System role of energy hubs in the North Sea by an energy system optimisation study

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SUMMARY

The North Sea has a large potential for offshore wind power, which can be harvested by offshore wind farms. With an increasing amount of deployed wind farms, the farms will be built farther from shore. Distribution of the harvested energy to shore becomes more challenging. One way to connect the offshore wind farms to shore is via offshore energy hubs. At an energy hub, energy can be collected, distributed, converted and/or stored.

In this thesis, an optimisation study has been performed on the system role of energy hubs in the North Sea. The energy system of the North Sea region has been modelled using the modelling framework PyPSA (Python for Power System Analysis). The model configuration PyPSA-NorthSea has been developed which is an extension on the default PyPSA-eur configuration. The North Sea region can be modelled in greater detail with the extended configuration. The increased level of detail has been achieved by creating a fine mesh in the North Sea and adding an offshore node in each of the elements of the mesh. The offshore nodes can be connected to each other and to shore via alternating current (AC) connections, direct current (DC) connections and/or hydrogen pipelines. The optimisation algorithm will determine what technical configuration of installed capacities is cost optimal.

The extensions to the model have been tested in a scenario study by incrementally adding different functionalities to the offshore hubs and analysing the effect on the model outcomes. This scenario study also has been used to test different input parameters and constraints for the model. From the scenario study some interesting results were found. AC connections hardly play a role in the optimised energy system of the future in the North Sea. A synergy was found between electrical DC connections and offshore hydrogen conversion and distribution. Also, from the scenarios that reflect cost uncertainty it can be concluded that the effect on the system behaviour is more reactive to the way energy hubs are modelled than to the cost assumptions. By default, PyPSA works with a linearised model of energy systems. When introducing non-linear cost functions, the effect of economy of scale is captured and a better representation of the system behaviour on the North Sea is found. However, a drastic increase in the computational burden is found. Results were found for a scenario with a coarse spatial and temporal resolution, a problem with a finer resolution was found to be unsolvable with the available resources.

With the implementation of the model extensions the total annual energy system cost of the North Sea countries has been reduced with 967 M€. Moreover, the introduction of offshore electrolysis reduces the installed electrical transmission capacity in the North Sea by 23%.

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1 PROBLEM STATEMENT

The objective of this study is to examine the potential of energy hubs in the North Sea can for improving the overall performance of the Northwestern European energy system. An energy system optimisation study can be used to determine the optimal configuration of the hubs in the North Sea. The study is carried out at Witteveen+Bos, a Dutch engineering firm with several offices in the Netherlands and abroad. They provide sustainable solutions for societal challenges.

Offshore wind energy is one of the building blocks of the energy transition [1] [2]. Especially in the Netherlands, offshore wind energy is highly relevant, since hydro power is hardly available and solar irradiation is not abundant. Also, the available land in the Netherlands is limited due to the dense population, nature and the land exploitation for agricultural purposes. The North Sea has a large potential for offshore wind power [3]. Investing in the offshore wind capacity helps in decarbonising the electricity production, one of the pillars of the energy transition [4].

With the roll-out of more wind farms, areas further from shore will be exploited as well. Offshore cables are expensive and both the cost as the electrical losses in the cables are directly proportional to the cable length. It is important to efficiently use the generated electricity and minimise transportation and conversion losses. Introducing energy hubs may be part of the solution by creating hub and spoke configurations.

Offshore energy hubs are locations where energy can be collected, converted, stored and/or distributed. The hubs can also function as interconnections between countries, this introduces geographical dispersion which causes a smoothing effect of the electricity supply [5].

In the future, the demand for green hydrogen is expected to increase drastically [6]. This is on the one hand induced by replacing grey or blue hydrogen with green hydrogen. On the other hand, the total demand for hydrogen will increase, for example to replace fossil fuels in high-temperature processes [7]. Electrolysis can be used to produce hydrogen and exploit electricity surpluses of renewable energy sources.

Energy hubs in the North Sea can be used to collect offshore wind power, facilitate interconnections between North Sea countries and convert electricity to hydrogen [8]. This thesis provides a methodology to find the cost optimal configuration of energy hubs in the North Sea within the Northwestern European energy system.

2 SCOPE OF STUDY

2.1 Geographical scope

This research is focused on the system role of energy hubs in the North Sea on the Northwestern European energy system. The geographical focus will be on the offshore regions of the North Sea countries: the Netherlands, Germany, Denmark, Norway, the United Kingdom and Belgium. The onshore energy demand and infrastructure is highly relevant for the energy offshore energy infrastructure. Therefore, the onshore regions of the aforementioned North Sea countries will be considered. However, the existing data and models available at Witteveen+Bos on the onshore regions will not be altered in this research.

Due to the location and main workfield of Witteveen+Bos and the available data within the company, the research will be biased towards the Netherlands. There will be relatively more onshore buses in the Netherlands than in the other countries.

2.2 Modelling framework

The Energy System Studies group at Witteveen+Bos is experienced with working with PyPSA (Python for Power System Analysis), an open source modelling framework to simulate and optimise energy systems. The framework is discussed in Chapter 5. To extend this knowledge on PyPSA, it will also be used as a modelling framework for this study. Using an open source modelling framework leads to transparent results and provides the opportunity to use the developed models in future (research) projects.

2.3 Optimisation algorithm

PyPSA is compatible with the Gurobi Optimizer. This software package is freely available for academic use. Gurobi is an excellent solver and currently significantly outperforms open source solvers for large-scale problems [9]. Therefore, Gurobi will be used to solve the scenarios.

3 RESEARCH QUESTIONS

The optimisation study that will be performed will be driven by the total annual system cost of the Northwestern European energy system. This leads to the research question

How can energy hubs in the North Sea contribute in reducing the total annual system cost of the Northwestern European energy system?

To answer this research question, first some sub-questions need to be answered. By extending the PyPSA-eur model, the first set of sub-questions can be answered to prepare the model for the scenario study.

(a) How can energy hubs be introduced in the existing PyPSA-Eur model?

  (i) What techniques can be used to cluster the North Sea region?
  (ii) How can the energy hubs be connected to shore and to each other?
  (iii) Which simplifications can be done to limit the computational cost while maintaining sufficient accuracy?

With the implemented extensions to the model, the second set of sub-questions can be solved using a scenario study. By giving the model different sets of constraints, the model outputs can be analysed.

(b) What is the optimal configuration of the energy infrastructure on the North Sea considering the location of energy hubs and the plausible conversion, storage and transmission technologies?

  (i) What is the effect of the model extensions on the optimisation output?
  (ii) How is the optimisation output affected by changes in the assumptions?

Lastly, with the output of the different scenarios, the following sub-questions on the system performance can be answered.

(c) What is the effect of energy hubs on

  (i) utilising electricity surpluses?
  (ii) reducing the required transmission capacity?
  (iii) meeting the green hydrogen demand?

4 LITERATURE BACKGROUND

This chapter reviews relevant technologies and energy system modelling studies.

4.1 Energy system modelling

The potential role of energy hubs in the North Sea has been studied by the North Sea Wind Power Hub (NSWPH) consortium [2][8][10]. They provide concepts to connect offshore wind farms to land and ways to interconnect the North Sea countries. Their main focus is to find ways to harvest the energy potential of the North Sea and distribute the energy efficiently to shore.

In the NSWPH study "Hubs and spokes – viable beyond theory", the technical feasibility of energy hubs was described [8]. The main conclusion is that all elements of a hub and spoke project are technologically feasible. The paper also describes the system integration of the North Sea power source. From the system study it can be concluded that North-South and East-West corridors will develop in the North Sea to transport energy via hubs. Also, (offshore) electrolysis will be an essential asset in the Northwestern European energy system.

Another paper of the NSWPH consortium relevant for this research, is the study "Discussion paper on Grid-integrated offshore Power-to-Gas" [10]. This paper compares the system role of offshore electrolysis to onshore electrolysis. The main reason to chose offshore electrolysis is to save on expensive HVDC cables and converter stations. However, as offshore electrolysis is considerably more expensive than onshore electrolysis, there is a trade-off that can be solved by cost optimisation of the energy system.

The TNO study "Offshore wind business feasibility in a flexible and electrified Dutch energy market by 2030" provides an energy system optimisation study for offshore electricity generation with offshore wind farms [11]. The main focus is on the Dutch energy market while interconnection capacity is also highly relevant for offshore energy hubs. Also, the target year of the study is 2030. This is a short time frame to develop energy hubs, as offshore projects generally are time consuming, since large investments are involved and planning and preparation needs to be done thoroughly.

The Northwestern European energy system can be modelled with PyPSA-eur. This configuration of the PyPSA framework has also been used in the scenario study nuclear energy at Witteveen+Bos [12]. This scenario study focuses on the onshore regions. Offshore electricity generation by OWFs is included, however, only radial AC and DC connections are assumed. Furthermore, the decision to connect the OWF to shore by an AC or a DC connection is based only on a threshold distance to the shore. Finally, the spatial resolution of the offshore regions is very coarse. A finer resolution would result in more realistic model outputs since distances, water depths and wind resources are averaged for each node. Between the smaller offshore regions, connections can be added. Glaum et al. [13] discusses the benefits of an offshore grid. The main conclusion is that an offshore grid promotes the cost-effective system integration of offshore wind generation in the North Sea.

4.2 Basic concepts

4.2.1 Grid connection systems

Offshore wind farms can be connected to the grid in several ways. Depending on the relevant criteria, the best method needs to be chosen for a particular wind farm. Currently, OWFs in the North Sea are connected either by AC radial or DC radial connections. In the future, hub-and-spoke (H&S) systems could also be used.

AC radial or DC radial

AC radial connections are particularly suitable for OWFs close to shore. For AC connections, the line costs are dominant over the station costs while for DC connections the station costs are much higher than the line costs [14].

Hub-and-spoke configuration

In a hub-and-spoke configuration, OWFs are connected to one or multiple centrally located hubs. These hubs are connected to other hubs and/or to the shore of the North Sea countries [15].

4.2.2 Energy hub types

Different foundation types are possible for offshore energy hubs. The choice for a foundation type depends on factors as sea depth and the hub size [15]. In general, an island is more suitable for larger applications than platforms [2]. The modelling methodology will not be influenced by altering the hub type. However, the hub type will influence the cost assumptions.

Sand island

An artificial sand island can be created by depositing sand on the seabed. The reclaimed land can be used as a foundation for the equipment on the energy hub, e.g. transformers, electrolysers and storage units.

Caisson island

A caisson island is an island created by placing a closed concrete or steel construction in the sea. This construction may be filled with sand.

Jacket platform

A jacket platform is an offshore platform with a steel truss structure as frame [16]. A jacket platform is easily scalable due to it’s modularity. Due to the wide range of applications of a jacket platform, the cost assumptions of the energy hubs will be based on platform based technologies.

4.2.3 Energy storage and conversion

Hydrogen

Hydrogen is an energy carrier that can be used as a building block in several chemical processes. It can also be used as a fuel or the stored energy can be used to convert to electricity. Hydrogen can be produced in several ways, e.g. from natural gas or methane, using steam methane reformation [17]. In this process, also carbon dioxide is formed. If this CO_2 is captured and stored (CSS), the hydrogen is called blue, otherwise it is grey hydrogen. If the hydrogen is produced by electrolysis using renewably generated electricity it is called green hydrogen.

Green hydrogen can potentially be produced at an offshore energy hub. Offshore hydrogen production becomes particularly interesting when the installed offshore wind power significantly exceeds the base load of the electricity demand [10]. Hydrogen can be produced with electricity surpluses. Hydrogen can be stored in underground salt caverns.

Battery energy storage system

Electricity surpluses can also be used to charge a battery system. The storage system can be discharged when the electricity consumption exceeds the electricity production. Different types of battery energy storage systems (BESS) are available. For a 4-hour BESS, Li-ion batteries offer the best option in terms of cost, performance, cycle life and technological maturity [18]. In the remainder of this research, only onshore battery storage will be considered.

4.2.4 Economy of scale

The costs of the different components of the energy system do not always scale linearly, for example, a 2 GW HVDC cable is not necessarily twice as expensive as a 1 GW HVDC cable. In general, the marginal costs for extra capacity are diminishing, i.e. the price per unit decreases for larger capacities. To cover the diminishing marginal cost for HVDC cables and converter stations, cost data from existing HVDC projects can be used and can be fitted with a trend line. A study by Liun [19] showed that the investment cost of HVDC cables can be estimated by an equation of the form

$$C_{cable} = Ax^{0.44} \tag{4.1}$$

where x is the nominal capacity of the cable in MW. The same study [19] shows that the cost of HVDC converter stations can be estimated by an equation of the form

$$C_{station} = Bx^{0.65} \tag{4.2}$$

where x is the nominal capacity of the station in MW.

For hydrogen pipelines, the non-linear effect is larger than for cables [20]. As opposed to cables, pipelines are hollow. Therefore, the material usage scales with the radius of the pipe while the transported volume of gas scales with the cross-sectional area. Table 4.1 displays the investment costs for hydrogen pipelines for different transmission capacities. Fitting a power law through the three points results in a power of 0.26.

Table 4.1: Offshore hydrogen pipeline investment cost as a function of the energy transmission capacity

Installed capacity [GW]	Investment cost [M€/km]
0	0
4.7	3.7
13	4.8

4.3 Conclusion

Different technologies that are relevant for offshore energy hubs have been reviewed already. System optimisation studies have been performed on the Northwestern European energy system and on the North Sea region. However, still a gap exists to include a detailed representation of the offshore region and the role of energy hubs in the Northwestern European energy system.

5 MODELLING FRAMEWORK

In this chapter, the modelling framework and the assumptions in the models will be discussed.

5.1 PyPSA

Python for Power System Analysis (PyPSA) is an open-source modelling framework which can be used for simulating and optimising energy systems [9]. PyPSA works with buses to which components, such as generators, loads and storage units can be connected. Buses can be connected to each other using lines or links.

5.2 Default PyPSA-eur configuration

PyPSA-eur is a configuration of PyPSA that includes the entire ENTSO-e (European Network of Transmission System Operators for electricity) area [21]. It contains the electricity infrastructure at and above the 220 kV voltage level. In the default PyPSA-eur configuration, the offshore generators are allocated to the onshore nodes. Also, the converter station costs and cable costs are included in the generator costs. An extension was made by Witteveen+Bos in the scenario study nuclear energy [12] to include hydrogen conversion and hydrogen demand. Regarding the hydrogen network, a greenfield approach is assumed, i.e. existing and planned hydrogen production plants are not included in the model. Which is valid since the current hydrogen economy is fossil based and in the scenario study a completely renewable energy system will be assumed.

5.3 Model inputs

5.3.1 Weather data

Weather data is used to determine generation profiles for renewable generators. In PyPSA-eur, ERA5 data is used [22]. ERA5 contains hourly data of a large set of weather parameters such as wind speeds and irradiation levels. Using the open-source Python package *atlite* [23], a cutout can be made of a specified region and a specified time frame. The weather data of 2015 will be used in order to match available demand profiles, the demand profiles are discussed in more detail in Section 5.3.3.

5.3.2 Landuse availability

The potential of renewable electricity generation also depends on the available area. It is not possible to use the existing area entirely for the energy system. Therefore, some regions need to be excluded. Examples of excluded regions are Natura 2000 areas and the built environment. For offshore regions shipping routes and water depth are highly relevant.

Natura 2000 areas

Natura 2000 areas form a network in the European Union set up to preserve Europe's most valuable and threatened species and habitats [24]. Natura 2000 areas are located both onshore and offshore. In PyPSA-eur, Natura 2000 areas are excluded when determining the potential land availability. This means that in Natura 2000 areas no electricity generation can be installed.

Shipping routes

Similar to the Natura 2000 areas, offshore wind farms can not be installed coincident to important shipping routes. The data for the shipping routes was retrieved from the World Bank's dataset 'Global Shipping Traffic Density' [25].

Water depth

Fixed offshore wind turbines can be placed up to 50 meters depth [26]. Sea regions deeper than 50 meters are excluded from the land availability for offshore electricity generation. Also, the investment costs for offshore wind turbines are directly related to the water depth. The relations between turbine cost and water depth are determined using an empirical model based on data from the Danish Energy Agency (DEA) [27].

5.3.3 Demand profiles

The model is constrained to match the energy supply to the energy demand for every hour of the year, for every node and energy carrier in the system. The demand profiles are inputs for the model. A distinction was made between the electricity demand and the hydrogen demand.

Electricity

For the Netherlands, the electricity demand profiles for the different regions are based on scenarios used in the integral infrastructure review conducted by the Ducth grid operators [28]. For Germany, Belgium and the United Kingdom the demand profiles are based on PPSGen data. PPSGen (Power Price Scenario Generator) is a model created by the eRisk group. The PPSGen profiles are in part based on historic data and adjusted to reflect technological shifts such as the introduction of heat pumps and electric vehicles. PPSGen is not available for Denmark and Norway. For these countries, open-source historic data from OPSD (Open Power System Data) is scaled to 2040 and 2050. For 2040 a scaling factor of 1.3 is used, for 2050 a scaling factor of 1.4 is used. These factors correspond to the average demand increase for the countries within the PPSGen scope [12].

Hydrogen

The hydrogen demand in the Netherlands is based on II3050 (Integrale Infrastructuurverkenning 2030-2050) data [28]. For the other countries the hydrogen demand is based on the 2030 no-regret hydrogen demand [29], this hydrogen demand is then scaled for 2040 and 2050 with factors 1.33 and 1.5 respectively. The hydrogen demand is on top of the hydrogen used to meet the electricity demand. The hydrogen demand for the clusters is assumed to be constant throughout the year, because the hydrogen demand mainly consists of constant industrial processes.

5.3.4 Cost assumptions

Cost assumptions are compiled from various sources. The most important cost assumptions for offshore energy infrastructure are listed in this section. These include offshore wind farms, offshore electricity transmission by AC and DC submarine cables, offshore hydrogen production via electrolysis and offshore hydrogen transport via hydrogen pipelines.

Offshore wind turbine investment costs are based on DEA (Danish Energy Agency) data. For a 15 MW offshore turbine with a hub height of 150 m, a CAPEX of 1725 €/kW is found at a water depth of 25 meters. This cost figure includes installation costs of the turbine, foundation and inter-array cables.

Submarine AC cables are assumed to cost 2685 €/MW/km. This cost figure is based on DEA data as well. Submarine DC cables are assumed to cost 1300 €/MW/km. This cost figure is based on cost data of the Dogger Bank offshore wind farms [30].

Offshore electrolysis is assumed to have a CAPEX of 800 €/MW in 2040 and 550 €/MW in 2050 [31] [32]. The cost parameters for electrolysis are applied to the electrical nominal power of the electrolysers. Some offshore hydrogen pipelines are assumed to be repurposed natural gas lines, while there will also be new pipelines. To account for this, in the cost assumption, a weighing factor is added. Using cost data of the European Hydrogen Backbone (EHB) initiative [20] and assuming 70% new pipelines, a cost figure of 350 €/MW/km was found.

5.4 Model outputs

PyPSA provides installed capacities of all components in the energy system. The output can be divided into two networks, the hydrogen network and the electricity network. The networks are connected via electrolysers, fuel cells and gas turbines. Also, PyPSA provides time series for all components of the model. From the time-series, yearly production/conversion figures can be extracted. These figures can then be used to determine the net electricity export of a country.

5.5 PyPSA-NorthSea

PyPSA-NorthSea [33] is an extension on the PyPSA-eur configuration that models the offshore region in greater detail. The extension also provides the possibility for interconnections between countries via energy hubs and enables offshore hydrogen electrolysis. The extension will be discussed in Chapter 6. Figure 5.1 displays the most relevant input parameters and components of PyPSA-NorthSea.

5.6 Conclusion

PyPSA and the PyPSA-eur configuration are excellent tools to model energy systems. Using weather data and landuse availability, the potential for renewable electricity generation can be determined for different regions. The software is an open-source modelling framework which provides transparency of the results and offers the possibility to create extensions. To investigate the system role of energy hubs an extension to the default configuration is required, this extension will be discussed in the next chapter.

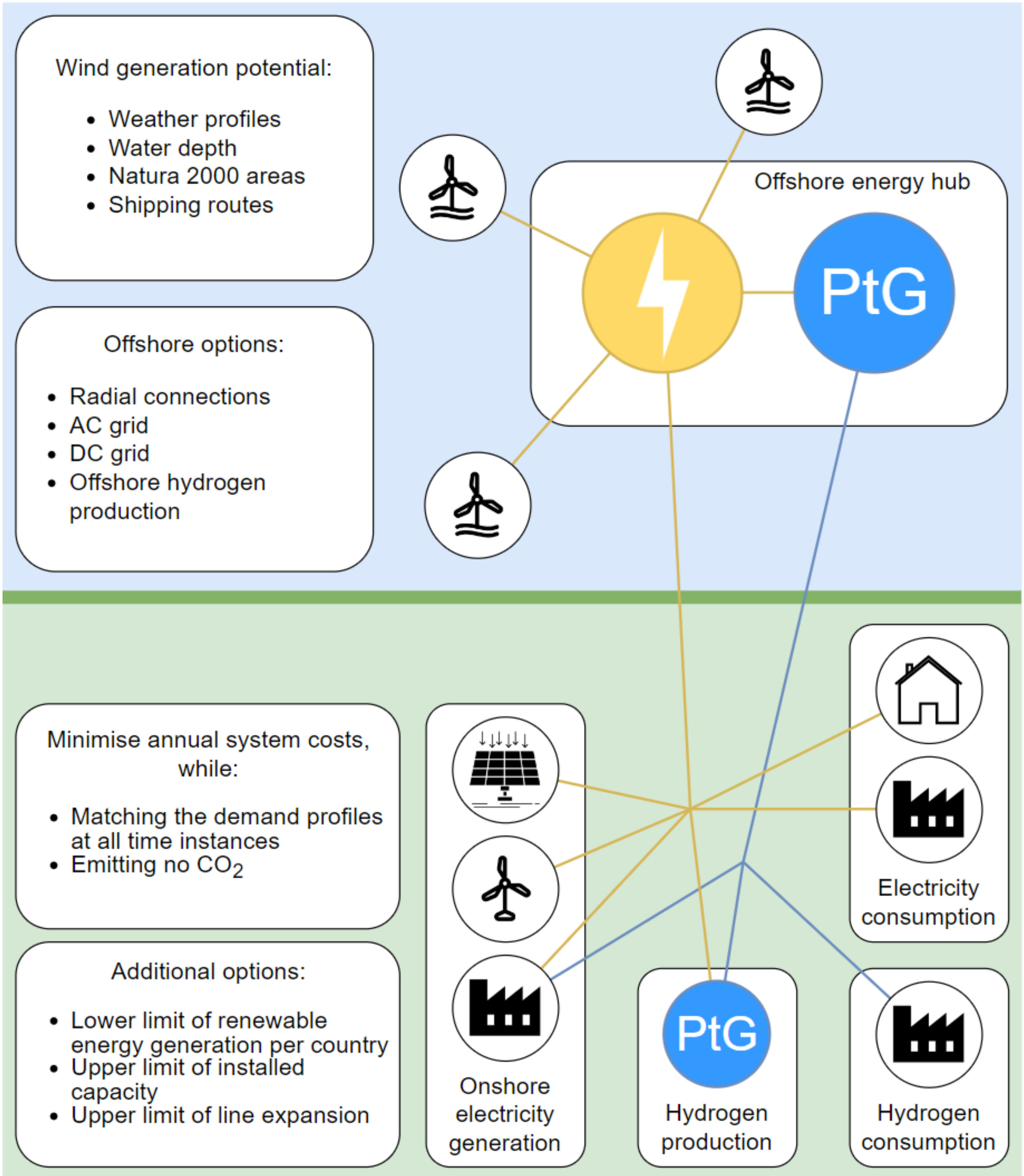


Figure 5.1: System overview in the PyPSA-NorthSea configuration with a connected electricity and hydrogen network

6 EXTENDING THE DEFAULT CONFIGURATION

To obtain a better representation of the offshore energy system, some elements need to be added to the PyPSA-eur configuration. These additional elements are required to get more detailed results on the electricity generation in the North Sea, as well as on the conversion and distribution of the electricity. In this chapter, the implementation of the additional elements will be discussed, in Chapter 7 the effect of the additions on the model outputs will be analysed.

6.1 Meshing the North Sea

To get more accurate model outputs, the spatial resolution of the offshore regions should be refined. This will be done for the North Sea region. The sea regions that do belong to the North Sea countries, but do not belong to the North Sea, e.g. the Baltic Sea and the Celtic Sea, are unaffected.

The economic exclusive zones (EEZ) will be considered as a starting point for the mesh. The EEZs of the North Sea countries are displayed in Figure 6.1. The economic exclusive zones were chosen as a starting point in order to ensure that the meshed regions are allocated to a specific country rather than consisting of multiple countries.

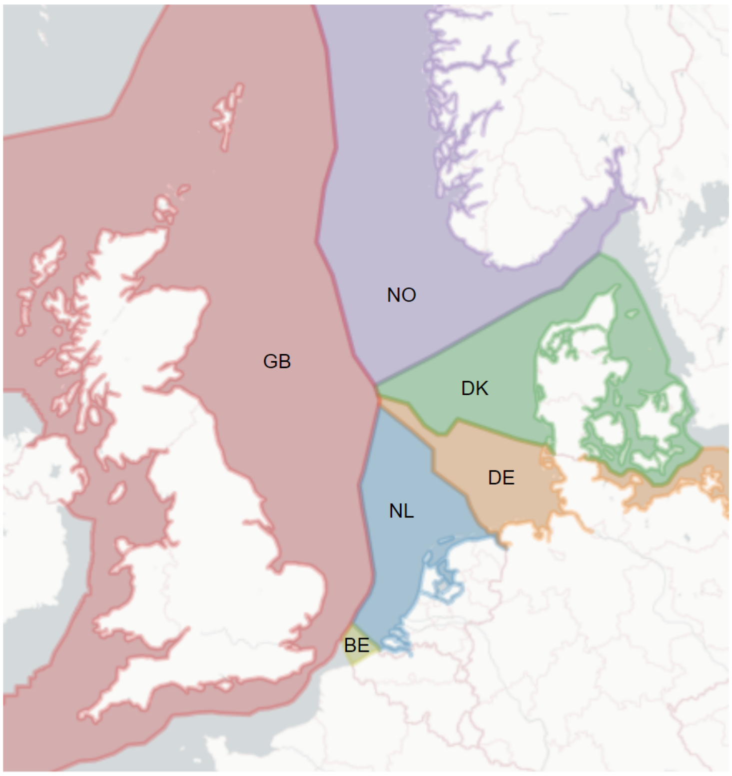


Figure 6.1: Economic exclusive zones of the North Sea countries

Some regions of the EEZs of the North Sea countries are not part of the North Sea. For example, the offshore regions to the west of the United Kingdom, the Celtic Sea, and to the east of Denmark, the Baltic Sea. A contour of the North Sea was placed over the offshore regions of the countries. The parts within the contour is included in the meshing algorithm, the remaining portion is not affected.

In the configuration file of the model, a threshold area can be chosen. If the area of the EEZ exceeds this threshold area, the offshore region will be divided into smaller regions. The number of regions is determined by the ratio between the North Sea region's area and the threshold area. To obtain an integer number of regions, the ratio is rounded up.

The large offshore regions are divided into the smaller regions using Voronoi tessellation. When using a threshold area of 5,000 km^2, the resulting mesh can be found in Figure 6.2. This threshold area results in 109 offshore regions compared to 10 regions in the default configuration. Instead of one offshore region per onshore region, the offshore clustering is decoupled from the onshore regions. This results in more evenly shaped regions with less variation in wind resources and water depth.

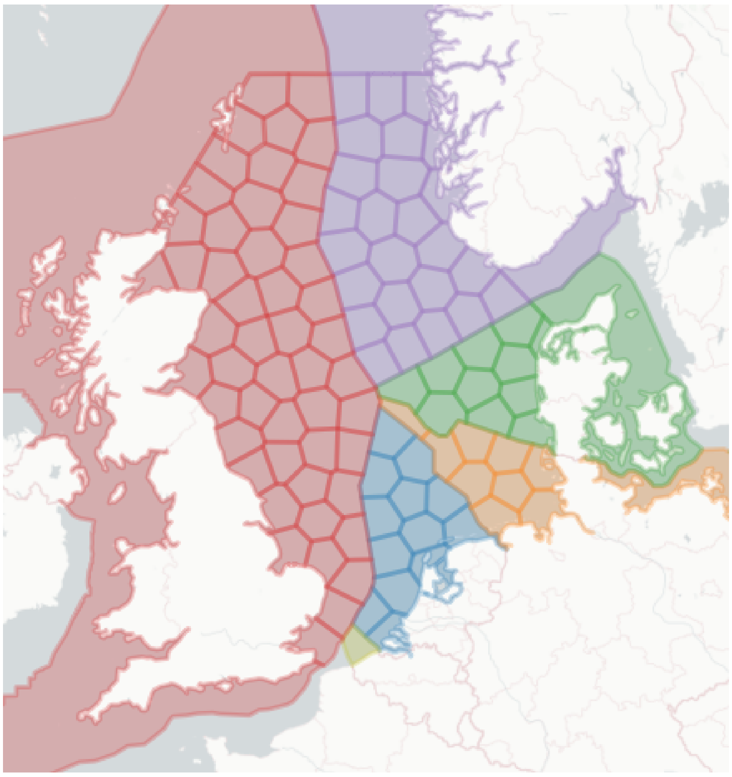


Figure 6.2: Meshed offshore regions of the North Sea countries

6.2 Offshore nodes

For the offshore regions, nodes are added to the base network of PyPSA-eur. These nodes are located at the same locations as used as seeds for the Voronoi partition. The meshed regions with the added nodes are visualised in Figure 6.3.

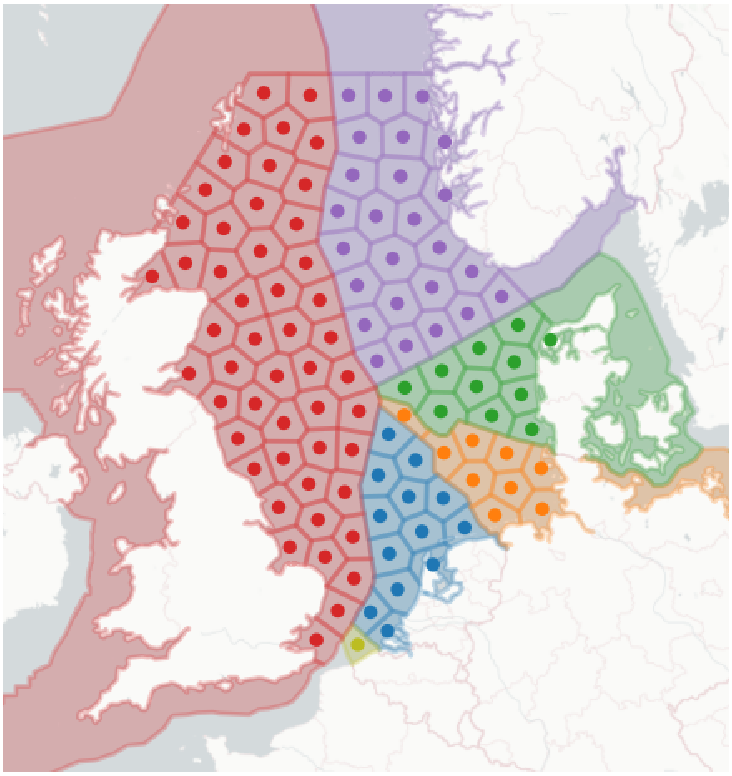


Figure 6.3: Offshore nodes in the meshed North Sea regions at the same locations as used as seeds for the Voronoi partition

The offshore generators that were assigned to onshore regions in the default configuration are moved to the offshore meshed regions. The station, cable and turbine costs are separated to be able to introduce different connection, conversion and storage options. This is only done for the North Sea, i.e. the offshore generators in other seas are untouched and remain allocated to the onshore regions.

At every offshore node, four buses are added to the PyPSA model. One 66kV bus to which the offshore generators are connected, one 380kV AC bus, one 525kV DC bus and a hydrogen bus. Between the three electric buses, links are added that represent the converter stations. An electrolyser is added as a link to convert the electricity to hydrogen. The buses at each offshore node are shown in Figure 6.4. The green box represents the generator, the blue boxes represent the buses and the yellow boxes represent links.

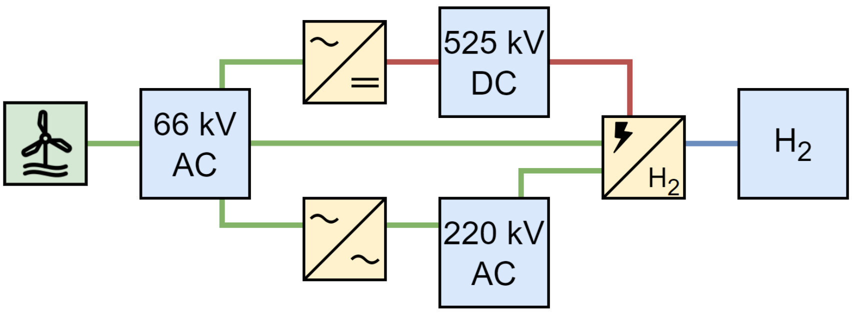


Figure 6.4: Different buses at the offshore nodes

The investment costs for the converter stations are based on the water depth. For DC stations, the investment costs are calculated by

$$C = (a + b \cdot (d - d_{ref})) \cdot P_{nom} \quad (6.1)$$

where d is the water depth and P_{nom} the nominal power of the converter station. The parameters a, b and d_{ref} can be chosen independently, a is the investment cost per unit rated power at the reference depth d_{ref}. The parameter b is the incremental cost per meter depth relative to a reference depth. Converter stations placed in deeper water than the reference depth are more expensive than in shallower waters. The default values for DC converter stations are chosen to be a = 400 €/kW, b = 1 €/kW/m and d_{ref} = 25 m [30]. For AC stations, b and d_{ref} will have the same value as for DC, a is 250 €/kW [27].

The buses can be connected via different modes of connection. The different buses at the nodes and the connections between nodes are visualised in Figure 6.5. AC connections are displayed in green, DC connections in red and hydrogen pipelines in blue. The generators, i.e. offshore wind farms, are connected to the 66 kV buses. From the figure, it can be seen that the offshore nodes are connected to each other by hydrogen pipelines, AC lines and DC links. Nodes near the shore are also connected to the shore by these three options. Finally, every offshore node can be connected directly to the shore by a DC link and by a hydrogen pipeline.

6.3 Offshore electricity grid

Between the offshore AC buses and the onshore buses close to shore, a meshed network of alternating current (AC) lines is created. By including the onshore nodes in this mesh, offshore electricity generation can be connected to shore using radial AC connections. With the threshold area of 5,000 km^2, the distances between nodes are generally small (<100 km), therefore, AC connections are well suited [34]. However, the distances between the offshore nodes are larger than 30 km, this means that 66 kV cables do not suffice [35] and AC converter stations are required to achieve a higher voltage level. The same offshore grid is implemented at the 525 kV DC level. This provides the model more freedom, the optimisation algorithm will determine the cost optimal technological configuration. For every cable connected to the shore, the cost of an onshore substation is added to the connection cost.

6.4 Radial DC connections

The offshore electricity grid creates the possibility to connect the offshore nodes to shore. However, nodes further from the shore are routed to the onshore nodes via other offshore nodes. In order to minimise the cable distance, direct DC links are added between the offshore nodes and the onshore nodes bordering the North Sea.

6.5 Hydrogen infrastructure

6.5.1 Offshore hydrogen production

An option has been introduced to allow for offshore hydrogen production via electrolysis. An electrolysis link has electricity as input, has an efficiency and produces hydrogen. The electricity input can either be alternating or direct current. No distinction is made in the cost assumptions whether the electrolyser is connected directly to the 66 kV wind farm output, to the AC grid or to the DC grid.

6.5.2 Hydrogen pipelines

Via pipelines, the hydrogen can be transported to shore. Then, the hydrogen can be stored, used, transported further or converted to electricity by gas turbines. It is assumed that some hydrogen pipelines will be new pipelines, while some pipelines will be repurposed natural gas pipelines.

6.5.3 Hydrogen storage

At each node, hydrogen can be stored underground in salt caverns.

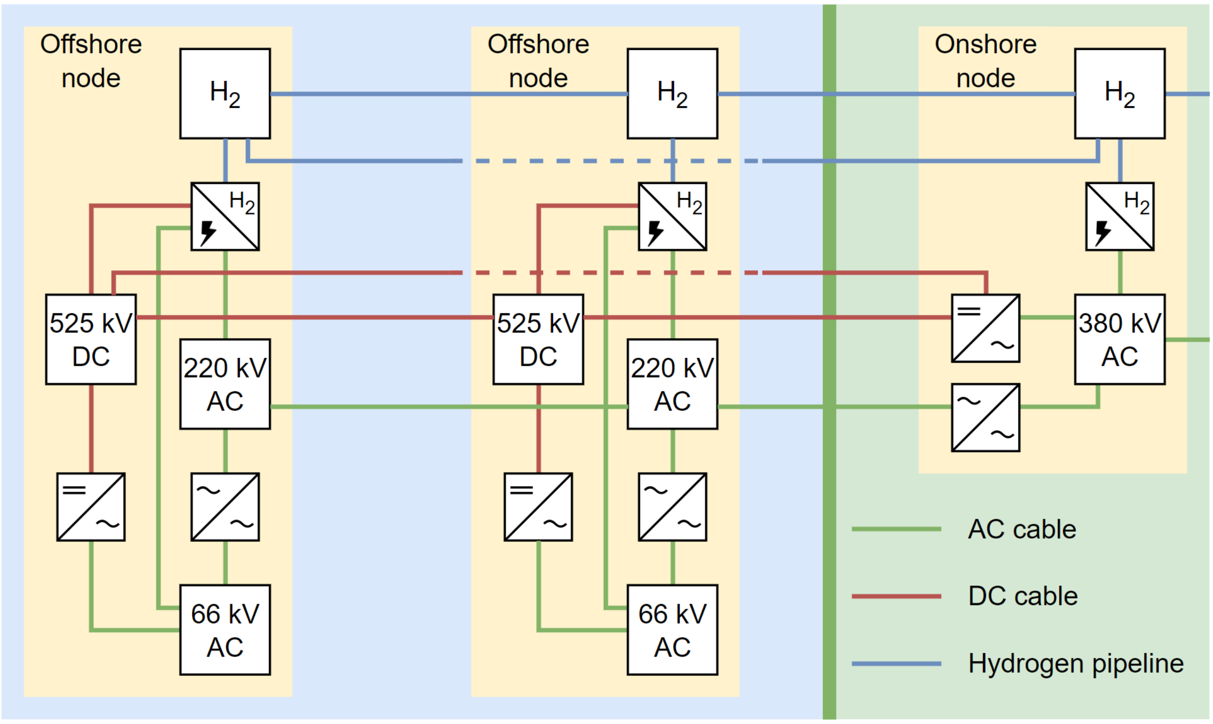


Figure 6.5: Schematic diagram of the different buses and connections

6.6 Economy of scale

To test the effect of a non-linear cost function, experiments were performed on a smaller network. This network contains four offshore wind farms with a mean distance of 150 km to shore. Each OWF has a nominal capacity of 500 MW and can be connected to shore either by a radial DC cable or via a hub centered between the farms. The distance between the OWF and the hub is assumed to be 20 km, this distance can be covered with 66kV inter-array AC cables [35]. The inter-array cables have a rated capacity of 90 MVA [36]. The transmission capacity of the DC and AC cables are the optimisation variables. The model minimises the total investment cost of the cables and converter stations.

The AC cables are assumed to cost 500 k€/km [37], thus, the required cables to connect the wind farms to the hub have a capex of

$$500 \text{ k€/km} \cdot \frac{500 \text{ MW}}{90 \text{ MVA}} \cdot 20 \text{ km} = 56 \text{ M€} \tag{6.2}$$

6.6.1 Linear cost functions

To examine the differences on the model output between a model with a linear cost function and a model with a piecewise linear cost function, first the linear situation was analysed. For the linear case, the costs for submarine DC cables is assumed to be 1300 €/MW/km. This cost figure is based on the DC connection of the 1.2 GW Dogger Bank wind farms [30]. The DC stations are assumed to cost 500 k€/MW.

With linear cost functions the optimisation results in the configuration shown in Figure 6.6, the figure is not to scale. The model does not invest in AC connections between the OWFs and the hub and therefore, there is also no connection between the hub and the load. This behaviour is expected, since one DC cable with a transmission capacity of 2 GW has the same investment cost as four separate DC cables with a transmission capacity of 500 MW. Therefore, adding AC cables results in a bigger total investment.

Forcing the model to invest in AC cables to a hub, i.e. constraining the transmission capacity of the radial DC-connections to 0 MW, results in a total investment cost that is 14% higher than the optimum.

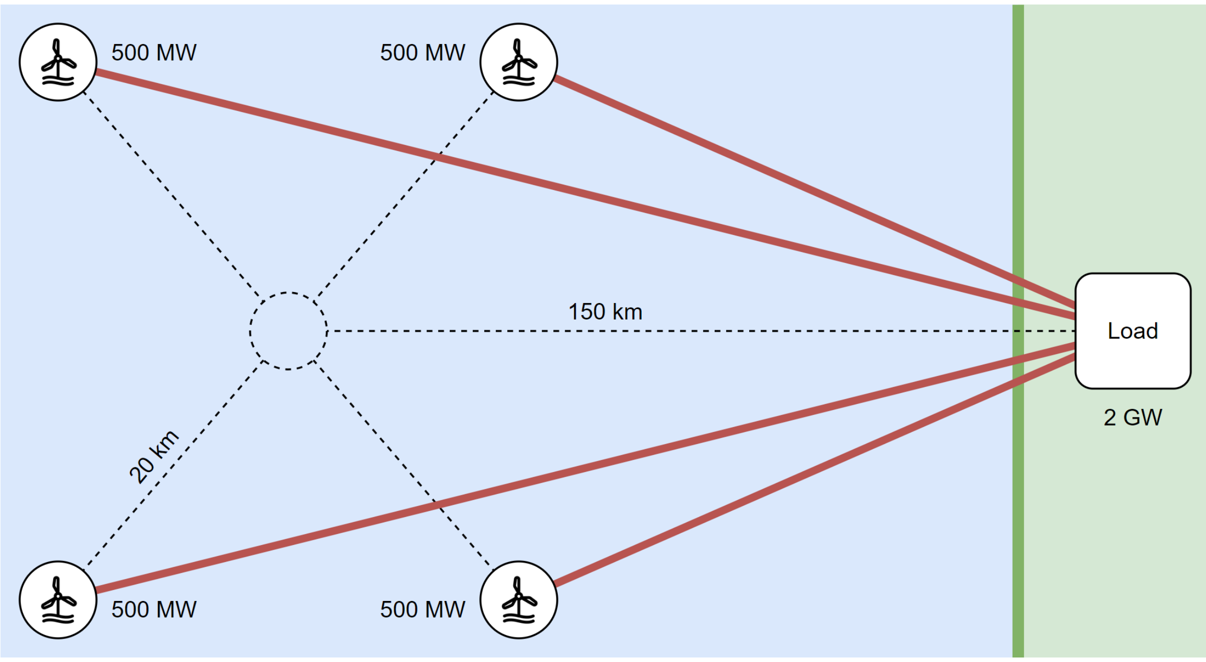


Figure 6.6: Schematic representation of the optimal connection configuration of 4 OWFs to the shore using a linear cost function

6.6.2 Piecewise linear cost functions

The non-linear cost functions described in Section 4.2.4 are fitted with the Dogger Bank data, i.e. for a transport capacity of 1.2 GW, the DC cable costs 1.54 M€[30], this leads to the following expression for the cable cost per unit length.

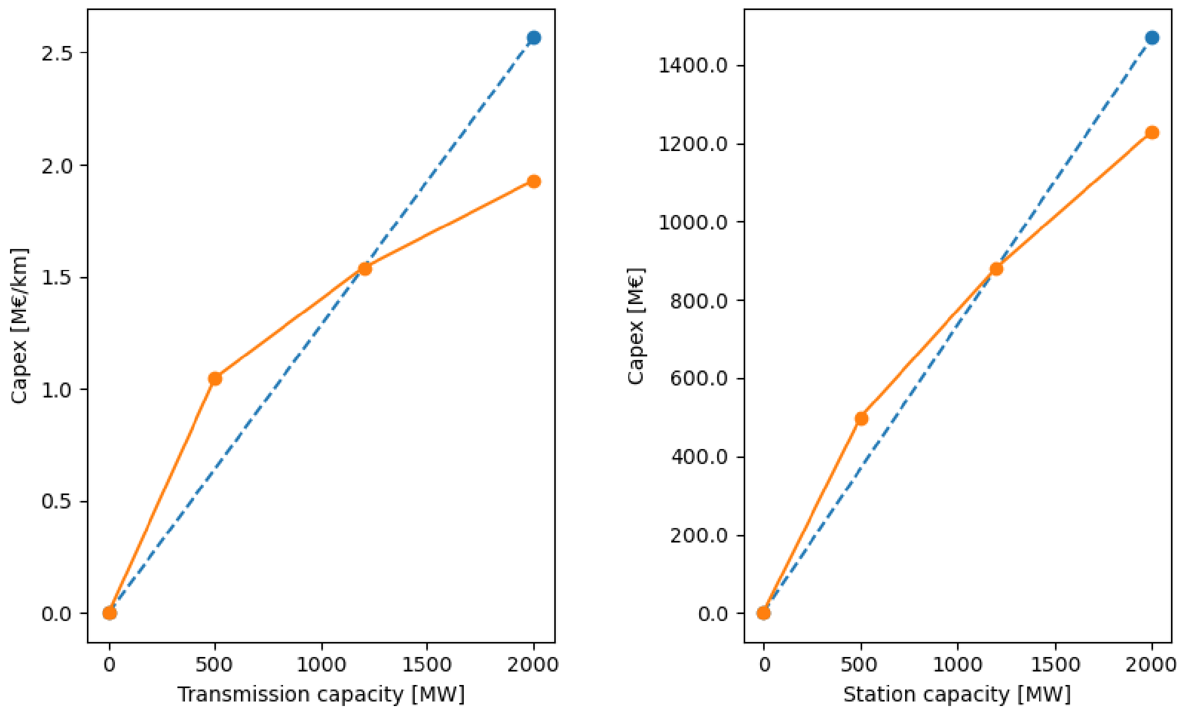
$$C_{cable} = Ax^{0.44}, \quad 1.54\ \text{M€} = A \cdot (1200\ \text{MW})^{0.44} \quad \rightarrow \quad C_{cable} = 68x^{0.44} \tag{6.3}$$

To mimic the behaviour of this power function a piecewise linear cost function is introduced. Figure 6.7a displays the piecewise linear cost function and, for comparison, the linear cost function of an offshore HVDC cable. Note that the capex for small transmission capacities is higher in the non-linear case with respect to the linear case. However for larger capacities, the non-linear costs are lower.

For a transmission capacity of 1.2 GW, the DC converter station, including the onshore converter, costs 882 M€. The following expression can be found for the converter cost:

$$C_{station} = Ax^{0.65}, \quad 882 \text{ M€} = A \cdot (1200 \text{ MW})^{0.65} \quad \rightarrow \quad C_{station} = 8.8x^{0.65} \tag{6.4}$$

Figure 6.7b displays the piecewise linear cost function of an offshore HVDC converter station and the linear cost function. From the figures it can be observed that for small capacities, the investment costs are higher for the non-linear case. This pushes the model to investing in larger cables and stations.



(a) Offshore HVDC cable

(b) Offshore HVDC converter station

Figure 6.7: Piecewise linear cost functions applied to the transmission components

These non-linear cost functions result in the configuration shown in Figure 6.8. The figure is not to scale. The model output is drastically different from the linear case. Instead of 4 separate small radial DC connections to shore, the OWFs are connected to the hub via the AC-connections. A large DC cable, with a capacity of 2 GW, is deployed between the hub and the load.

When forcing the model to deploy only radial connections, i.e. restrict the model from deploying connections to the hub, the total investment costs are 32% higher.

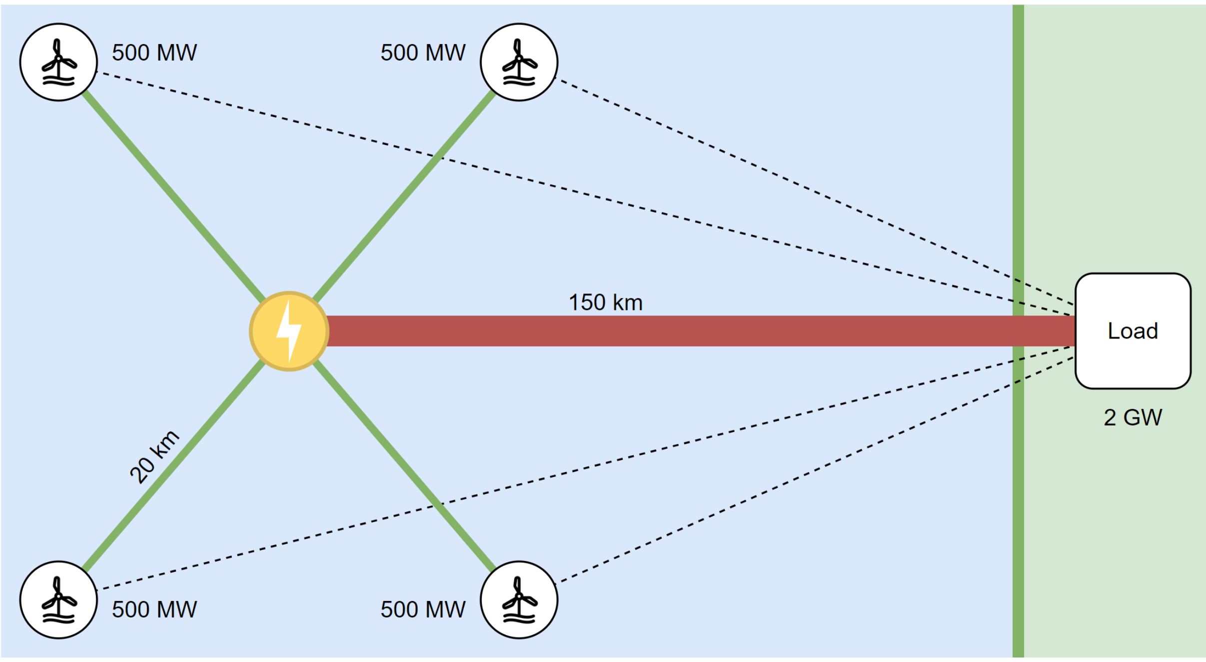


Figure 6.8: Schematic representation of the Hub and Spoke configuration resulting from optimisation of the connection configuration of 4 OWFs to the shore using a piecewise linear cost function

6.6.3 Implementing non-linear cost functions in PyPSA

The non-linear cost functions can be implemented in PyPSA by changing the linear objectives by PWL objectives, the Gurobi Optimizer then creates a new integer variable for every discontinuity in the piecewise linear objective function. It is not realistic to have diminishing costs for large capacities, since large transmission capacities would consist of multiple cables. For DC cables and stations, units of 2 GW are assumed, based on the 2 GW program of TenneT, TSO of the Netherlands and one of the TSOs of Germany. For capacities above 2 GW, linear behaviour is assumed again in order to limit the number of integer variables in the problem. For hydrogen pipelines, units of 13 GW are assumed.

6.7 Conclusion

With the added components, the model provides a better representation of the many possible configurations of the Northwestern European energy system. First of all, the spatial mesh of the North Sea increased the spatial resolution of the model. Using Voronoi tessellation, smaller and more evenly shaped offshore regions were created. In this way, the variation in wind resources and water depth within a region is limited.

Secondly, moving the offshore generators to the offshore buses decoupled the offshore electricity generation from the onshore nodes. Connection costs will be allocated to the actual connections rather than to the wind farms. The AC and DC grids provided the possibility to connect hubs to each other and to the shore. The radial DC connections allow the direct connection between the offshore energy hubs and the shore. Also, they create interconnection opportunities. By adding different electricity and hydrogen buses to the offshore nodes, the optimisation can find the optimal technological configuration of the different converter and transmission capacities.

With a small network, the relevance of non-linear cost functions was demonstrated. These non-linear cost functions capture the economy of scale. The non-linear cost functions can be used to better represent the behaviour of energy hubs.

In Chapter 7, these extensions to the model are tested and the effect on the model outputs will be analysed. By incrementally adding the features, the effect of each addition can be tested separately.

7 SCENARIOS

In this chapter, the model is tested by running various scenarios. This serves four different goals: Establishing the starting point, testing the model extensions and analysing the effects on the model outputs by changes in the model assumptions and by changes in the model configuration. To limit the number of combinations, the scenarios are divided into four stages. Various results are provided in this chapter, for more results on the scenarios presented in this thesis and on some additional scenarios, a scenario explorer can be consulted [38]. More information on the scenario explorer can be found in Appendix A.

Stage 1 - Establishing the starting point

The first set of iterations is done to establish the starting point of the model. In this step the input parameters and constraints will be determined in order to be able to properly compare the model with and without the extensions. These constraints will be added to generate meaningful results that comply with policies and public support. In this stage, offshore wind farms can only be connected to the closest onshore node.

In **Scenario 1**, the expected demand profiles of 2040 will be used. The line expansion limit for 2040 is 150% with respect to today's capacity, this percentage corresponds to 25% line expansion per decade and is based on the ten year network development plan (TYNDP) [39]. In **Scenario 2**, the expected demand profiles of 2050 will be used. The line expansion limit for 2050 is 175%. Then, the lower limit of renewable energy sources will be altered. This is done to find out whether tighter constraints lead to drastically different model outcomes (**Scenario 3**). Lastly, the upper limit of renewables is altered. The technological potential of renewable electricity generation may not be acceptable. To comply with public support, the installed capacity will be limited (**Scenario 4**).

Stage 2 - Testing the model extensions

The model extensions as discussed in Chapter 6 are tested and the effects on the model outcomes are analysed. By incrementally implementing the different options different functions of the hubs will start to develop. By adding the AC grid first (**Scenario 5**), followed by the DC grid (**Scenario 6**), the radial DC connections (**Scenario 7**) and the offshore hydrogen infrastructure (**Scenario 8**), the PyPSA-NorthSea configuration will take form.

Stage 3 - Altering the assumptions

The effect of changes in the model inputs on the model outcome are then analysed by altering the mesh size (**Scenario 9**) and the cost assumptions (**Scenarios 10 & 11**). Important cost parameters for the offshore energy hubs are the costs of offshore electrolysis and offshore energy transmission.

Stage 4 - Altering model configurations

Furthermore, a comparison will be made between linear and non-linear cost functions. Due to the computational burden this will only be done on a network with a limited amount of offshore nodes and a lower time resolution. To be able to compare the results, first the case with linear cost functions will be solved with a limited amount of offshore nodes and a low time resolution (**Scenario 12**). Then the non-linear cost functions will be added to PyPSA (**Scenario 13**).

Lastly, the ambitious goal of 300 GW offshore wind generation in the North Sea will be implemented in **Scenario 14**. This goal was stated in the Ostend Declaration.

7.1 Stage 1 - Establishing the starting point

In stage 1, offshore wind farms are only allowed to connect to shore radially to the closest onshore node. This configuration is displayed schematically in Figure 7.1. The green lines represent AC cables, the red lines represent DC cables. Hydrogen can only be produced onshore.

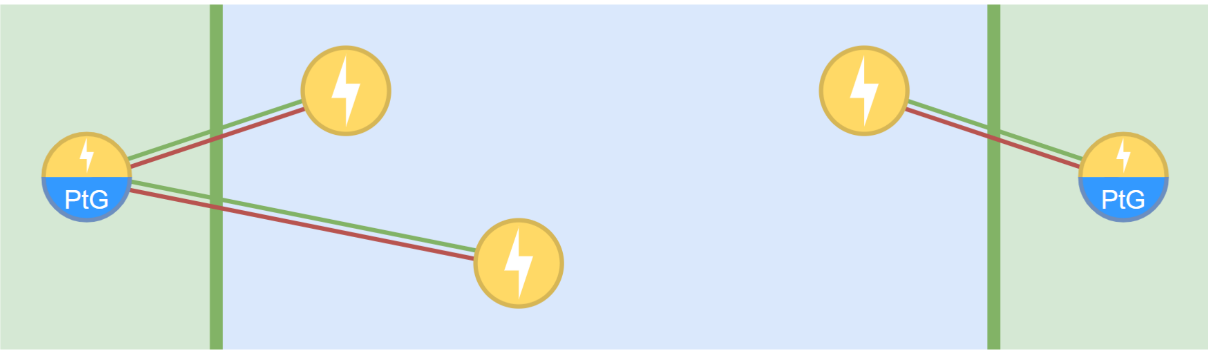


Figure 7.1: Schematic representation of the connection configuration in stage 1

7.1.1 Scenario 1 - 2040

The first scenario is the 2040 scenario. In this scenario, the demand profiles of 2040 are implemented, the generation potentials are only limited to the technological potential and the lower limits are based on the existing electricity network. Hydrogen production is limited to onshore electrolysis. This first scenario functions as a base scenario, therefore, the system behaviour will not be discussed in great detail.

Figure 7.2 displays the installed capacities of the transmission network and the renewable electricity generators of the Northwestern European energy system. The most dominant electricity generators are on- and offshore wind turbines, solar-PV panels and hydrogen fueled gas turbines.

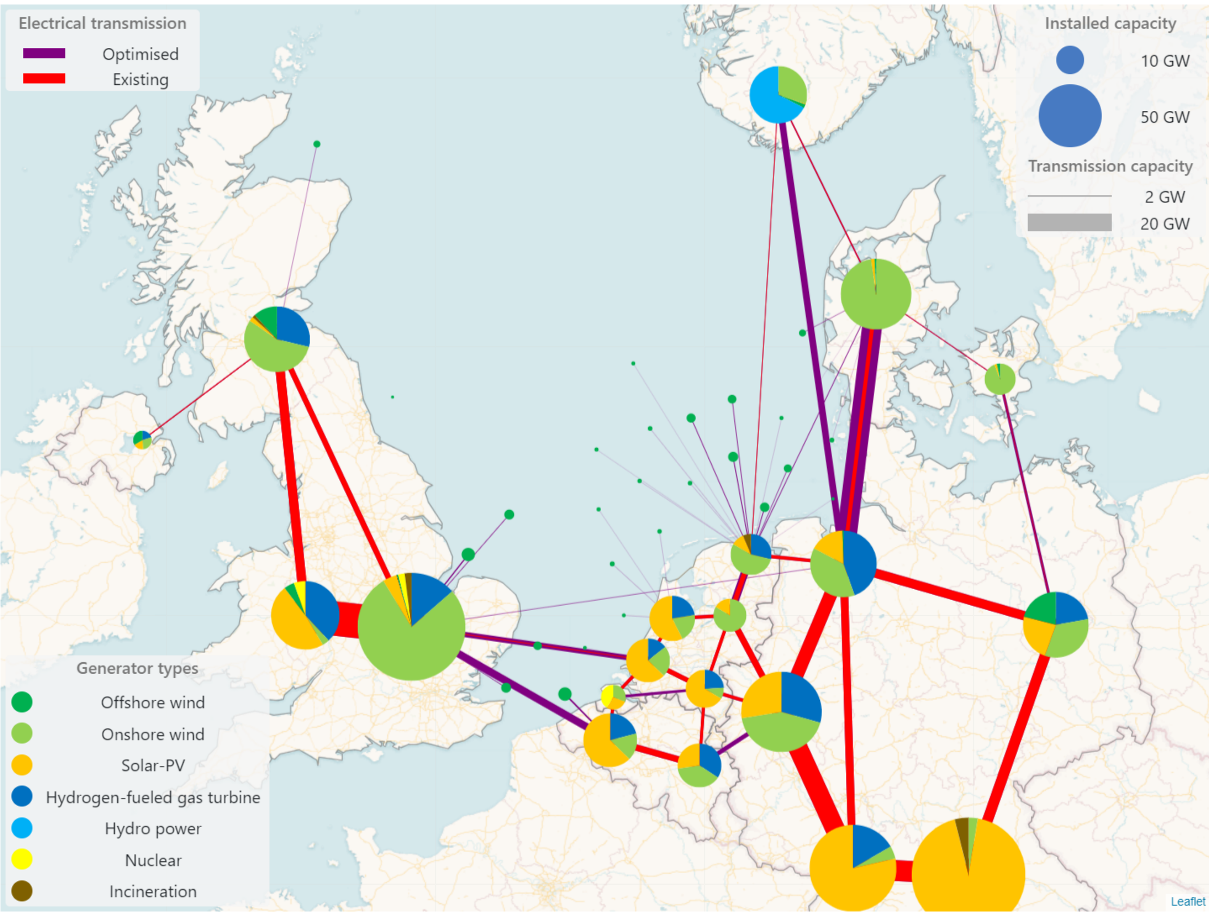


Figure 7.2: Geographical overview of the installed capacities of electricity generation and transmission of scenario 1 - 2040 - resulting from optimisation of the Northwestern European energy system

In the network overview, the generators are grouped per node. Alternatively, the generator capacities can be grouped per technology, Figure 7.3 shows the total installed capacities in Northwestern Europe per technology. In this scenario, the electricity generation is mainly performed by onshore wind turbines and solar-PV panels. Note that, while the installed capacity is roughly equal, the yearly electricity production by the onshore wind turbines is significantly higher than the electricity production by the solar panels. Wind turbines have a high capacity factor compared to solar-PV panels. This effect is visualised by displaying the average yearly power output of the generators. The capacity factor is defined as the ratio between the average yearly power and the nominal power.

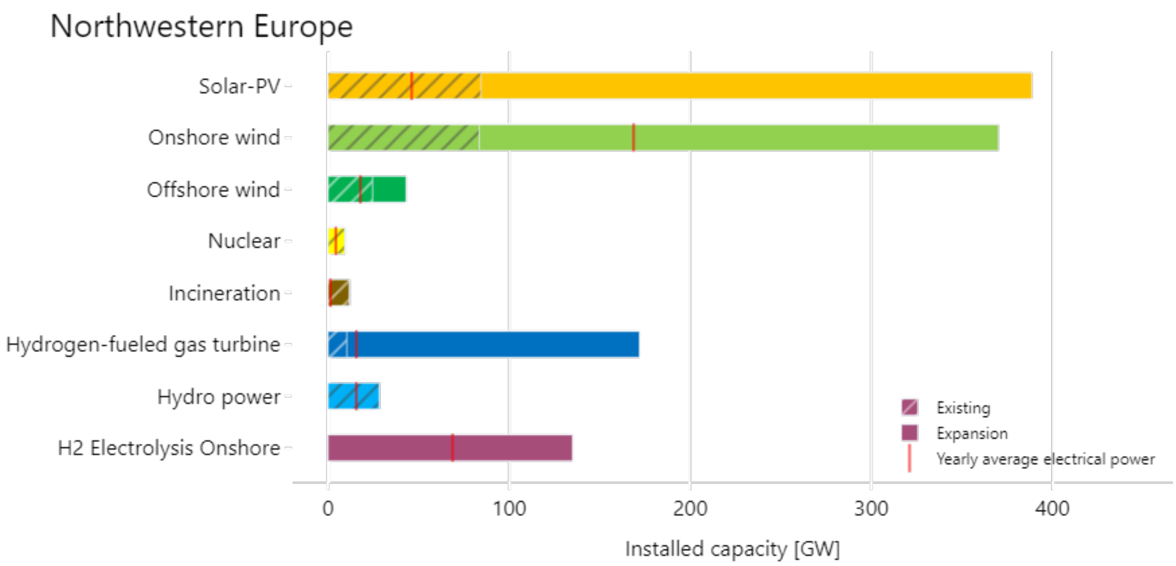


Figure 7.3: Total installed nominal capacities of different technologies in the Northwestern European energy system resulting from scenario 1 - 2040

Table 7.1 shows some key results of scenario 1. The results represent the combined installed capacities of the North Sea countries. The 'Electrical transmission North Sea' represents the total electrical transmission capacity in the North Sea. The unit GWkm is a convenient unit to compare cables with different lengths and transmission capacities.

Table 7.1: Key parameters of the Northwestern European energy systems resulting from scenario 1 - 2040

	Installed capacity	Unit
Hydrogen-fueled gas turbine	172	GW
Offshore wind	43	GW
Onshore wind	370	GW
Solar-PV	389	GW
H2 Electrolysis Onshore	135	GW
Electrical transmission North Sea	8606	GWkm

Both the electricity consumption as the hydrogen consumption are expected to grow in the decade 2040-2050. Therefore, installed capacity of renewable generators, interconnection capacity and hydrogen conversion are expected to grow. In scenario 2, the demand profiles of 2050 will be implemented.

7.1.2 Scenario 2 - 2050

In the 2050 scenario, the demand profiles and cost assumptions for 2050 are used. Due to the expected electrification of the energy system, the consumption patterns are higher in 2050. More renewable energy needs to be harvested which makes the energy system configuration problem more challenging.

The electricity network overview is shown in Figure 7.4. The system behaviour is very similar to the system dynamics of the 2040 scenario, however the installed capacities are larger. The increased capacity can be found mainly in the solar-PV generation. Most of the onshore wind potential is already used in the 2040 scenario.

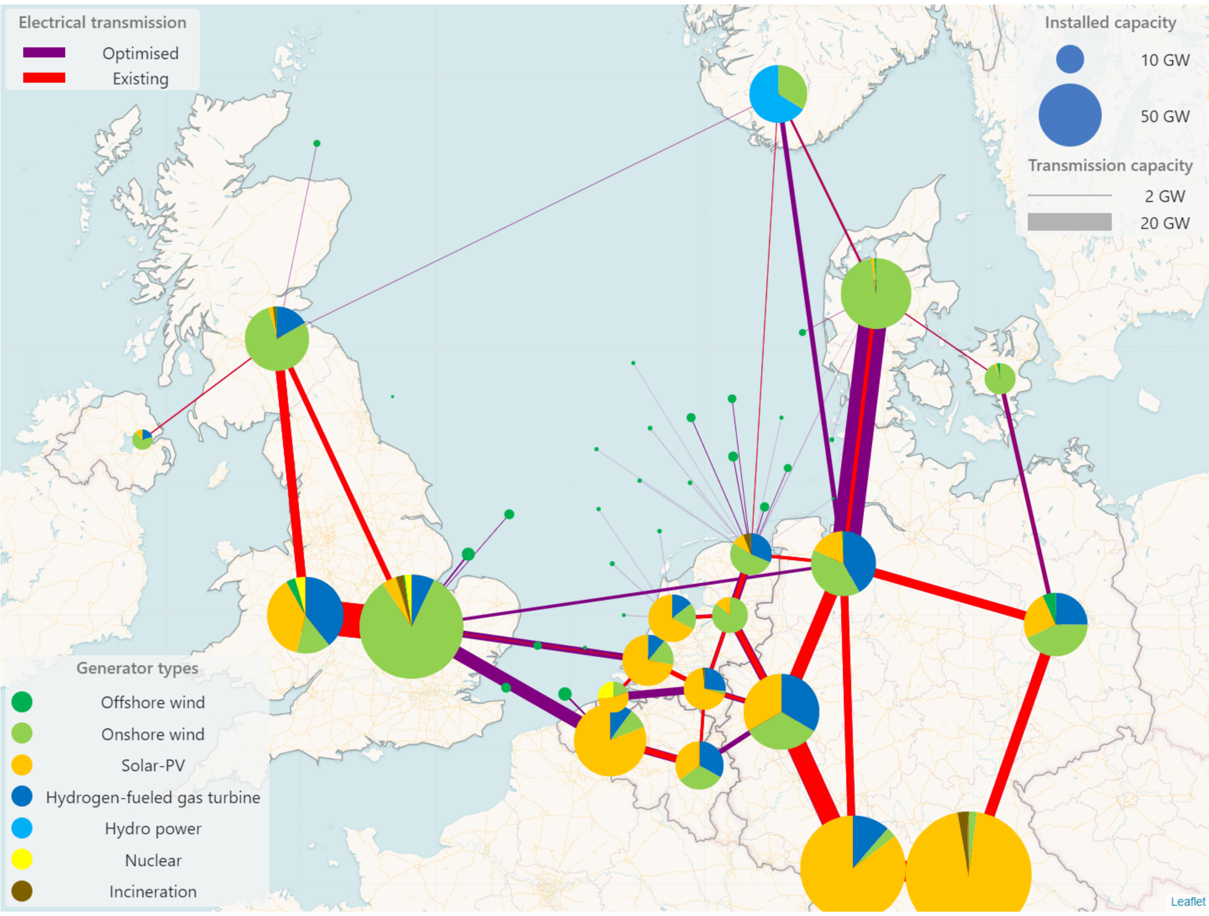


Figure 7.4: Geographical overview of the installed capacities of electricity generation and transmission of scenario 2 - 2050 - resulting from optimisation of the Northwestern European energy system

The hydrogen network overview is shown in Figure 7.5. From both networks, which are connected to each other by electrolysers and gas turbines, it can be seen that there are large transmission corridors between Denmark and Germany and from the UK via the Netherlands to Germany. Relative to Germany, the energy demand in Denmark and in the UK is low. The hypothesis is that a significant portion of the onshore wind generation is exported to Germany via the formed corridors.

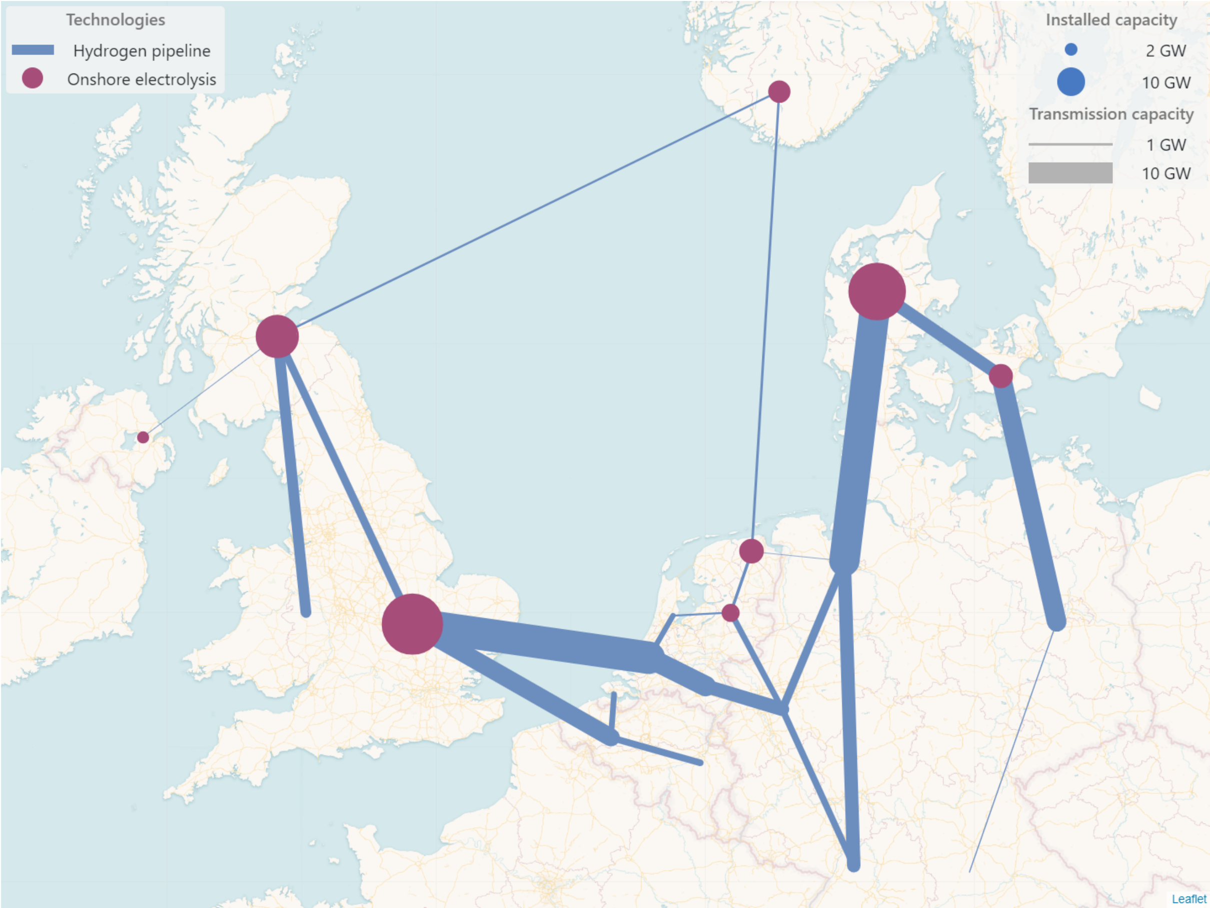


Figure 7.5: Geographical overview of the installed capacities of hydrogen conversion and distribution of scenario 2 - 2050 - resulting from optimisation of the Northwestern European energy system

To verify this hypothesis, one can look at the energy balances of each country. The electricity balance can be found in Figure 7.6. The red part of the consumption is the electricity consumption excluding the electricity conversion to hydrogen. The largest portion of the hydrogen production is performed in Denmark and the United Kingdom. Producing hydrogen close to the electricity source is sensible, since hydrogen can be stored and transported easier in large volumes than electricity. Even with the hydrogen production, the electricity production exceeds the consumption. Denmark and the UK are electricity exporters.

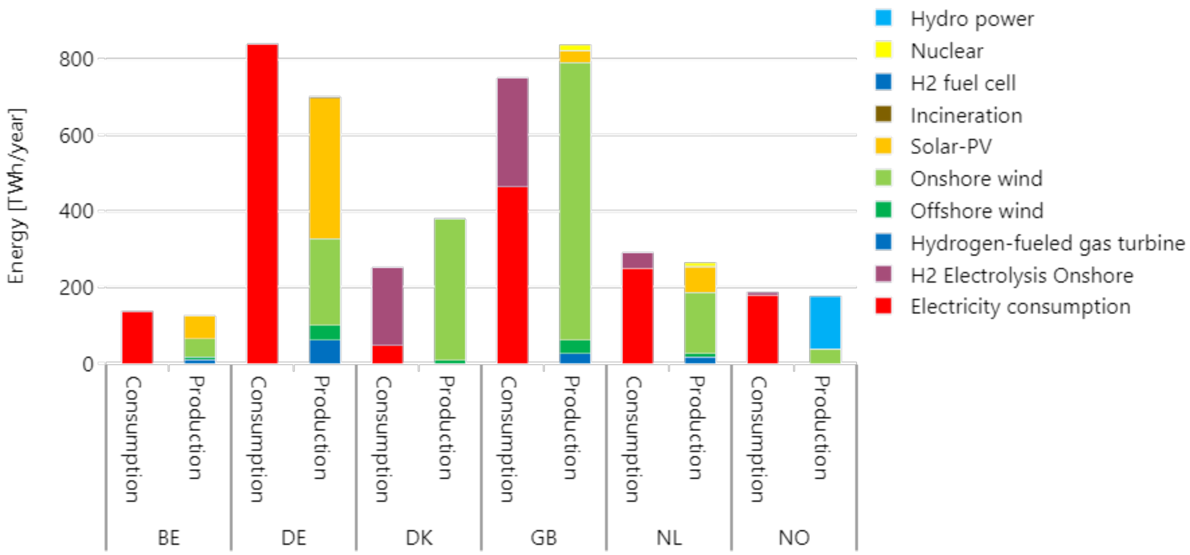


Figure 7.6: Yearly electricity consumption and production per North Sea country resulting from scenario 2 - 2050

Figure 7.7 visualises the hydrogen balance of each country. Belgium and Germany do not produce any hydrogen, however, they do consume hydrogen either directly or convert it to electricity. Belgium, Germany and the Netherlands need to import hydrogen to meet the energy demand.

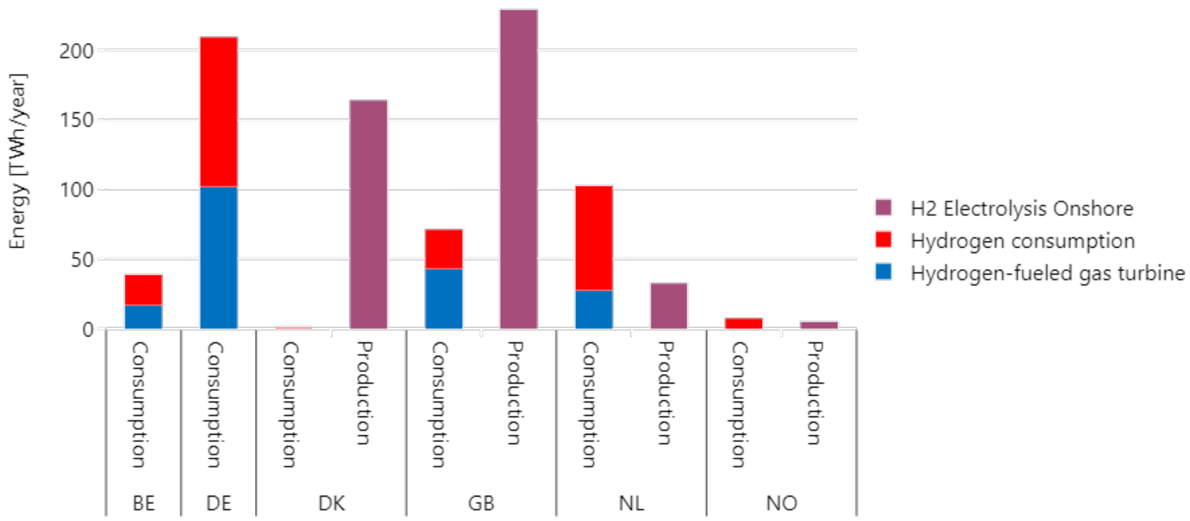


Figure 7.7: Yearly hydrogen consumption and production per North Sea country resulting from scenario 2 - 2050

Table 7.2 shows some key results of scenario 2. The results represent the combined installed capacities of the North Sea countries.

Table 7.2: Key parameters of the Northwestern European energy systems resulting from scenario 2 - 2050

	Installed capacity	Unit
Hydrogen-fueled gas turbine	162	GW
Offshore wind	27	GW
Onshore wind	388	GW
Solar-PV	529	GW
H2 Electrolysis Onshore	126	GW
Electrical transmission North Sea	10388	GWkm

While the resulting configuration may be cost optimal, the installed capacities are not in line with national policy plans. This mismatch is particularly visible in the offshore wind generation as it lags the planned generation capacity significantly. For example, in the Netherlands, by 2035 an installed capacity of 27.5 GW of offshore wind turbines is expected to be build according to the PPSGen analysis. This is more than the installed capacity of offshore wind in the North Sea countries combined resulting from the optimisation. In order to comply with national policy plans, the Brownfield starting point will be implemented in the next scenario. In the remainder of the scenarios, the demand profiles of 2050 are used.

7.1.3 Scenario 3 - Brownfield

In the Brownfield scenario, the national plans for 2035 will be considered as a starting point for the model, the model will then decide how to expand the energy system. The minimal installed capacities for the Brownfield scenario are based on an analysis from PPSGen, these minima have been used in the scenario study nuclear energy as well [12]. For each country, minimal capacities were added for gas turbines, on- and offshore wind turbines, PV panels, batteries and electrolysers. The Brownfield scenario was implemented to obtain results that are in line with policy. Figure 7.8 displays the electricity network resulting from scenario 3.

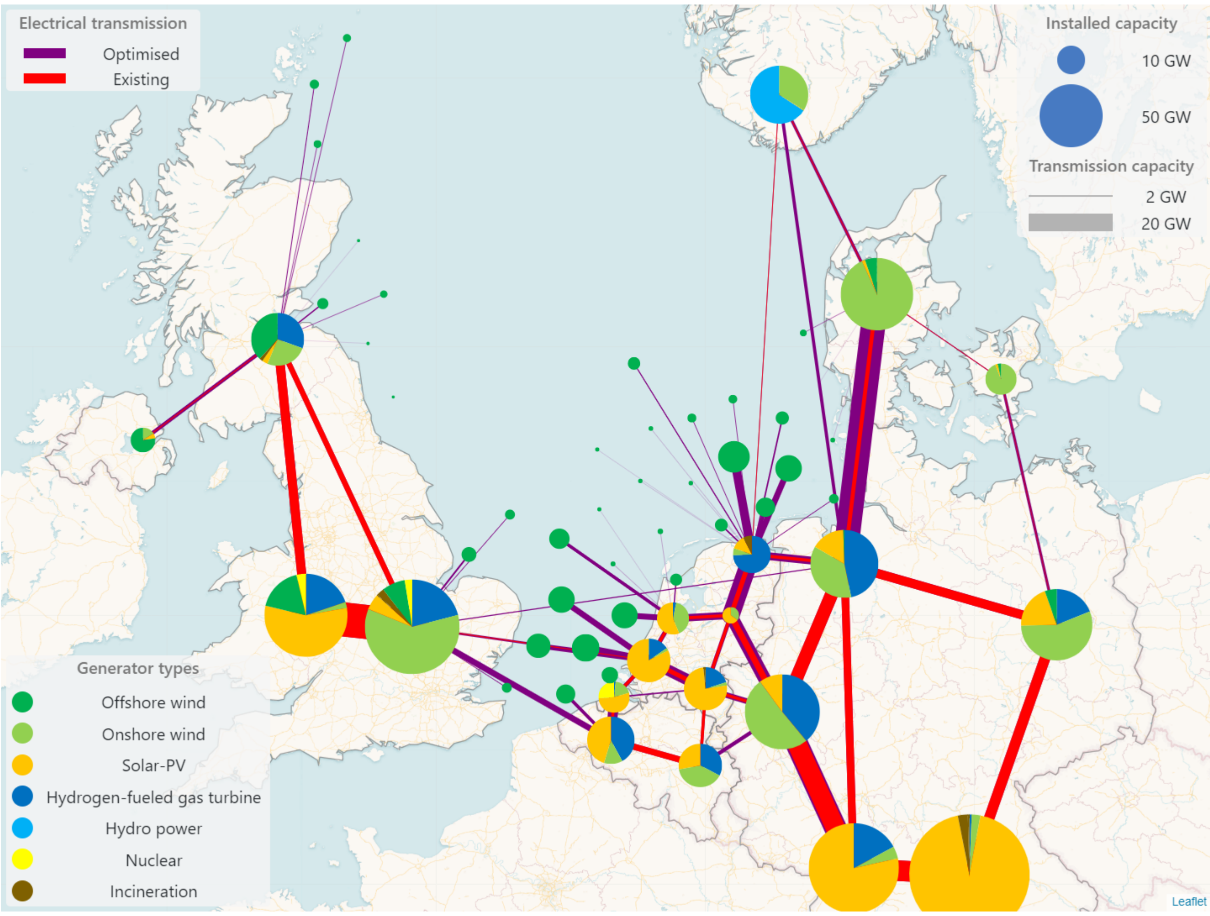


Figure 7.8: Geographical overview of the installed capacities of electricity generation and transmission of scenario 3 - Brownfield - resulting from optimisation of the Northwestern European energy system

The most apparent effect on the results can be found in the increased capacity of offshore wind turbines. Also, the onshore generation capacity of wind turbines in Germany increases, while in the Netherlands and the United Kingdom the capacity decreases. The dependency on onshore wind energy is eased due to the increased installed capacity of offshore wind generators. The total yearly renewable electricity production of Germany increases from 701 TWh to 931 TWh, enough to cover the yearly electricity demand.

Table 7.3 shows some key results of scenario 3. The results represent the combined installed capacities of the North Sea countries.

Table 7.3: Key parameters of the Northwestern European energy systems resulting from scenario 3 - Brownfield

	Installed capacity	Unit
Hydrogen-fueled gas turbine	180	GW
Offshore wind	150	GW
Onshore wind	294	GW
Solar-PV	415	GW
H2 Electrolysis Onshore	133	GW
Electrical transmission North Sea	14430	GWkm

In Denmark, still the entire technological potential for onshore wind generation is being used. While this may be cost optimal, exploiting the entire available land area for electricity production by wind turbines will not be accepted by society. In order to get public support, the onshore wind generation potential will be limited to 30% of the technological potential in the next scenario. This generation potential is in line with the upper limit of policy outlooks for most countries [12].

7.1.4 Scenario 4 - Limited onshore wind generation

In this scenario, the onshore wind generation potential is limited to 30% of the technological potential. This new potential corresponds to 14 GW for the Netherlands and 142 GW for Germany. The new potential reflects the upper limit of the public support while still offering the model the option to extend on the Brownfield wind generation capacity by approximately 35% from 2035 to 2050. The overview of the electricity and hydrogen network can be found in Figures 7.9 and 7.10, respectively.

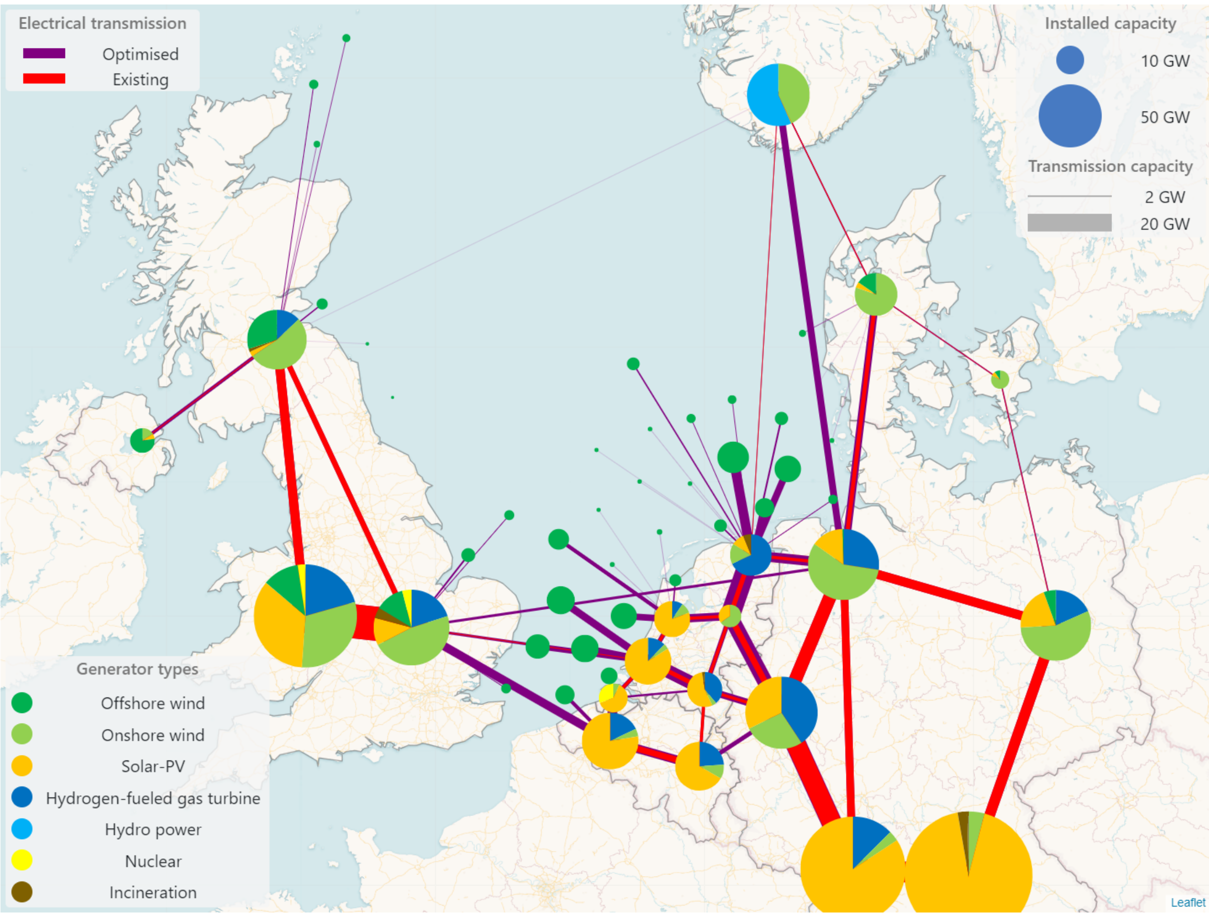


Figure 7.9: Geographical overview of the installed capacities of electricity generation and transmission of scenario 4 - Limited onshore wind generation - resulting from optimisation of the Northwestern European energy system

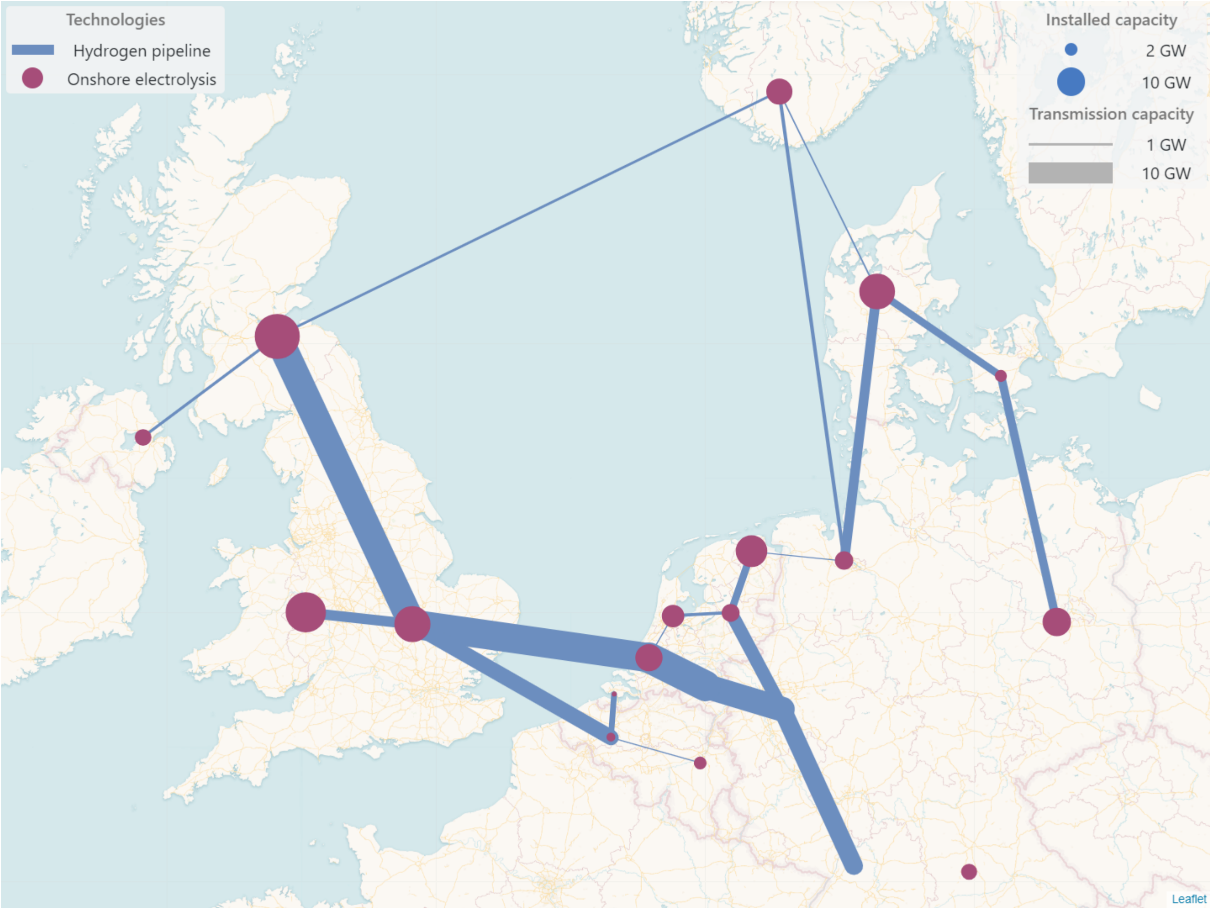


Figure 7.10: Geographical overview of the installed capacities of hydrogen conversion and distribution of scenario 4 - Limited onshore wind generation - resulting from optimisation of the Northwestern European energy system

By adding the lower limits (in scenario 3) and the upper limits (in scenario 4), the transmission capacities and energy exchange between countries is decreased significantly with respect to scenario 2. The net electricity exchange between the North Sea countries decreases with 4.5%, the net hydrogen exchange decreases with 36%. The electricity balance can be found in Figure 7.11, the hydrogen balance can be found in Figure 7.12. Table 7.4 shows the key results of scenario 4. The results represent the combined installed capacities of the North Sea countries.

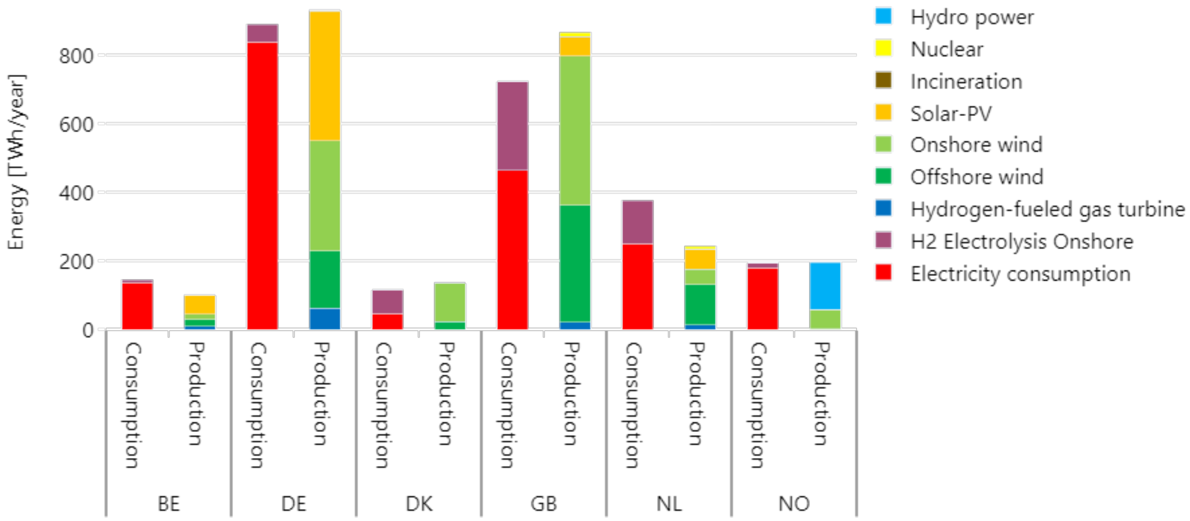


Figure 7.11: Yearly electricity consumption and production per North Sea country resulting from scenario 4

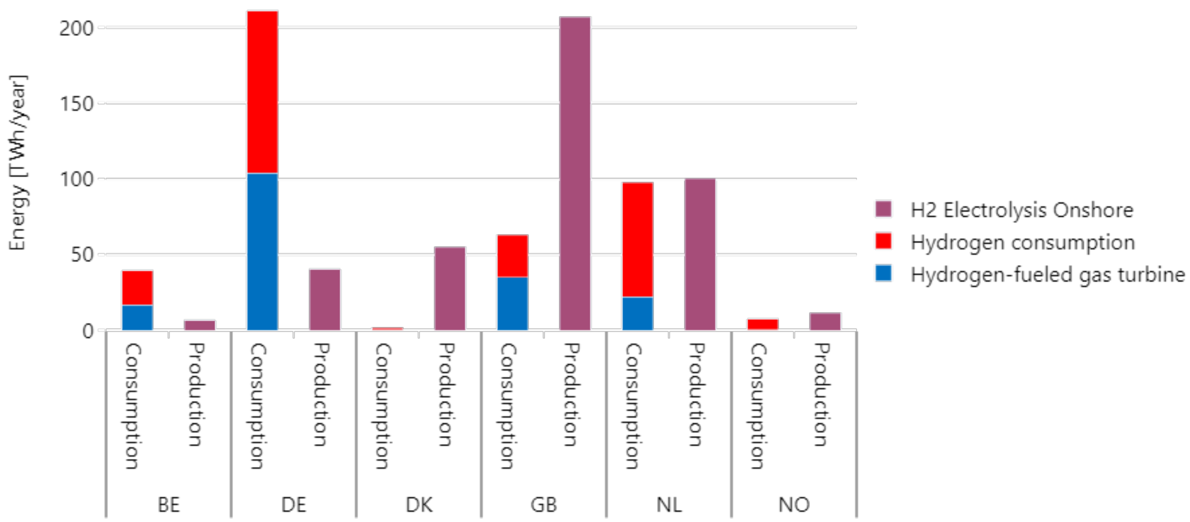


Figure 7.12: Yearly hydrogen consumption and production per North Sea country resulting from scenario 4

Table 7.4: Key parameters of the Northwestern European energy systems resulting from scenario 4 - Limited onshore wind generation

	Installed capacity	Unit
Hydrogen-fueled gas turbine	162	GW
Offshore wind	150	GW
Onshore wind	261	GW
Solar-PV	520	GW
H2 Electrolysis Onshore	126	GW
Electrical transmission North Sea	18146	GWkm
Total system cost	96.7	bn€/yr

7.1.5 Conclusion

With the scenarios that have been run in stage 1 of the scenario study, the starting point of the model has been established. Alterations were necessary to line up the results with policy plans for 2035. This has been done adding a lower limit to the installed capacities of renewable generators. An upper limit for onshore wind generation was added to match the limit for social support. These changes led to a shift from onshore wind generators to offshore wind generators.

7.2 Stage 2 - Testing the model extensions

In stage 2, the model extensions will be tested by adding them incrementally to the model. The different offshore technologies will be added to the model to obtain a better representation of offshore energy hubs. Effective additions are used in the next scenario, while changes that hardly affect the model outcomes are discarded to limit the degrees of freedom of the model and reduce the computing time.

7.2.1 Scenario 5 - Offshore AC grid

In scenario 5, the radial DC links between the offshore wind farms and onshore regions are removed. Instead, an offshore AC grid is added to the model. This provides the opportunity to form interconnections between countries via offshore nodes, or hubs. This configuration is displayed schematically in Figure 7.13.

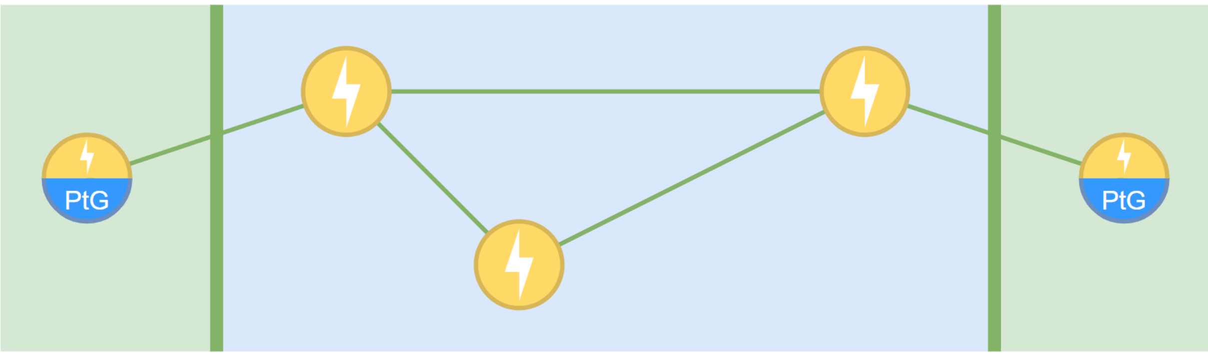


Figure 7.13: Schematic representation of the connection configuration in scenario 5

In this scenario, offshore DC links and and offshore hydrogen production are not included. Figure 7.14 displays the electricity network overview for scenario 5.

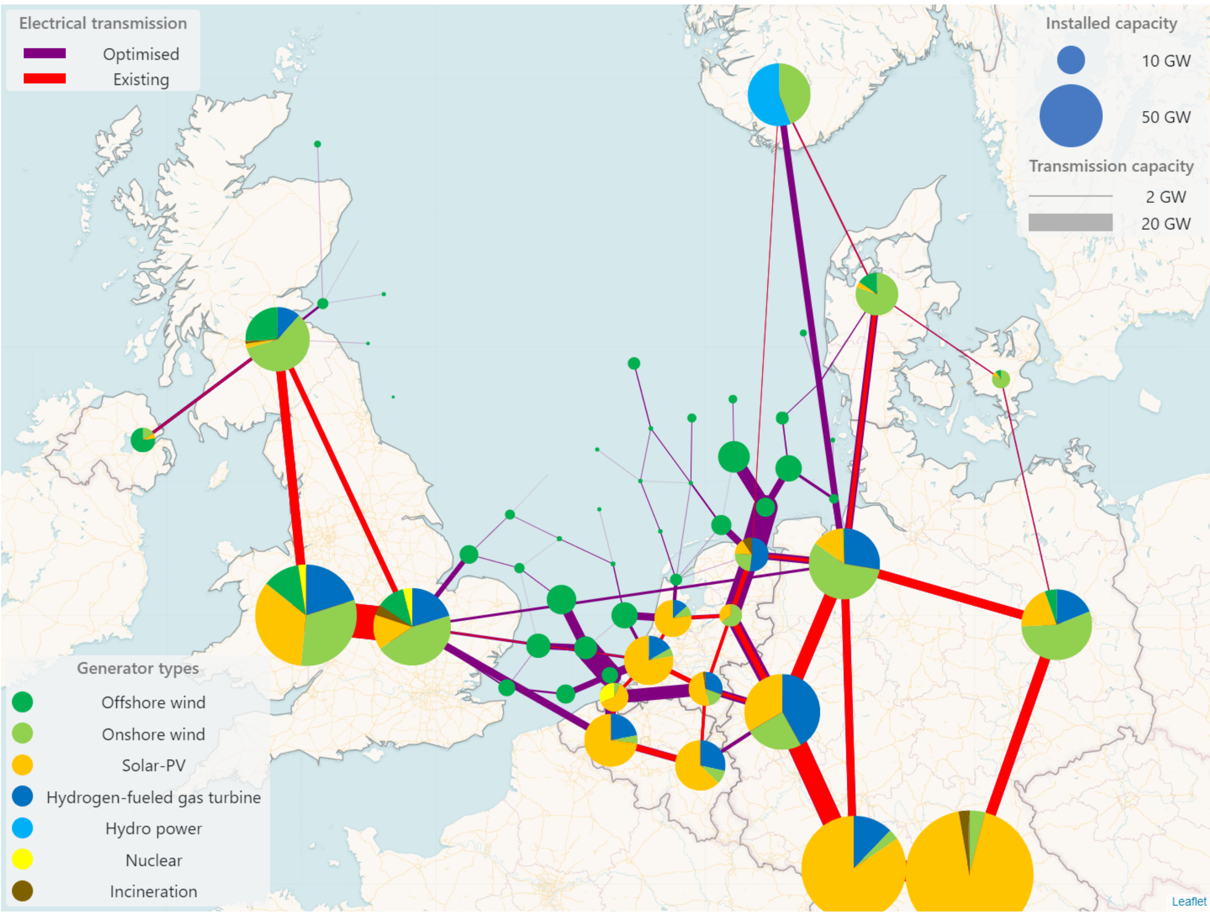


Figure 7.14: Geographical overview of the installed capacities of electricity generation and transmission of scenario 5 - Offshore AC grid - resulting from optimisation of the Northwestern European energy system

With the implemented AC grid, distinct connection structures can be identified. Firstly, an interconnected grid between the Netherlands, Germany and Denmark forms. Also, an interconnected grid can be found between the United Kingdom, the Netherlands and Belgium. Furthermore, branches are formed near Scotland and from the Dogger Bank to the Netherlands.

Table 7.5 shows the key results of scenario 5. The results represent the combined installed capacities of the North Sea countries.

Table 7.5: Key parameters of the Northwestern European energy systems resulting from scenario 5 - Offshore AC grid

	Installed capacity	Unit
Hydrogen-fueled gas turbine	162	GW
Offshore wind	150	GW
Onshore wind	271	GW
Solar-PV	518	GW
H2 Electrolysis Onshore	126	GW
Electrical transmission North Sea	21690	GWkm
Total system cost	98.4	bn€/yr

This scenario provides more interconnection possibilities, however, the total system costs increase with respect to scenario 4 by 1.75%. The AC cables are more expensive per kilometre than DC cables. On the other hand, AC converter stations are less expensive than DC converter stations. This trade-off is a typical problem that can be solved by an optimisation algorithm. Therefore, in the next scenario, a DC grid will be introduced and placed over the AC grid. The optimisation algorithm will decide which connection configuration is cost optimal.

7.2.2 Scenario 6 - Offshore DC grid

Scenario 6 offers the model the choice between offshore AC and DC cables, or a combination of both. The connection configuration used in scenario 6 is displayed schematically in Figure 7.15.

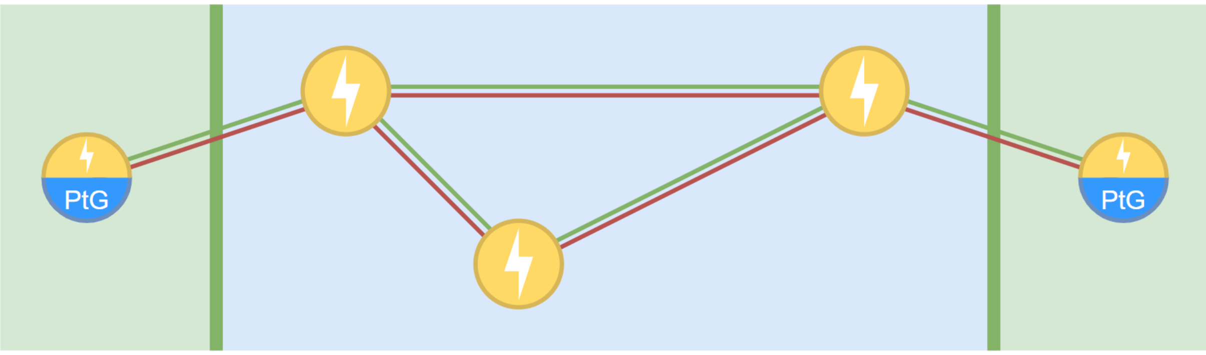


Figure 7.15: Schematic representation of the connection configuration in scenario 6

In Figure 7.16, the resulting electricity network overview for scenario 6 is shown.

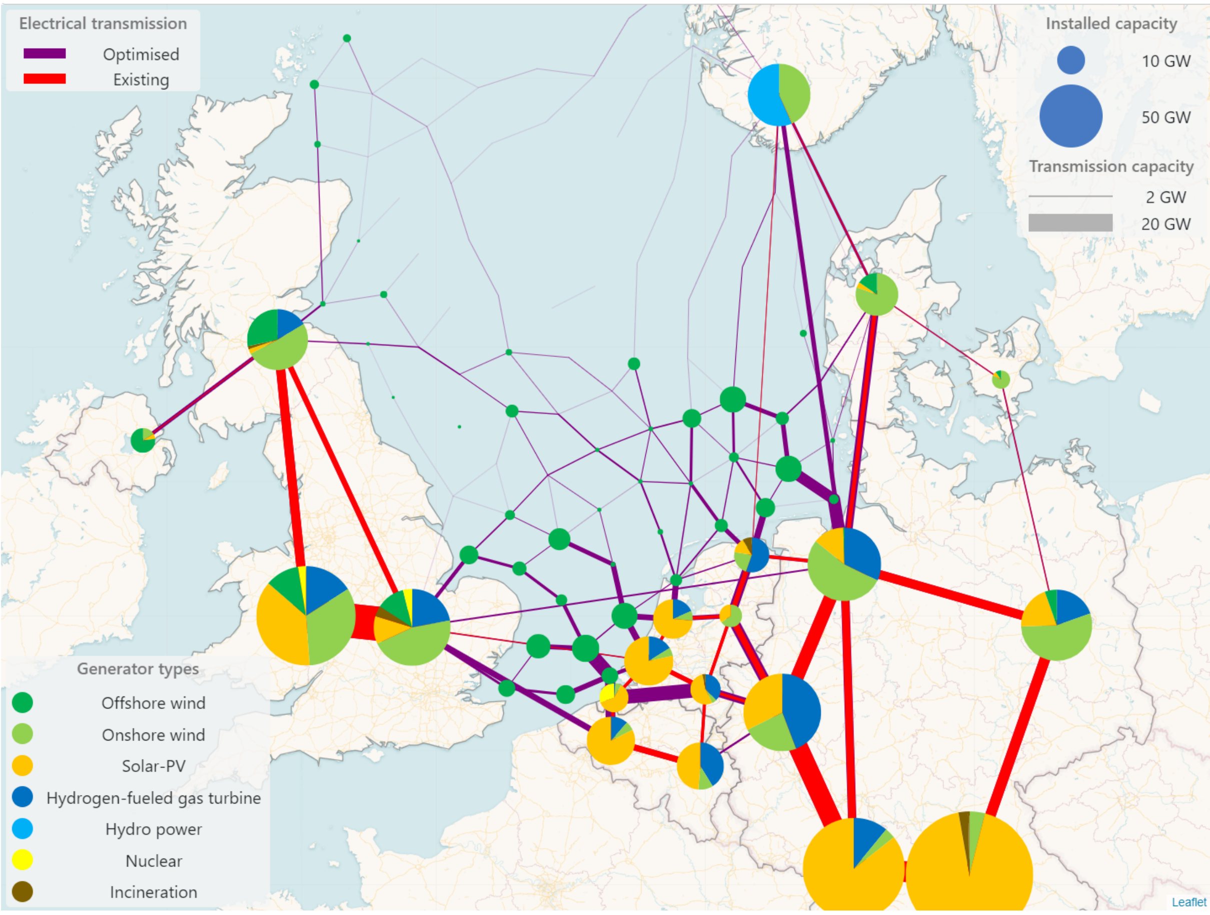


Figure 7.16: Geographical overview of the installed capacities of electricity generation and transmission of scenario 6 - Offshore DC grid - resulting from optimisation of the Northwestern European energy system

When comparing the offshore network of scenario 6 to the network of scenario 5, one can clearly see a more extensive grid forming in the scenario with both AC and DC cables. The resulting network in scenario 6 hardly contains any AC lines. DC infrastructure is apparently cost optimal when covering larger distances. The largest offshore AC line in the resulting network is 37 MW. To save computation costs, the AC grid will not be used in the remainder of the scenarios.

Also, the total system costs were reduced, which can be attributed to the cost reduction that DC offers for greater distances. In comparison to scenario 4, where only radial connections to the closest onshore node were allowed, the total system cost was reduced by 455 M€/yr. Also, the interconnection capacity via the offshore nodes reduces the required storage capacity by 1.5% and 1.3% for hydrogen and battery storage respectively.

Table 7.6 shows the key results of scenario 6. The results represent the combined installed capacities of the North Sea countries.

Table 7.6: Key parameters of the Northwestern European energy systems resulting from scenario 6 - Offshore DC grid

	Installed capacity	Unit
Hydrogen-fueled gas turbine	163	GW
Offshore wind	150	GW
Onshore wind	262	GW
Solar-PV	503	GW
H2 Electrolysis Onshore	122	GW
Electrical transmission North Sea	25373	GWkm
Total system cost	96.2	bn€/yr

In this scenario, electricity can only be connected to shore via other offshore nodes. In order to limit the total cable length, radial connections will be added in the scenario 7.

7.2.3 Scenario 7 - Radial DC connections

In the seventh scenario, for every offshore node, radial connections to each of the ten onshore nodes neighboring the North Sea were added. Only DC connections are used for this purpose, since in scenario 6 it was concluded that DC cables are preferable for larger distances. This new connection configuration is visualised in Figure 7.17. The resulting system costs are expected to be lower as the total cable length will be limited.

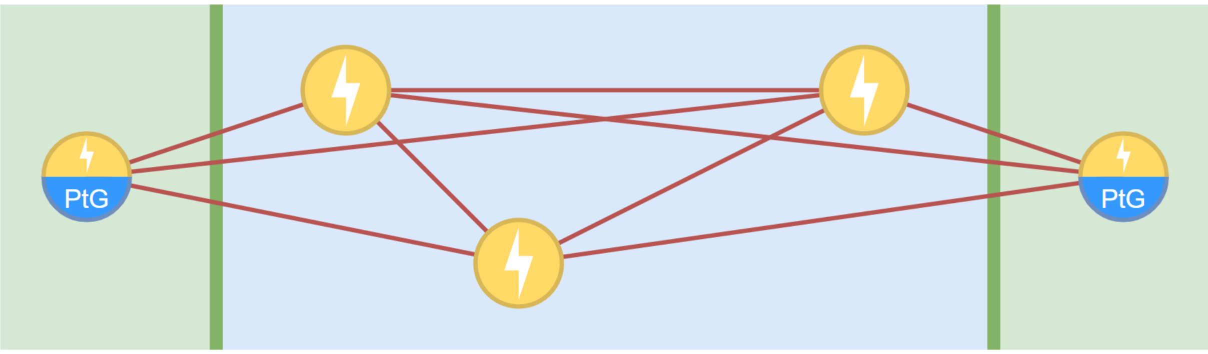


Figure 7.17: Schematic representation of the connection configuration in scenario 7

Figure 7.18 displays the resulting electricity network overview for scenario 7.

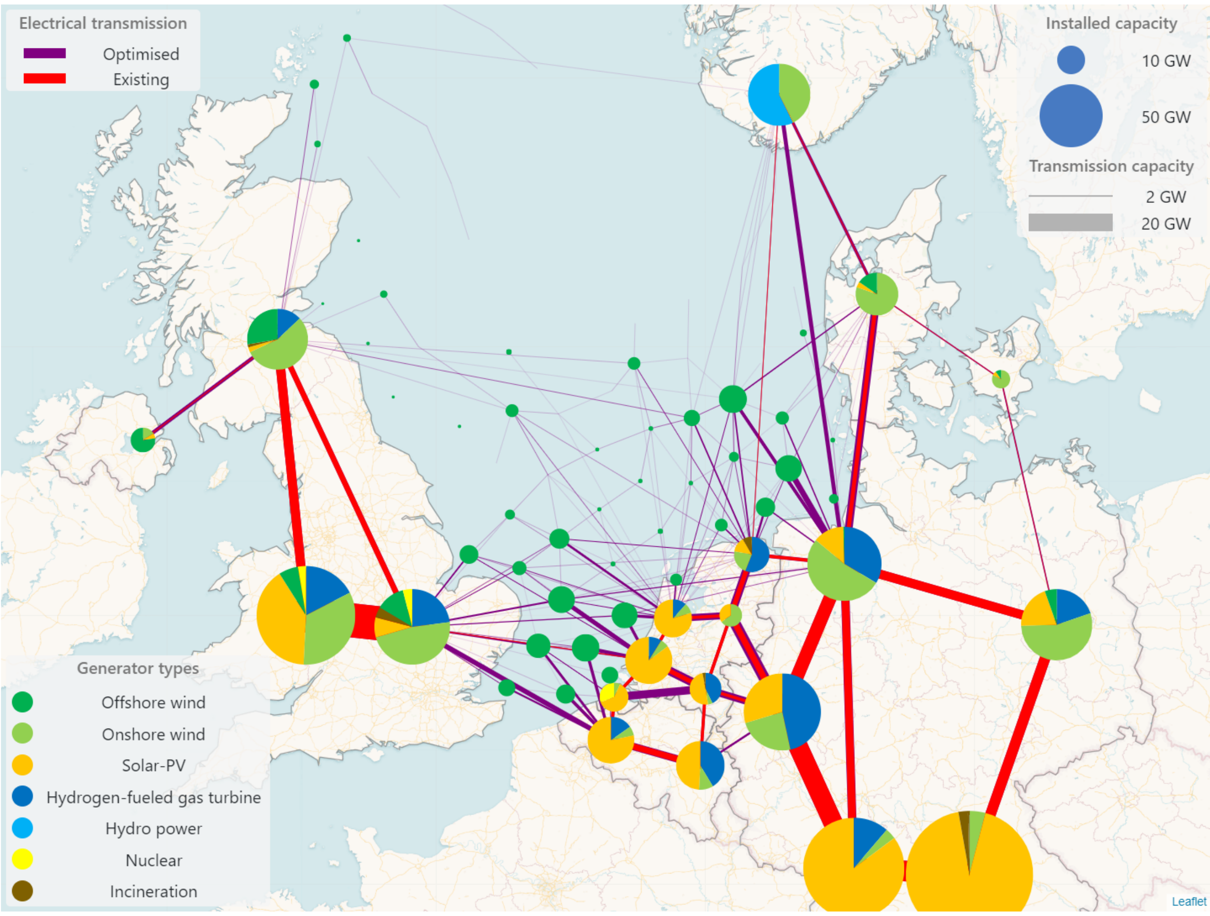


Figure 7.18: Geographical overview of the installed capacities of electricity generation and transmission of scenario 7 - Radial DC connections - resulting from optimisation of the North-western European energy system

With this configuration, the optimisation algorithm oftentimes chooses to connect to shore radially, as this is the shortest distance. By minimising the cable distance, one minimises the cable cost. With linear cost functions, this is expected behaviour. With respect to scenario 6, the total system costs are 259 M€/yr lower in scenario 7. While the system costs are lower, this is not a realistic scenario since a lot of small cables are deployed with the same cost assumptions as thicker cables. This problem can be solved by varying specific costs depending on the transmission capacity. However, this changes the problem to a non-linear problem. For a large network with more than a hundred nodes and a time resolution of 3 hours, the system becomes unsolvable with the available computational resources. Therefore, the non-linear cost functions will be mimicked by omitting the radial connections and only considering the DC grid. This pushes the model into deploying larger cables. The effect of actually implementing non-linear cost functions will be discussed in scenarios 12 and 13 where a system with fewer nodes and a coarser time resolution will be solved.

Using only the DC grid instead of both the grid as the radial connections also reduces the computation time. By omitting the radial DC connections the solving time decreased by a factor 4. Table 7.7 shows the key results of scenario 6. The results represent the combined installed capacities of the North Sea countries.

Table 7.7: Key parameters of the Northwestern European energy systems resulting from scenario 7 - Radial DC connections

	Installed capacity	Unit
Hydrogen-fueled gas turbine	165	GW
Offshore wind	150	GW
Onshore wind	264	GW
Solar-PV	495	GW
H2 Electrolysis Onshore	122	GW
Electrical transmission North Sea	26166	GWkm
Total system cost	96.0	bn€/yr

Up to scenario 7, offshore wind farms can only be connected to shore via electricity cables. However, due to lower transport costs of hydrogen pipelines compared to DC cables, it may be beneficial to add offshore electrolysis. Offshore electrolysis and offshore hydrogen pipelines will be added in scenario 8.

7.2.4 Scenario 8 - Offshore hydrogen production

In this scenario, offshore hydrogen infrastructure is added. The new connection configuration is visualised in Figure 7.19. The blue connections represent hydrogen pipelines.

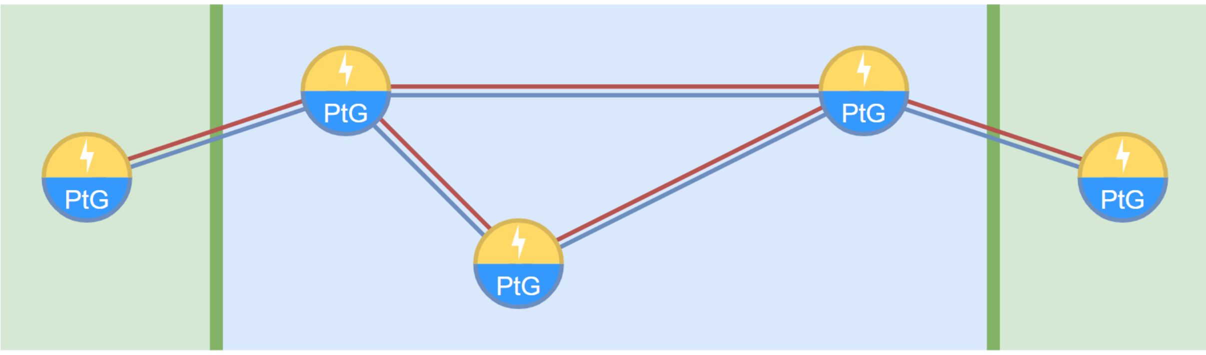


Figure 7.19: Schematic representation of the connection configuration in scenario 8

Electricity conversion close to the generator is attractive due to the low cost of hydrogen transport. The penalty one pays, are conversion losses in electrolysers and in gas turbines. Also, offshore electrolysis is more costly compared to onshore electrolysis. This trade-off will be solved by optimisation of the total annual system cost. The electricity network resulting from scenario 8 is displayed in 7.20.

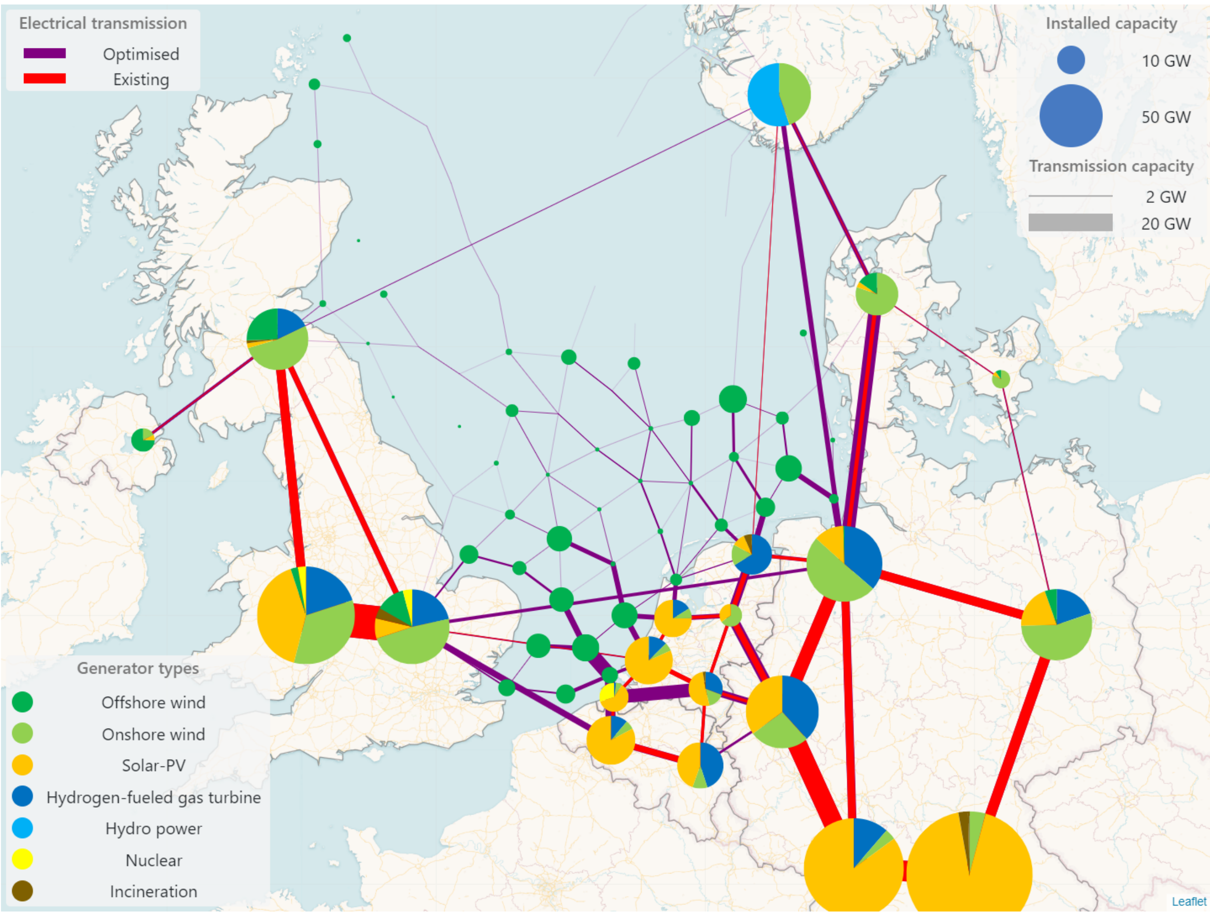


Figure 7.20: Geographical overview of the installed capacities of electricity generation and transmission of scenario 8 - Offshore hydrogen production - resulting from optimisation of the Northwestern European energy system

One can see a decrease in the number of offshore electricity cables as well as a decrease of the capacity of the cables. The total amount of offshore dc cables in scenario 6 is 20,305 GWkm, in scenario 8, this is reduced to 14,654 GWkm. While some interesting results can be seen in the electricity network, the most interesting results of this scenario are in the hydrogen network. Figure 7.21 displays the electricity network overview for scenario 8. Corridors from the North-West to the South-East going inland can be distinguished.

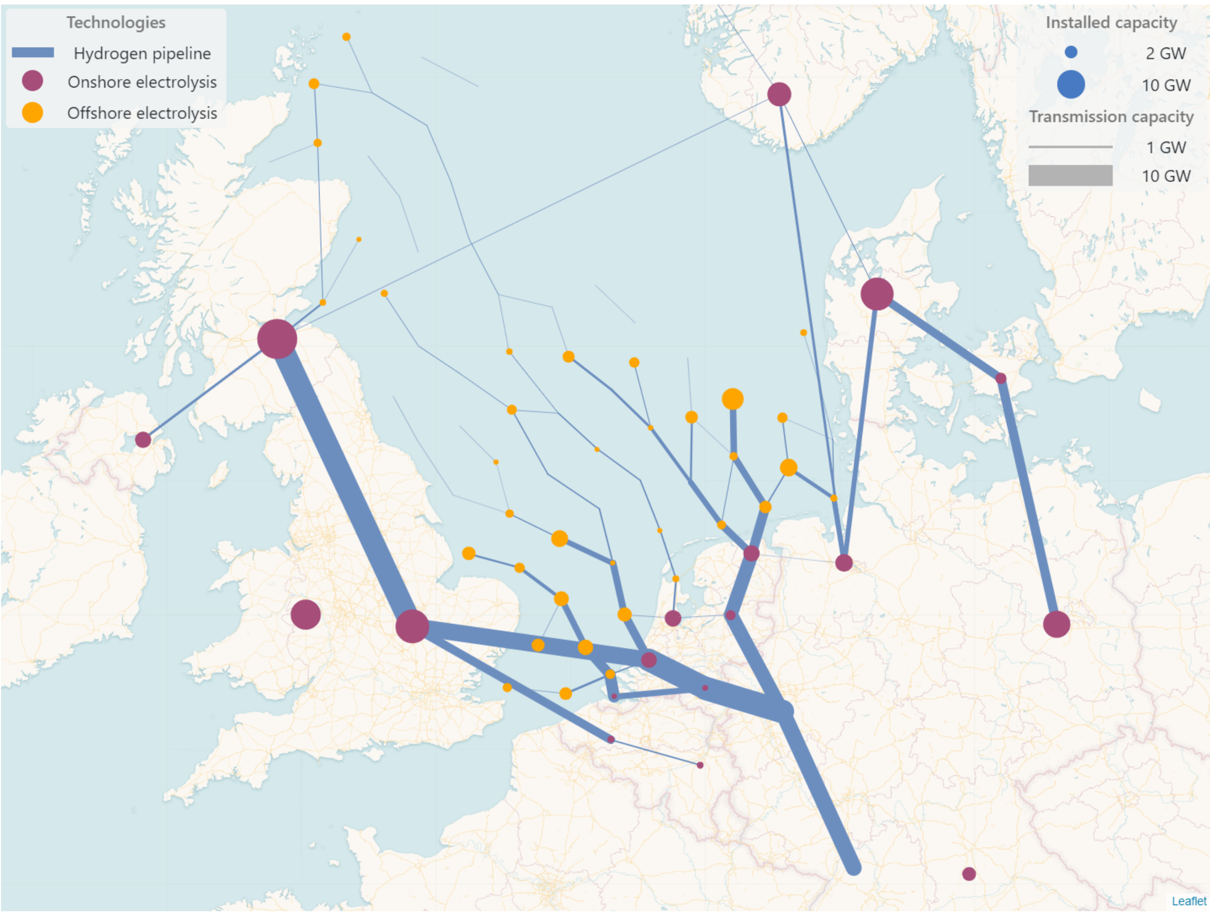


Figure 7.21: Geographical overview of the installed capacities of electricity generation and transmission of scenario 8 - Offshore hydrogen production - resulting from optimisation of the Northwestern European energy system

The hydrogen balance for the North Sea countries is shown in Figure 7.22. From the overview and the graph, it can be concluded that offshore hydrogen electrolysis plays a significant role in the hydrogen production.

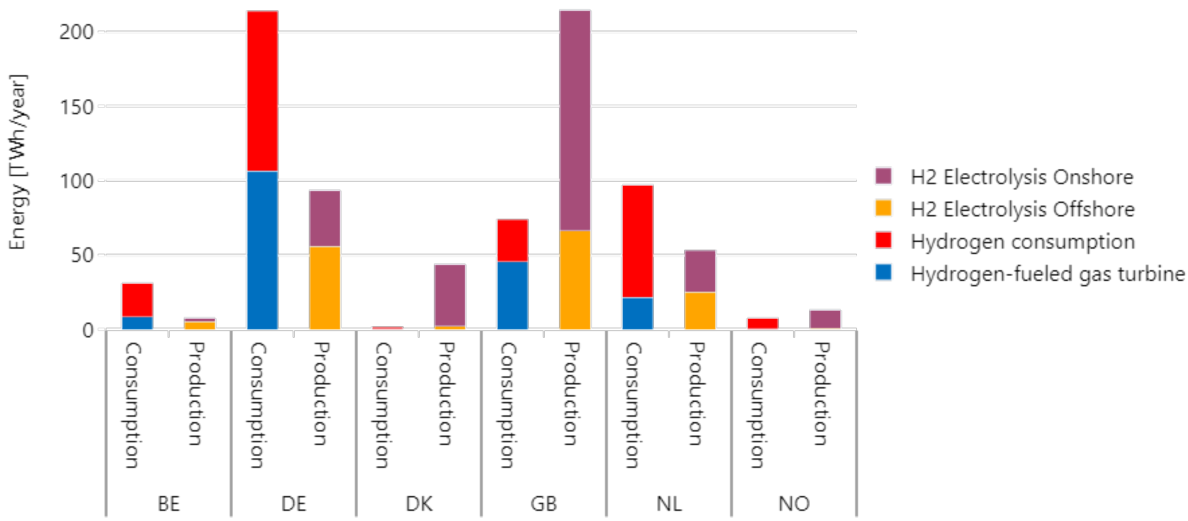


Figure 7.22: Yearly hydrogen consumption and production per North Sea country resulting from scenario 8

Table 7.8 shows the key results of scenario 8. The results represent the combined installed capacities of the North Sea countries. The total system cost in scenario 8 is 966 M€/yr less expensive than the system cost of scenario 4. Furthermore, 28.9% of the generated electricity by offshore wind farms in the North Sea is converted into hydrogen.

Table 7.8: Key parameters of the Northwestern European energy systems resulting from scenario 8 - Offshore hydrogen production

	Installed capacity	Unit
Hydrogen-fueled gas turbine	168	GW
Offshore wind	150	GW
Onshore wind	267	GW
Solar-PV	492	GW
H2 Electrolysis Offshore	38	GW
H2 Electrolysis Onshore	84	GW
Electrical transmission North Sea	20090	GWkm
Total system cost	95.7	bn€/yr

7.2.5 Conclusion

By solving scenario 8, the second stage of the scenario study has been finished and the different extensions to the model were tested. From scenario 5, the conclusion can be drawn that the AC grid does offer extra connection configurations, however, when adding a DC grid in scenario 6, the AC connections are hardly deployed by the model. Therefore, in the remainder of the scenarios the AC grid has been omitted.

Scenario 7 shows that radial connections from the offshore nodes to all onshore nodes resulted in an extensive network with a vast amount of small connections. In this configurations, only linear cost functions have been used. However, it is not valid to assume the low cost (in €/MW) for small cable capacities while the cost assumptions are based on large capacity cables. Therefore, the radial connections have been omitted. Having the DC-grid as the only electrical connection configuration forces the model into grouping the cables between nodes and mimics the economy of scale.

Scenario 8 shows the relevance of offshore electrolysis in the energy system of the future. With the implementation of the model extensions the total annual energy system cost of the North Sea countries has been reduced with 967 M€. In the next stage, the model outputs will be analysed for different input parameters.

7.3 Stage 3 - Altering the assumptions

By altering the assumptions, the effects on the model outputs can be analysed. In this stage, the same connection configuration as in scenario 8 has been used, i.e. offshore and onshore nodes are connected to each other through a DC grid as well as through a grid of hydrogen pipelines. Also, offshore hydrogen production capacity can be deployed by the model. The schematic representation of the connection configuration can be found in Figure 7.19.

7.3.1 Scenario 9 - Larger offshore regions

In this scenario, the offshore region size was increased from 5,000 km^2 to 20,000 km^2. The resulting electricity network can be found in Figure 7.23.

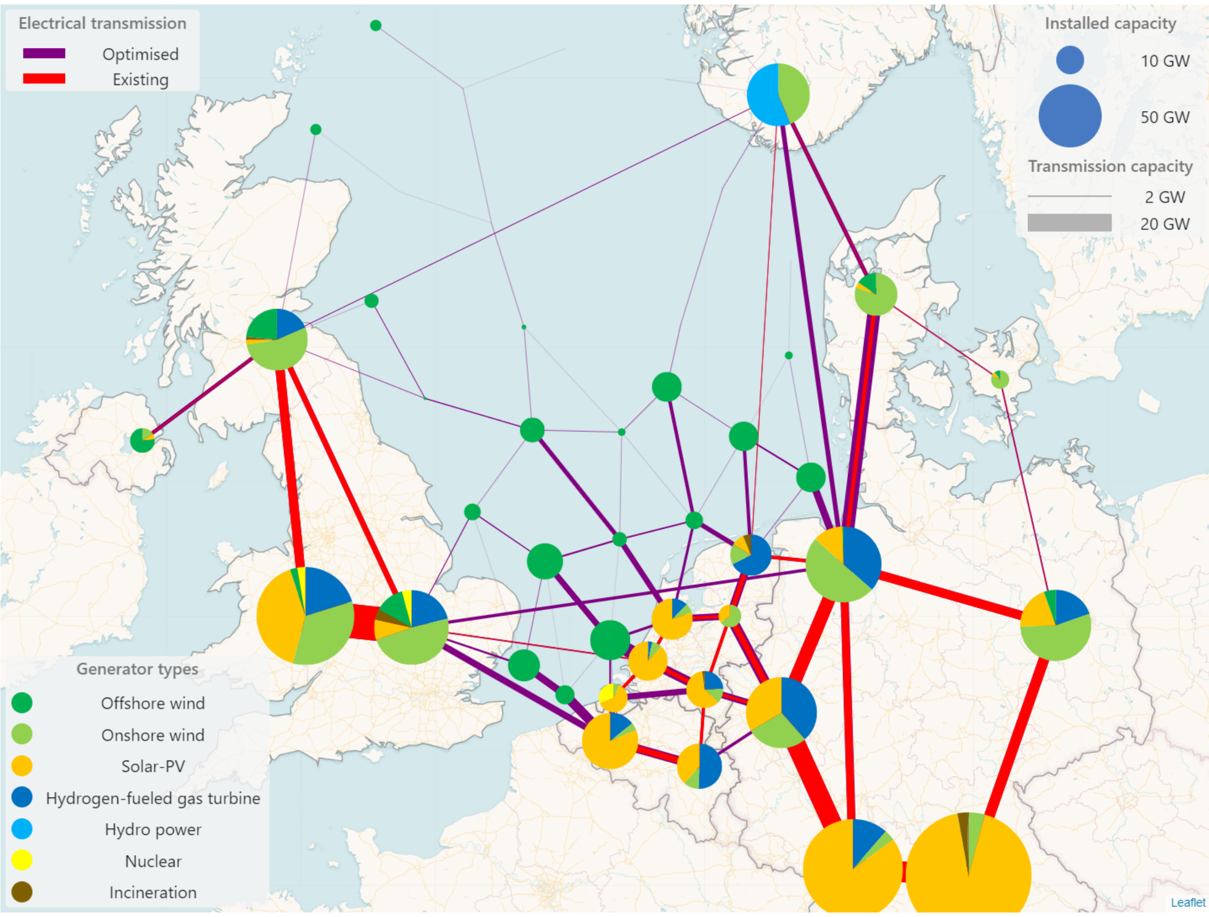


Figure 7.23: Geographical overview of the installed capacities of electricity generation and transmission of scenario 9 - Larger offshore regions - resulting from optimisation of the Northwestern European energy system

The key results of scenario 9 can be found in Table 7.9. The results are very similar to the results of scenario 8. This observation leads to the conclusion that the mesh size in the North Sea does not influence the behaviour of the Northwestern European energy system. However, a finer mesh size does provide a more detailed representation of the spatial configuration in the North Sea.

Table 7.9: Key parameters of the Northwestern European energy systems resulting from scenario 9 - Larger offshore regions

	Installed capacity	Unit
Hydrogen-fueled gas turbine	168	GW
Offshore wind	150	GW
Onshore wind	266	GW
Solar-PV	494	GW
H2 Electrolysis Offshore	37	GW
H2 Electrolysis Onshore	84	GW
Electrical transmission North Sea	19720	GWkm
Total system cost	95.7	bn€/yr

7.3.2 Scenario 10 - More expensive offshore hydrogen infrastructure

By adjusting the cost assumptions, the robustness of the model can be tested. The most important parameters for the offshore regions are the costs of the hydrogen infrastructure and the costs of the DC connections. For scenario 10, the investment costs of offshore hydrogen infrastructure, i.e. electrolysers and pipelines, are increased by by 10% and the costs of the DC connections, i.e. DC cables and converter stations, are decreased by 10%.

The key results of scenario 10 can be found in Table 7.10. Aside from a shift from hydrogen to electrical connection to shore, the system dynamics are hardly affected. The offshore electrolysis capacity decreased from 37.9 GW in scenario 8 to 33.1 GW in scenario 10. The total offshore transmission capacity in the North Sea increased with respect to scenario 8.

Table 7.10: Key parameters of the Northwestern European energy systems resulting from scenario 10 - More expensive offshore hydrogen infrastructure

	Installed capacity	Unit
Hydrogen-fueled gas turbine	166	GW
Offshore wind	150	GW
Onshore wind	266	GW
Solar-PV	494	GW
H2 Electrolysis Offshore	33	GW
H2 Electrolysis Onshore	89	GW
Electrical transmission North Sea	20848	GWkm

7.3.3 Scenario 11 - More expensive offshore DC infrastructure

When increasing the costs of the offshore DC infrastructure by 10% and decreasing the cost of the offshore hydrogen infrastructure by 10% with respect to scenario 8, the offshore electrolysis capacity increases from 37.9 GW to 40.8 GW with respect to scenario 8. The total offshore transmission capacity in the North Sea decreases. With the change in cost assumptions in mind, this is an expected shift. Table 7.11 displays the key results of scenario 11.

Table 7.11: Key parameters of the Northwestern European energy systems resulting from scenario 11 - More expensive offshore DC infrastructure

	Installed capacity	Unit
Hydrogen-fueled gas turbine	169	GW
Offshore wind	150	GW
Onshore wind	267	GW
Solar-PV	492	GW
H2 Electrolysis Offshore	41	GW
H2 Electrolysis Onshore	82	GW
Electrical transmission North Sea	19259	GWkm

7.3.4 Conclusion

When comparing the procedure in scenarios 5-8 with the procedure in scenarios 10 and 11, it can be concluded that the effect on the system behaviour is more reactive to the way energy hubs are modelled than to the cost assumptions.

7.4 Stage 4 - Altering model configurations

In the last stage, two different configurations will be analysed. In scenario 13, non-linear cost functions will be tested for a model with a coarser spatial and temporal resolution. In order to make a comparison, these resolutions first will be used in scenario 12 with linear cost functions. In scenarios 12 and 13, the connection configuration shown in Figure 7.24 is used.

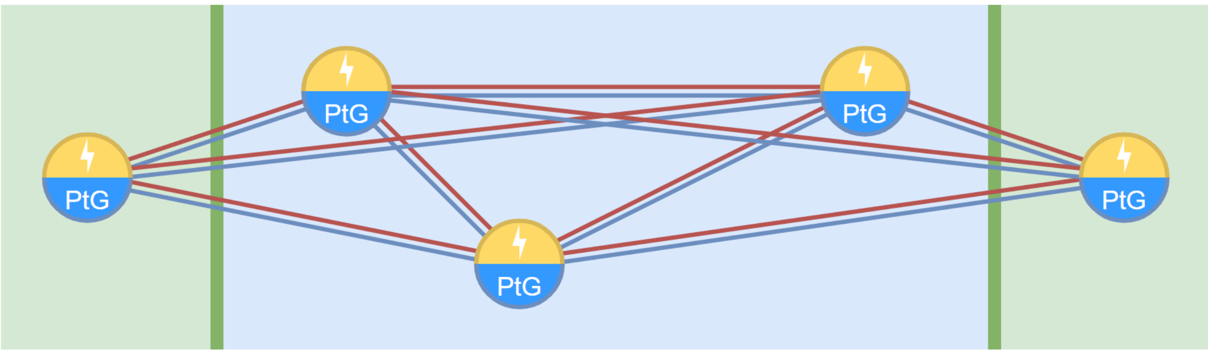


Figure 7.24: Schematic representation of the connection configuration in scenarios 12 and 13

7.4.1 Scenario 12 - One offshore node per country - Linear cost functions

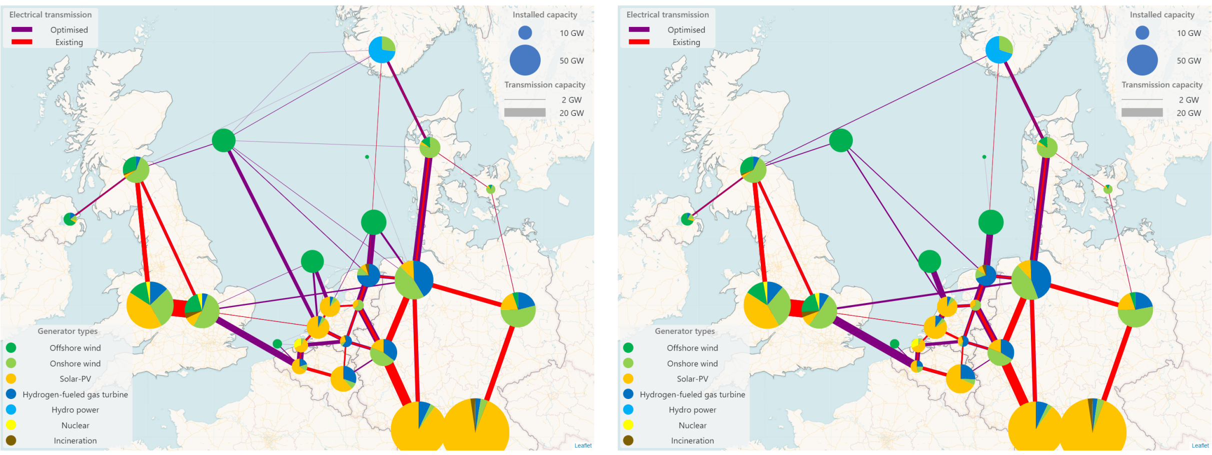
The energy system with a offshore mesh size of 5,000 km^2 and a time resolution of 3 hours appeared to be unsolvable with the available resources. After testing the solving algorithm for different model sizes, one can conclude that the solution time of a mixed integer problem strongly depends on the total number of variables as well as on the number of integer variables.

Therefore, the effect of non-linear cost functions was tested on a network with fewer nodes and a time resolution of 24 hours. Due to the coarser spatial resolution in the North Sea, the wind resources and water depth are averaged over a significantly bigger area. Due to the coarser temporal resolution, the generation and demand profiles are averaged over a day. This makes solar-PV generation more attractive and decreases the necessity of storage solutions. Because of these altered solution parameters, comparing the results of scenario 12 and 13 to the rest of the scenarios is nugatory. However, the results of scenario 12 and 13 can be compared to each other.

To be able to make a comparison, the new resolution settings are first applied to a network with linear cost functions. In this scenario, both the DC grid as well as the radial DC connections were implemented. Also, offshore electrolysis is possible. Figure 7.25a shows the electricity network resulting from scenario 12. As can be seen from the figure, most DC cables are going directly to shore, rather than being routed via the different hubs. Furthermore, there are several small (< 2GW) links. Figure 7.26a shows the hydrogen network resulting from scenario 12. Similar behaviour as in the electricity network can be found.

7.4.2 Scenario 13 - One offshore node per country - Non-linear cost functions

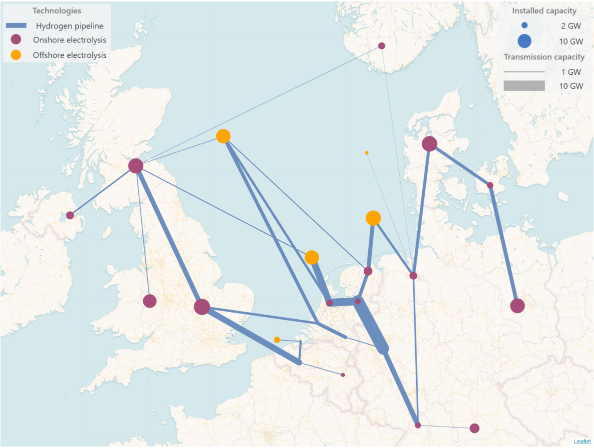
In scenario 13, the non-linear cost functions are implemented for the offshore DC cables and the offshore hydrogen pipelines. In Figure 7.25b and Figure 7.26b a different configuration can be found with respect to scenario 12. In the electricity network, one can see that the model does not deploy small electricity cables anymore. However, the most apparent results can be found in the hydrogen network. A strong interconnection between the offshore hub of the UK and the Dutch offshore hub is formed.



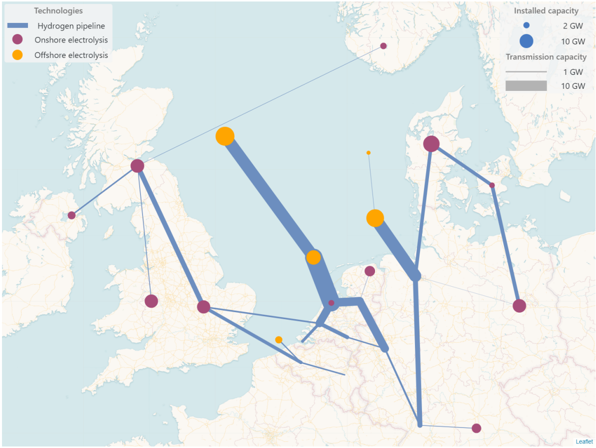
(a) Resulting electricity network with linear cost functions

(b) Resulting electricity network with non-linear cost functions

Figure 7.25: Comparison between the electricity networks of scenario 12 and 13



(a) Resulting hydrogen network with linear cost functions



(b) Resulting hydrogen network with non-linear cost functions

Figure 7.26: Comparison between the hydrogen networks of scenario 12 and 13

7.4.3 Scenario 14 - 300 GW installed capacity offshore wind North Sea

In April 2023, the Ostend Declaration was signed by the North Sea countries, including Ireland, France and Luxembourg. The declaration states that the countries jointly aim to produce 300 GW of offshore wind energy by 2050 in the North Sea. In scenario 14, this ambitious goal was simulated. The same connection configuration as in scenario 8 is used. The resulting electricity network is shown in Figure 7.27. Most of the energy generation potential of the Southern part of the North Sea will be exploited in order to meet the goal. Also, there will be a large deployment of offshore electrolysis. The total installed capacity of offshore electrolysis in this scenario is 137 GW.

When comparing the installed capacities shown in Table 7.12 to the capacities of scenario 8 (see Table 7.8), one can see that the ambitious offshore wind goal eases the load of the solar-PV and onshore wind generation. Also, due to the increased offshore hydrogen production, the gas turbine capacity increases. Having large gas turbine capacities in combination with (hydrogen) storage capacity makes the system less prone to extreme weather conditions. However, the total annual system costs are significantly higher in this scenario.

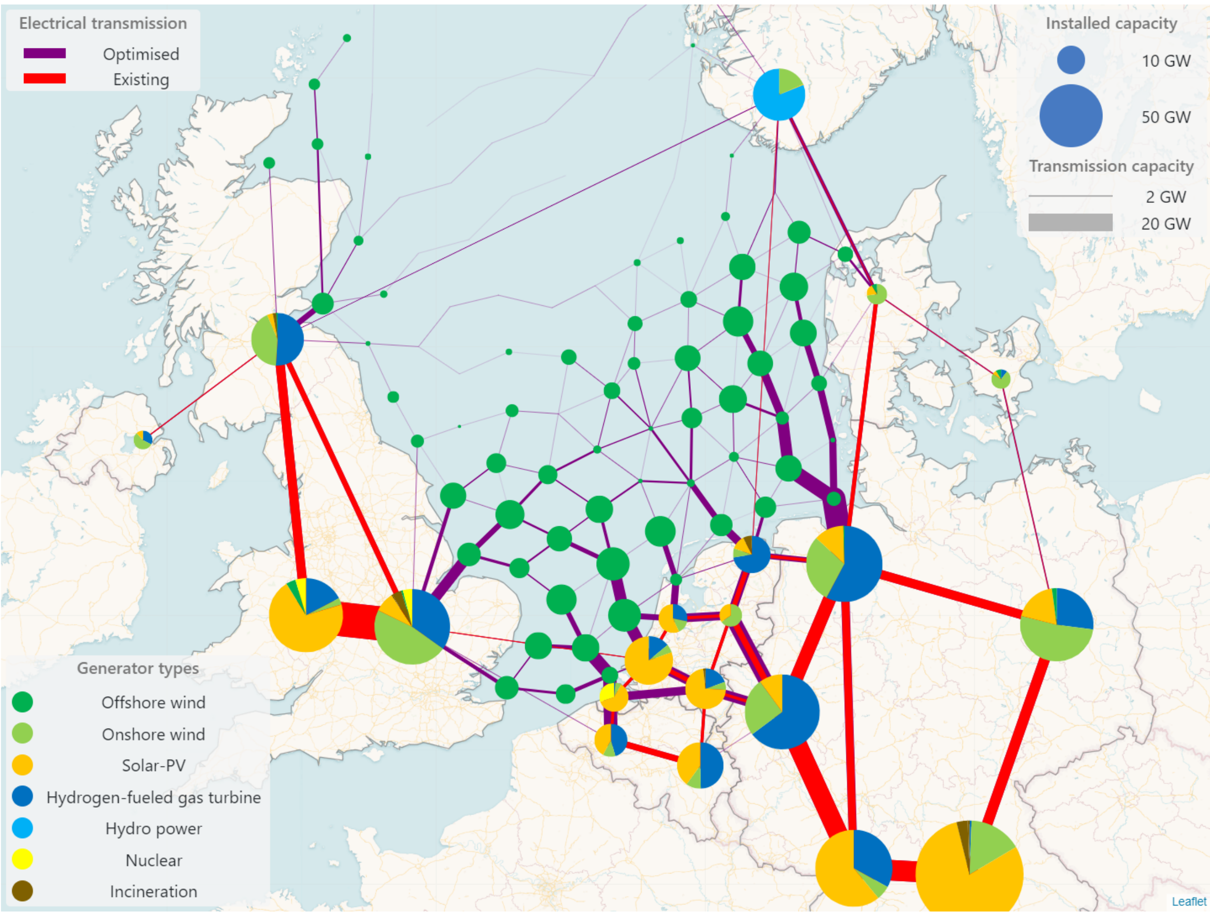


Figure 7.27: Geographical overview of the installed capacities of electricity generation and transmission of scenario 14 - 300 GW installed capacity offshore wind North Sea - resulting from optimisation of the Northwestern European energy system

Table 7.12: Key parameters of the Northwestern European energy systems resulting from scenario 14 - 300 GW installed capacity offshore wind North Sea

	Installed capacity	Unit
Hydrogen-fueled gas turbine	233	GW
Offshore wind	306	GW
Onshore wind	185	GW
Solar-PV	323	GW
H2 Electrolysis Offshore	137	GW
H2 Electrolysis Onshore	11	GW
Electrical transmission North Sea	32287	GWkm
Total system cost	106.2	bn€/yr

7.4.4 Conclusion

From scenarios 12 and 13, it can be concluded that the shape of the cost function does influence the model output. In the case with non-linear cost functions for hydrogen pipelines and DC cables, fewer connections are made and hardly any small connections are deployed. However, one pays a penalty of an enormous increase in computing time. For comparison, the solution time for scenario 12 is 27 seconds while the solution time for scenario 13 is more than 22 hours.

Scenario 14 shows the far-reaching investments that need to be performed to fulfill the ambitious generation goals stated in the Ostend declaration. Also, it shows the flexibility of the PyPSA-NorthSea configuration. Different goals and constraints can be implemented easily to generate new output configurations.

8 DISCUSSION

In this chapter, limitations of this study will be highlighted. As with all models, the developed model configuration is a simplification of reality. Furthermore, recommendations for future research are provided.

8.1 Validity of the results

With a threshold area of 5000 square kilometres, the distances between the offshore nodes are too large for inter-array cables [35]. This model does provide a proper representation of the connections between the energy hubs. However, this model does not aim to provide results for the infrastructure and spatial configuration within a region. Rather, the total generation, conversion and storage capacity of an offshore region form the input of a more detailed study of that region.

The weather data forms an important set of input parameters as they determine electricity generation profiles. The data set that has been used for this research is the weather data of 2015. This means that the resulting time series are only valid for a year in the past and not for any year in the future. However, the results do provide valuable indications for yearly energy production and consumption. In future research a sensitivity study could be performed in which multiple weather years are used as model input to catch extremes and to find a bandwidth for the resulting model output.

The cables and pipelines form direct connections between nodes. While the water depth, Natura 2000 areas and shipping routes were included in the generation potential, properties of the sea bed and the Natura 2000 areas were not included in determining the cable routes. This may result in an underestimation of cable cost. This is countered, in part, by a length correction factor, which is a constant and does not depend on the location of the link.

8.2 Model limitations

The model includes the energy infrastructure in the North Sea countries, these countries are assumed to be self-sufficient as a whole. Interconnection capacity to other countries (France, Ireland, Luxemburg, the Baltics, Sweden, etc.) are not included. These interconnections might influence the energy system configuration on the North Sea. Further research is required to quantify this effect.

Only wind turbines, electrolysis and hydrogen storage are considered in the offshore regions. Other technology types as floating wind turbines, offshore (on an island or floating) solar, tidal energy and wave energy could be implemented in the model. Glaum et al. describes the benefits of floating wind in the North Sea [13].

In the optimisation algorithm, a time resolution of three hours is used. Increasing the resolution to an hourly resolution would give more accurate results, however computational burden would increase. One would expect larger storage requirements as the generation and demand profiles will fluctuate more [40]. Also, the nominal installed capacity of gas turbines is expected to grow to account for peak power demand [41].

Cost assumptions and demand profiles for 2050 are predictions and are based on trends. These assumptions involve uncertainties which are reflected in the model outputs. Parametric uncertainty, such as costs and efficiencies of technologies, should be assessed using robust methods such as global sensitivity analysis or Eplorative Modelling Analysis (EMA) [42][43]. Moreover, recent publications have demonstrated the feasibility of combining parametric and structural uncertainty assessment using Modelling to Generate Alternatives (MGA) and stochastic sampling based on surrogate models [44].

The modelling framework PyPSA linearises the objective function and constraints to be able to solve large problems with multiple nodes and a high time resolution. This is a sensible simplification since solving a problem with only six offshore nodes and a time resolution of 24 hours, costs seconds if the problem is a programming problem while it costs hours if the problem is a mixed integer programming problem. In PyPSA-NorthSea, the non-linear effects were mimicked by omitting radial connections and forcing connections to be grouped in the offshore DC grid. In future research, filtering small connections can also be done by solving the problem iterative and removing small connections between runs. This prevents the model from deploying small connections where the cost assumptions are not valid while keeping the problem linear and limit the computational burden.

In PyPSA-eur, the power output of the wind generators is scaled with a correction factor to account for wake losses. With this implementation, the power curve is scaled vertically. This means that the nominal power of the wind farm will never by reached. However, in reality, the nominal power will be generated, only at a larger wind speed. One effect of shifting the power curve vertically is that nominal transmission capacities are underestimated. Therefore, it is more convenient to transpose the power curve along the axis of wind speed.

8.3 Future research

Based on the limitations of the model and the resulting networks from the scenarios a list of future research topics is formulated.

1. Develop a more detailed model of offshore wind farms and connection of the wind farms to an energy hub including inter-array cables. The outputs of this model can be used in the cost assumptions for offshore wind generation.
2. Perform a sensitivity study in which multiple weather years are used as model input to find a bandwidth for the resulting model output.
3. Perform a sensitivity study in which a spectrum of cost assumptions is used as input for the model to find a bandwidth for the resulting model output.
4. Test the robustness of the energy system configuration for extreme weather and/or demand conditions.
5. Test the effect of the inclusion of interconnection capacity to countries that do not border the North Sea.
6. Include more offshore regions in the offshore mesh, e.g. the Baltic Sea and/or the Celtic Sea.

7. Attach more generation and storage techniques to the energy hubs.
8. Create a better representation of wake losses in offshore wind farms.

9 CONCLUSION

This thesis presents an energy system optimisation study on the system role of energy hubs in the North Sea. While various energy modelling systems have been performed already, this quantitative study on the Northwestern energy system with the main focus on the North Sea integrates a representation of the energy infrastructure in the North Sea region in a complex, developing energy system. By integrating the offshore regions as energy hubs in the Northwestern European energy system, the potential collaboration between countries and between technologies is captured.

9.1 Model extensions

The Northwestern European energy system was modelled using the modelling framework PyPSA. PyPSA is an excellent tool to model the Northwestern energy system. The open-source nature of this framework ensures transparency of the results and allows for a contribution to the open source modelling the community. The default PyPSA-eur configuration was used as a starting point for the model, however, this configuration lacks a level of detail for the offshore regions. To fill this gap in the model configuration, PyPSA-NorthSea has been developed. The model extensions and concepts provided in this thesis can be used by others in future research.

The model extensions developed in this study can be divided into three categories: the creation of offshore nodes, the introduction of different buses at the offshore nodes representing different energy carriers and the modes of connection between the buses.

The created offshore nodes are evenly distributed over the economic exclusive zones of the North Sea countries. The locations of the offshore nodes are used in a Voronoi tessellation to form small offshore regions for which the generation potential has been determined individually. The new regions are smaller and more evenly shaped than the offshore regions in the PyPSA-eur configuration. This results in less variation of the available wind resources and the water depth within the offshore regions.

In the default configuration, only radial electricity connections were included using either AC cables or DC cables. In the PyPSA-NorthSea configuration, offshore generators that were allocated to onshore nodes are moved to the offshore nodes and the transmission infrastructure was decoupled from the electricity generation. Decoupling the transmission infrastructure provides more freedom to the model to choose the way to utilise the generated electricity, which is a better representation of real life dynamics. By introducing a high voltage DC bus, a high voltage AC bus and a hydrogen bus at each offshore node, the electricity output of the wind generators is converted to a suitable energy carrier at each time instance. This provides insight into the best mode of connection for offshore electricity generation.

9.2 Scenario study

In the scenario study, constraints were added to the model to get meaningful results that comply with policy. Without these constraints, the full technological potential for onshore wind generation is used and hardly any offshore wind farms are deployed which is unlikely due to societal resistance.

From the scenario study it can be concluded that an offshore electricity grid plays an important role in a cost optimal energy system. When offering the model the freedom to choose between an AC and a DC grid or a combination of both, it was found that an offshore AC grid is hardly deployed by the model and does not form a significant asset in the energy system.

Moreover, the introduction of offshore electrolysis reduces the installed electrical transmission capacity in the North Sea by 23% and reduces the total energy system cost by 247 M€/yr. 28.9% of the generated electricity by offshore wind farms in the North Sea is converted into hydrogen.

9.3 Societal relevance

The results from the optimisation study can be used by transmission system operators and policy makers. Long term investment plans can be justified to be able to work towards a sustainable energy system. The nominal capacity of the offshore wind farms, converter stations and hydrogen electrolysis in a certain region can be used as input for detailed engineering of offshore energy infrastructure.

By optimising for the entire energy system rather than for the electricity infrastructure in the North Sea only, the focus shifts from exploiting the wind potential of the North Sea to serving the energy needs of the North Sea countries. The configuration in the North Sea that has been found shows the benefits of close collaboration between the North Sea countries. In an energy system without carbon dioxide emissions, the security of energy supply depends on the weather conditions. Geographical dispersion induced by strong collaboration helps reducing this dependency.

Furthermore, the model configuration is created in an open-source modelling framework. Therefore, new scenarios can be created and optimised when called for. Unforeseen developments in technology costs or demand profiles may result in a decreased validity of the results of the scenarios presented in this thesis. However, the developed model will still be usable by implementing adjusted cost assumptions and demand profiles.

Overall, the created model provides more configuration options to connect offshore electricity generators to the shore than the default PyPSA-eur configuration. Strong interconnection capacity between the North Sea countries via offshore energy hubs benefits the performance of the energy system. Furthermore, offshore electrolysis is an important asset in the energy system of the future. The model outputs can be used by system operators and policy makers to form the basis for long-term investment plans.

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A SCENARIO EXPLORER

A scenario explorer has been developed to view the results of all scenarios. With the scenario explorer, interactive figures and tables can be accessed, some of these figures are included in this thesis. The user of the explorer can select the scenario by combining the different model options. Some elements that are included in the explorer are the geographical network overview and the installed capacities of generators and hydrogen converters per North Sea country. Furthermore, one can take a look at the yearly energy balances and storage capacity.

A peak into the explorer is displayed in Figure A.1. The scenario explorer can be found online [38], it contains scenarios that have been discussed in this thesis along with some scenarios that were not included in this thesis. Note that all scenarios in the explorer have been solved already, the scenario explorer functions merely as a viewer and can not be used to solve new scenarios.

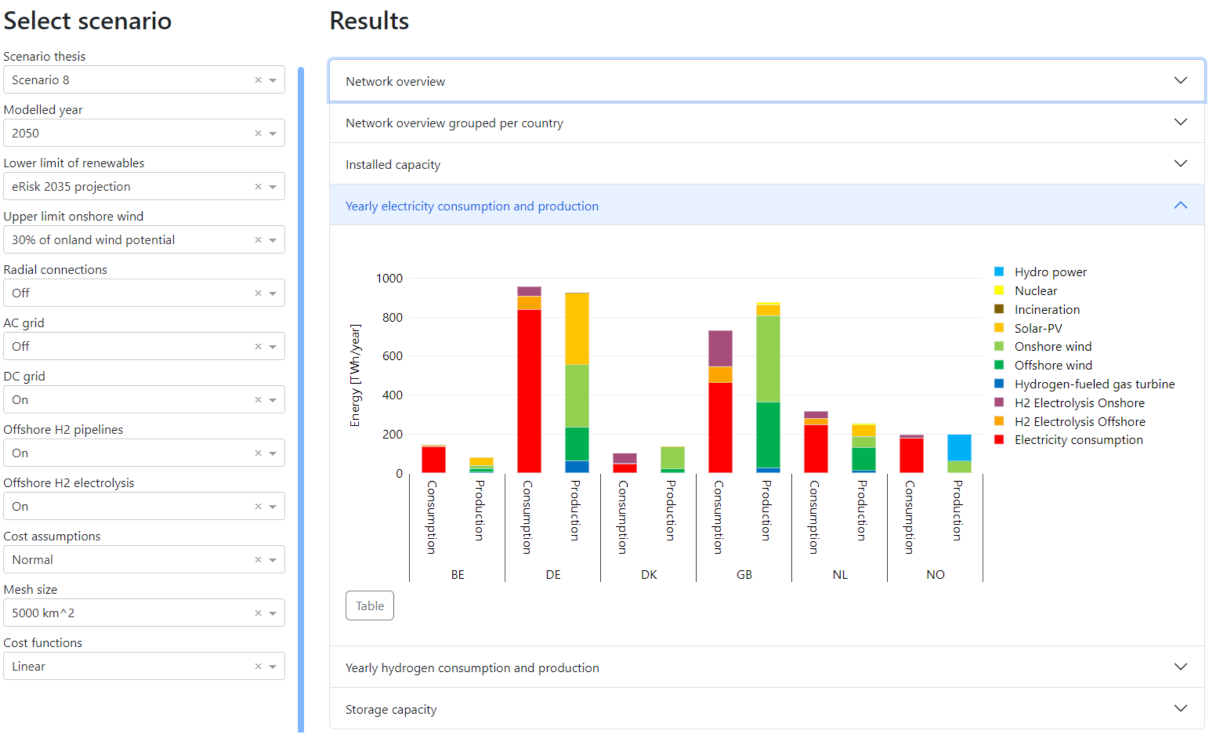

Figure A.1: Example view of the scenario explorer with the scenario selector on the left and the results on the right