Configuration analysis of the Danish energy island in the North Sea

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Configuration analysis of the Danish energy island in the North Sea

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Abstract:

In this project, the impact the Danish energy island have on the energy system is investigated. The predicted GHG reduction only corresponds to a 44 % reduction, which is not sufficient as Denmark made a binding goal of 70 %. Hence, it is investigated how much impact the 3 GW energy island have on the energy system and what configuration of electrolysers are favourable. To make a comprehensive analysis, both electrolysers and e-fuels are studied. Alkaline electrolyser cell and methanol is used for this project, as it is considered the best suited for the energy island along with the Danish energy system. In the analysis, three scenarios with different configurations is analysed, together with sensitivity analyses concerning infrastructure and electrolyser technology. When taking the future expansion of 10 GW wind capacity and the ability to have multilinked interconnectors in consideration, the most favourable configuration have electrolysis on the artificial island. Hydrogen is then transported through pipeline to main land, where hydrogen and carbon dioxide is synthesised to methanol. Though, the total costs are so close to each other, that the costs is not the determining factor, but more the system in general. The energy island of this configuration would lower the annual GHG emissions by 2.31 Mt, approaching the 70 % GHG reductions.

Summary

In the recent years, climate change have become a rising concern, which needs to be solved by reducing the use of fossil fuels. In the problem analysis, it was discovered that Denmark would only reach 44 % greenhouse gas reduction by 2030, with the current roll out of renewable energy sources and consumption of fossil fuels according to a prediction. As this is not sufficient to the binding goal of 70 % greenhouse gas reduction by 2030, radical measures have to be considered.

In this master thesis, the impact of the Danish energy island to the Danish energy system is analysed. Before the model is made, the methods used to solve the stated problem is presented. As the goal of the project is to simulate and obtain the best suited configuration for the energy island in the North Sea, a simulation tool is needed. Here, EnergyPLAN is used, as it can simulate the whole energy system, and at the same time have a fast simulation time. This is followed by a scenario development, as multiple scenarios are to be investigated. This is included to make sure the right configuration is chosen in the end, as it is of importance to the final operation and cost of the energy island.

As the energy island is to be modelled, electrolysers and electrofuels are studied as they are key factors of the energy island. Electrolysers convert electricity and water into hydrogen, which is a fuel with high energy density. Electrofuels are fuels produced from electricity, this could be hydrogen, but in this project methanol is used, which is a combination of hydrogen and carbon dioxide. Neither electrolysers and e-fuels are commonly used at a commercial scale at the given time, hence uncertainty of the future development is involved. It is decided to used alkaline electrolysis cell and methanol as both share good properties for the energy island and the energy system in general.

The calculations of the model is made in Excel, then imported into EnergyPLAN to simulate it. Three main scenarios are conducted, followed by a future perspective on the energy island. As the energy island is planned to be expanded to 10 GW, the ability to interconnect other countries is analysed as well. In the analysis the total cost of methanol production is estimated to be in between 0.72-0.84 €/l, which is 41-64 % more expensive than petrol.

The analysis shows the configuration with electrolysers on the energy island and methanol synthesis on main land is favourable as it has less infrastructure elements and if a leak occurs, hydrogen is not toxic for the marine life opposite to methanol. This configuration produce ≈13.3 TWh of electricity, whereas ≈10.7 TWh is used to produce methanol for the transport sector. This reduces the annual GHG emissions by 2.31 Mt annually.

Preface

This study has been conducted by Peter S. Højland, which is on the Masters program of Sustainable Energy Planning and Management at Aalborg Univeristy.

It is recommend to read the project in chronological order, as it gives the reader a better understating of the decisions made in the report.

Three appendices are attached to help the reader understand the model in more detail and the possibility to run the model in EnergyPLAN. In the list below the three appendices can be seen, whereas Appendix A is attached in the end of the report and Appendix B and C are attached digital.

- Appendix A - Implementaion in EnergyPLAN
- Appendix B - The calculations for the model which is attached electronically
- Appendix C - The files for the EnergyPLAN model

Nomenclature List

Acronyms

Acronym	Abbreviation:
AEC	Alkaline electrolyser cell
CC	Carbon capture
CEEP	Critical excess electricity production
CH3OH	Methanol
CHP	Combined heat and power
CO2	Carbon dioxide
DME	Dimethyl ether
e-fuel	Electrofuel
GHG	Greenhouse gas
H2	Hydrogen
H2O	Water
HHV	Higher heating value
HP	Heat pump
LCOE	Livelised cost of energy
LHV	Lower heating value
NH3	Ammonia
PEMEC	Proton exchange membrane electrolyser cell
PP	Power plant
PtX	Power-to-X
PV	Photovoltaics
RES	Reneable energy sources
SOEC	Solid oxide electrolyser cell
TRL	Technology readiness level

Contents

Problem analysis 1

In the recent years, climate change have become a rising concern globally. The people of many nations do consider a radical change concerning the use of fossil fuels. This was seen in the last election in Denmark (2019), and the American election (2020). Here the people had a great focus on climate change, and one of Joe Bidens promises was that USA would join the Paris Agreement again.

Paris agreement

The Paris agreement was formulated in 2015, which had the purpose of reducing the greenhouse gasses (GHG). This reduction should be made such the global average temperature would not increase more than 2 degrees compared to pre-industrial level, and pursuing to keep it well below 1.5 degrees. This goal is made to meet the threats of climate change, such as food production and consequently poverty. The goal differs from party to party, as one nation may have less resources to reduce their carbon footprint. This is mainly due to the economic situation of the nation and the current renewable share [United Nations, 2015]. In the Paris agreement, the greenhouse gas GHG emissions is to be reduced by 40 % in 2030 compared to 1990 levels. This is the general goal to keep the temperature below the 2 degrees compared to the pre-industrial levels. This goal was not ambitious enough for EU, hence they decided in December 2020 to adopt a new binding goal of reducing their GHG emissions by 55 % in 2030 [European commission, 2020].

All joining parties should strive to make a long term GHG emission strategy, which takes the capabilities of the specific nation into account. This is of most importance, as greater mitigation of GHG emissions reduces the need for additional needs, consequently increases the total costs [United Nations, 2015].

When the Paris agreement was formulated in 2015, Denmark already had a large share of renewable electricity production in the energy system. It can be said the modern wind industry started in Denmark after the oil crisis, where a new alternative to oil had to be found. Hence, the oil crisis gave incentives to research in the technology, consequently resulted in the modern turbine which is seen in large fold all over Denmark today [Vestergaard et al., 2004]. Therefore, Denmark decided to make a binding goal of 70 % reduction by 2030 compared to 1990 [Ministry of Foreign Affairs of Denmark, 2020]. To reach this goal of 70 % GHG reductions in Denmark, all sectors have to be involved in the GHG reductions.

Baseline scenario of Denmarks greenhouse gas emissions

In Figure 1.1, the GHG emissions in CO2 equivalents from 1990-2030 can be seen. The data obtained for 2025 and 2030 are both projections made by Danish Energy Agency [2020], these projections are made on a frozen policy scenario.

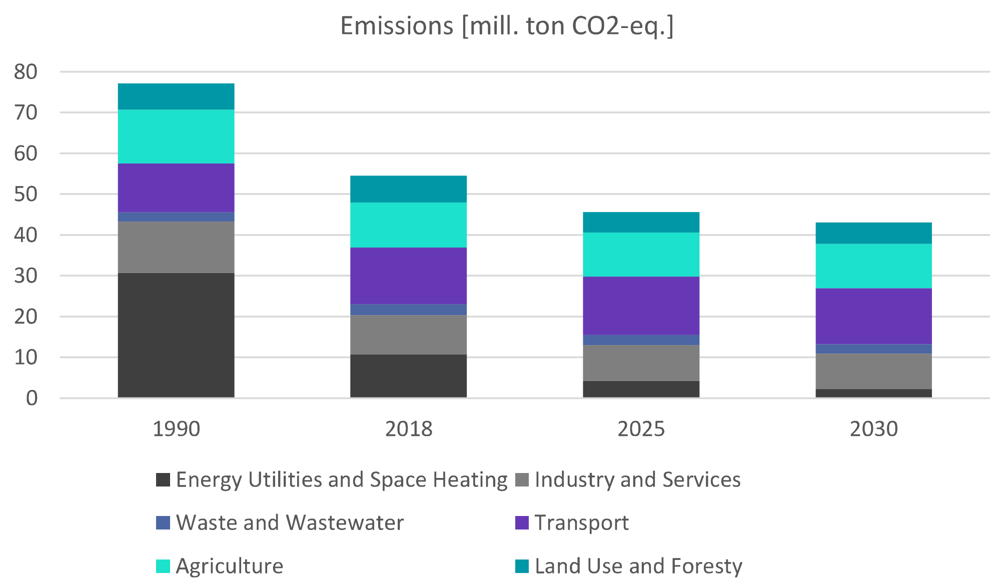

Figure 1.1. Total CO2 emissions from 1990-2030 divided into sectors [Danish Energy Agency, 2020]

In 2018, Denmarks total GHG emissions had been reduced by 29 % since 1990. All sectors but the transport have been reduced to some degree, where the most significant reduction is occurring at the *Energy Utilities and Space Heating*. This sector have been reduced by about 65 % since the 1990 where it emitted 31 Mt CO2-eq, whereas in 2018 it was only 10.8 Mt CO2-eq. This significant reduction of GHG emissions is caused by multiple changes in the energy system, some of which are:

- Reduced use of fossil fuels
- Increased share of renewable energy sources
- Increased share of biomass
- Improved overall efficiency

By 2030, the *Energy Utilities and Space Heating* sector is expected to reduce the emissions to 2.3 Mt CO2-eq. Hence, this sector only emits 7.5 % of the total emissions in 2030.

In Figure 1.2, a 2030 projection of the total CO2-eq emission can be seen. These projection only corresponds to a 44 % reduction of GHG gasses compared to the 1990. This is not sufficient, since Denmark have binding goal of reducing the emission by 70 %. To reach this goal, an additional 20 Mt CO2-eq have to be removed.

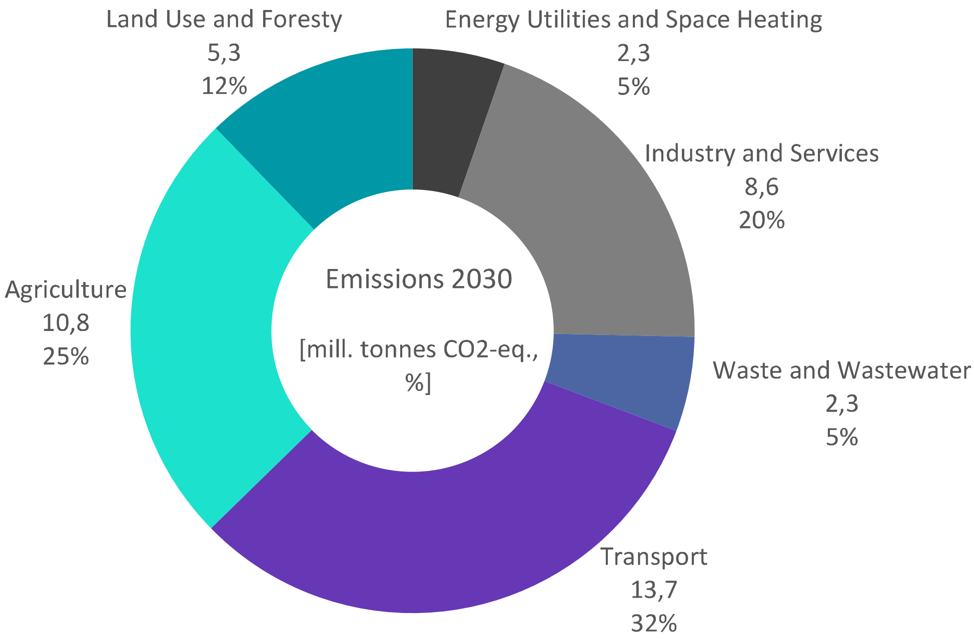

Figure 1.2. Total CO2 emissions in 2030 divided into sectors [Danish Energy Agency, 2020]

Industries which emits high level of GHG compared to their energy intensity are hard to reduce significantly in the near future. The *Land Use and Forestry* is predicted to lower the CO2-eq emission by 34 % in 2030 compared to 1990, where the most of the reduction comes from agricultural cropland and grasslands. *Agriculture* is predicted to lower their CO2-eq by 16 % in 2030 compared to 2018. The emission from *Agriculture* are divided into three different categories, fertiliser on fields, fertiliser management and ruminant digestion. The only category with a predicted reduction is the fertiliser management, this is because of the increased biogas production from manure.

Waste and wastewater is predicted to have a 5 % GHG reduction in 2030 compared to 2018. This is because the organic waste is used in biogas plants instead of being dumped on landfills. The incineration of ordinary waste is going to be unchanged from 2018 to 2030.

The last two sectors are the *Transport* and *Industry and Services*. These constitutes for more than half of the GHG emissions in 2030, and both are heavily dependent on fossil fuels.

Industry and Services is projected to lower the emission by 11 % towards 2030 compared to 2018, even though the energy consumption is going to increase 1.9 % annually. This is because of an increase of renewable gas and heat pumps (HP). The sector have great potential to a further reduction, since 54 % of the sectors emission are energy related.

In 2030, 65.9 PJ is consumed in the *Industry and Services*. The fossil fuels is used in internal transport and process heat. The internal transport represent 30 % of the total fossil fuels consumed in *Industry and Services*. The fossil fuels is used in construction machines, tractors, combine harvesters, fishing boats and trucks. The majority of these vehicles can operate on renewable fuels, by either small changes or replacing the engine. Process heat are divided into medium- and high temperature process heat. The medium temperature is temperatures below 150 °C, and represents 45 % of the total fossil fuels in *Industry and Services*. The high temperature represents 25 % of the total fossil fuels in *Industry and Services*, and is temperature above 150 °C [Danish Energy Agency, 2020]. In theory, all fossil fuels from process heat can be supplied by either HPs or directly electrified [Zühlsdorf et al., 2019].

In the transport sector, the fuel demand is going to remain the same in 2030 compared to 1990. This is caused by a combination of a demand growth of 24 % in road transport and increased efficiency. The total amount of fossil fuels consumed in the transport sector is 183 PJ. In regards to the emissions, road transport is expected to account for 92 %, and the rest is divided into domestic air, maritime, rail and defence. Passenger cars alone account for 58 % [Danish Energy Agency, 2020]. According to Energinet [2020], 95 % of private cars can be electrified, where busses and heavy duty vehicles have the potential of 75 % and 60 % respectively.

Both the *Transport* and *Industry and Services* have a great potential to reduce the GHG emitted within the sectors. Hence, a renewable alternative is needed to replace the fossil fuels. This renewable alternative can be based on electricity produced from renewable energy sources (RES), biomass or biogas. For the transport sector, direct electrification, indirect electrification and biogas can be used. The indirect electrification is also known as electrofuel (e-fuel), this can be a variety of fuels produced from electricity. All e-fuel are based on hydrogen (H2), where it is often synthesised with carbon or nitrogen [International Renewable Energy Agency, 2019]. The *Industry and Services* can be supplied by HPs, electric heaters, e-fuels, biomass and biogas. The most suited source of energy varies from each use case.

To reach the GHG reduction goal of 70 % by 2030, Denmark have to substitute the fossil fuels with renewable energy. Hence, the first priority is to increase the share of renewable electricity production. This have to increase significantly, even though the baseline scenario expects the *Energy Utilities and Space Heating* sector only emits 5 % GHG in 2030 compared to 1990. An increase of RES capacity is needed, in order for the other sectors to become more renewable. Both *Transport* and *Industry and Services* have great potential of reducing the use fossil fuels, where the majority of the solutions are dependent on RES.

The most common RES in Denmark are onshore wind turbines (WT), offshore wind turbines and photovoltaics (PV). In Figure 1.3, the levelised cost of electricity (LCOE) is presented for the mentioned RES. To reach the Danish GHG goal, the GHG reductions have to occur before 2030, hence both the costs for 2020 and 2030 have to be considered. According to Mathiesen et al. [2017], Onshore wind farms are the favourable option both in 2020 and 2030 in regards to LCOE. Offshore wind farms are the second most economic favourable both in 2020 and 2030, but Utility-scale PV is cheaper in 2050 compared to offshore win farms.

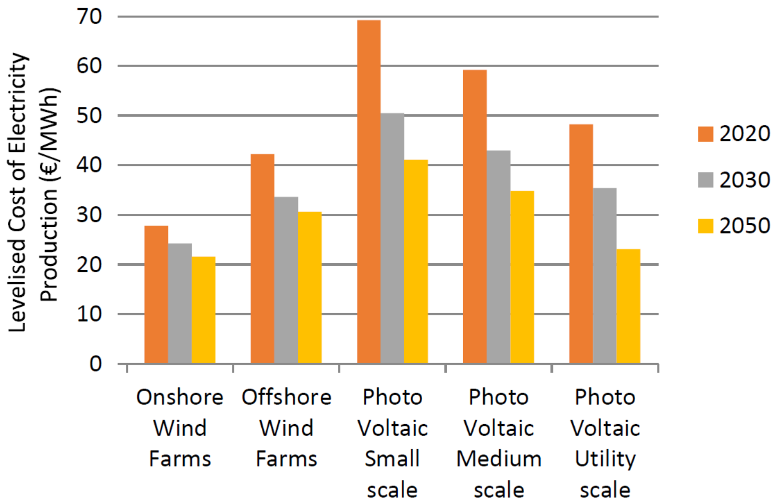

Figure 1.3. LCOE of RES used in Denmark for [Mathiesen et al., 2017]

Costs are not the only incentive to choose one technology over the other - land use, social acceptance and the electricity grid is also of importance.

If land use is considered, PV reserves the land which it is installed at, whereas onshore WTs does have the possibility to have crops around them [Mathiesen et al., 2017]. Offshore WTs does only occupy an area which could potentially be used by the fishing industry.

The amount social acceptance for RES are highly area dependent. Denmark have a history of achieving a large social acceptance when starting to roll out wind turbines in the 1980s. This is said to be caused by the involvement and ownership of the wind turbines. In the 1980s, the wind turbines was manufactured by small machinery manufactures located in Denmark, whereas today it is dominated by large companies, which is owned by national and international investors. This is then followed by the local wind turbine ownership in the 1980s being replaced by large investors. This transition have made it difficult to maintain the local support for wind turbines [iea wind, 2009]. Since Utility scale PV does not have a long history in Denmark, the level of social acceptance cannot be stated. According to Ladenburg [2008], the public do in general prefer offshore wind turbines compared to onshore, and acknowledge that the future wind power should to a large extent be offshore.

Offshore wind turbines potential in the North Sea

Offshore wind turbines is expected to be the RES producing the most electricity in Europe by 2050. The economic attractive potential is almost as great as all Europe's electricity generation combined in 2030. According to [BVGassociates, 2017], the potential is as great as 80 % and 180 % of Europe's electricity demand by 2030 for their baseline and upside scenario respectively. The baseline is based on the current policy framework and cost reductions. Whereas the upside scenario is based on what the industry have the potential to deliver if the governments acts on the cost reductions, hence multiple drivers within the wind turbine industry becomes cheaper.

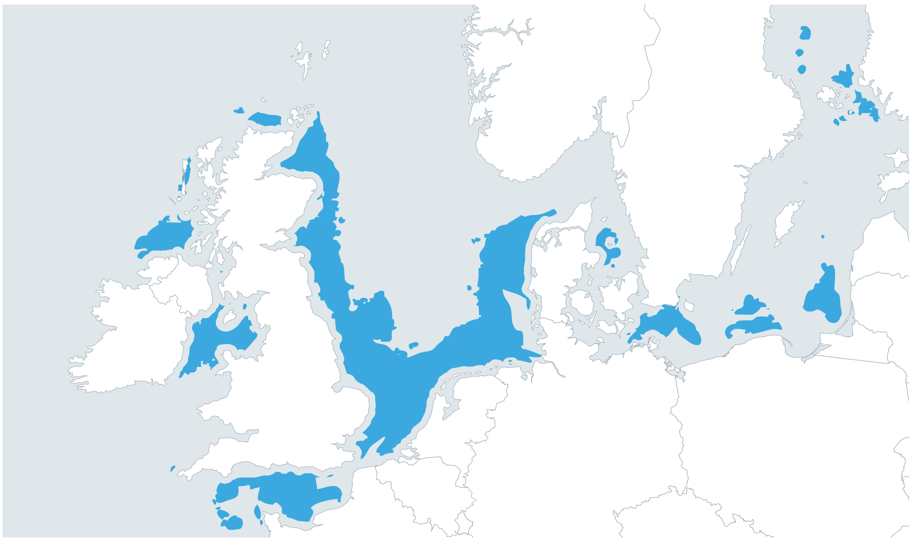

Figure 1.4. The areas where it is economical feasible to deploy offshore wind turbines by 2030 [Ørsted, 2019]

In terms of placement of the offshore WTs, the sea with the highest economically attractive resource potential with the current policy framework is the North Sea with 355 GW. The Atlantic's potential close to half of the North Sea, whereas the Baltic Sea is only about one quarter of the North sea. The economic attractive potential for the upside scenario is about 100 % greater than the baseline scenario.

If the baseline scenario conducted by BVGassociates [2017] is considered, Denmark have the second highest economic attractive potential of offshore WTs by 2030. This is about 400 TWh annually, produced by 90 GW WTs. This maybe be the reason to the Danish government have decided to build multiple energy islands.

The Danish energy island

In 22th of July 2020, a Danish climate agreement was made, which decided that two energy islands were to be constructed. One of the energy islands is going to be located at Bornholm in the Baltic Sea, where Bornholm acts like the hub for the offshore WTs. The energy island is going to have a capacity of 2 GW wind turbines, and connection two or more countries. The other energy island is going to be located in the North Sea about 100 km from the Danish coast. This is going to be an artificial island which have a capacity of 3 GW wind turbines, but in the long run it is expected to expand to 10 GW [COWI, 2021b].

The term "energy island" is still relatively undefined since nobody have build any yet. Hence, an Energy Island is going to be defined to some degree.

- It is an existing or artificial island.
- It acts like a energy hub for near by RES, which at the given time is only offshore WTs.
- It have interconnectors to two or more countries.
- It can include energy conversion

The two Danish energy islands is still in the planning phase, but some of the most essential elements of the islands have been either drafted or decided. The energy island in the North Sea still have many uncertainties, such as type of artificial island, exact placement, interconnections and the use of offshore energy conversion and storage [COWI, 2021b].

The energy conversion is production of e-fuel from the renewable energy, where the uncertainties involve the placement of the conversion site. Energy conversion is also known as Power-to-X (PtX) where the X is a fuel in this context.

Since the production of e-fuel and transmission lines is of great importance and influence each other, it is looked further into to get a better understanding of how this contribute to the Danish energy system.

Problem formulation 2

In the problem statement, the European Unions and Denmark's goal regarding the Paris Agreement was described. The projections with frozen policy only reduces the GHG emissions by 44 % compared to 1990, whereas the Danish goal is a 70 % reduction. Therefore other measures have to be taken to comply with the Danish reduction goals.

The sectors which have the largest GHG emissions were then studied briefly, where it was discovered the *Industry and Services* and the *Transport* sector have a great potential of GHG reductions. Both sectors are very energy intensive, and the fossil fuels used in the sectors can be replaced.

This was followed by the most favourable RES in Denmark, where onshore WTs is the cheapest per installed capacity, but both the land use and social acceptance favour offshore WTs. PV showed to have a great potential in 2050.

Lastly, the offshore WT potential in the North Sea was described. Here it was discovered that Denmark have the second highest economic attractive potential of all the countries in Europe. This is then followed by the Danish energy islands which by 2030 have a capacity of 5 GW offshore WTs. The one in the North Sea contribute with 3 GW and potentially 1 GW of electrolysers and is studied further.

Research Question:

What is the potential role of the Danish energy island in the North Sea in reducing the greenhouse gas emissions by 2030, and what configuration of electrolysers are most feasible?

Sub-questions

1. What e-fuels are best suited for the Danish energy system?
2. How does the production of electrofuels effect the use of fossil fuels?
3. What placement configuration of electrolysers are most economic feasible?

3 Research design

In this chapter the research design is presented, to provide a basic overview for the reader. The three methods is used throughout the project are at the right side of Figure 3.1, these are equipped with arrows which points to the chapters and sections they are applied in. At the left side, the research- and sub questions are located. These do also have arrows, which shows where they are answered. Naturally, the structure of the report is in the middle, chronological from top to bottom.

Starting with the problem analysis, the rising concern of increasing GHG emissions are enlightened. Here it is discovered the transport sector and industry are predicted to emit the most GHG in the future. Here it is decided to see what impact the danish energy island can have on these emissions.

To answer this, a knowledge about electrolysers and e-fuels have to be obtained, as they are the replacement of the fossil fuel in these fuel heavy sectors. Therefore, the best suited electrolyser together with the e-fuel is found.

The knowledge gained in "state of the art" is then used to make a model which is able to simulate the impact the energy island have on the Danish energy system. Here three different scenario are made, with the purpose of finding the most feasible electrolysis configuration.

In the analysis the results are analysed, and a future aspect is made, such the future investments are included as well. This is then finished by a sensitivity analysis concerning multilinked infrastructure and the used of another electrolyser technology as it improves the efficiency, consequently lowers the total GHG emissions. At last, the discussion, conclusion and recommendations are presented.

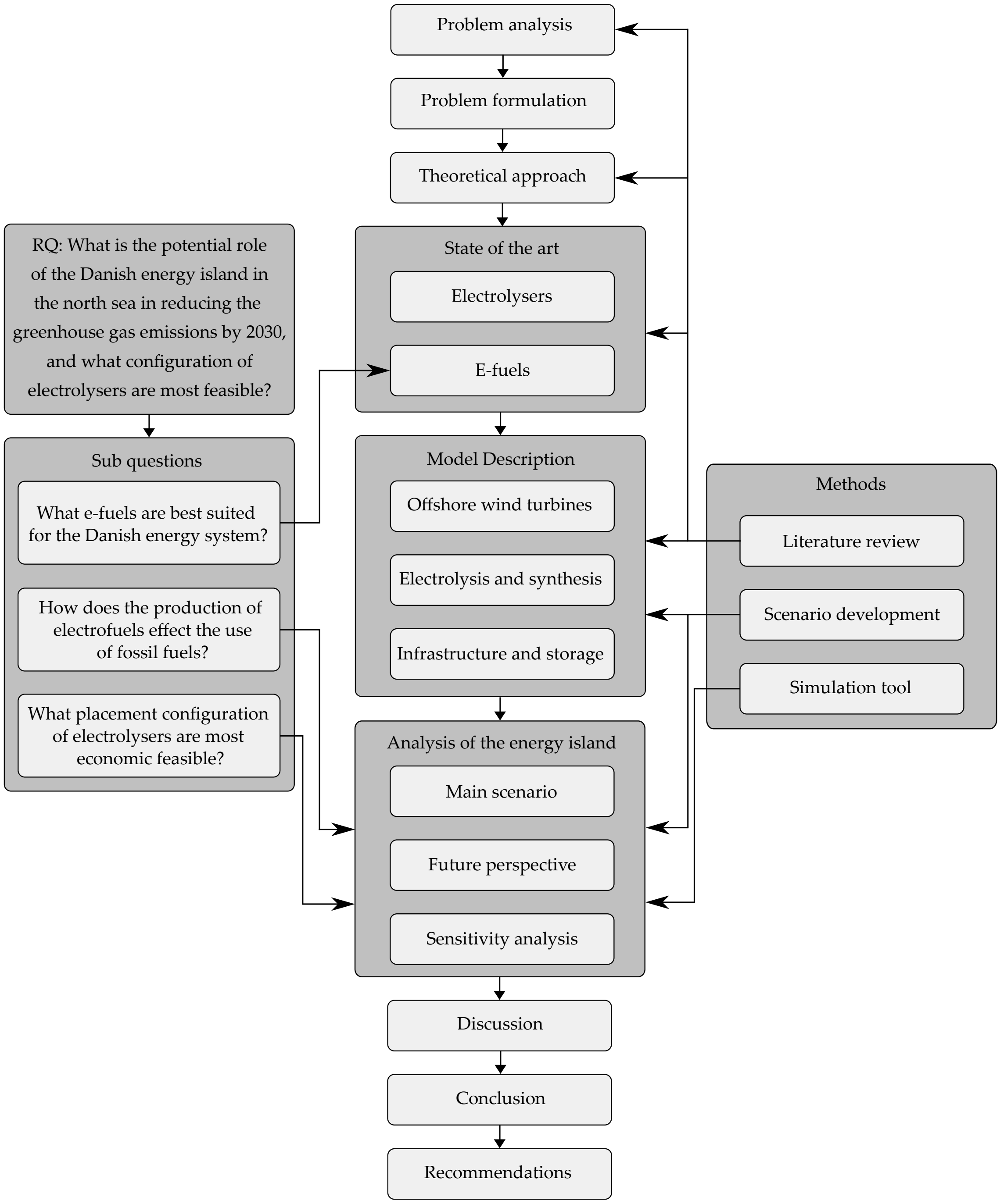

Figure 3.1. Overview of the structure of the report

4 Theoretical approach

4.1 Adequate level of detail

Adequate level of detail is a theoretical approach which ensures the an adequate amount of knowledge withing the research area is obtained to make the given analysis. Simplified, the theoretical approach is made up by first and second order macro and micro structures. The first order governance systems is societally constructed, and can only be changed through political processes. This could be regulations regarding the specific RES, nature conservation and the electricity grid. Whereas the second order governance systems can be changed seamlessly. The macro structure consist of elements which are crucial to have knowledge about to finish the analysis, this could be the implementation of PtX in regard to this project. This is of importance, as the Danish energy island modelled to include 1 GW of electrolysers. The micro structure is a more defined macro structure, which is used if the knowledge in the macro structure is not sufficient to make the analysis. A micro structure of the implementations of PtX could be specific technologies, placement, efficiencies and etc. [Hvelplund, 2001].

The macro and micro structures which are necessary to conduct the analysis outlined in the research question are seen below, where the macro structures are the dots and the indent are the micro structures.

- Type of renewable energy sources
  - Offshore wind turbines
  - Power-to-X
- Base scenario for energy system - $IDA2030_{Vision}$
  - Existing demands
- Implementation of Power-to-X
  - Type of electrolyser
  - Type of electrofuel

The listed structures are all essential to reach the final conclusions. Some of the structures are pre-decided on either a political level or delimited in the problem analysis.

The technologies used at the energy island are of great importance, as they are the foundation of both the energy island and the model. For electricity generation, offshore WTs are used. Part of the electricity is then used to produce e-fuel. E-fuel is used to reduce the use and independence of fossil fuels, hence the national GHG emissions are expected to lower when e-fuels are introduced to the energy system. E-fuels can both be based carbon and nitrogen, the various fuel have different use cases and production processes, hence they are looked further into in Section 6.2.

Methods 5

5.1 Literature review

The aim of this project is to make a detailed simulation of different electrolysis configurations to find the best suited for the Danish energy island. Hence, data concerning electrolysers, e-fuels and infrastructure is of importance. Therefore, a literature review is conducted.

The sources used for the project and model are both primary and secondary sources. These sources are collected through article databases like "Science Direct" or non biased reports published by Danish Energy Agency for instance.

An article database can both include primary and secondary sources. Primary sources is when the research have been generated through original experiments or data samples. Whereas, secondary sources do often interpret others work which both can be based on primary and secondary sources [USC Libraries, 2021]. Reports are often a gathering of primary and secondary sources, which is then interpret or combined to reach the desired goal of the specific report.

In this project, the technique of chain searching have been used to find relevant sources for the report. An chain search is when the bibliography of a article or report is searched for relevant sources [NJIT, 2021].

The search strategy used to find relevant articles and reports are through keywords like: Power-to-X, Power to liquids, methanol synthesis, electrolysis. These are the varied slightly to get another search result, this could be PtX, P2X or AEC electrolysis.

5.2 Simulation tool

In this project, the simulation tool EnergyPLAN is used to simulate the affect the Danish energy islands combined with the electrolysis plants have on the national energy system. EnergyPLAN includes the whole energy system, this is of importance as the future energy system is expected to be more cross-sectoral.

Sector coupling is key to reach the 70 % reduction by 2030, because of the increased share of non-dispatchable energy sources such as wind and solar. Hence, sector coupling provides a flexibility to the energy system. In a cross-sectoral energy system, the benefits of an investment can effect multiple sectors, making it less or more favourable. One example of this is implementation of electrolysers, where the produced hydrogen or liquid fuel can be stored. This makes the energy system more flexible and can have a positive effect on fossil fuel consumption [Münster et al., 2020].

EnergyPLAN is a input/output model, with different simulation strategies. Since the purpose of this project is to analyse what effect the future Danish energy islands have on the energy system of Denmark, together with the optimal amount of electrolyser capacity to compensate for the increased power generation. The inputs given to EnergyPLAN for this specific analysis are listed below:

- Capacity for offshore WTs and electrolysers
- Demands for e-fuels
- Storage for e-fuels
- Costs for the entire energy island including WTs, electrolysers and infrastructure

The inputs are calculated and explained in more detail in Chapter 7. The outputs which is of most interest are the annual costs, annual energy balance, total CO2 emissions and fuel consumption.

The simulation strategy used for this EnergyPLAN model is chosen based on the objective of the simulation. Since, the most important aspect is how the implementation of the energy island impacts the energy system, the technical analysis strategy is used. This strategy is superior when large shares of non-dispatchable energy sources are modelled and in general gives a more accurate result, eventually the most cost effective solution can be found [Lund og Thellufsen, 2020].

The EnergyPLAN model is based on $IDA2030_{Vision}$ conducted by Lund et al. [2020], since it has been published in 2020, hence new data have been used in the model. The model can be downloaded here EnergyPLAN [2021] or is digitally attached in Appendix C.

5.3 Scenario Development

When looking at actions taking to reduce the GHG emissions in the energy sector, a technology or political action is rarely decided without reflecting on alternative solutions or applications. Hence, scenario development is of importance when conducting an analysis regarding future changes. This gives the decision units a possibility to observe how changes within the project influence the outcome, hence affecting the final decision. Before defining some of the technical aspects of a scenario development, it is critical to define the purpose of it in the start. This will help the decision unit to form the scenarios, such the outcome of the scenarios is useful for the analysis [Ash et al., 2010].

Before the scenarios are defined, some reflecting questions are listed below, which justify the use of scenario development and what outcome is expected by conducting one.

- Why is a scenario development being conducted?
- What is expected to be gained from a scenario development in respect to final decisions?

A scenario development is conducted in this analysis to make sure the right decisions are made in regard to the applied technologies and system costs. This is applicable for the renewable energy sources, infrastructure and end product (e-fuel). When the scenario development have been conducted, it is expected to have an understanding of what the pros and cons are for each scenario, together with a recommendation of the preferred option from this analysis point of view.

The scenario typology used in this report is quantitative scenarios, which is based on numerical estimates of future developments. The output of this type of scenarios are often generated in a simulation tool, which is applicable for this analysis since it is conducted in EnergyPLAN [Ash et al., 2010]. The origin of the data used can then partially decide whether it is fact, predictions, scenarios or speculations which are conducted, as seen in Figure 5.1.

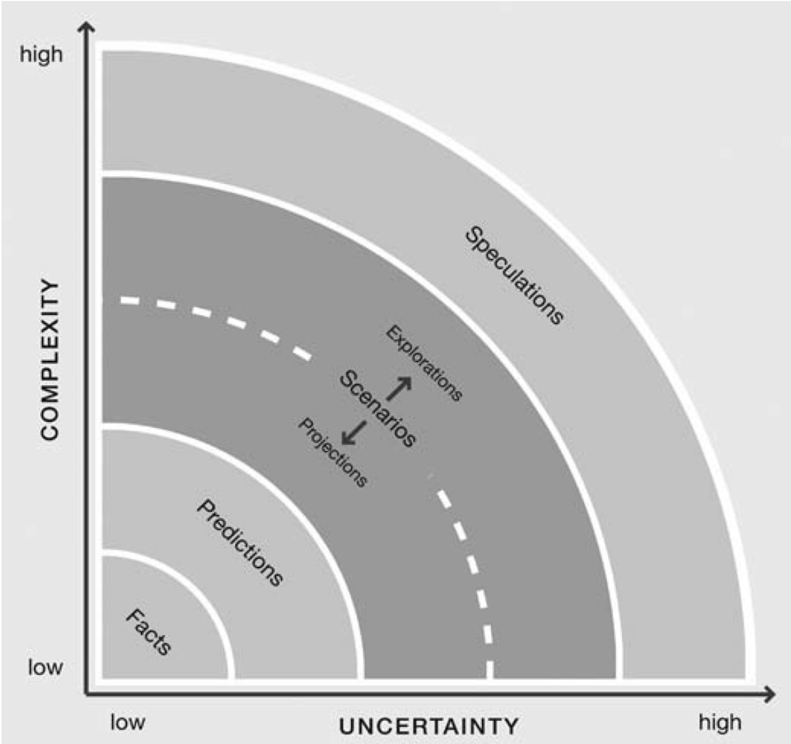

Figure 5.1. Type of scenarios linked with the level of complexity and uncertainty [Ash et al., 2010]

Since this project have focus on Danish energy island in the North Sea which is already in the planning phase, a lot of the framework is pre-decided with a number of uncertainties. These uncertainties is going to be simulated in EnergyPLAN, consequently observations obtained from this software can give a more clear picture of the final design of the Danish energy islands.

The EnergyPLAN model conducted by Lund et al. [2020] is used as a foundation, whereas modifications will be made such the model reflects more to the Danish energy system with the energy island in the North Sea. The e-fuel demand is removed from the model together with 1335 MW of offshore WTs, forming the base model in this project. The wind capacity is lowered, since the electricty demand for e-fuels are not present in the model anymore, and it is desired to reach the same critical excess electricity production (CEEP) as the original model. A fixed amount of biomass is also used, as Lund et al. [2020] have estimated this to be a sustatinable amount of biomass for Denmark. By doing this, the behaviour of the Base scenario of the Danish energy system is similar to the model conducted by Lund et al. [2020]. The $IDA2030_{Vision}$ EnergyPLAN files are avaliable on EnergyPLANs domain EnergyPLAN [2021] and attached in Appendix C together with the Base scenario.

As the modifications change the whole energy system, hence a list of key values will be shown below to get an overview.

Table 5.1. $IDA2030_{Vision}$ made by Lund et al. [2020] compared to the Base scenario

	Vision 2030	Base scenario model	Unit
Onshore wind turbines	6630	5295	MW
Electrolyser consumption	5.56	0	TWh/year
Oil consumption	32.90	35.89	TWh/year
Natural gas consumption	11.79	12.37	TWh/year
Biomass consumption	38.00	38.00	TWh/year
Import	0.19	0.20	TWh/year
CEEP	3.57	3.57	TWh/year
Total CO2 emission	11.50	12.41	Mt/year
Total Cost	21719	20552	M€/year

The Base scenario will be used as a foundation for the three scenarios which are to be conducted. It is expected to obtain the most suitable electrolyser placement for energy island in the North Sea.

The scenarios are all modelled with the same end product (e-fuel), which makes the scenarios comparable both in cost and the use case for the e-fuel. The energy island in the North Sea is expected to have 3 GW of wind capacity by 2030, whereas the electrolyser capacity is still in the research state. According to COWI [2021b], the electrolysis plant is expected to have a capacity of 1 GW. The simulations will include the 3 GW of wind capacity, while the total electrolyser capacity will be sized to achieve the most optimal energy system. 1 GW electrolysers will be placed on the energy island, while the remaining will be modelled in the energy system.

All the e-fuel transportation is through pipelines, according to COWI [2021b], H2 pipelines are superior over ships as the cost per ton of H2 i significant lower. Hence, the technology for transport of hydrogen by ships may not be mature for commercial use by 2030. This have also been confirmed from calculation in Appendix B.

The end product is the same for all scenarios, as the scenarios then are comparable. Hydrogen is be converted into a liquid fuel with the used of either carbon or nitrogen. These fuels are easier to transport than hydrogen and have similar properties to gasoline and diesel [International Renewable Energy Agency, 2019]. In Section 6.2, the most suitable e-fuels for this application are described in more detail.

The variables in the simulation will be explained in more detail in 7. The framework for each of the three scenarios will be described below.

5.3.1 Scenario 1.X

In Scenario 1.X, the electrolysers are placed on the energy island. The electrolysers will then produced hydrogen, which are to be transported back to main land. The transportation of hydrogen is through a pipeline. By having the electrolysis plant on site, the sea cable connecting the energy island to main land can be reduced. The reduction is dependent on the capacity of the electrolysis plant, the hourly production of hydrogen and the hourly distribution profile for the offshore WTs. On main land, the hydrogen in converted into e-fuel by either excess carbon from a biogas plant or air captured nitrogen.

5.3.2 Scenario 2.X

In Scenario 2.X, the electrolysers are placed on the island producing hydrogen. The hydrogen is then converted into a liquid fuel on site by either a nitrogen or carbon sources. If the fuel is carbon based, the carbon is harvested from biogas plants and transported through pipelines to the island. If nitrogen is used, it will be captured from the air, hence it will be placed locally on the island. The produced e-fuel will then be transported by a pipeline to main land. This scenario can lower the capacity of the sea cables to main land, by using the electricity on site.

5.3.3 Scenario 3.X

In Scenario 3.X, the electrolysers are placed on main land, hence the sea cable is dimensioned for the full 3 GW of wind capacity. The electrolysis plant have a heat loss, whereas some of that loss is recoverable and can be used for district heating. The e-fuel production will still get the carbon and nitrogen from biogas plants or air capture, respectively.

Throughout the analysis in Chapter 8, the three scenarios will be compared to each other. The scenarios will be analysed in respect to the Danish energy system, hence the different configurations can be seen in a energy system perspective. The data collected from the simulations will then be evaluated in such manner, the most suitable scenario is recommended.

State of the art 6

This chapter is conducted to address which type of electrolysers is best suited for the energy island. The chosen electrolyser technology is assessed based on 2030 predictions. The characteristics of the electrolysers will be compared. It is not modelled to be used for auxiliary services, hence the ramp times is not investigated.

In regards to the end product, the most suited e-fuel will be evaluated as well. Since the aim of the project and the energy island in general is to reduce the total CO2 emissions, e-fuel is replacing fossil fuels. It is chosen to be used in the transport sector, since there is a great potential to reduced the emission as mentioned in Chapter 1.

6.1 Electrolysers

Traditionally, hydrogen is produced from fossil fuels, such as natural gas, coal and naphtha. Today, 96 % of all produced hydrogen comes from one of these fossil fuels, consequently contributing to the increase of CO2 emissions. This can be avoided with the use of electrolysers which produce hydrogen (H2) with only electricity and water (H2O) as an input. Even though electrolysis can produce hydrogen without emitting CO2, the process does require 4 times as much energy than steam reforming [Martínez-Rodríguez og Abánades, 2020]. A by product of hydrogen production by electrolysis is oxygen, this have a commercial value, as it is used in the chemical industry and steel production. The origin of electrolysers goes as far back as 18th century, where alkaline electrolyser cell (AEC) was invented, this have been followed by the proton exchange membrane electrolyser cell (PEMEC) and the solid oxide electrolyser cell (SOEC) [Danish Energy Agency, 2017c].

Recently, the technology have received more attention because of its appealing characteristics of producing fuels without emitting GHG, which is only applicable if the electricity is sourced from a renewable production. energy storage is of importance, as RES lack of flexibility. Hence, with the Danish reduction goal of 70 % by 2030 compared to 1990, electrolysers are crucial for energy systems stability. Therefore, the three different electrolysis technologies will be investigated to choose the best suited for the Danish energy island [Danish Energy Agency, 2017b].

The electrolysers will be evaluated based on the same terminology, since this makes them comparable. The input energy have to be solely electricity, even though some technologies have the possibility to utilise the surplus heat to preheat the water.

The efficiency for electrolysers is often stated in both the lower heating value (LHV) and the higher heating value (HHV). The difference depends on the chemical composition of the fuel [Mathiesen et al., 2013]. In this project LHV will be used.

6.1.1 Alkaline electrolyser cell

Alkaline electrolysers are the most commercially used type of electrolysers today, this is partly due to its high level of technology readiness level (TRL), which have increased the efficiency and lowered the cost over time. Both in Germany and Denmark, 1 GW plants have been commissioned, which are expecting to produce fuels for the transport sector. Hence, AEC is capable to have single plants in the gigawatt scale .

Even though AEC is the most abundant type of electrolysers today, there is still a great potential for improving the catalyst, consequently improving the efficiency. Today the catalyst stacks have a long lifetime of 100,000 hours, resulting in a relatively low fixed O&M of 2 %. This have a big impact of the running costs, since the investment cost is quiet high for electrolysers. Overall, it have good economics combined with a relatively high efficiency of 68 % by 2030 as seen in Table 6.1 [Danish Energy Agency, 2017b].

Table 6.1. Alkaline electrolyser cells properties for a 100 MW plant [Danish Energy Agency, 2017b]

AEC	2030	Unit
Efficiency (LHV)	68.00	%
Heat output	3.00	%
Technical lifetime	30	Years
Specific investment	0.57	M€/MWe
Specific investment	1.16	M€/tH2/day
Fixed O&M	2.00	% of inv cost

6.1.2 Proton exchange membrane electrolyser cell

PEMEC is used commercially for small and medium scaled plants or applications. Siemens have the largest operational plant at 3.75 MW capacity, but the technology can scale to >100 MW by 2030. Even though the electrolyser can form large scale plants, they are unlikely to do to a high degree with the present predictions of the technology. This is because of the high electrolysis stack cost due to the used of scarce materials such as platinum together with the stack lifetime of 50,000 hours.

The biggest advantages of PEMEC are the quick response time and the high current density. These properties makes the system compact and fast changing loads. This is great for applications such as fuel cell for the transport sector [Danish Energy Agency, 2017b].

The PEMEC reach a 65.50 % efficiency by 2030 with a specific investment cost of 0.65 M€/MWe and 4 % of fixed O&M. This is about 14 % increase of investment cost and 100 % increase of the fixed O&M compared the the AEC .

Table 6.2. Proton exchange membrane electrolyser cells properties for a 100 MW plant [Danish Energy Agency, 2017b]

PEMEC	2030	Unit
Efficiency (LHV)	65.50	%
Heat output	3.00	%
Technical lifetime	25	Years
Specific investment	0.65	M€/MWe
Specific investment	1.38	M€/tH2/day
Fixed O&M	4.00	% of inv cost

6.1.3 Solid oxide electrolyser cell

SOEC is still in the research state even though its have been a known technology for many decades [Danish Energy Agency, 2017c]. The lifetime of electrolysis stack is 20,000 hours, which is relatively short compared to AEC and PEMEC [Danish Energy Agency, 2017b]. The electrode material for the stack can be nickel based, which is a cheap material compared to many of the alternatives [Danish Energy Agency, 2017c]. SOEC is expected to achieve a efficiency of 76.8-80.5 % as seen in Table 6.3, this can be increase further by introducing co-electrolysis. Instead of first producing hydrogen and then a carbon based e-fuel at another process, this can be done simultaneously by feeding the plant with CO or CO2. According to Mathiesen et al. [2013], co-electrolysis can improve the efficiency from electricity to a carbon based e-fuel by almost 12 %. By using co-electrolysis, the fuel is never in a hydrogen state, consequently avoiding the need for hydrogen storage, which is expensive.

SOEC have a low TRL which makes it hard to predict the properties and costs for a large scale application. Hence, Danish Energy Agency [2017b] have decided not to include data for large scale plants, because of the level of uncertainty. Though, they have still conducted a literature study which estimates the investment cost to be in between 380-500 €/kW which is similar to AEC and cheaper than PEMEC [Danish Energy Agency, 2017b].

Table 6.3. Solid oxide electrolyser cells properties for a 1 MW plant [Mathiesen et al., 2013] [Danish Energy Agency, 2017b]

SOEC	2030	Unit
Efficiency (LHV)	76.8-80.5	%
Heat output	-	%
Technical lifetime	20	Years
Specific investment	0.35-1.901	M€/MWe
Specific investment	0-3.28	M€/tH2/day
Fixed O&M	3.00-12.00	% of inv cost

6.1.4 Choice of electrolyser

Based on the data obtained from the previous sections, an electrolyser technology for the energy island is chosen. This decision is derived from characteristics and properties of the electrolysis technologies.

In general, the AEC is superioer over the PEMEC, where the most significant advantages for the PEMEC is not utilised in the use case of an energy island. Hence, the PEMEC will not be considered as a viable option for this project. In regards to the SOEC, it is superior in all aspects according to Mathiesen et al. [2013], whereas according to Danish Energy Agency [2017b], the investment cost and fixed O&M is more than 500 % and 2100 % larger respectively. This is because of the uncertainty of how fast the technology matures and the scale of the plant.

Typically, the O&M is between 2-5 %, but it can go as far down as 1.5 % with no more advantage of scale. This is present for AEC and PEM. There is no data concerning SOEC, but the factor of scaling have great impact on the cost.

Because of the TRL of SOEC and the uncertainty of the pace the technology matures in, the energy island will be modelled with AEC. Though a sensitivity analysis will be conducted with the SOEC, this is done to analyse what impact it haves on the energy system.

6.2 Electrofuels

In order to produce e-fuels with water electrolysis, the end product have to be chosen. This can be a variety of fuel, which all have the similarities of being carbon based with a exception of ammonia which is nitrogen based. Strictly speaking, hydrogen itself is also considered a e-fuel, but is not seen as a viable fuel for this project, as the handling and storage is very costly [IRENA, 2019]. Through a literature study, a number of fuels have been decided to examine closer to find the best suited for this project. The production of e-gasoline, e-diesel and e-jet fuel have been omitted due to the poor efficiency compared to the alternatives. Methane will not be investigated further, since it have to be pressurised by 32 MPa (316 atm) to become a liquid, hence it would be too costly for the transport sector compared to the alternatives.

In the Figure 6.1, an general overview of the use case for carbon and nitrogen fuels can be seen related to the transport sector. Each process is elaborated in this section, with an exception of electrolysis with is elaborated in Section 6.1. The carbon based fuels which is further investigated are methanol and dimethyl ether where ammonia is nitrogen based.

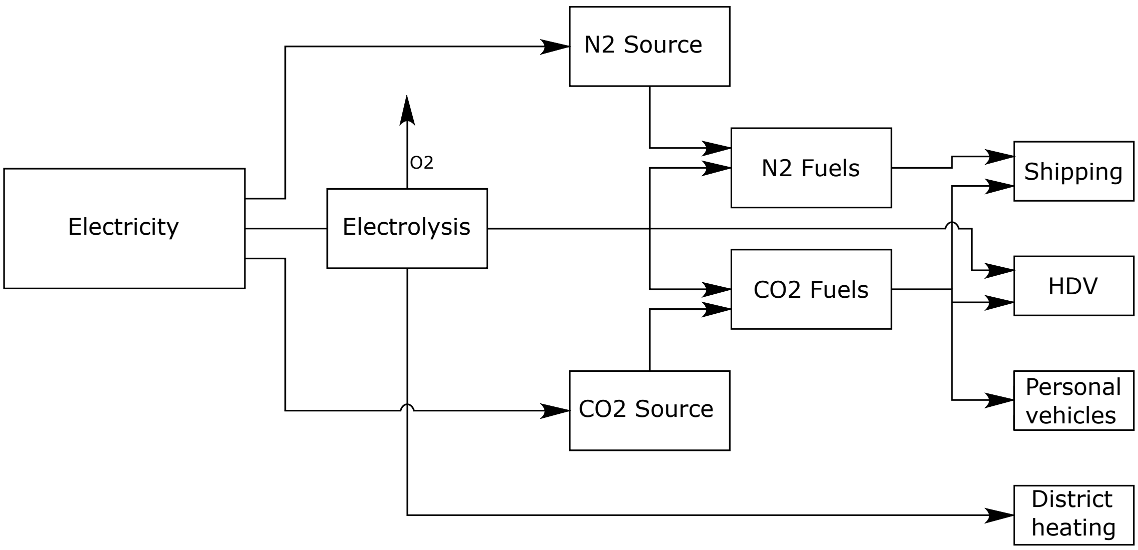

Figure 6.1. Overview of use cases for carbon and nitrogen based e-fuels

6.2.1 Ammonia

Ammonia (NH3) is a well known chemical compound of hydrogen and nitrogen which historically have been produced as a fertiliser. Today, about 180 Mt of NH3 is produced annually, which is mostly produced from fossil fuels. About 97 % of all nitrogen fertilisers origins ammonia, which together with the global demand requires a large NH3 source. Since ammonia is made up by hydrogen and nitrogen, it does not omit CO2.

Ammonia is a gas at atmospheric pressure (atm), and is in liquid form at a modest pressure of 0.8 MPa (8.9 atm). This requires a new infrastructure for the gas stations to store ammonia. The tanks to store ammonia is most likely to be double walled, as it is very toxic. When this is said, the transport of ammonia (pipeline and ships) is mature, as it have been through more than one century of development, this have also reduced the risks of leaks.

The combustion of ammonia emits NOx gasses, which are high potent in terms of CO2 equivalent, impacts the ozone depletion and give health issues. This may be mitigated by using a catalyst like diesel engines, but is still at a research state. Ammonia have a high auto ignition, hence a blend of hydrogen is needed to ignite the fuel during combustion. Ammonia do also have the ability to be reformed back to hydrogen, hence it can be used in a fuel cell, avoiding the NOx emissions [Valera-Medina et al., 2018].

6.2.2 Methanol

Methanol (CH3OH) have been used in decades in the transport sector because of its good properties. It is a carbon based liquid fuel, which have many similarities to gasoline such as the high energy density. Gasoline used in the EU is allowed to have up to 3% of methanol mixed in.

Methanol is well suited for spark ignition engines due to the lack of carbon to carbon bonds, resulting in a clean combustion without soot and is less likely to catch fire [Bechtold et al., 2007]. Though, a combustion engine can run with 100 % methanol, studies have shown 85 % methanol with 15 % gasoline delivers a smoother power delivery [Danish Technological Institure, 2019].

Methanol is a liquid at atmospheric pressure, which make it is easy to store and transport, therefore the existing infrastructure from the transport sector can be used.

In terms of GHG emission, methanol can reduce the emissions by 86 % compared to petroleum based fuels, and reduced NOx gasses as well. This reduction is from well to wheels and takes the captured CO2 into consideration as well as the pollutants [Matzen og Demirel, 2016]. A future advantage of methanol, is that it can be reformed back to hydrogen, hence it can be used in fuel cell like ammonia. By doing so, there close no none emissions will occur since no combustion is happening [Bechtold et al., 2007].

6.2.3 Dimethyl ether

Dimethyl ethers (DME) chemical formula is C2H6O, and is a gas at atmospheric pressure, but becomes liquid at a modest pressure of 0.5 MPa (5 atm). DME is seen as a potential substitute to diesel, as it burns cleaner due to the lack of carbon to carbon bonds and is safe for storage and handling. Since DME only have to be lightly pressurised to become a liquid, the existing LPG infrastructure for the transport sector can be used. Since LPG is mostly used for heavy transport, new infrastructure have to be rolled out if it should replace the light transport.

DME can be produced by two methods, direct and indirect. The most common method is indirect, which first synthesises carbon to methanol, then converted to DME in a second process by an reactor. The direct method converts the hydrogen and carbon to DME in a single process, making it more efficient and more expensive as well compared to indirect method [Azizi et al., 2014].

DME can be used as a fuel without any mixture, but needs a special motor designed for combustion of DME. A DME motor does achieve high performance together with low emission of CO2 and NOx [Azizi et al., 2014]. According to Matzen og Demirel [2016], DME introduces a GHG reduction up to 82 %. This is well to wheels and does consider pollutants and the captured CO2 in the calculations.

6.2.4 CO2 capturing

As all e-fuels but ammonia is carbons based, a reliable carbon source is needed to feed the upcoming production of e-fuels. CO2 can be extracted from fuel combustion and biomass/biogas plants. This makes biomass plants, combined heat and power (CHP) plants, and industrial processes ideal as a CO2 source [Ghaib og Ben-Fares, 2018].

Table 6.4. CO2 concentration in processes that are commonly used in Denmark [Ghaib og Ben-Fares, 2018] [PFPI, 2011]

	CO2 sources	CO2 concentration
Biomass process	Biomass fermentation	15-50 %
	Biogas upgrading	100 %
	Bioethanol production	100 %
PP/CHP plants	Natural gas combustion	3-5 %
	Coal combustion	10-15 %
Industrial process	Cement production	14-33 %

As seen in 6.4, the CO2 concentration of widely used technologies in Denmark is shown. The biogas upgrading shows great potential as the CO2 concentration is 100 % and therefore does not need to get further processing before used for carbon based e-fuel. According to Skov et al. [2019], Denmark have a potential of 71 PJ of biogas by 2035, and if all is upgraded biogas, a total of 2.11 Mt of CO2 is available annually. This is calculated in Appendix B.

Since the aim for the energy island is to be finished after 2030, the PP/CHP plants are to use biomass as a fuel instead of coal because of a political decision [Regeringen, 2017]. Even though biomass is seen as a carbon neutral energy source, it consists about the same amount of CO2/Btu [PFPI, 2011]. According to Energistyrelsen [2020], the energy system is to consume about 25 TWh annually, which would emit almost 10 Mt CO2. If both biogas upgrading and biomass combustion have carbon capture (CC), about 7 Mt of CO2 could be recovered and used for e-fuel production. Calculation for CO2 available can be seen in Appendix B.

6.2.5 Choice of e-fuel

The investigated e-fuels do all have a similar production efficiency, though the properties differ greatly between the fuel types. In the decision regarding the used e-fuel for the Danish energy system, factors such as level of toxicity, infrastructure and versatility are taken into consideration.

Ammonia shows great potential since it is nitrogen based which is abundant in the atmosphere. Though, the high level of NOx gasses and the need for new infrastructure makes ammonia unsuitable for the road transport, though it could have a big potential for international shipping in the long run due to the unlimited quantity of nitrogen in the atmosphere.

Both DME and methanol is very similar in terms of GHG reductions, and the combustion gasses. Though the difference lays in the state the fuel is in while being at atmospheric pressure, as methanol is a liquid while DME is gas. Therefore, Methanol is to be used for the Danish energy system as substitution to fossil fuels.

7 Model description

If the model is roughly generalised, it consists of three parts: electricity generation, electricity consumption and energy distribution. The electricity generation is 3 GW of offshore wind turbines, which is pre-decided for the Danish energy island COWI [2021a]. The electricity consumption is the electrolysis plant together with the methanol synthesis. The energy distribution include the pipelines for CO2, H2 and CH3OH together with the interconnectors and energy island construction. The model conducted will be explained to some degree such the reader have a general idea of the calculations and decisions made in the model.

In the end of the chapter, an overview of the economics for each technology will be made.

In this chapter, some of the calculations for the model will be explained and the differences between each scenario will be highlighted. First the calculations for the annual costs and interpolation will be visited, as they are of importance for the model, and is used to obtain costs and capacities for multiple technologies.

The annual cost is as the name indicates, the annual cost for an investment taking the interest rate and lifetime in consideration as well. The interest rate used for all calculations is 3 % as it is used in $IDA2030\_vision$ in EnergyPLAN. The equation for annual costs can be seen below, where $Cost_{inv}$ is the investment cost, $Interest$ is the interest rate and n is the lifetime of the investment which is typical set as the technical lifetime of the specific technology.

$$Cost_{annual} = Cost_{inv} \cdot \frac{Interest}{1 - (1 - Interest)^{-n}} \tag{7.1}$$

Even though EnergyPLAN calculates the annual cost, it is done for all investments in Appendix B, to get the total cost of the energy island without the rest of the energy system.

Interpolation is used for several calculations to get a more precise capacity or loss, consequently more accurate cost. It is used every time more than one data point is available.

$$y = \alpha + \beta x \tag{7.2}$$

Where (α) is the y-intercept, which is also called start point and (β) is the differential coefficient which describes the slope of the function. This is used for the cost of the interconnectors, transformers and construction cost for the energy island.

7.1 Offshore wind turbines

As earlier mentioned, the energy island have a 3 GW wind capacity. Though, this is without taking any losses into consideration. The placement of the electrolysis plant and methanol synthesis varies for each scenario, which introduces different amount of cable loss. This is due to the amount of electricity transported to main land gets reduced when consumed on the energy island. Below the electricity loss in the interconnector is calculated and subtracted from the wind capacity, resulting in a new capacity. The new capacity is used in the rest of the model, and the cost of the lost capacity is compensated for in the EnergyPLAN model.

In the Equation 7.3, the wind capacity after the losses is obtained for Scenario 1.X. Here the $Wind_{cap}$ is the capacity before the losses, AEC_{cap} is 1 GW of electrolyser capacity on the energy island, AEC_{CF} is the capacity factor for the electrolysers and lastly $Cable_{loss}$ is the cable loss and is obtained with interpolation. Interpolation is used as 120 km of interconnector is needed for the application, but the data obtained from Jayasinghe [2017], only had the loss for 100 and 150 km.

$$Wind_{cap1.X} = Wind_{cap} - (Wind_{cap} - AEC_{cap} \cdot AEC_{CF})) \cdot Cable_{loss} \tag{7.3}$$

The cable loss for Scenario 2.X is similar to Scenario 1.X, as it excludes the electricity consumed by the electrolysis plant in the cable loss. Though, since the Scenario 2.X also have the methanol synthesis on the artificial island, the the electricity consumption from that process is included by multiplying $\frac{1}{1-synth}$ to the electrolysis plants electricity consumption as seen in Equation 7.4.

$$Wind_{cap2.X} = Wind_{cap} - (Wind_{cap} - (AEC_{cap} \cdot AEC_{CF} \cdot \frac{1}{1 - Synth_{loss}})) \cdot Cable_{loss} \tag{7.4}$$

In Equation 7.5, the new wind capacity for Scenario 3.X is calculated. As there are no electricity consumed on the energy island in the scenario, the cables loss is applied to all the produced electricity.

$$Wind_{cap3.X} = Wind_{cap} - Wind_{cap} \cdot Cable_{loss} \tag{7.5}$$

In Table 7.1 the wind capacity after the cable loss and the cable loss compared to the installed 3000 MW is shown. The loss introduces a difference of 5 MW between the scenarios, which can be seen as lost capacity. The annual production is calculated with a capacity factor of 0.51. This is obtained with the distribution profile and correction factor obtained from $IDA2030_{Vision}$ in EnergyPLAN. The calculation can be seen in Appendix B.

Offshore wind turbines	Scenario 1.1	Scenario 2.1	Scenario 3.1	Unit
Capacity incl. loss	2977.38	2977.63	2972.85	MW
Capacity loss	0.754	0.746	0.905	%
Annual production	13.27	13.27	13.25	TWh

The total costs of the offshore wind turbines is shown in Table 7.4, here the cost inputs are obtain from Danish Energy Agency [2016].

7.2 Electrolysis

Electrolysis is a key factor for the Danish energy island, as it produce e-fuels to reduce the use of fossil fuels. In Section 6.1, AEC was chosen for the energy island as well as the rest of the energy system. The data used to make the calculations for electrolysers are obtained from Danish Energy Agency [2017b]. The electrolysis capacity is chosen such the CEEP is constant at 3.57 TWh in EnegyPLAN, to make the energy system comparable to $IDA2030\_vision$ and Base scenario, both models are reviewed in Section 5.3. The energy island have 1 GW of electrolyers, while the total energy system have about 2450 MW, hence losses related to the energy island is only applied to 1 GW of electrolysers.

In Equation 7.6 the annual production of hydrogen is calculated, where the $hour_{year}$ is the number of hours within a year. The produced hydrogen is later used to calculate the produced methanol and losses in H2 pipelines. In this analysis hydrogen is not considered a end-fuel, hence all the produced hydrogen is hydrogenated with CO/CO2 to get methanol.

$$H2_{annual} = AEC_{cap} \cdot AEC_{eff} \cdot AEC_{CF} \cdot hour_{year} \tag{7.6}$$

In Scenario 1.1 and 2.1, the recoverable heat output is seen as waste heat as the electrolysis plant is on the energy island. Scenario 3.1 utilises the excess heat, as it is located on main land. According to Danish Energy Agency [2017b], AEC can recover 3 % of the electricity input, this is equivalent to 0.32 TWh for Scenario 3.1.

Electrolusers	Scenario 1.1	Scenario 2.1	Scenario 3.1	Unit
Capacity - total	2450	2450	2445	MW
Annual H2 production	7.30	7.30	7.29	TWh/year
Annual H2 production	0.22	0.22	0.22	Mt/year
Recoverable heat	-	-	0.32	TWh

7.3 Methanol synthesis

The methanol synthesis via CO/CO2 hydrogenation is the last step of producing e-fuel for the energy system. In Section 6.2.5, methanol is chosen to be the most feasible e-fuel for this application, as is has good properties for domestic transport. According to Mathiesen et al. [2013], methanol synthesis have an efficiency of 90 %. This loss is divided into an electricity consumption and hydrogen loss. According to Danish Energy Agency [2017c], the H2 required to produce 1 t of methanol is 0.1922 tH2. Though, by doing a ratio between the energy density of H2 and CH3OH, it can be seen that it only takes 0.1833 of hydrogen to get one ton of methanol. In Equation 7.7, the hydrogen loss is calculated by combining these two hydrogen requirements for methanol synthesis. Here the $H2_{ED}$ and $CH3OH_{ED}$ are the energy density for hydrogen and methanol respectively, whereas $H2_{con}$ is the actual hydrogen consumption to produce on ton of methanol. The hydrogen loss during the synthesis process is calculated to 4.62 %.

$$H2_{loss} = 1 - \frac{H2_{ED}/CH3OH_{ED}}{H2_{con}} \tag{7.7}$$

With a 90 % efficiency, the remaining 5.38 % is treated as a electricity consumption. The annual electricity consumption is calculated in Equation 7.8.

$$CH3OH_{elec\_con} = H2_{annual} \cdot CH3OH_{elec\_demand} \tag{7.8}$$

Here the $CH3OH_{elec\_con}$ is the annual electricity consumption for the production of methanol and the $CH3OH_{elec\_demand}$ is the 5.38 % of electricity consumption. All three scenarios have a annual electricity consumption of about 0.40 TWh.

The hydrogen loss is included in the following calculations of methanol, whereas the electricity loss is included in the EnergyPLAN model as a fixed electricity consumption.

In Equation 7.9, the methanol synthesis capacity is found. The average production of H2 is calculated by multiplying AEC_{cap}, AEC_{eff} and AEC_{CF}. This is then multiplied by the capacity factor for methanol synthesis which result in the capacity for methanol synthesis. In EnergyPLAN a capacity factor of 0.625 is obtained by increasing it till it had a negative influence. Normally this is set as 0.5, but 0.625 seemed to be a sweet spot in terms of flexibility and cost.

$$CH3OH_{cap\_synth} = AEC_{cap} \cdot AEC_{eff} \cdot AEC_{CF} \cdot CH3OH_{synth\_CF} \tag{7.9}$$

In Equation 7.10 the annual production of methanol is found by multiplying the annual production of hydrogen with the conversion loss of 5.38 %. The equation can be used for all three scenarios, though for both 2.X and 3.X $H2_{loss\_pipeline} = 0$ as the electrolysis plant and methanol synthesis is at the same location, whereas for 1.X the hydrogen loss is included.

$$CH3OH_{annual} = H2_{annual} \cdot (1 - H2_{loss}) + H2_{loss\_pipeline} \tag{7.10}$$

In Table 7.1, the capacity, methanol production and electricity consumption can be seen. The changes here are due to the slightly larger AEC capacity and roundings. This capacity is for the whole energy system, which is about 2.5 times larger than the energy islands. The costs for the methanol synthesis for the energy island solely can be seen in Table 7.4, the cost inputs are obtain from Korberg et al. [2021].

Table 7.1.

Methanol synthesis	Scenario 1.1	Scenario 2.1	Scenario 3.1	Unit
Capacity - total	1333	1333	1330	MW
Annual CH3OH production	6.95	6.96	6.95	TWh
Annual CH3OH production	1.14	1.14	1.14	Mt
Electricity consumption	0.39	0.39	0.39	TWh

7.4 Storage and infrastructure

In this section, the calculations and decisions behind storage and infrastructure are shown. In the model, hydrogen and methanol storage is calculated, which is directly dependent on the annual production of hydrogen and methanol respectively. The hydrogen storage have the equivalent of 2 days of storage, while the methanol storage have 4 days.

Official models such as $IDA2030_{Vision}$ generally use 4 days of storage for both hydrogen and methanol, where it was discovered in this analysis that 2 days of hydrogen is sufficient to have almost the same flexibility and the same CEEP. Methanol storage have the equivalent to 4 days as it is the norm among other models, and it is only a cost input in the software, hence it does not effect the energy systems flexibility. The cost data available for both methanol and hydrogen storage changes greatly among the different technologies, consequently the same inputs is used as the $IDA2030_{Vision}$.

Interconnector and pipelines used in the model differs for each scenario, as the placements of the electrolysis plant and hydrogenation is different. The same criteria is applied for all scenarios, the capacity has to sufficient to transport the produced energy.

The energy transportation are pipelines which transport CO2, H2 and CH3OH together with a submarine power cable. Below, the calculations for these technologies will be presented. To obtain the capacity for the interconnectors, both the corrected capacity factor for wind turbines have to be estimated to obtain the produced electricity. This is followed by the electricity consumption on the artificial island, which subtracted from the produced electricity. This is explained in more detail below.

First the hourly corrected capacity factor for offshore wind turbines is calculated in Equation 7.11. Where $Wind_{CF}(t)$ is the hourly capacity factor without the correction factor. $Wind_{CORR}$ is the correction factor, which is the only constant in this equation and is obtained from $IDA2030_{Vision}$ - the used value is 0.395. The $Wind_{CF}(t)$ is the capacity factor before the correction factor is applied. All variable but the correction factor is time dependent, as there is a value for each hour, hence this equation is used for all 8765 hours a year. A correction factor is used, since the capacity factor is improving gradually over time, and it would not be feasible to create a new distribution profile whenever an improvement is occurring. Hence Equation 7.11 increases the capacity factor for all hours but the ones where it is 0 and 1 [Lund og Thellufsen, 2020]. The average capacity factor without the correction factor is 0.43, whereas the corrected capacity factor is 0.51.

$$Wind'_{CF}(t) = \frac{Wind_{CF}(t) \cdot 1}{(1 - Wind_{CORR}) \cdot (1 - Wind_{CF}(t))} \tag{7.11}$$

With the corrected capacity factor, the interconnector capacity can be calculated. This is done as interconnectors are very expensive, and a large part of the energy islands total costs. In Equation 7.12, the hourly needed capacity for the interconnector is calculated. Here many of the variables are time dependent like in Equation 7.11, as this have to be calculated for each hour of the year. First the hourly wind production is calculated by multiplying the wind capacity ($Wind_{cap}(t)$) and hourly corrected capacity factor ($Wind'_{CF}(t)$) as shown in Equation 7.11. The second part of the equation is the hourly consumption of the electrolyser on the energy island which is subtracted from the wind production. The hourly consumption of electrolysers have been obtained from the EnergyPLAN model, where the system have been simulated to obtain the "distribution profile".

$$Cable_{cap}(t) = Wind_{cap}(t) \cdot Wind'_{CF}(t) - \frac{AEC_{prod}(t)}{AEC_{cap}/AEC_{cap\_island}} \tag{7.12}$$

To make the results of the cable capacity more visual, a histogram is shown in Figure 7.1. This shows the needed capacity for every hour of the year. The plot is done with data from Scenario 1.1. It can be seen that the export of electricity varies throughout the year, but never exceeds 2.2 GW. A interconnector capacity of 2.2 GW can be used for both Scenario 1.1 and 2.1 but 3.1 needs the full 3 GW of interconnector, as there is no electricity consumption before it is transported to main land.

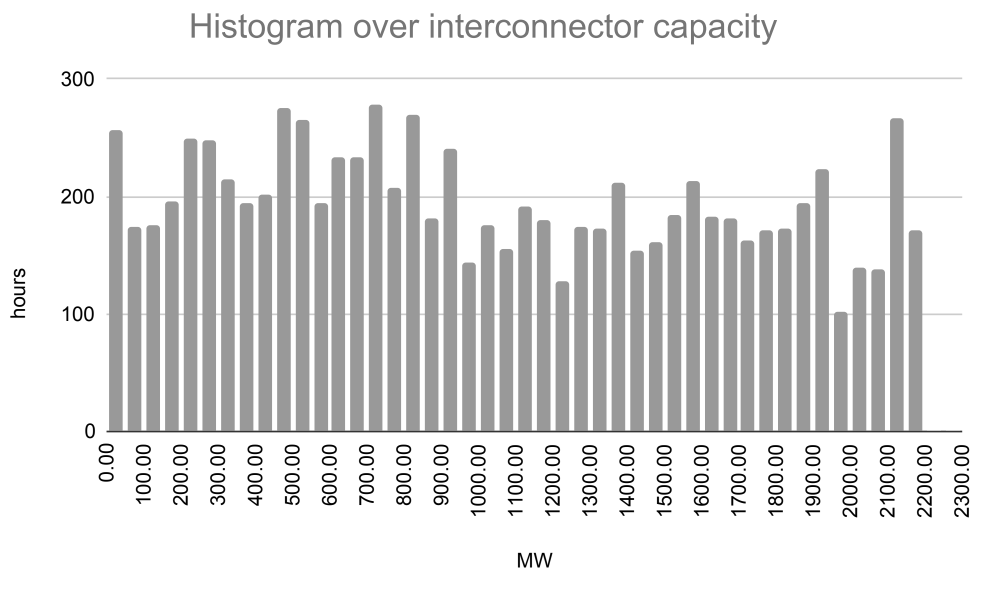

Figure 7.1. A histogram of the needed interconnector for all hours of the year

When the capacity for the interconnector is found, the total interconnector cost have to be obtained. In the electricity transport, multiple factors is taken into consideration. The interconnector is 120 km between the island and main land, then an additional 80 km on shore cables in modelled, as the energy island have to be connected to a strong node of the main grid. The transformer costs for the energy island and main land is also included [COWI, 2021a]. As the data for the distance of the cables and losses are obtained from two sources, the losses are not for the specified 120 km. The distance for the interconnectors are obtained from COWI [2021a], wheras the electricity loss of the interconnector is described in Jayasinghe [2017]. In Table 7.2 the results of interpolations for the electricity loss in the interconnectors as well as the cost of the submarine cables for 2.2 and 3 GW. Interpolation is used for the most infrastructure calculations, as the obtained data is not on point with the data needed for the energy island. The equation for interpolation shown in Equation 7.2.

Table 7.2. Interpolation of interconnector loss and costs

	Value	Unit
Submarine cable - 100 km	0.88	%
Submarine cable - 150 km	0.95	%
Submarine cable - 120 km (interpolated)	0.91	%
Submarine cable - 0.75 GW	163.20	M€
Submarine cable - 1.5 GW	272.00	M€
Submarine cable - 2.2 GW (interpolated)	373.55	M€
Submarine cable - 3.0 GW (interpolated)	489.60	M€

All the pipelines is calculated by energy flow, distance, loss and a electricity consumption, the calculations of the pipelines can be seen in Appendix B.

Since methanol consist of hydrogen and carbon, a CO2 source has to be considered. As described in 6.2.4, the best CO2 source is biogas upgrading as it does not have to be purified after it is captured. The national CO2 potential of biogas have been calculated to be 2.11 Mt CO2 annually, which is based on a biogas potential of 71 PJ Skov et al. [2019]. This is sufficient for the three main scenarios, but it is a national potential and not local at the energy island. To supplement the carbon capture from biogas plants, biomass combustion in CHP/PP would increase the available CO2 to about 7 Mt, if the full potential is utilised.

The annual CO2 consumption for the methanol synthesis is calculated by multiplying the annual methanol production, with the CO2 consumed to produce one ton of methanol which is obtain from Danish Energy Agency [2017c]. The annual CO2 consumption for the three main scenarios are about 1.15 Mt CO2.

CO2 transport via ships is not considered as a feasible option for this amount of CO2, as just the investment cost is about 10 times as high as CO2 pipelines without counting the higher O&M and energy demand [Danish Energy Agency, 2021].

The cost of CO2 pipelines is calculated in Equation 7.13, where $CO2_{Cost}$ is dependent on the CO2 flow and pipeline distance. The hourly CO2 capacity is obtained by the annual CO2 consumption ($CO2_{con}$), divided by the total hours of the year ($hour_{year}$). This is multiplied by the pipeline length ($Pipeline_{length}$) to get the total costs of the pipeline, followed by adding the costs of CO2 pumps. The $CO2_{Cost}$ is both available for onshore and offshore [Danish Energy Agency, 2021]. The cost ratio between offshore and onshore is 1.74, which is used later to estimate the cost of offshore H2 and CH3OH pipelines. As Scenario 2.1 have the hydrogenation on the energy island, a 120 km offshore CO2 pipeline is modelled. All three scenario includes 200 km of onshore CO2 pipeline to the CO2 sources, this is an estimation which is the same for all scenarios, but can be insufficient to supply the needed CO2. The loss is calculated by the average CO2 flow per hour.

$$CO2Pipeline_{inv} = CO2_{Cost} \cdot \frac{CO2_{con}}{hour_{year}} \cdot Pipeline_{length} + CO2_{pump} \tag{7.13}$$

Both the H2 and CH3OH pipeline is only used in one scenario each, and is similar in regards to calculations. The investment costs is only dependent on the length of the pipe, as the investment cost is given for a capacity interval [Danish Energy Agency, 2021]. The data for methanol pipelines is obtained by using the values for ammonia and methane which according to Danish Energy Agency [2017a] is very close to be the same. In the hydrogen pipeline, as loss of 0.49 % for 120 km is included, where the methanol have no losses what so ever.

A water purification plant is needed for Scenario 1.1 and 2.1 as electrolysis conducted on the energy island. The costs of this is obtained from COWI [2021a] which have a investment cost for 1 GW plant, as well as running costs depending on the amount of water produced annually [Mehmeti et al., 2018]. The lifetime of water purification is similar to the rest of the infrastructure with 50 years [Raghuvanshi et al., 2017].

Lastly, the expenses for the energy island itself is calculated. As all the elements which is placed on the energy island such as electrolysers, hydrogenation and transformers are already calculated, the construction of the artificial island is the final element. As the electricity system, electrolysers and water purification all take up space. According to COWI [2021a], a 1 GW electrolysis plant takes up 33,000 m2 and the water purification only 220 m2. The supplied cost is for 12.1 and 18.12 hectares, hence an interpolation is made to obtain cost for the specific scenario. Scenario 1.1 and 2.1 require about 15.55 ha, whereas Scenario 3.1 does not have an artificial energy island.

To get an overview of the total costs of the energy island before the analysis, two tables is shown below. In Table 7.4, wind turbines, electrolysis plant and methanol synthesis is shown. As all of these are fixed for the energy island, they share the same costs.

	Scenario X.1	Unit
Offshore wind turbines - Investment cost	5790	M€
Offshore wind turbines - O&M	2.49	%
Alkaline electrolyser - Investment cost	582	M€
Alkaline electrolyser - O&M	2	%
Methanol synthesis - Investment cost	179.52	M€
Methanol synthesis - O&M	4	%
Total investment cost	6551.52	M€
Average O&M	2.49	%
Total annual cost	335.50	M€

In Table 7.4 the remaining which is included in the energy island is shown. Here it can be seen the largest expenses are the interconnector and construction of the energy island, followed by pipelines, storage and lastly the water purification.

	Scenario 1.1	Scenario 2.1	Scenario 3.1	Unit
Interconnector - Investment cost	1203.56	1203.56	1521.56	M€
Interconnector - O&M	1	1	1	%
CO2 pipeline - Investment cost	97.93	191.42	97.76	M€
CO2 pipeline - O&M	1.44	1.60	1.44	%
H2 pipeline - Investment cost	139.07	-	-	M€
H2 pipeline - O&M	2.04	-	-	%
CH3OH pipeline - Investment cost	-	100.13	-	M€
CH3OH pipeline - O&M	-	1.01	-	%
H2 storage - Investment cost	124.03	124.03	124.03	M€
H2 storage - O&M	2.5	2.5	2.5	%
CH3OH storage - Investment cost	1.62	1.62	1.62	M€
CH3OH storage - O&M	0.6	0.6	0.6	%
Water purification - Investment cost	6.67	6.67	-	M€
Water purification - O&M	17.94	17.94	-	%
Energy island - Investment cost	638.61	638.61	-	M€
Energy island - O&M	1	1	-	%
Total investment cost	2211.49	2266.05	1748.77	M€
Average O&M	1.22	1.18	1.13	%
Total annual cost	85.95	88.07	67.97	M€

The implementation of the calculated data in EnergyPLAN can be seen in Appendix A.

Analysis of the energy island 8

In this chapter, the results of the simulations will be analysed. This is done to determine what placement of the electrolysis plant is best suited for the Danish energy island in the North Sea, consequently the Danish energy system. The most important outputs of the simulations such as fuel consumption, energy system cost and GHG emissions will be seen for each scenario to get the full picture for each placement of the electrolysis plant. As the energy island is expected to be expanded to 10 GW offshore wind capacity over time, a second series of simulations is made to observe how each scenario reacts to a expansion.

Since the definition of an energy island for many people includes connections to more than one country, a cost analysis is conducted to identify which scenario is preferable when the extra expense of an interconnector to the united kingdom is included.

In Chapter 6.1 the SOEC was decided not be used, as the technology may not be commercial available before the construction of the energy island. Here it will be observed what effect this technology would have on the energy system in terms of fuel consumption and GHG emissions. The energy system costs will not be considered as the predicted SOEC cost varies as much as it do.

As the conducted model is based on predictions of technologies, the obtained data have high uncertainty. Hence, a sensitivity analysis is made for the wind turbine costs and the electricity price. This is conducted as it is desired to observe what impact it has on the cost of methanol.

8.1 Main scenarios

The main scenario refers to X.1, which have been described in Chapter 7. When referring to Scenario X.1, its a plural of all three scenarios. The scenarios do all have 3 GW of offshore wind capacity together with a 1 GW of AEC electrolysis plant. Scenario 1.1 has the electrolysis plant on the energy island, where the methanol synthesis is on main land. Scenario 2.1 have both the electrolysis plant and methanol synthesis on the energy island. Lastly, Scenario 3.1 have both the electrolysis plant and methanol synthesis on main land.

As these configuration introduces different needs for energy transportation. The losses within each scenario varies which can be seen in Table 8.1.

Table 8.1. Cable and pipeline losses

	Scenario 1.1	Scenario 2.1	Scenario 3.1
Offshore wind capacity incl. losses (MW)	2977.38	2977.63	2972.85
Electrolyser capacity (MW)	2450.00	2450.00	2445.00
Cable losses	0.754 %	0.746 %	0.905 %
Pipeline losses	0.34 %	0.08 %	0.05 %

The cable losses depends directly on the the amount of electricity transported from the energy island to main land. Here the Scenario 3.1 have the full 0.905 % cable loss, where Scenario 1.1 and 2.1 have reduced loss, as they consumed some of the electricity on site with electrolysers and methanol synthesis. When it comes to the pipeline losses, both the actual losses and energy consumption is included in the table. The losses and energy consumption are introduced by the H2 and CO2 pipelines, where the CH3OH pipelines does not include any losses. The total energy loss of the infrastructure is greatest for Scenario 3.1, 1.1 and 2.1 respectively. This will lower the overall electricity production of the the wind turbines.

As explained in Chapter 7, the interconnector capacity for Scenario 1.1 and 2.1 have been calculated to be 2200 MW, whereas Scenario 3.1 is 3 GW. This is adequate for the produced electricity to be transported to main land. In Figure 8.1, a graph consisting of the interconnector capacity and lost electricity income can be seen. For the lost income, the hourly Nord Pool price is used from EnergyPLAN [2021]. Since the Nord Pool price is not predicted with this high share of RES, the chart have a high level of uncertainty. Though, the takeaways from this chart is that the cheapest option is not the one which are able to transport all electricity, but the ones which have to stop the production for a few hours each year. The capacity with the lowest annual cost are with 2100 and 2150 MW. These capacities shut down the production 6.23 and 1 hours each year respectively, assuming the capacity factor is 1 for those hours. The same approach can be used for Scenario 3.1.

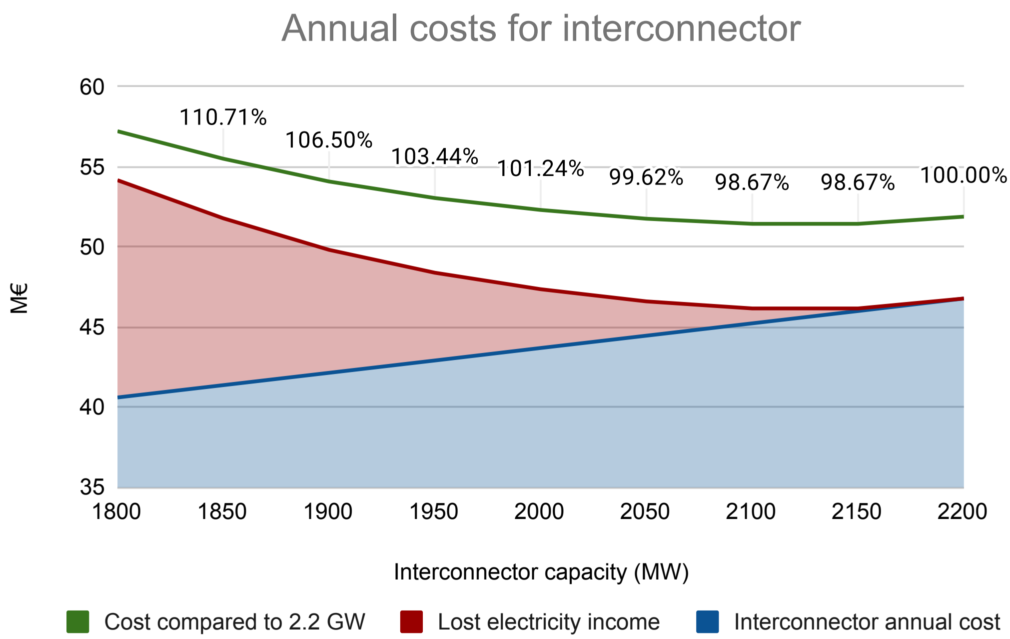

Figure 8.1. Annual interconnector costs with wind turbine down time included

In the simulations 2200 MW is used, as the simulation tool EnergyPLAN does not allow down time of wind turbines and the uncertainty of the hourly Nord Pool prices. Though, it is of importance to look further into this before construction starts, as the interconnectors are the biggest expense on the energy island other than the wind turbines.

In Figure 8.2, the total investment cost of the energy island can be seen for Scenario X.1. Since, the wind turbines and electrolysis plant are fixed at 3 GW and 1 GW respectively, the same expense is included for all the scenarios. Though, the wind turbines does not produce the same amount of electricity due to losses.

The infrastructure costs varies for each scenario, as different needs are required for each scenario. The included infrastructure is essential for the production of methanol, excluding only the offshore wind turbines, electrolysers and methanol synthesis. In Chapter 7, Table 7.4 gives an overview of what expenses each scenario have concerning the infrastructure, but the main difference are the pipelines, interconnector capacity and the construction of the artificial island. In terms of the overall expenses for the energy island, Scenario 3.1 is the cheapest, mainly because it does not have the artificial energy island, which have an expense of about 600 M€.

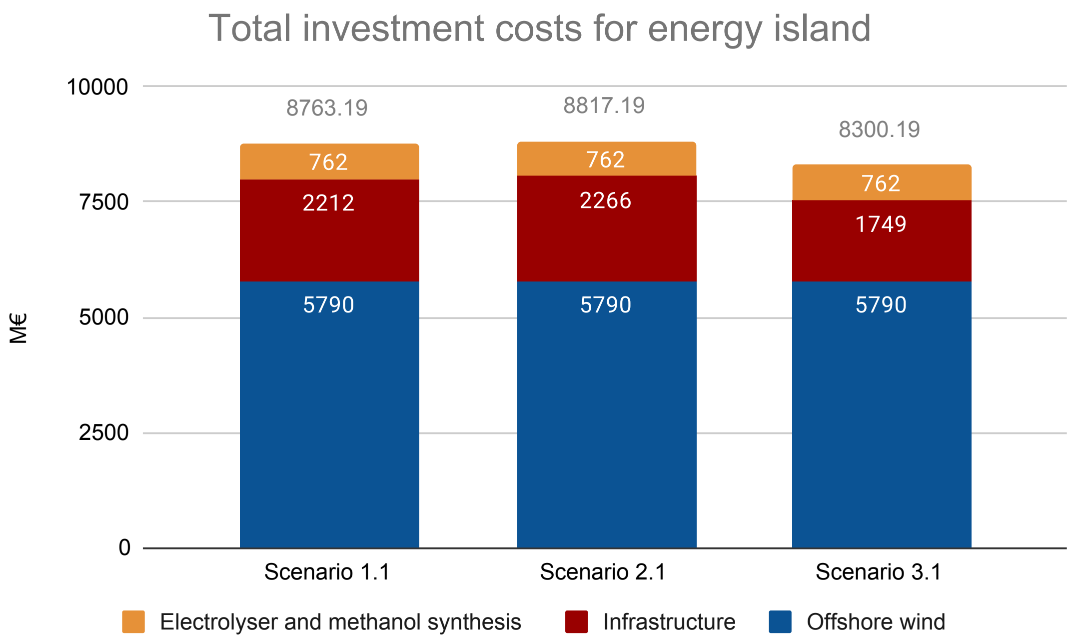

Figure 8.2. Investment costs for the energy island for Scenario X.1

As the goal of this project is to allocate the best suited energy island configuration in regards to the Danish energy system. Hence, the energy island have to be seen in a energy system perspective. Therefore, each of Scenario X.1 have been simulated in EnergyPLAN with the whole energy system based on the EnergyPLAN model "*Basescenario*" described in Section 5.3.

In Figure 8.3, the annual production of energy through power plants (PP), combined heat and power (CHP) and boilers can be seen for each Scenario X.1. The total energy production from these technology is lower for the scenarios with the energy island compared to the Base scenario. This is mainly due to the higher share of RES in the electricity production, which lowers the need for the electricity production though PPs and CHPs. This does consequently lower the need for CHP, as it produced both electricity and heat. Hence, all the hours where the electricity system is saturated with electricity from RES, boilers are used instead.

When taking a closer look to the graph, Scenario 3.1 deviates from Scenario 1.1 and 2.1. This is due to the placement of the electrolysis plant, as Scenario 3.1 have a 3 % recoverable heat, whereas the two other scenarios use the sea as cooling for the electrolysis. Scenario 3.1 produce 0.32 TWh heat annually from the 2445 MW capacity, whereas about 0.13 TWh are obtained from the 1 GW electrolysis plant. This lowers the annual heat production from CHPs and boilers by 0.15 TWh compared with Scenario 1.1 and 2.1. As Scenario 1.1 and 2.1 are similar in AEC capacity and losses, the energy system have very little to no difference in terms of electricity and heat production.

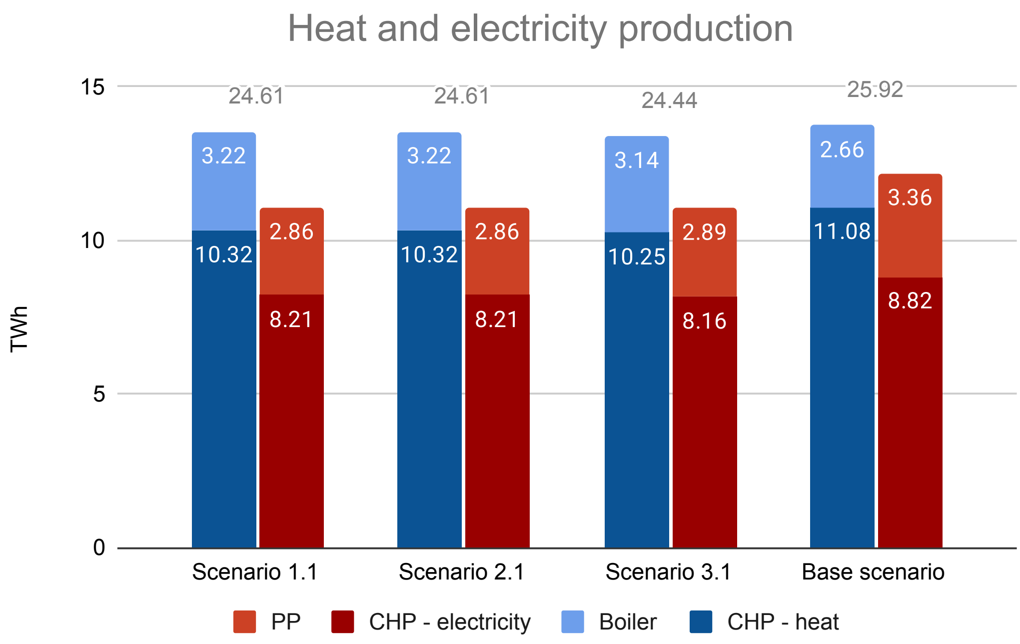

Figure 8.3. Annual heat and electricity production

In Figure 8.4, the annual fuel consumption for biomass, oil, natural gas and the annual GHG emissions are shown. According to [Lund et al., 2020], the national GHG emissions from the energy sector have to be reduced to 11 MtCO2 eq. or less to reach the 70 % reduction. All the three scenarios does achieve this, though the the Base scenario is a cut down IDA_{Vision} which all ready reached a 70 % reduction. Scenario X.1 are based on Base scenario, which consequently makes the final GHG emissions optimistic, hence the difference between the Scenario X.1 and the Base scenario is assessed instead.

The introduced 3 GW of offshore wind and ≈2.45 GW of AEC electrolysers have reduced the GHG emissions by ≈2.3 Mt. As seen the biomass have been set as a constant at 38 TWh, as Lund et al. [2020] have estimated this to be a sustainable biomass consumption. Scenario 1.1 and 2.1 are very similar and changes less than 0.01 TWh in natural gas and oil, whereas Scenario 3.1 have reduced its natural gas consumption by 0.15 TWh due to the recoverable heat from the electrolysis plants. The reduction in oil between Base scenario and Scenario X.1 is proportional to the implementation of methanol in the energy system. The three scenario do all produce about 6.95 TWh annually.

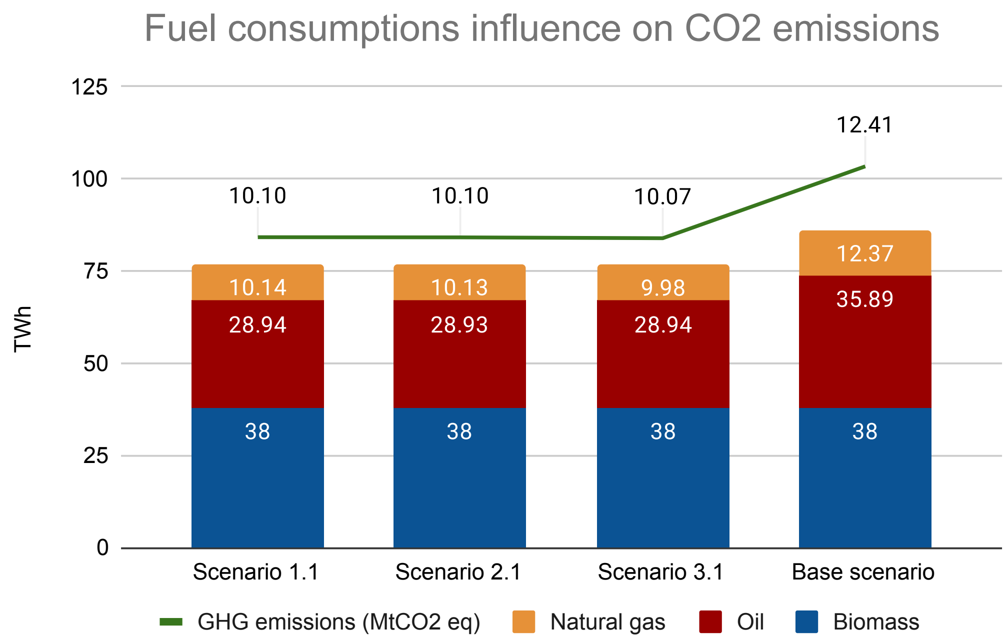

Figure 8.4. Fuel consumptions impact on the GHG emissions

In Figure 8.5, the annual costs for both the energy island and the whole energy system is presented. The costs are divided into annual investment costs and annual O&M which both includes fixed and variable O&M. Scenario 1.1 and 2.1 only varies by 1 M€ annually solely due to the cost difference of the energy islands infrastructure. Scenario 3.1 is cheaper when it comes to the infrastructure as it does not include the artificial energy island. The variable O&M is lower as well, due to the reduced consumption of natural gas, as the excess heat from the electrolysis plant is utilised. This makes Scenario 3.1 ≈30 M€ cheaper than Scenario 1.1 and 2.1. Compared to the Base scenario, Scenario 1.1 and 2.1 is ≈300 M€ more expensive.

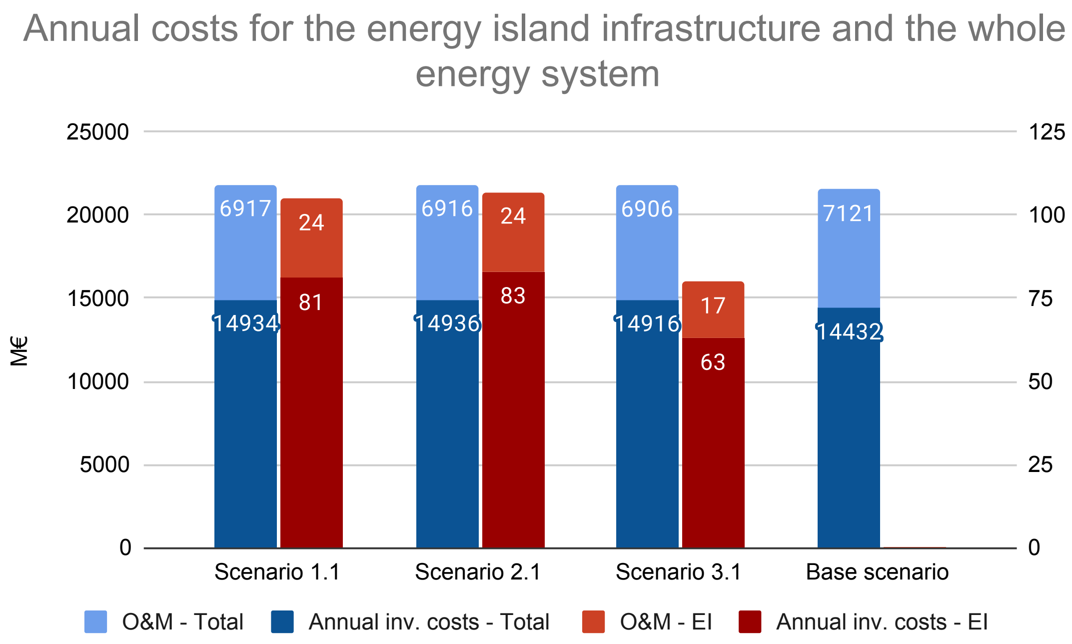

Figure 8.5. Annual costs for the energy system and the energy island infrastructure (without storage)

As the definition on an energy island is yet unspecified, whether it should be a hub for nearby RES, have multilinked interconnector or even produce e-fuels on site. The most favourable solution on a national perspective would be the traditional method, where electricity is transported to main land and then consumed. Though, as the future plan is to expand the energy island to 10 GW wind capacity, this have been simulated to see what impact it have on the results.

8.2 Future aspect - 10 GW wind turbines

To get a better understanding on how the energy system react to the planned 10 GW offshore wind turbines at the energy island, three simulations have been conducted with 10 GW of wind together with 3 GW of electrolysers at the island. These scenarios is referred to as X.2 and the most important capacities are shown in Table 8.2

Table 8.2. Capacities and costs regarding Scenario X.2

	Scenario 1.2	Scenario 2.2	Scenario 3.2
Offshore wind capacity incl. losses (MW)	9923	9923	9910
Electrolyser - Total (MW)	9593	9558	9480
Electrolyser - EI (MW)	3000	3000	3000
EI infrastructure costs (M€)	5453	5493	4650

As the share of non dispatchable energy increases, the load have to increase as well to acheive the same CEEP. In this model, the electrolysers capacity is ≈95 % compared to the offshore wind capacity of 10 GW. In Scenario X.1, this ratio between the offshore wind and the electrolysers were ≈82 %. Consequently, the increased share of RES require a larger load relative to the capacity.

The capacity factor of methanol synthesis is 0.625 in Scenario X.1, compared to the production of hydrogen. In Scenario X.2, the capacity factor had to be 0.50 otherwise it would bottleneck the whole electricity system, using more natural gas and exporting more electricity.

In Figure 8.6, the annual heat and electricity production can be seen from combined heat and power, power plants and boilers. As seen, the annual production have increased compared to the Base scenario. This is because of the larger electrolyser capacity, consequently increasing the annual methanol production. This increased electricity demand introduces less heat produced from heat pumps, consequently increasing the heat production from CHP and boilers. Scenario 3.1 have a lower electricity and heat production from CHP and boilers due to the recoverable heat from electrolysis. Though electricity production from PP is higher, as the system have more hours where where only electricity is needed.

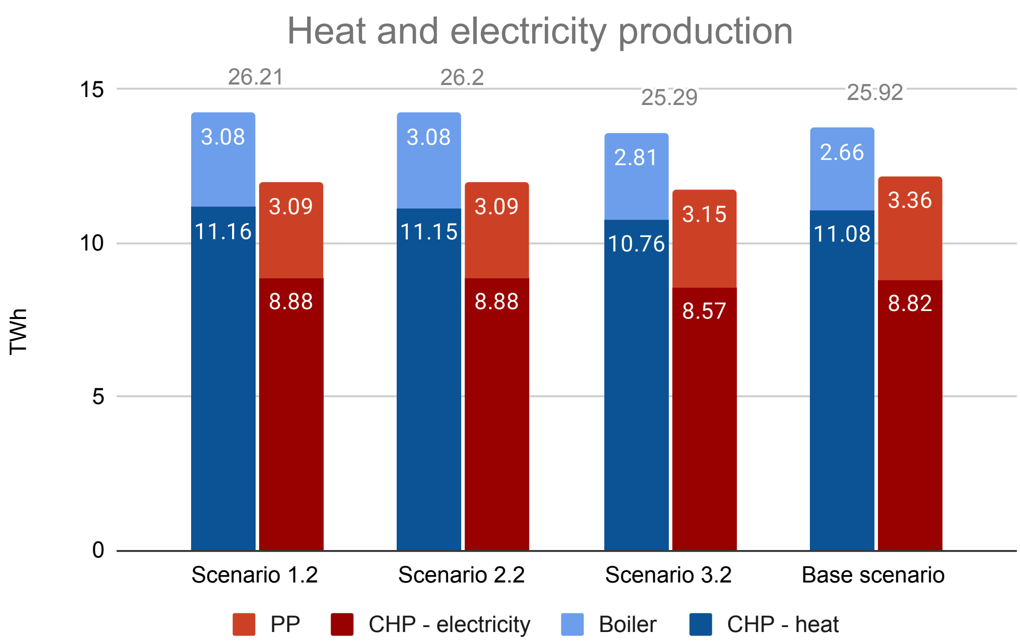

Figure 8.6. Annual heat and electricity production from Scenario X.2

In Figure 8.7, the fuel consumption impact on the GHG emissions can be seen. It can be seen that the natural gas consumption is about 1 TWh lower for 3.2 than for 1.2 and 2.2 as the increased electricity and heat production all came from natural gas as the biomass is fixed at 38 TWh. The oil consumption is directly dependent on the electrolyser capacity, as the capacity factor for the electrolysis is fixed at 0.50. In general the same trends is occurring for Scenario X.2 as for X.1. The total GHG emissions have lowered by more than 7 Mt for all three scenarios compared to Base scenario.

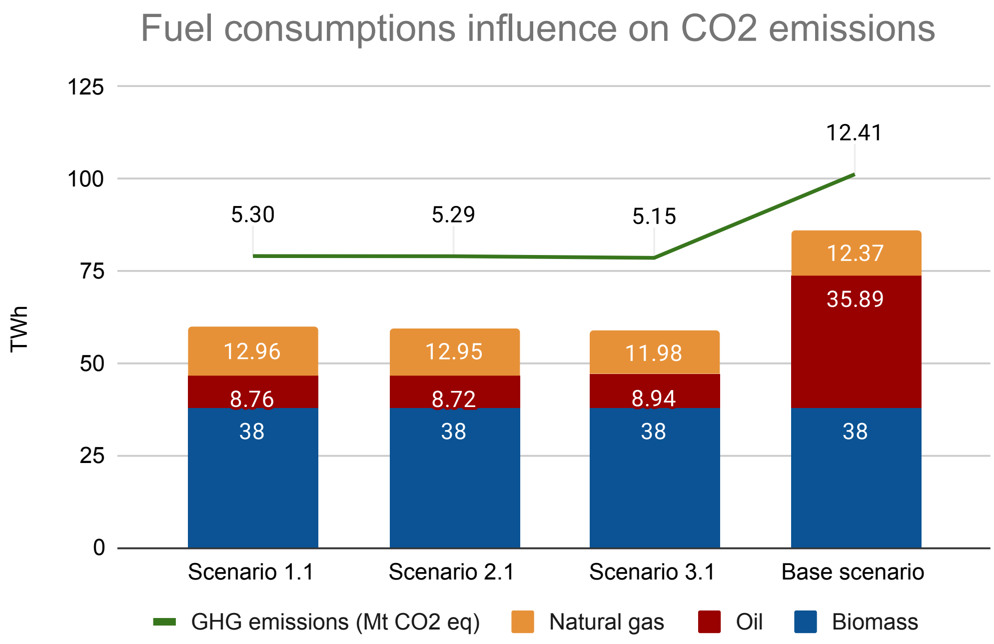

Figure 8.7. Fuel consumptions impact on the GHG emissions

As for now, the fuel consumption together with the lower GHG emissions favours Scenario 3.2 over the other two scenarios. But as every investment is highly dependent on the costs, this have to be considered as well.

In Figure 8.8, the total energy system cost can be seen with the Base scenario as a reference. This shows that Scenario 3.X is the best scaling scenario as well, which makes it superior over the other two scenarios. Though, this scenario does not include the artificial energy island, hence it does not have the same properties of a energy hub.

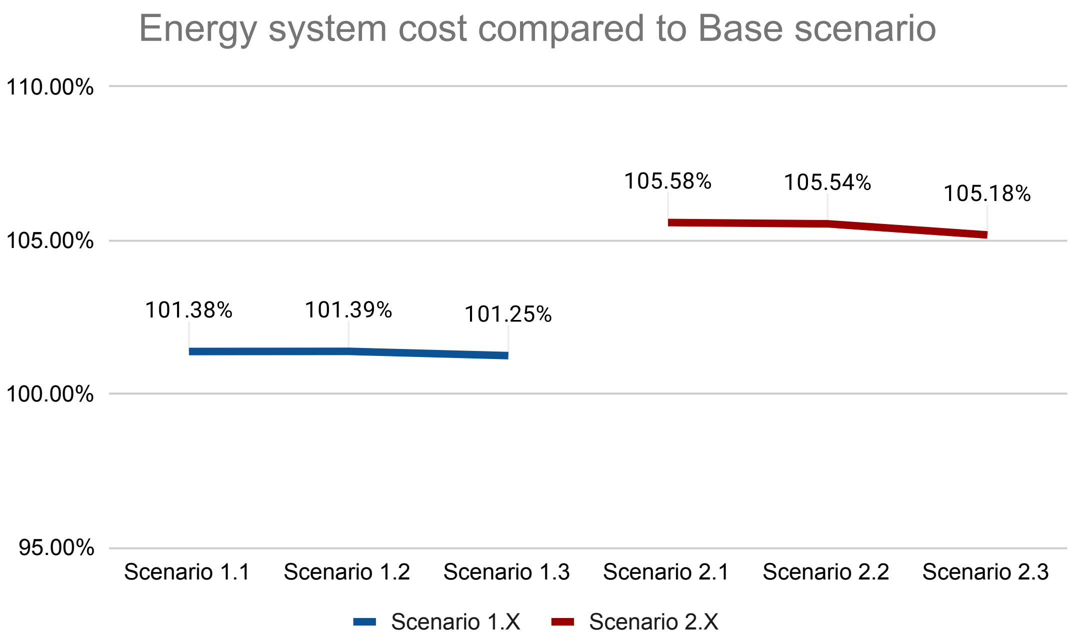

Figure 8.8. Total annual costs for Scenario X.1 and X.2 compared to Base scenario

Therefore, before a final verdict can be made concerning what scenario fits the Danish energy system the best, a sensitivity analysis is made to assess what scenarios are most economic viable when introducing a interconnector to the united kingdom, making the energy island multilinked.

8.3 Multilinked interconnector

The following analysis have been conducted in Appendix B, and it purely made in Excel, making it only cost relevant. Hence, the result of this have to be considered in context to Scenario X.1. In Figure 8.9, the total energy island cost for all three scenario can be seen. This is with the additional interconnector to United Kingdom, which is 550 km from the energy island and 670 km from main land. The capacity is decided to be 2 GW for all three scenarios, but can be discussed that an additional interconnector would give incentives to lower the capacity of the sea cable to main land for Scenario 1.1 and 2.1, as the total cable capacity is 5 GW. Scenario 3.1 have the interconnector from main land to united kingdom.

The total cost of the energy island differs by 55 M€ from the cheapest to the most expensive, which is about 0.5 % of the total investment costs of the energy island. Here scenario 1.1 is the cheapest, and the cost difference between Scenario 1.1 and 2.1 compared to 3.1 would be even greater, if the capacity of the cable between the energy island and Denmark was reduced or even interconnected more countries. The cost difference is so small, it should not give incentives to chose one scenario over the other.

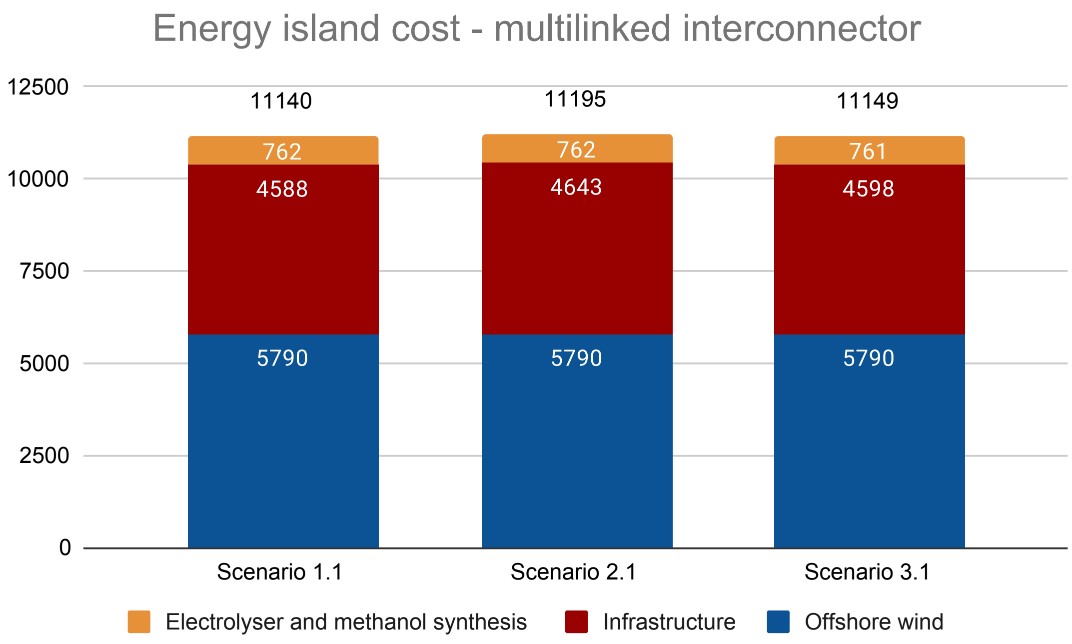

Figure 8.9. Investment costs for the energy island with interconnector to United Kingdom included

8.4 Solid oxide electrolysis cells impact on fuel consumption

As stated earlier, the SOEC was deselected as it is still uncertain if its commercial ready before 2030, and a high uncertainty regarding to costs. Though, it have included in a brief analysis concerning the overall impact SOEC would have on the energy system compared to AEC. As the cost varies as much as it do, the same cost have been used, therefore it is not desired to look at the final cost price. The only input changed compared to Scenario X.1 is the efficiency. Scenario 1.3 have a electrolysis efficiency of 76.8 % compared to the 68.00 % for Scenario X.1. Scenario 2.3 and 3.3 have an efficiency of 81 %, as co-electrolysis is used, this means the methanol synthesis happens in the same process as electrolysis, hence the 10 % loss from synthesis is avoided as well.

In Figure 8.10, the fuel consumption and the GHG emissions can be seen. The annual GHG emissions are lowered by 2-5 % copared to Scenario X.1, which is mainly due to the higher efficiency, which allows the electrolysers to produce more methanol. Here the co-electrolysis shows its advantage as Scenario 2.3 and 3.3 reaches about 5 % GHG reduction, whereas Scenario 1.3 only lowers the GHG emissions by 2 %. Scenario X.3 lowers the GHG emissions by 2.52-2.80 Mt compared to the Base scenario.

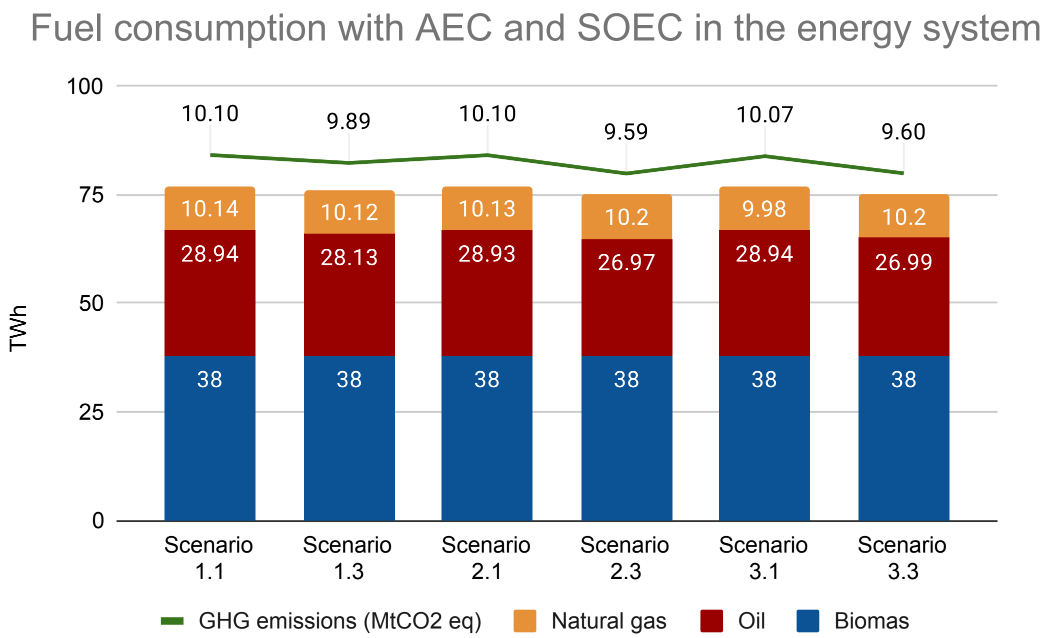

Figure 8.10. GHG emissions for 3 GW energy island with AEC and SOEC

Sensitivity analysis

A sensitivity analysis is conducted to observe what impact the cost of electricity and wind turbines have on the methanol production cost for Scenario X.1. The electricity price and wind turbine cost are decided as the are the biggest expenses for the production of methanol. Even though the electricity and wind turbine cost does not change between the scenarios, the share does as the remaining costs changes.

The costs included is for the methanol produced on the energy island, hence this can not be directly converted other cases of renewable methanol production.

8.5 Wind turbine and electricity costs' impact on methanol price

The cost of methanol is calculated by adding all annual expenses related to methanol production, then divided by the produced methanol. In Table 8.3, an overview of these expenses can be seen for each scenario. The only value that changes between each scenario is the "remaining costs" with include infrastructure and storage. The individual expenses of "remaining costs" can be seen in Table 7.4.

Table 8.3. Costs for methanol production

	Scenario 1.2	Scenario 2.2	Scenario 3.2	Unit
Cost of electricity	235.52	235.52	235.52	M€
Wind turbine	103.20	103.20	103.20	M€
AEC	29.69	29.69	29.69	M€
Methanol synthesis	10.41	10.41	10.41	M€
Remaining costs	85.95	88.07	67.97	M€
Total costs	464.77	466.89	446.79	M€

In Figure 8.11, the cost per litre of methanol can seen for each scenario. The cost varies by almost 5 %, with the most expensive being 0.80 €/l. The petrol price used in the model is 14.9 €/GJ, which is equivalent to 0.51 €/l. This makes methanol about 57 % more expensive per litre. The energy island produces 0.59 Mt of methanol annually, which is equivalent to 2.84 TWh.

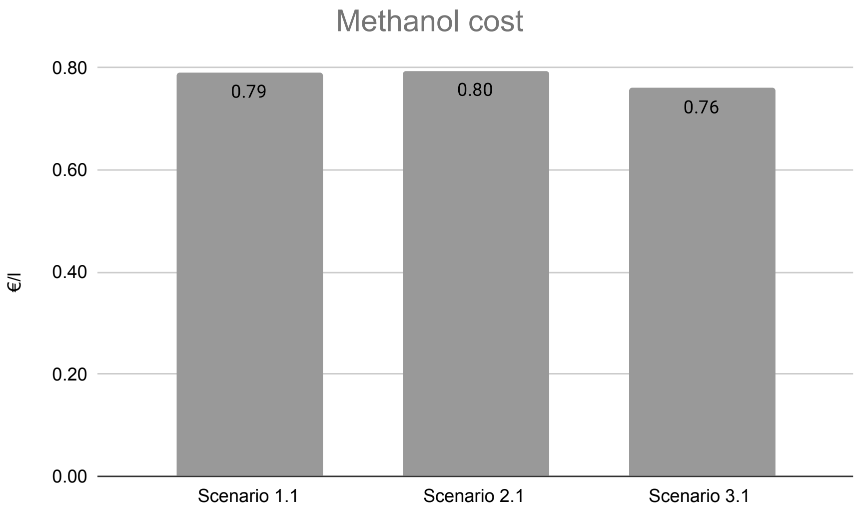

Figure 8.11. Cost of methanol production

Though, as mentioned before, there is a great uncertainty concerning the costs of the electricity and the technologies used. Therefore, a sensitivity analysis is conducted. The two largest expenses will therefore vary by ±10 %, to observe what impact it has on the production costs of methanol.

In Figure 8.12, the impact of the annual costs for wind turbines can be seen. The cost reduction/increase is similar for the three scenarios. The production cost for methanol change by ±2.2 %, with minor deviations. These deviations are caused by the different "remaining costs", consequently changes the impact of the ±10 % of wind turbine cost.

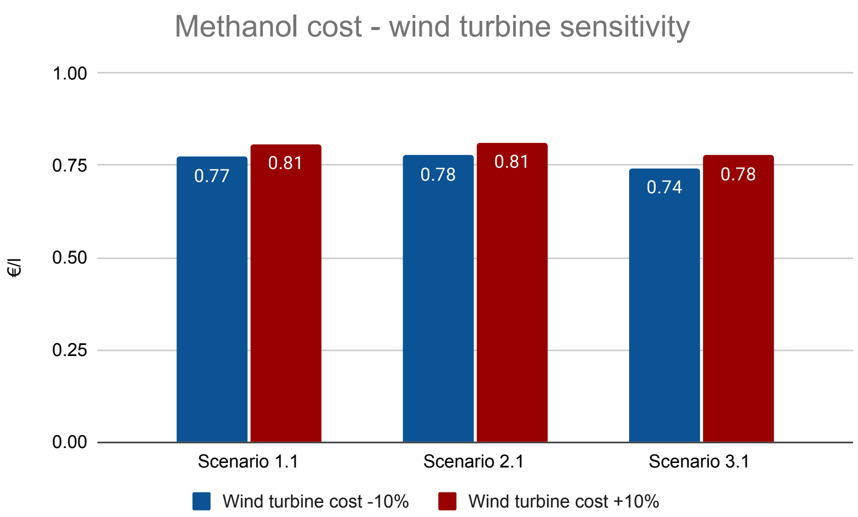

Figure 8.12. Cost of methanol production with ±10 % costs of wind turbines

The electricity price is obtained by calculating the average Nord Pool price obtained from EnergyPLAN [2021]. The same distribution profile is used to find the most optimal interconnector capacity. The price is calculated to be 50.80 €/MWH, which introduce great uncertainty as it is prediction. Since the cost of electricity is the largest expense for methanol production, it affect the production costs even more than wind turbines.

In Figure 8.13, the production cost of methanol can be seen with ±10 % change of the electricity price. The same tendency is occurring as for wind turbines, just by a greater amount. Here the cost is changed by ±5.2 %, compared to the methanol cost for Scenario X.1 without any changes in cost. The reduction to 0.75 €/l would make methanol 48 % more expensive than petrol according to this analysis.

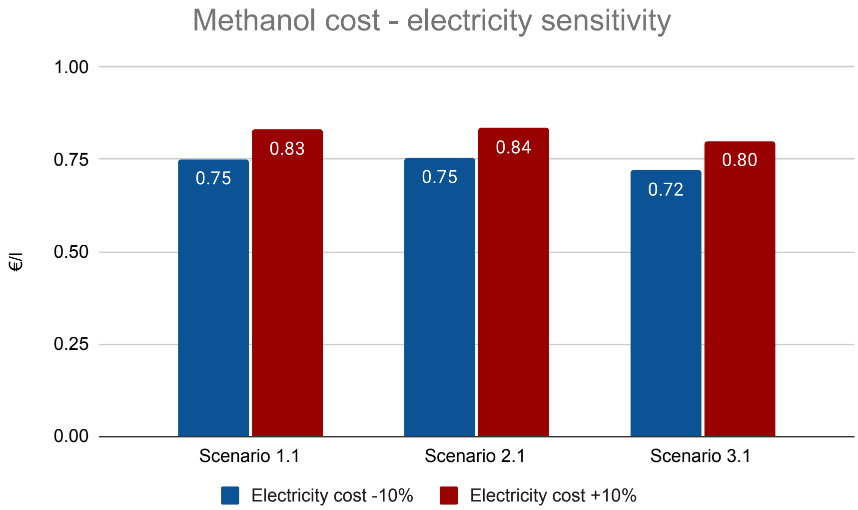

Figure 8.13. Cost of methanol production with ±10 % of electricity price

Discussion 9

In this project, multiple assumptions had to be made to construct the model and simulate it in EnergyPLAN. Below, some of these are presented to give the reader an understanding of what have been omitted or downgraded due to the time frame.

First, the available CO2 is calculated from a predicted biogas production in 2030, this is significantly higher than the current and is with great uncertainty. 12 TWh of carbon capture for CHP and PP is also included to supply carbon dioxide as the final size of the energy plan is expected to be 10 GW on wind capacity, which makes biogas insufficient of providing enough CO2.

The recoverable heat from electrolysers in Scenario 1.X and 2.X is set as 0. This should only have been for the energy island, which is only a part of the total electrolysers. This should have been taken into account when simulating the model to give a more accurate result. This does consequently favour Scenario 3.X over Scenario 1.X and 2.X, as they would consume less natural gas if heat was recovered from electrolysers.

As the wind capacity of the energy island was predetermined to be 3 GW, it was decided to have the electrolyser as variable. This was done to have a fixed CEEP, consequently making the scenarios comparable. Though, by having the electrolyser as a variable, the GHG emissions vary as the one with larger capacity produced more methanol. Hence, the impact of the energy island is seen as a energy system perspective.

In the model, a capacity factor of 0.5 is used for the electrolysers, as this is the norm. Though, an extensive analysis could have been made to find a higher capacity factor where flexibility is not compromised but the electrolyser capacity could be lower in sake of costs. This could have been done in a sensitivity analysis.

As methanol was chosen as the best suited e-fuel for the transport sector, it have replaced petrol one to one. In fact, methanol can achieve a higher efficiency than petrol if used in combustion engines designed for methanol. This could have resulted in a lower methanol consumption, consequently reducing the petrol even further.

The cost of the storage solutions are also gain from $IDA2030_{Vision}$, which may be outdated or optimistic in terms of storage solution. This does mostly effect the energy island cost, as about the same capacity is used in every scenario, making the overall price similar.

In the graph concerning the optimal interconnector capacity (Figure 8.1), the Nord Pool price was used to simulate the lost income because of down time of wind turbines. The distribution profile used is obtained from EnergyPLAN [2021], this model have a lower share of renewable energy sources, potentially changing the Nord Pool price. Though, this have only been used to shown to illustrate the full capacity may not be the cheapest option. The Nord Pool price was later used to determine the methanol production costs, which introduced the same uncertainties.

In the future aspect with 10 GW of wind capacity, a large share of methanol replaces both petrol and diesel. This is not optimal, as the majority of the personal transportation is better of being directly electrified, since the efficiency is significantly higher and most likely at a lower cost. This was mostly done to see the impact methanol would have on the energy system.

Since the simulated system is the national energy system, the international shipping is not included. Though, it is expected a large share of the produce e-fuel is used in the maritime sector as it consumes large quantities of fuel. The maritime sector can potentially consume ammonia instead of methanol, since it is not close to populated areas, hence air pollution is not as a big concern as on main land.

10 Conclusion

What is the potential role of the Danish energy island in the North Sea in reducing the greenhouse gas emissions by 2030, and what configuration of electrolysers are most feasible?

First, multiple e-fuel was investigated as one should be used for the energy system, consequently methanol was considered the best suited e-fuel for this project. This is mainly because of its great properties and ability to use the existing infrastructure. Though, it have been discovered that carbon will become a scarce resource in the future. If 9 GW of electrolysers is introduced to the energy system, close to 100 % of the CO2 potential according to this project is required. For the initial capacity of the energy system with $\approx$ 2.45 GW, whereas 1 GW is placed on the energy island, the available CO2 is sufficient for methanol synthesis.

Based on the knowledge obtained from the report and simulations, a modest GHG reduction is occurring for all scenarios conducted. The energy island configuration with electrolysis and methanol synthesis plants placed on main land is cheapest for 3 GW wind and 1 GW of electrolysis. Though, with the future expansion of 10 GW wind, 3 GW electrolysis plant, and the possibility to expand connection to other countries are considered, an artificial island is favourable as it does not limit the applications.

If SOEC is commercial available in 2030 at a similar price as AEC, then both electrolysis and methanol synthesis should be made on the artificial energy island, as co-electrolysis could be utilised. If not commercial available, the configuration with electrolysis on the energy island with methanol synthesis on main land is preferred, as it have less infrastructure elements and if a leak occurs, hydrogen is not toxic for the marine life opposite to methanol.

From the sensitivity analysis conducted regarding variation in electricity price and wind turbine cost, it was discovered the electricity price have the largest impact on methanol production costs. Without any measures, methanol would cost 0.76-0.80 €/l to produced. If $\pm$10 % of the wind turbine and electricity cost applied, the methanol production cost would change by $\pm$2.2 % and $\pm$5 % for methanol production respectively. This would make renewable methanol 41-64 % more expensive than petrol.

The recommended energy island configuration is estimated to cost 8,763 M€. This would lower the O&M by 204 M€ compared to Base scenario, reduce the oil consumption by 6.95 TWh and reduce the total GHG emissions by 2.31 Mt annually. Even though the annual O&M is lowered, the total annual costs are increased by 1.38 % compared to the Base scenario due to the large investments.

11 Recommendation

This study have investigated the most suitable electrolyser configuration for the upcoming energy island in the North Sea. Different scenario have been conducted, which showed the impact of each type of infrastructure and technology. Methanol was chosen as the end fuel, as it possesses many great properties such as being able to used the existing infrastructure, low GHG emissions when used in combustion engines and the option of being reformed back to electricity if used in a fuel cell or power-to-power in the future. Though, if 9 GW of electrolysis is constructed, as the scenarios with 10 GW of wind capacity, the use of ammonia should be considered for maritime use. About 100 % of the potential carbon capture from the predicted biogas and 12 TWh of biomass would be met with a capacity factor of 0.5.

When it comes to type of electrolysers, SOEC is recommended if ready for commercial scale by 2030, else the AEC should be used as it is fairly cheap compared to PEMEC and have a great efficiency.

The main objective of this analysis was to find the best configuration of the energy island in terms of electrolyser and methanol synthesis placement. Even though the most cost effective solution is the conventional wind farm structure, it is recommended to have both the electrolysers and methanol synthesis on the artificial energy island if SOEC is used, as it would achieve great efficiencies and give the option to interconnect the island with other countries. If SOEC is not on a commercial available by 2030, AEC should be considered, which favours a configuration where the electrolyser should be placed at the energy island and the methanol synthesis on main land. This have less infrastructure elements and if leaks occur, then hydrogen would have smaller impact on marine life compared to methanol.

As this analysis have not simulated the impact multilinked interconnectors have on the energy system and electricity price, these recommendation should not be used as a economic guideline without doing further research within the topic.

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Implementation in EnergyPLAN A

In this appendix the implementation of the model in EnergyPLAN is presented. This section would make a EnergyPLAN user able to run the simulations only with the data from the Excel model which is provided in Appendix B, though all EnergyPLAN files are attached in Appendix C. All the figures below, is screenshots for Scenario 1.1.

In Figure A.1, the electricity demand can be seen. In the additional electricity demand, the the energy demand for H2 and CO2 pipelines is added, as it introduced a fixed electricity demand during the year.

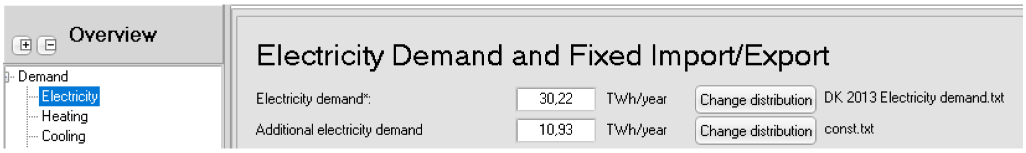


Figure A.1.

In Figure A.2, the demand for the transport sector is shown. Here petrol is replace by methanol 1/1. For the scenarios with 10 GW of wind capacity, diesel is replaced as well, due to the large quantities of methanol produced.

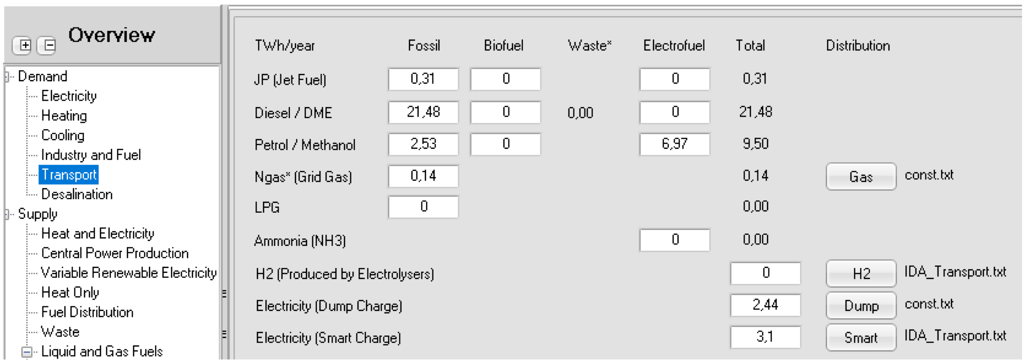


Figure A.2.

In Figure A.3, electricity supply by renewable energy sources can be seen. Here the 3 GW of offshore wind is introduced as Tidal for the sake of implementation in the software. The capacity inserted is including the losses, hence the costs of the remaining capacity is included in Figure A.9. BOth the distribution profile and correction factor is the same as the one used for offshore wind power in the $IDA2030_{Vision}$.

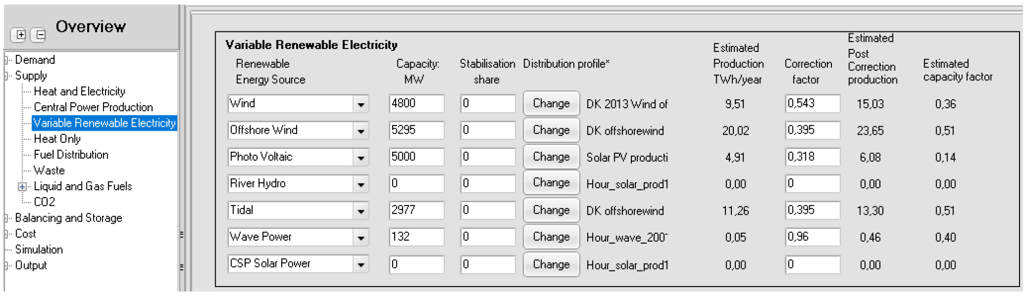


Figure A.3.

In Figure A.4, the electrolyer capacity, efficiency and hydrogen storage is included. For some scenarios, recoverable heat is introduced in district heating group 3 as well.

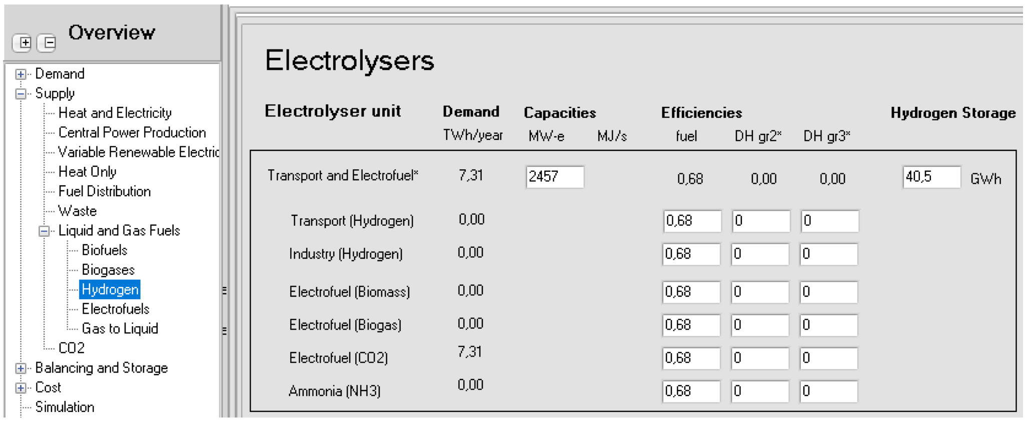


Figure A.4.

In Figure A.5, the methanol synthesis is is shown. Here multiple inputs have been made. First the CO2 consumption to produce have been changed, as data from Danish Energy Agency [2017c] is used. 0.224 Mt of CO2 is used to produced 1 TWh of methanol. The next box introduces a hydrogen loss in the process, this have been calculated in the Appendix B, to be 4.62 %, whereas 5.38 % is electricity loss which is accounted for in carbon recycling. Next up is the annual produced methanol with a capacity factor of 0.50 for electrolysers. The energy consumption of carbon recycling was reused from $IDA2030_{Vision}$, whereas the energy consumption of methanol synthesis is added into this process. As methanol synthesis have no recoverable heat, the distric heating input is set as 0. Lastly, the maximum carbon capture is specified. This is modelled, such the desired methanol synthesis capacity is reached. Scenario 1.1 have a capacity of 1333 MW, which is about 300 tCO2 per hour.

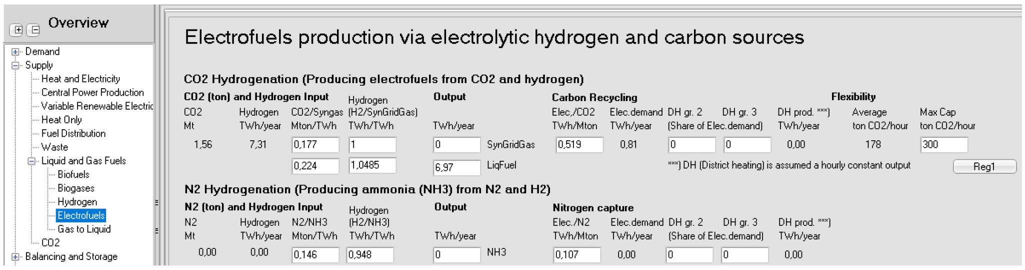


Figure A.5.

In Figure A.6, the methanol capacity is included, this is equivalent to 4 days of methanol storage.

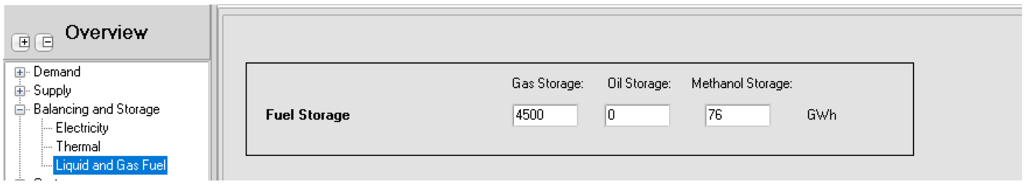


Figure A.6.

In Figure A.7 the costs for renewable energy sources is inserted. Here the costs and technical lifetime for wind power is included in the model under "Tidal Power".

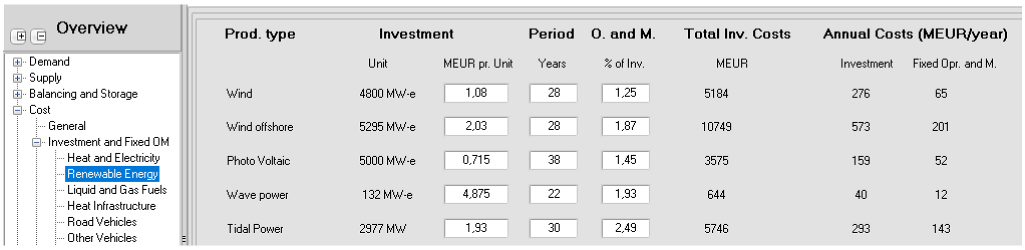
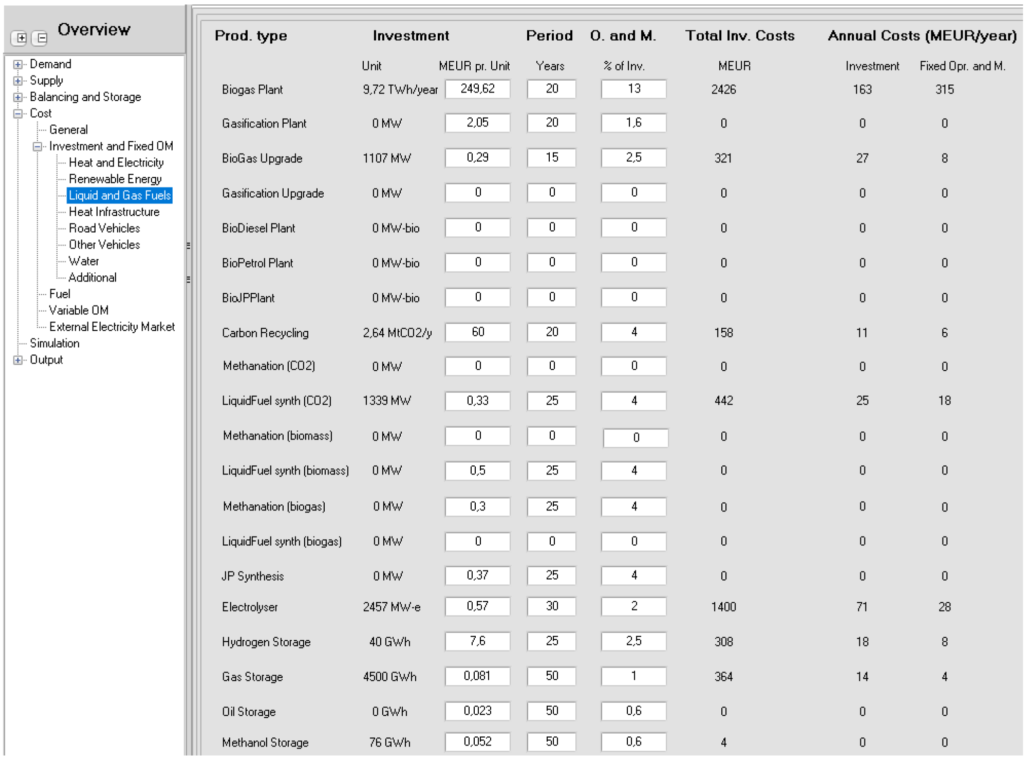


Figure A.7.

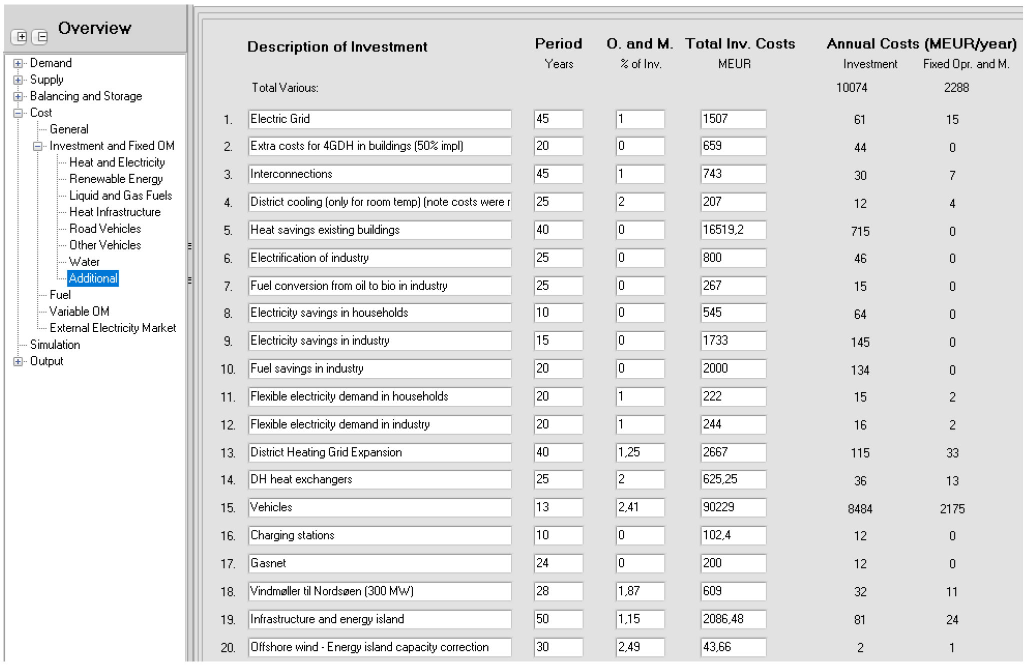
In Figure A.8, the costs for carbon recycling, methanol synthesis, electrolysers, hydrogen storage and methanol storage is included. Here the costs for carbon recycling, hydrogen storage and methanol storage is obtained from $IDA2030_{Vision}$, whereas the rest is obtained for various sources and calculated in Appendix B.



Prod. type	Investment		Period	O. and M.	Total Inv. Costs	Annual Costs (MEUR/year)	
	Unit	MEUR pr. Unit	Years	% of Inv.	MEUR	Investment	Fixed Opr. and M.
Biogas Plant	9,72 TWh/year	249,62	20	13	2426	163	315
Gasification Plant	0 MW	2,05	20	1,6	0	0	0
BioGas Upgrade	1107 MW	0,29	15	2,5	321	27	8
Gasification Upgrade	0 MW	0	0	0	0	0	0
BioDiesel Plant	0 MW-bio	0	0	0	0	0	0
BioPetrol Plant	0 MW-bio	0	0	0	0	0	0
BioJPPlant	0 MW-bio	0	0	0	0	0	0
Carbon Recycling	2,64 MtCO2/y	60	20	4	158	11	6
Methanation (CO2)	0 MW	0	0	0	0	0	0
LiquidFuel synth (CO2)	1339 MW	0,33	25	4	442	25	18
Methanation (biomass)	0 MW	0	0	0	0	0	0
LiquidFuel synth (biomass)	0 MW	0,5	25	4	0	0	0
Methanation (biogas)	0 MW	0,3	25	4	0	0	0
LiquidFuel synth (biogas)	0 MW	0	0	0	0	0	0
JP Synthesis	0 MW	0,37	25	4	0	0	0
Electrolyser	2457 MW-e	0,57	30	2	1400	71	28
Hydrogen Storage	40 GWh	7,6	25	2,5	308	18	8
Gas Storage	4500 GWh	0,081	50	1	364	14	4
Oil Storage	0 GWh	0,023	50	0,6	0	0	0
Methanol Storage	76 GWh	0,052	50	0,6	4	0	0

Figure A.8.

Lastly, the costs for the infrastructure of the energy island is included together with the remaining wind capacity which represents the loss in the interconnectors. The infrastructure of the energy island includes the costs for water purification, pipelines, interconnectors and the artificial energy island.



	Description of Investment	Period	O. and M.	Total Inv. Costs	Annual Costs (MEUR/year)	
		Years	% of Inv.	MEUR	Investment	Fixed Opr. and M.
	Total Various:				10074	2288
1.	Electric Grid	45	1	1507	61	15
2.	Extra costs for 4GDH in buildings (50% impl)	20	0	659	44	0
3.	Interconnections	45	1	743	30	7
4.	District cooling (only for room temp) (note costs were r	25	2	207	12	4
5.	Heat savings existing buildings	40	0	16519,2	715	0
6.	Electrification of industry	25	0	800	46	0
7.	Fuel conversion from oil to bio in industry	25	0	267	15	0
8.	Electricity savings in households	10	0	545	64	0
9.	Electricity savings in industry	15	0	1733	145	0
10.	Fuel savings in industry	20	0	2000	134	0
11.	Flexible electricity demand in households	20	1	222	15	2
12.	Flexible electricity demand in industry	20	1	244	16	2
13.	District Heating Grid Expansion	40	1,25	2667	115	33
14.	DH heat exchangers	25	2	625,25	36	13
15.	Vehicles	13	2,41	90229	8484	2175
16.	Charging stations	10	0	102,4	12	0
17.	Gasnet	24	0	200	12	0
18.	Vindmøller til Nordsøen (300 MW)	28	1,87	609	32	11
19.	Infrastructure and energy island	50	1,15	2086,48	81	24
20.	Offshore wind - Energy island capacity correction	30	2,49	43,66	2	1

Figure A.9.