil"             CX="53200"     CO2="0.7167"/>
  <item name="res"             CX="85000"     CO2="0"/>
  <item name="others"          CX="85000"     CO2="0.2"/>
  <item name="lignite"         CX="110000"    CO2="0.9"/>
</gentype>
<!-- 2030 CAPEX data from EU Roadmap 2050 -->
<!-- 2010-2030 CO2 emission rates and from OffshoreGrid -->

<!-- Financial parameters -->
<parameters
  financeInterestrate="0.05"
  financeYears="30"
  omRate="0.02"
  curtailmentCost="0"
  CO2price = "30"
  VOLL="300"
  stage2TimeDelta="0"
  stages="1"
/>
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Figure A.1: Financial parameters used in the transmission expansion model

Appendix B – Island transmission line utilization for scenarios in case 3

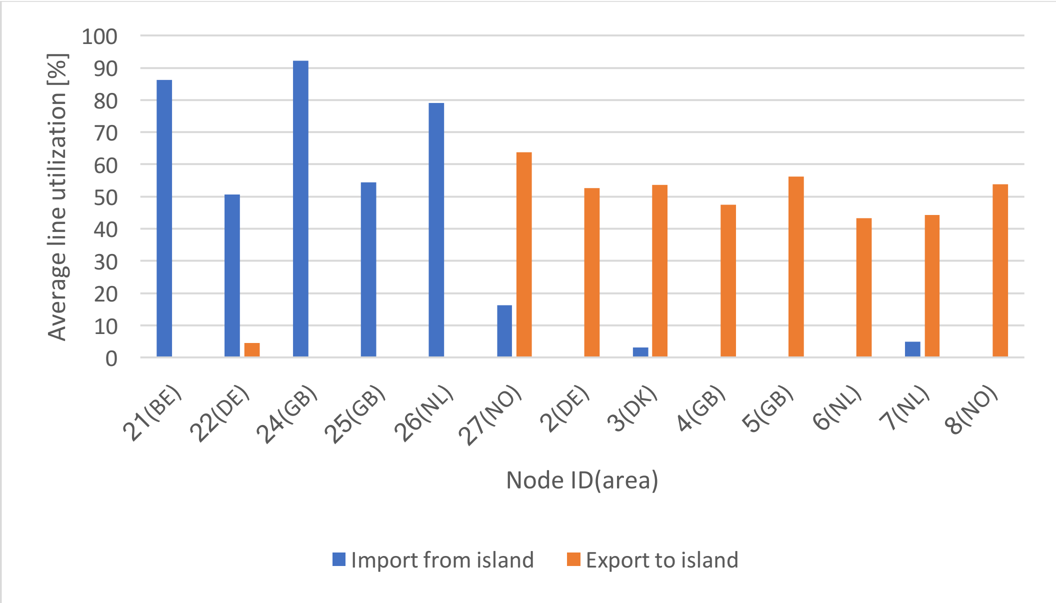

Figure B.1: Average island transmission line utilization for scenario H, vision 1

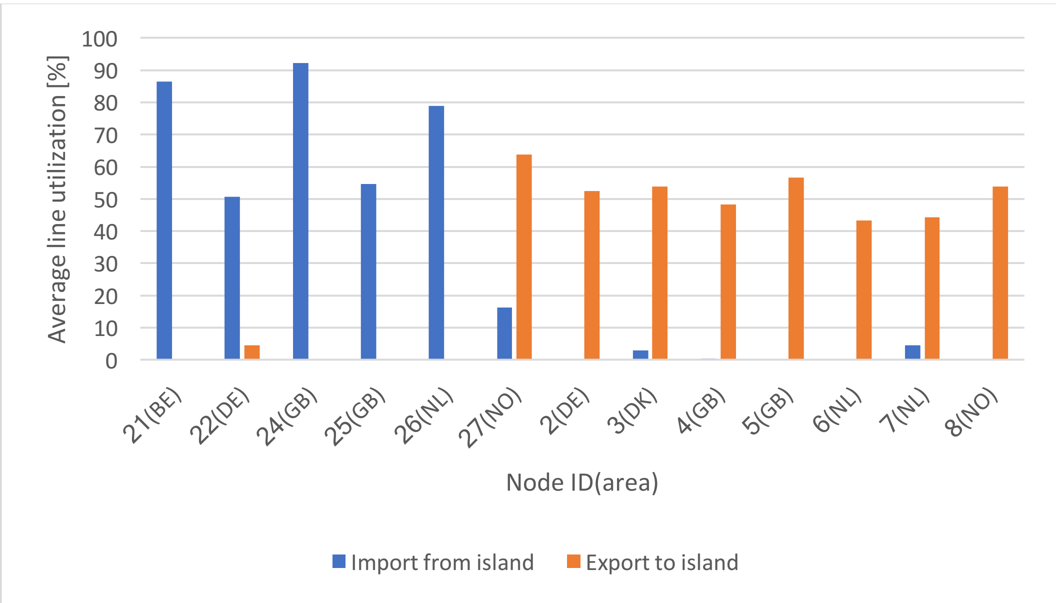

Figure B.2: Average island transmission line utilization for scenario I, vision 1

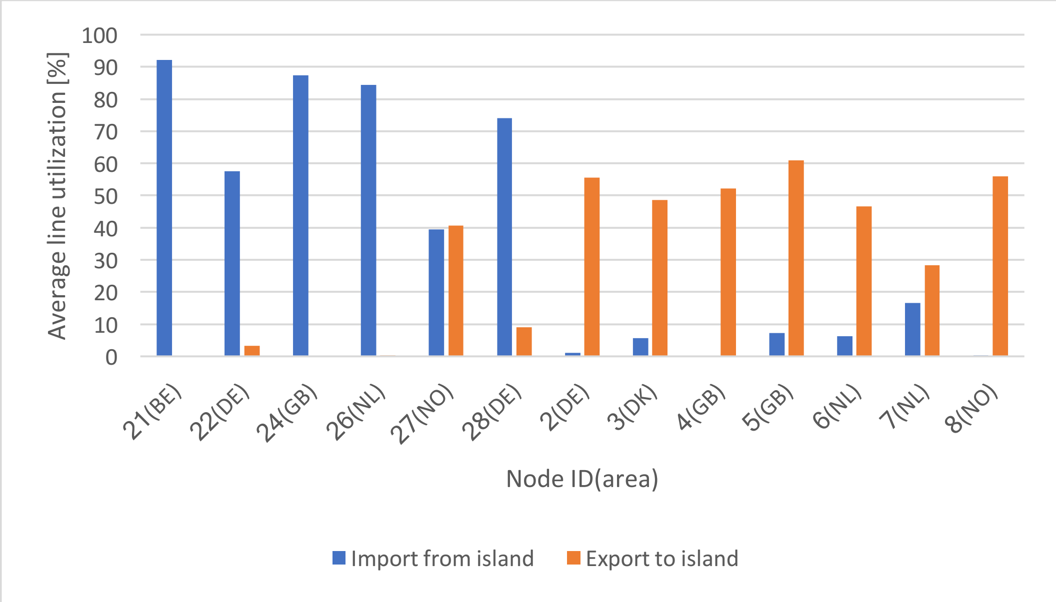

Figure B.3: Average island transmission line utilization for scenario G, vision 4

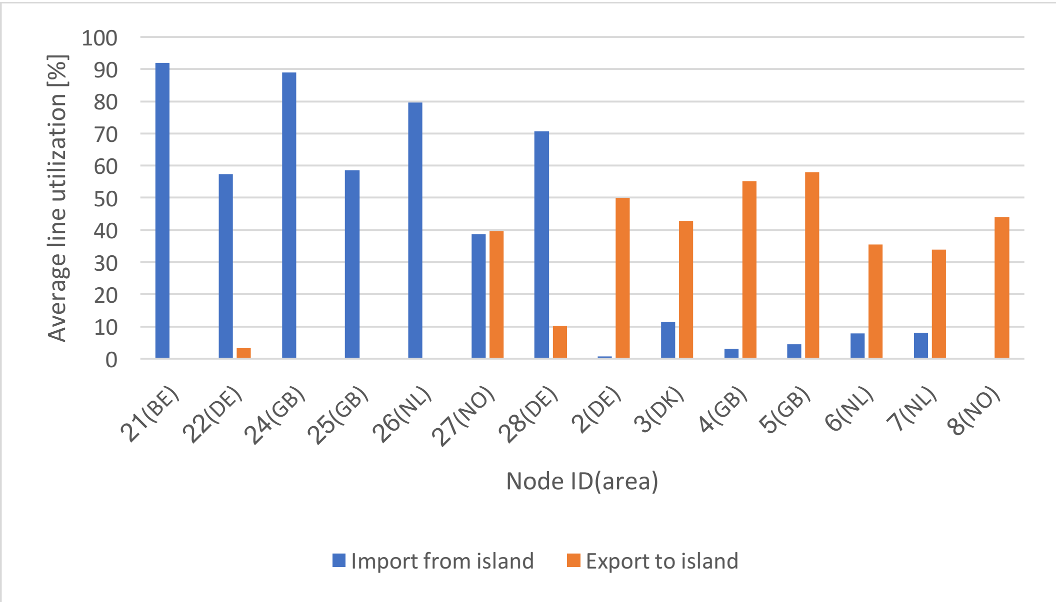

Figure B.4: Average island transmission line utilization for scenario I, vision 4