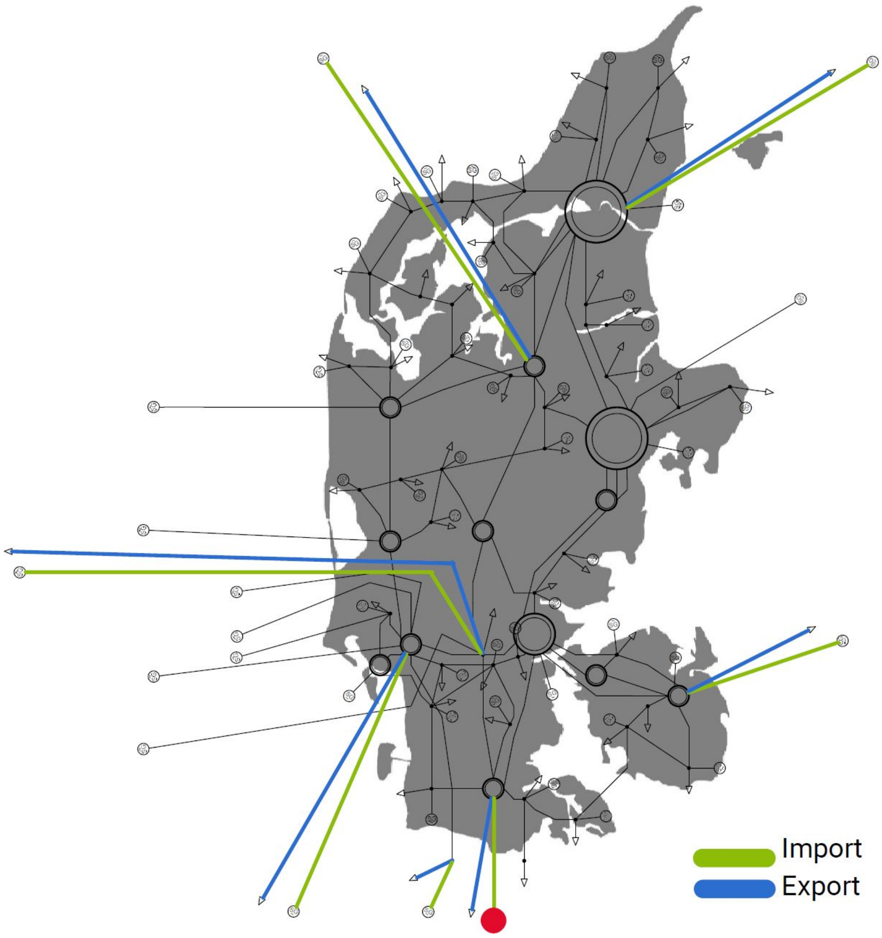
Integration of large-scale electrolysers in the Danish energy system



Master's Thesis

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Abstract:

This thesis investigates the impacts of integrating large-scale electrolysers in the Danish energy system and transmission grid in 2030.
A partial-equilibrium energy system model is applied to assess how the energy system should be composed, with regard to capacities of production, consumption and storage units. Subsequently, a DC load flow analysis is conducted to investigate how large-scale electrolysers impact loading of the transmission grid, based on electrolyser capacity, location and energy system composition.
The theories regarding synoptic planning and the adequate level of detail are applied throughout the thesis.
In the thesis it was found that large electrolyser capacities can facilitate increased integration of fluctuation renewable production units, and increase utilisation of these units. Furthermore, it was demonstrated that electrolysers can reduce the need for other flexible consumption units, such as electric boilers.
From a transmission grid perspective it was evident that large electrolyser capacities can be integrated without overloading the grid, if electrolysers are placed in feed-in zones for offshore wind power plants, and are operated proportionally to the production of the wind power plants. If these criteria are met, larger electrolyser capacities can even reduce grid loading, as compared to lower electrolyser capacities.

Summary

For at leve op til klimalovens målsætninger om at reducere de danske CO_2-udledninger med 70% i 2030, er det nødvendigt at omlægge den nuværende energiforsyning. En af vejene til CO_2 reduktioner er at elektrificere aktiviteter som, på nuværende tidspunkt, forsynes af fossile brændsler. Det er dog ikke muligt at elektrificere samtlige sektorer, hvorfor produktionen af CO_2-neutrale brændsler og gasser er afgørende. Disse kan overordnet set produceres på to måder. Ved forgasning af biomasse eller syntetisk fremstilling.
Eftersom biomasse anses for at være en begrænset ressource, som efterspørges i både energi- og fødevaresektoren, er det ikke plausibelt, at biomasseressourcen kan forsyne begge sektorer. Derfor er disse syntetiske brændsler essentielle i opnåelsen af 70% målsætningen.

De syntetiske brændsler har et fælles træk, idet de alle indeholder brint, hvilket kan produceres på elektrolyseanlæg, hvorved strøm omdannes til brint. Denne specialeafhandling omhandler indpasningen af disse elektrolyseanlæg i det danske energisystem og deres påvirkning på det danske eltransmissionsnet.

Elektrolyseanlæggenes påvirkningen på det danske energisystem undersøges ved at opstille tre scenarier for elektrolyseanlægskapacitet, og simulere disse scenarier ved at bruge en matematisk model af det danske energisystem.
Hensigten med simuleringerne er både at finde frem til udfordringer ved indpasning af elektrolyseanlæg, samt at finde den optimale sammensætning af forbrugs- og produktionsenheder i 2030. Tilmed anvendes energisystemmodellen til at generere time-baserede produktions- og forbrugsmønstre, som efterfølgende anvendes til at simulere elektrolyseanlæggenes påvirkning på eltransmissionsnettet.

Ud fra de time-baserede produktions- og forbrugsmønstre udvælges forskellige timer til videre analyse. Timerne udvælges på baggrund af en række kriterier for at finde frem til de mest relevante.
Elproduktions- og forbrugsmønstre for de udvalgte timer indsættes i en model af eltransmissionsnettet, hvormed belastningen på ledninger og kabler i nettet udregnes. Eftersom der simuleres tre forskellige elektrolyseanlægskapaciter, er det muligt at udlede sammenhænge mellem elektrolyseanlægskapacitet og påvirkning på eltransmissionsnettet.

Et andet formål med simuleringerne af eltransmissionsnettet er at finde frem til ideelle placeringer for elektrolyseanlæg. Da påvirkningen på nettet varierer alt efter anlæggenes placering, undersøges 24 relevante lokationer.

I afhandlingen fremsættes resultater og analyser, som fastslår, at elektrolyseanlæg kan udgøre en væsentlig påvirkning på både det danske energisystem og eltransmissionsnettet. Dog medfører disse påvirkninger både fordele og ulemper. Det har med resultaterne været muligt at påvise, at elektrolyseanlæg kan bidrage positivt til at indpasse øgede kapaciteter af vedvarende elproducerende enheder, såsom vindmøller og solceller. Tilmed kan elektrolyseanlæg øge udnyttelsen af disse enheder. Herudover kan elektrolyseanlæggene også reducerer behovet for at inkludere andre fleksible elforbrugende enheder, såsom elkedler, i systemet. Dog påvises også en sammenhæng mellem øget elektrolysekapacitet og øget import af elektricitet, hvilket indikerer at Danmark potentielt kan blive mindre selvforsynende med elektricitet, hvis større elektrolysekapaciteter implementeres.

Under analysen af eltransmissionsnettet påvises det, at elektrolyseanlæg kan integreres uden at overbelaste nettet. Analysen påviste ydermere situationer, hvor en forøgelse af elektrolyseanlægskapaciteten kan mitigere overbelastninger, som forekom ved en lavere elektrolysekapacitet. Det kræves dog, at elektrolyseanlægskapaciteten placeres i indfødningszoner for havvindmølleparker, og driftes proportionelt med havvindmøllernes produktion.

Under forudsætningerne og antagelserne gjort i denne afhandling, viste Idomlund sig som den, ud fra et eltransmissionsnetsperspektiv, ideelle placering for storskala elektrolyseanlæg. Det skal dog nævnes, at hvis ikke de ovennævnte kriterier overholdes, vil integrationen af elektrolyseanlæg forårsage markante overbelastninger af eltransmissionsnettet.

Det anbefales derfor at elektrolyseanlæg placeres i indfødningszoner, men da det vil være muligt at øge den samlede systemeffektivitet ved at udnytte overskudsvarme fra elektrolyseanlæg. Hvorfor det imidlertid anbefales at undersøge mulighederne for at flytte indfødningszoner nærmere større fjernvarmeområder.

Preface

This master's thesis is made by a study group on the 10th Semester on the study of Sustainable Energy planning and Management at Aalborg University.

The group would like to express their gratitude to Ea Energy Analysis for providing access to their version of the Balmorel model and the data needed to conduct the analyses in this thesis. Furthermore, the group would like to thank IT responsible at Ea Energy Analysis, Daniel Macchini Schrøder for his assistance throughout the thesis. Additionally, the group would like to emphasise their gratefulness to DIgSilent for providing the group with a thesis license to PowerFactory, which enabled the group to perform an analysis of transmission grid in DK1. Moreover, the group would recognise Maria Broe from Energinet for sharing knowledge, needed to conduct the transmission grid analysis in this thesis. Lastly, the group would like show their appreciation to Poul Alberg Østergaard for his supervision and guidance during this master's thesis.

All references used in this project can be found in the literature list in the end of the thesis. The group recommends reading the thesis in chronological order. Additionally, it is recommended to have Figures 6.5 and 6.6 at hand when reading through Section 8.2, as this will increase the readers understanding.

The following appendices are attached:

- Appendix A: Condensation of the interview with Maria Broe.
- Appendix B: Full interview with Maria Broe.
- Appendix C: Distribution keys for load flow analysis
- Appendix D: PowerFactory model
- Appendix E: Background data from energy system analysis
- Appendix F: Grid loading data for the 95% hour
- Appendix G: Grid loading data for the max production hour
- Appendix H: Grid loading data for the max offshore hour

Nomenclature List

Special Symbols and Denotations

Symbol	Description	Derived unit	Unit
B	Susceptance	Siemens	S
G	Conductance	Siemens	S
I	Current	Ampere	A
P	Active power	Watt	W
Q	Reactive power	Volt-ampere-reactive	var
R	Resistance	Ohm	Ω
V	Voltage	Volt	V
W	Power	Watt	W
X	Reactance	Ohm	Ω
Y	Admittance	Siemens	S
Z	Impedance	Ohm	Ω

Acronyms

Acronym	Abbreviation:
AC	Alternating current
CO_2	Carbon Dioxide
DEA	Danish Energy Agency
DC	Direct current
DH	District heating
DKK	Danish krone
EC	Electrolyser
EU	European Union
EV	Electric vehicle
FACTS	Flexible AC transmission system
FLH	Full load hours
H2	Hydrogen
PE	Partial equilibrium
PtX	Power-to-X
PV	Photovoltaic
RE	Renewable energy
RES	Renewable Energy Share
TSO	Transmission system operator

Contents

Problem analysis 1

This chapter entails a series of problems and barriers for obtaining the 70% CO_2 reduction goal for 2030. These are formed into a problem formulation and a research question, which defines the research that is conducted in this thesis.

1.1 The Danish climate goals

In 2020 the Danish parliament passed a climate law, which legally binds Denmark to reduce CO_2 emissions by 70% in 2030, compared to the emissions in 1990. In addition, the law dictates that Denmark must become climate neutral by 2050.
However, the transition towards climate neutrality must happen in a manner that ensures that the Danish industry remains competitive in an international perspective. Furthermore, the transition must not cause the welfare standards in Denmark to decline. The climate law also states that the measures taken to reduce domestic emissions are not allowed increase emissions in other countries. [Klima-, Energi- og Forsyningsministeriet, 2020]

In order to reduce emissions by 70% in 2030 and become climate neutral in 2050, polluting activities from all sectors, must be reduced or negated. Thus, the use of fossil fuels must be significantly reduced.
According to Energinet [2019], 40-60% of the energy demand can be electrified. The remaining 40-60% must be supplied by fuels and gasses, which are needed for shipping, air traffic, heavy transport, industry, agriculture, and back-up power generation. Consequently, it can be stated that to obtain net zero emissions, renewable and climate neutral fuels and gasses are needed. These can be produced using biomass or through the use of Power-to-X (PtX).

Biomass can be turned into biofuels or biogas. According to Skov og Mathiesen [2017], biomass is a limited resource with an uncertain potential. Skov og Mathiesen [2017] states that the biomass potentials in Denmark are not sufficient to cover the current fossil fuel demands. The same is true from a global perspective. Furthermore, biomass resources are vital for the international food supply. Hence, biomass should only be used as an energy source when absolutely necessary [A.Muscat et al., 2019]. Therefore, non-biomass based products are essential to adhere to the climate goals.
An alternative to biomass-based fuels and gasses are PtX products. Hydrogen can be produced from power through electrolysis, and this hydrogen H_2 can then be used for production of several e-fuels and gasses, some of which are mentioned below:

- Green hydrogen - H_2
- Synthetic biogas e.g. methane CH_4
- Synthetic liquid fuels e.g. methanol CH_3OH
- Ammonia NH_3

The different PtX products mentioned above can be used in various applications. A rough overview of these products are given in Figure 1.1.
As illustrated, all PtX products start with hydrogen as the building block. Hydrogen is combined with carbon from various sources or nitrogen, to form those listed above.

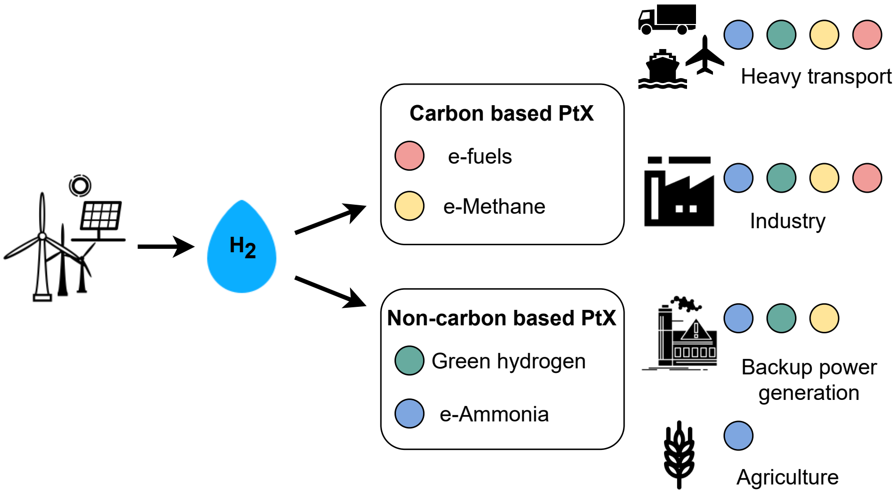

Figure 1.1. Production and utilisation of PtX products. Based on [Energinet, 2020c].

Due to the properties and advantages of the different PtX products, they will likely all play a role in the transition towards a climate neutral society. In the EU-Commissions climate neutral scenarios, PtX is expected to cover approximately 21% of the final energy consumption in 2050. Consequently, the EU-Commission has made a hydrogen strategy which states sub targets for electrolysis capacity in 2024 and 2030. These are, respectively 6 GW in 2024 and 40 GW in 2030.

As the electricity price greatly influences whether or not PtX will be economically feasible, it is expected that the technology will develop in Denmark, as the large share of wind power in the Danish electricity mix results more hours with low electricity prices.
The Danish government has not currently made any concrete PtX strategy or political plan. However, several large industrial organisations have made various recommendations to the government. According to Dansk Energi [2020], the government should aim for an electrolyser (EC) capacity of 0.5 GW in 2025 and 3+ GW in 2030. Brintbranchen [2020] suggests an EC capacity of 1 GW in 2025 and 6 GW in 2030. Even though the government has not made an official PtX strategy, Danish Energy Agency [2020] still expects the EC capacity to increase to 250 MW in 2025 and 1 GW by 2030.

Both Dansk Energi [2020] and Brintbranchen [2020] have stated recommendations for how the government should form their PtX strategy, in order to reach the desired capacities within the time frame. According to Dansk Energi [2020], the PtX industry is limited by the PtX paradox, illustrated in Figure 1.2.

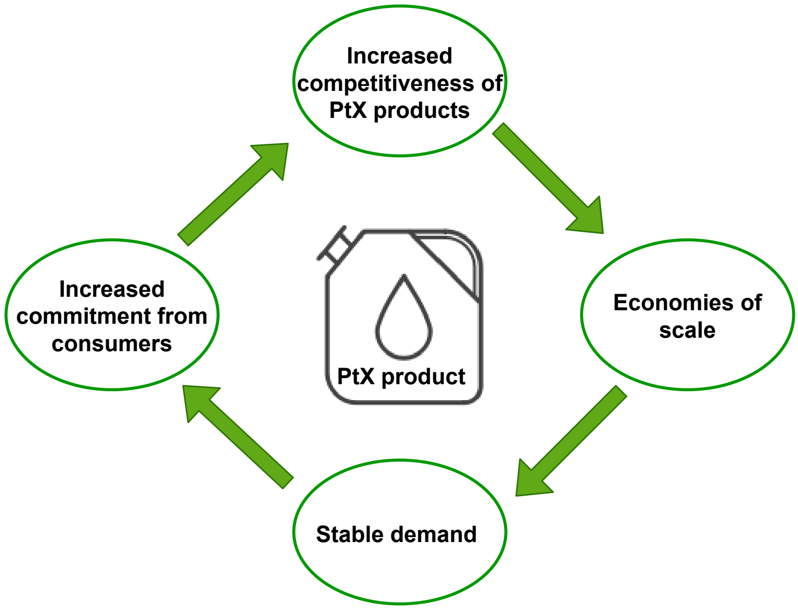

Figure 1.2. The PtX industry will be competitive once production has scaled up, but to reach economy-of-scale, the demand has to rise. However, the demand is only expected to rise once the PtX products are competitive, hence the paradox. [Dansk Energi, 2020]

From Figure 1.2 it can be understood that the PtX industry will not become market competitive before it has achieved the benefits associated with economy-of-scale. Consequently, Dansk Energi [2020] recommends that the government grants economic subsidies to kick-start investments and development in the industry.

According to Brintbranchen [2020], the current tariff structure is made for a fossil based system, meaning that a key element in the framework conditions is lacking behind. Dansk Energi [2020] concurs and states that the magnitude of the current tariff does not equate to the expenses actually caused by ECs in the grid. The TSO Energinet also mentions in their assessment of barriers for PtX plants, that flexible tariffs should be available for flexible loads, such as ECs [Energinet, 2020c].

The cost associated with prodction of green hydrogen, which is hydrogen produced from ECs, can be seen in Figure 1.3. Here it can be seen that tariffs account for a significant part of the expenses in the production of green hydrogen, which underlines the importance of the tariffs.

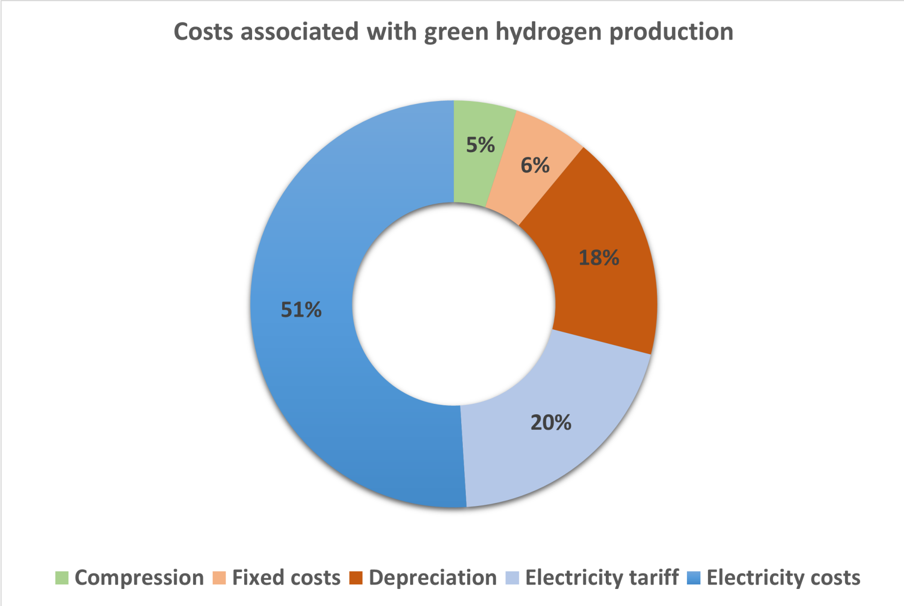

Figure 1.3. The cost associated with green hydrogen production in Denmark, as estimated by Dansk Energi [2020].

Neither Dansk Energi [2020] nor Brintbranchen [2020] states how the tariff should be structured, but merely points to the fact that it must be restructured for PtX to become competitive. A new tariff product with limited security of supply has been proposed by Energinet. According to Energinet [2020a], this tariff is made as a response to the customers need for a tariff that addresses more flexible consumers. These customers include, amongst others, the district heating sector and the PtX sector. They argue that, given their flexible nature, the marginal costs of supplying them are lower than traditional customers and therefore tariff should reflect that. Energinet [2020a] do agree that the marginal costs are lower for the customers, but only if they do not have the same security of supply as traditional customers. Hence, the new tariff product gives Energinet the possibility to regulate the costumers consumption in order to balance the transmission grid. Energinet [2020a] does not specify how often the costumer can expect to be down-regulated, nor do they guarantee a minimum number of full load hours (FLH). Energinet states that it would, for both Energinet and the costumer, be beneficial to place the consumption at grid connection points where the likelihood of being down-regulated by Energinet is lowest.
On another note, Energinet [2020b] points to the fact that large flexible loads strategically placed in the grid can potentially stabilise grid loading and allow higher RE capacity to be integrated in the system without the need for grid reinforcements. However, this will be dependant on how distributed this RE capacity is and how flexible these loads are.

1.2 E-fuel demand and cost predictions

As of now, e-fuels are still more expensive than their fossil-based counter parts. According to Dansk Energi [2020], green hydrogen is approximately two times more expensive than grey hydrogen, which is fossil-based. As hydrogen is a key building block for all e-fuels, this price difference has a ripple effect for all e-fuels. However, the price of green hydrogen is expected to become competitive, if key factors fall into place:

- Utilisation of excess heat for district heating.
- Changes in the tariff structure.
- Efficiency of ECs improves.
- Increased number of hours with low electricity prices.

By their most optimistic estimations, Dansk Energi [2020] expects cost parity between blue hydrogen (fossil-based with carbon capture and storage) and green hydrogen by roughly 2026. Furthermore, cost parity between fossil based grey hydrogen and green hydrogen is expected by 2030. These cost predictions can be seen in Figure 1.4.

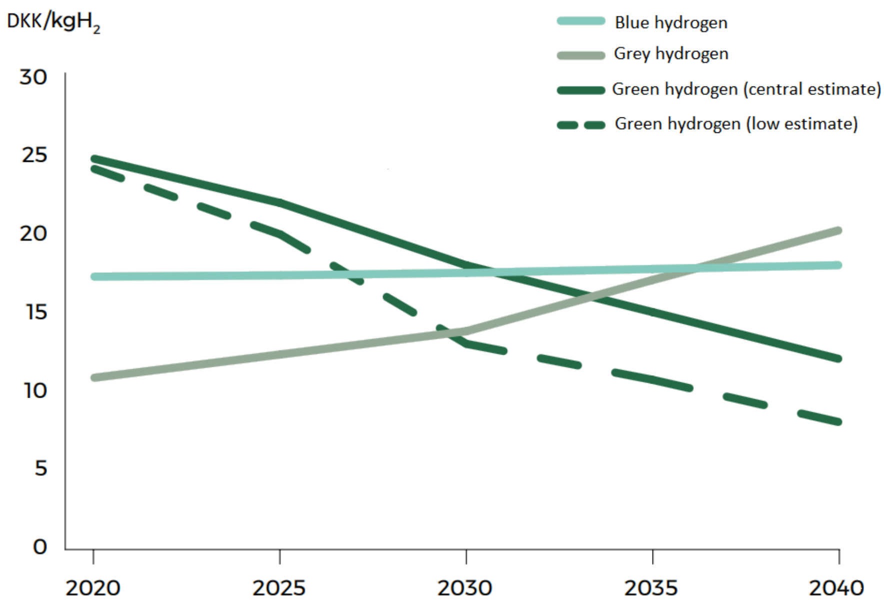

Figure 1.4. Cost development of blue, grey and green hydrogen, as predicted by Dansk Energi [2020].

However, if a CO_2-tax of roughly 1500 DKK per ton CO_2 is implemented, like Klimarådet [2020] suggests, the price of grey hydrogen would increase by approximately 13.5 kr. per kg hydrogen (given 9 kg of CO_2-eq per kg of grey hydrogen [Dansk Energi, 2020]). Meaning that cost parity would happen earlier.

If the market is to decrease the price of PtX products on its own, it is, according to the PtX paradox, essential that the demand for PtX products rises to drive the development of the industry.

Considering the use of ammonia and methanol as fuel for shipping, Dansk Energi [2020] expects that there there will be a steady transition towards ammonia and methanol until 2035. However, from 2035 to 2045 a surge in the utilisation of ammonia and methanol is expected for shipping worldwide. This development can be seen in Figure 1.5.

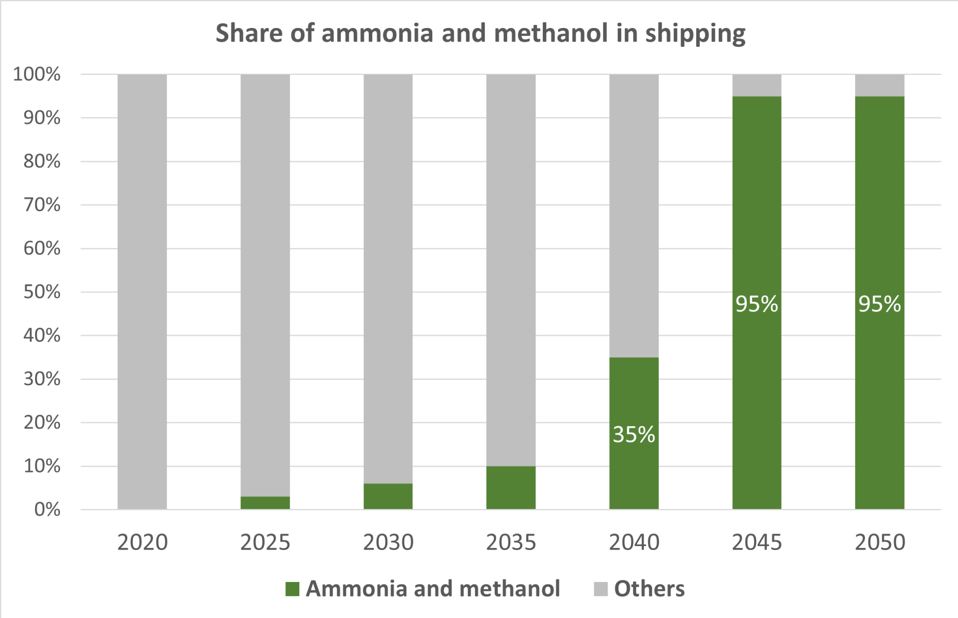

Figure 1.5. Expected share of global shipping covered by ammonia and methanol. [Dansk Energi, 2020]

As seen in Figure 1.5 the demand for PtX products is expected to rise, even though the current tariff structure and the PtX paradox should limit development. In Denmark several companies have published plans to construct large EC plants. According to Ingeniøren [2021], there are already projects in the pipeline with a collected EC capacity of around 4.55 GW by 2030.

By considering the large-scale EC projects already in development, the EC capacity will be 4.55 times larger than the projections made by the Danish Energy Agency in 2030.
As mentioned, EC based PtX products are essential to reach the desired emission reduction, thus it is of great importance that the industry takes charge in this situation, as there is lack of governmental plans for development of PtX.
However, the mismatch between the industries plan for PtX development and the governmental expectations for development can result in various issues. If the projections in expected EC capacity is underestimated by the Danish Energy Agency, then the electrical transmission grid and the energy system might not be able to accommodate large-scale ECs, as the TSO Energinet follows the predictions laid out by the Danish Energy Agency. As it can take up to ten years to connect plants and upgrade new transmission grid capacity, this can potentially delay PtX development, and ultimately hinder the ability to reach the 70% reduction goal by 2030. [Energinet, 2020d]

1.3 Problem formulation

In the problem analysis it has been stated that direct electrification of all sectors, can only cover 40-60% of the end energy demand. The remaining energy demand must be covered by fuels and gasses. It has been found that the these fuels and gasses can be produced through the use of EC based PtX. Therefore, it has become clear that developing PtX and increasing the EC capacity is essential to achieve the 70% CO_2 reduction goal and become climate neutral. However, the government have yet to make a national PtX strategy or action plan.

For PtX to become market competitive it must break free from the PtX paradox, which can either be achieved by a large demand or by changing the framework conditions to help the technology become economically viable. The industry is expecting the authorities to make the necessary changes to the framework, in order to ensure economic feasibility for PtX projects in Denmark [EnergiWatch, 2021], and as PtX is essential to reach the 70% CO_2 reduction goal, it is adamant that these changes are made.

ECs are the building block of PtX-based e-fuels and gasses and they are consequently identified as key enablers for evolving the PtX industry. However, it was found that there is a significant mismatch between EC capacity projected by the Danish Energy Agency and the already planned capacity by the industry, as companies have plans to construct around 4.55 GW of EC capacity by 2030.
This mismatch can result in issues accommodating large-scale ECs both in the energy system and the electrical transmission grid.

According to Dansk Energi [2020], another obstacle for PtX development is the current tariff structure, which they state is not cost genuine for EC plants. Energinet has proposed a new tariff product with limited security of supply, however the product does not entail any clear guidelines for the likelihood of down-regulation. Moreover, it also became evident that large flexible loads, such as EC plants, can potentially stabilise grid loading and increase RE integration. This means that from an energy system and transmission grid perspective, EC plants can be both a benefit and a burden depending on how they are integrated. Ultimately, it can be understood that an assessment of how EC plants could be integrated in the transmission grid in a manner that is beneficial for both the energy system and the transmission grid, is needed. Finally, the following research question is formulated:

"How should large electrolyser capacities be integrated in Danish transmission grid and energy system, from a technical point of view, while still complying with the 70% CO_2 reduction goal of 2030?"

Underlying research questions:

- How do large-scale electrolysers affect the dispatch and capacities of electricity production, consumption and storage units in the energy system?
- How do electrolyser plant locations and capacities impact transmission grid loading, and how should electrolysers be integrated in the transmission grid to minimise these impacts?

1.3.1 Delimitation

The following outlines the aspects of the subject which are delimited from being assessed in this thesis.

The economic value of EC produced hydrogen and PtX products is not covered in this thesis, as this is not within the scope of this thesis.

In this thesis it is chosen to delimit from presenting the impacts of ECs on the heating sector in detail. This is done in order to reduce complexity of the analysis and allow for a deeper analysis of the impacts of ECs on the electricity sector. It should however be noted that electricity consuming heat production units, such as electric boilers, are accounted for in the analysis, but only from an electrical point of view. Following the logic described above, surplus heat from ECs is not considered.

Gas infrastructure and storage perspectives are not considered in this thesis, as this will drastically increase the complexity of the analysis, and thereby not allowing enough of the limited resources to be spent on the key issues investigated in this thesis. The same goes for CO_2 infrastructure and storage, which are not considered in the analysis for the same reasons.

The transmission grid analysis conducted in this thesis is only conducted for DK1 (western Denmark). Thereby, a delimitation from DK2 (eastern Denmark) is made. This is partly done because the EC capacity is expected to be higher in DK1, but also because the RE potentials are significantly higher in DK1. Hence, the it is deemed more important to investigate the effects in DK1.

Research design 2

This chapter is used to explain how the thesis is structured. Furthermore, it is used to describe how the research design, developed in this thesis, is used to answer the research question. The purpose of this chapter is to describe the train of thought used to answer the research question.

To answer the research question a research design has been developed. This research design entails the theory, methods and analyses that are needed to answer the research question and underlying research questions.

As the intention of this thesis is to investigate the how large-scale ECs should be integrated in the energy system and the transmission grid, several theories, methods and analyses are needed. However, in any research it necessary to incorporate some literature searching techniques before the research can begin. Consequently, it is essential to establish some guidelines for how literature is obtained. Once these guidelines have been established, scenarios that can be used to analyse and test the impacts of ECs in a future perspective, must be developed. In order to develop relevant scenarios, scenario development theory must be applied to a scenario development method.
Armoured with suitable scenarios, the methods for analysing how ECs should be integrated in the energy system and transmission grid, must be developed. Planning theory is applied to figure out how this long term planning problem of integrating ECs should be assessed. Consequently, a theory section regarding planning theory is needed.
As technical analyses of the energy system and transmission grid can be executed with countless combinations of detail levels and perspectives, it has been chosen to apply the Adequate Level of Detail Theory. This theory is meant to guide the researcher to focus on the necessary details, needed to complete the specific analyses.

When it comes to analysing the impacts of ECs on the transmission grid, data inputs regarding electricity production and consumption are needed. To acquire these data, an energy system simulation that optimises dispatch of electricity production and consumption is needed. Consequently, an energy system analysis must be conducted firsthand. Thus, this energy system analysis has multiple purposes. Initially, the analysis is meant to gather information about how ECs impact dispatch, utilisation of RE and investments in production capacity and storage. Secondly, optimal production and storage capacities should be derived. Thirdly, hourly electricity production and consumption patterns should be exported into a load flow transmission grid analysis.

Equipped with hourly production and consumption data, an analysis of how ECs are best integrated into the transmission grid, from a technical point of view, can be conducted. With the help of the adequate level of detail theory and a suitable load flow simulation software, this analysis should help the researcher answer how ECs impact the transmission grid in different scenarios and system configurations.

To ensure that both an energy system analysis and a transmission grid analysis can be performed, it is not certain that all data can be obtained through literature. Thus, expert interviews are needed. To achieve valid and reliable knowledge, these interviews should be carried out based on interview theory and a defined interview method.

Once all results, findings and analyses has been secured, these should be discussed in relation to the research question. Subsequently, the research question should be answered in a conclusion.
Furthermore, it has been decided to state recommendations based on the findings in this thesis.

In Figure 2.1 an overview of the structure is given. Here it can also be seen where the underlying research questions are answered, as well as where different methods are applied.

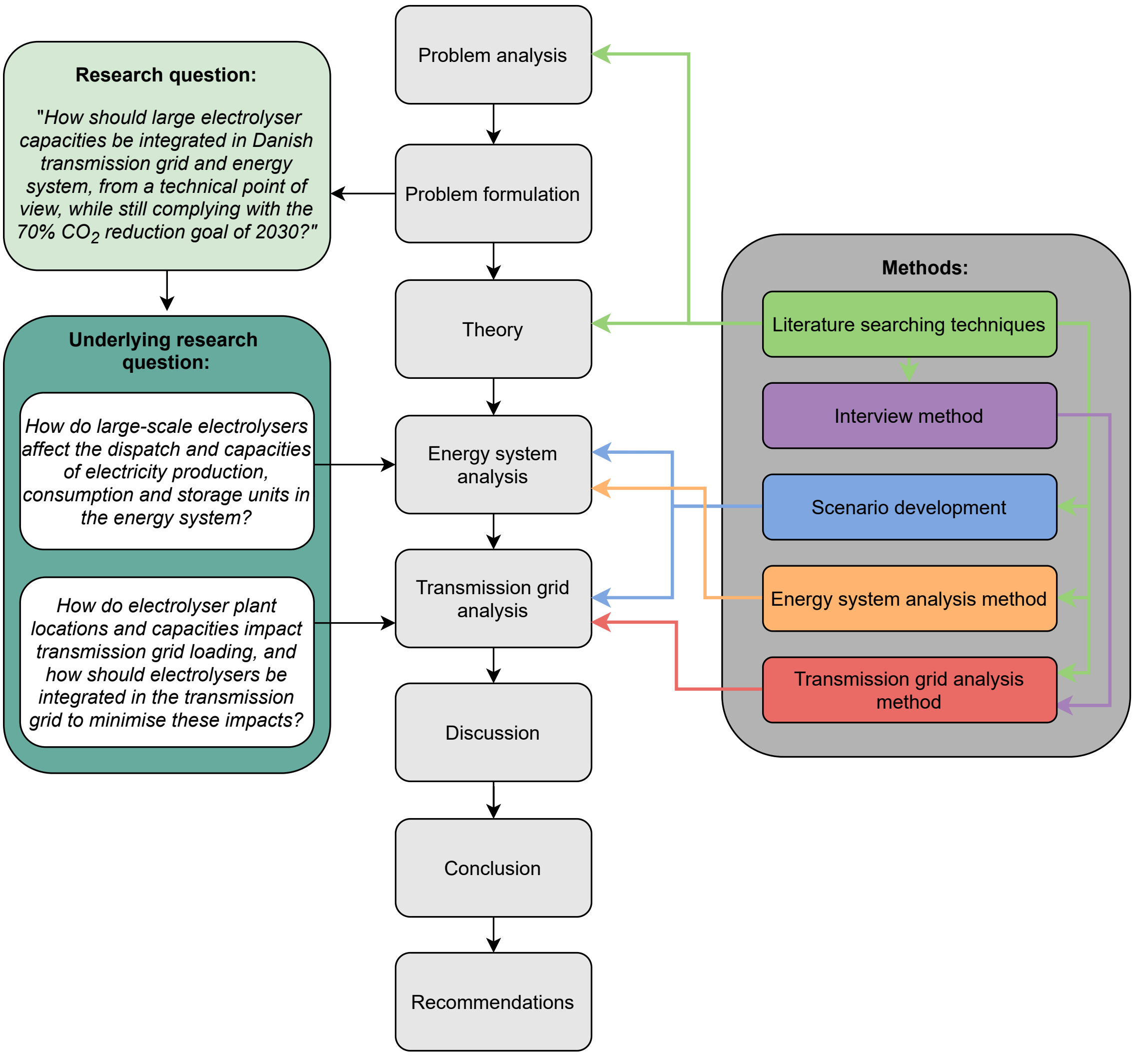

Figure 2.1. Overview of the research design used in this thesis.

Theory 3

The purpose of this chapter is to introduce the theoretical framework used in this thesis. Here the theoretical planning approach used is introduced, followed by the Adequate level of detail theory. These theories are applied throughout the thesis.

3.1 Planning theory

When dealing with complex future goals or objectives, planning theory can be beneficially used to reach these desired objectives. However, firstly a few defining words on planning should be spilled.
Overall, planning is concerned with obtaining specific goals or expectations in a future perspective through a planning process. Throughout the planning process several decisions must be made based on various rationals. Depending on the future objective and planning approach, these rationals can be both technical, economic, political, ethical etc.. [Holden, 1998]

For this thesis it can be said that the objective is to investigate how ECs can be integrated in the transmission grid and overall energy system, as ECs are seen as essential enablers for reaching the 70% CO_2 reduction goal in Denmark. Thus, integrating ECs is the actual future goal. Therefore a theoretical planning approach is needed to ensure that ECs can be integrated, while also ensuring that the integration is accomplished in a manner that is technically suitable for both the transmission grid and the overall energy system.

From the given definition of planning, it can perhaps be understood that different planning theories are concerned with various parts of the planning process and the rationals used in the process. Numerous planning theories exist, but Holden [1998] have summed recurrent features of various types into four overall types. These types are briefly introduced in the following.

Synoptic planning is an often technocratic long term top-down oriented approach, that through data-based modelling seeks to find one optimal solution to reach a future goal. The general idea is that with enough data, all options can be investigated and barriers can be overcome by analysing all paths to the desired future goal. A comprehensive total plan is usually the outcome of a synoptic planning approach. The synoptic planning theory is build on a positivistic scientific approach.
The ***incremental planning theory*** is in contrast to the synoptic planning theory, as it originated from critique of comprehensive total plans, arguing that sufficient data was not always available and unforeseen changes in reality would alter framework conditions. Consequently, the incremental planning approach utilises incremental steps to obtain an overall change. Short term goals are continuously constructed over time, and these are reached by continuously analysing the present situation. Thus, long term action plans are not utilised, as incrementalism is an iterative process that keeps starting over, and bases

actions on the present situation. This theory has also been referred to as *the science of muddling through*.
A third planning theory is more concerned with the planning process and decision making. This is called ***advocacy planning*** and it is based on a consensus seeking approach, where a multitude of societal groups and stakeholders are empowered to participate in the decision-making process through individual spokespersons. Subsequently, the idea is to choose actions based on the collected opinions, thus making all societal groups more empowered during the planning process. With this approach the planner does not act as a technical or economic expert, but rather as a facilitator of consensus seeking debate. Lastly, ***democratic planning*** is introduced. This type focuses on moving the decision making power closer to the citizens and holds the democratic principles above all else in the process. [Holden, 1998]

As this thesis is concerned with assessing how large EC capacities can be integrated in the Danish energy system and transmission grid, the objective can be denoted as a rather technical one, which is assumed solvable with advanced system modelling tools, quantitative data and technical analysis. Moreover, this assessment of EC integration has a longer time frame, as the objective of integrating ECs is build on the 2030 CO_2 reduction goal. Thus, an incremental planning approach is less suited for obtaining perspectives on how the future objective can be solved. Moreover, it is not assumed that involving various social groups or facilitating a democratic citizen process in the analytical part of the EC assessment is beneficial, due to the technical nature of the objective. Consequently, advocacy and democratic planning methods are not utilised in this project.
Finally, that leaves the long term analytical top-down oriented synoptic planning theory. The assessment of EC integration in Denmark is therefore inspired by the approach of the synoptic planning theory, as the approach is to shed light on various solutions for integrating ECs, in the search of the optimal solution by utilising large data quantities and analytical modelling tools. This approach is well suited for the purpose of this thesis, as sufficient analytical data and modelling tools are assumed to be available.

Even though the synoptic planning approach is utilised during the first part of the energy system planning approach, it is recommended that the subsequent decision-making process is based on more democratic and citizen involving principles. Chapter 11 entails the final remarks of this thesis, which is a list of recommendations for how ECs should be integrated in Denmark, and how the research should be taken further. These recommendations are intended for decision-makers and stakeholders with interest in the subject of EC integration.

As the research process in this thesis is inspired by the synoptic planning approach, this thesis is build on technical energy system analysis and consequently focuses on technical perspectives in relation to EC integration.

3.2 Adequate level of detail theory

In this thesis the theory regarding the adequate level of detail is applied. The theory states that the researcher should only focus on the knowledge that is instrumental in order to conduct the specific analyses needed to answer the research question [Hvelplund, 2001]. In this thesis it is desired to investigate how ECs should be integrated in the Danish energy system and the transmission grid in a manner that is technically beneficial for both. As a result, some specific structures, which are deemed adequate for these analyses, is used. The adequate structures needed in this thesis are as follows:

- Scenario development
- The structure of the general energy system.
- Structure of the transmission grid in DK1.
- The relevant time frame of the analyses.

The reasoning behind the selection of these structures is outlined in the following. Neither the energy system analysis or the transmission grid analysis can be conducted without developing scenarios that represents potential future energy systems with various EC capacities. Hence, scenario development is adamant.
The structure of the general energy system refers to existing production, storage and consumption units, electricity and heat demand. However, to conduct the intended analysis of how ECs should be integrated, it is also essential to know the expected future structure and the potentials for increasing capacities of production and consumption units in the future. As the Danish energy system is integrated in an international system, the structures of the neighbouring energy systems are also needed. These structures are essential to perform the intended energy system analysis.

The structure of the transmission grid of DK1 refers to the electrical properties of the cables and overhead lines in the transmission system. This structure is essential, as it is the basis of assessing the impacts of how different EC capacities and locations impacts the transmission grid. Without the structure of the transmission system in DK1, it is not possible to assess how ECs can be integrated in the transmission system in a technically viable manner.
The time frame of the analyses is of importance, as it will impact the technologies available, electricity and heat demands as well as the composition of the energy system.

These structures and how they are used in this thesis are further explained in Chapters 4, 5 and 6.

General methods 4

This chapter presents a series of methods that are essential to investigate the research question and construct adequate methods for detailed technical analyses needed to answer the research question.

In order to assess how ECs impact the energy system and transmission grid, a series of methods are needed to ensure valid and useful technical analyses. In this chapter broader methods regarding literature searching, interviews and scenario development are presented. The methods for conducting both an energy system analysis and a transmission grid analysis are presented in separate chapters later.

Literature search techniques are useful to obtain the relevant knowledge needed, in order to properly conduct the analyses in this thesis. Interviews are needed to obtain knowledge which cannot be derived from literature. Scenario development is of importance, as it allows for analysis of multiple possible futures.

4.1 Literature search techniques

Literature search techniques are used to obtain knowledge in the form of material and raw data. Therefore, these techniques are of importance in this thesis. Firstly, a brief introduction to the two types of sources is given.

Primary sources is a term used to describe data obtained directly from first hand sources, such as expert interviews, maps, etc. In this thesis primary sources include expert interviews, correspondence and raw data obtained from e.g. Energinet. [University of Southern California, 2021a]

The term secondary sources refers to data sources that describe, or present matter which was originally presented elsewhere. This also includes data obtained from literature reviews of existing literature. [University of Southern California, 2021b]

In this thesis, knowledge is obtained through both primary and secondary sources, among these various material is gathered. This material includes: books, research articles, governmental reports, organisational report and interviews. To find potentially relevant material, search words include e.g. electrolysers, PtX, load flow analysis, RE development, Balmorel, RE potentials and transmission grid. When the sources found during the initial search have been read and central points and arguments are located, a chain search is carried out. In the chain search sources of interest, referred to in the initial literature, are identified and read, as they may provide valuable information not presented in the initial literature. [Emrald Publishing, 2021]

As the Danish energy system is constantly evolving, attention is also given to the publishing data of the material which has been identified as relevant. It is especially important

that literature regarding the transmission grid structure and analyses hereof is updated, as the transmission grid is constantly evolving. Furthermore, attention is given to the author(s) of the literature. Material from authors with commercial interests in a subject or organisations with an obvious political agenda is taken with a grain of salt, while articles or reports from esteemed sources are generally deemed more trustworthy. As this thesis includes modelling of the Danish energy system and the transmission grid, raw data and information regarding technologies and systems is needed. This data is essential for the reliability of this thesis, thus it is obtained from trusted sources such as the Danish Energy Agency [2021d] in the form of both primary and secondary sources. [Aarhus University, 2021]
These literature search techniques were also used during the problem analysis, as many different paths were investigated.

4.2 Interview method

As mentioned above, interviews are in this thesis utilised to obtain knowledge that cannot be obtained through literature. Therefore, a method for conducting interviews is developed.

In order to conduct an interview, it must be considered what type of interview is relevant, for the interview which is to be conducted. Here three interview structures are considered. First off is the unstructured interview. In this type of interview the questions are not predetermined. Thereby, the interviewer can decide the questions as the interview unfolds. In contrast, the structured interview offers little room for the interviewer to alter questions as the interview unfolds, as this type of interview is reliant on a set of predetermined questions, which are asked exactly as predetermined [Brinkmann og Tanggaard, 2010]. The semi-structured interview is exactly what the name suggests. It allows the interviewer to have a set of predetermined questions, but also offers the opportunity to deviate from these questions, in order to ask questions which might arise during the interview. Here the predetermined questions are used more as a guideline than a fixed structure. According to Brinkmann og Tanggaard [2010], this requires the interviewer to have sufficient knowledge about the field in which the interview is revolving.

In this thesis, it is decided to conduct the interviews as semi-structured interviews, as this interview type allows the interviewer to make new relevant or follow up questions, that arise during the interview. Furthermore, it still offers a chance to have some predetermined questions, which can be helpful in order to keep the interview on the right track.

In this thesis an interview is conducted with Maria Broe, who is a project leader at the grid planning department at Energinet. The interview is conducted in order to obtain additional knowledge about Energinets perspective regarding ECs and PtX, points of connection for offshore wind power plants in DK1, and capacities of overhead lines and cables. A summary of the interview can be seen in Appendix A, while the full interview can be found in Appendix B.

4.3 Scenario development

Predicting the future energy system is hard, if not impossible due to the high degree of complexity and uncertainty. These uncertainties are caused by a number of different factors, among these are policies, public opinion and technical developments. Therefore, this thesis does not attempt to predict the future, instead scenarios are developed and used for the analysis. Figure 4.1 illustrates how scenarios exist in the space between predictions and speculations, on a scale of complexity and uncertainty.

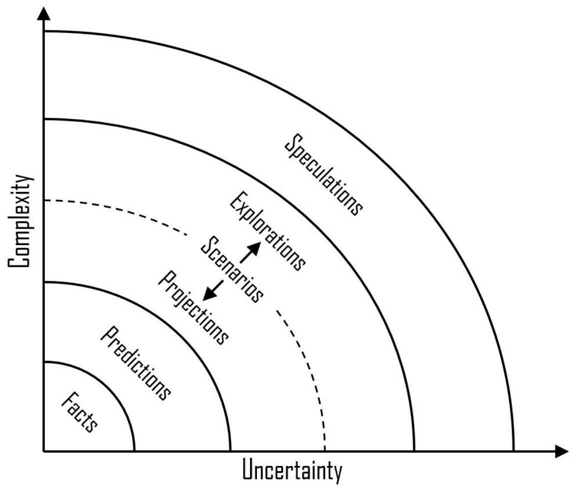

Figure 4.1. Scenarios plotted on a scale of uncertainty and complexity. [Ash et al., 2010]

According to Ash et al. [2010], scenarios can be utilised when investigating systems with a high degree of complexity and uncertainty, as they do not predict the future. Instead they provide a range of possible futures, hence allowing for analysis of different possible futures. Ash et al. [2010] define scenarios as *"plausible and often simplified descriptions of how the future may develop based on a coherent and internally consistent set of assumptions about key driving forces and relationships"*.

In this thesis the scenarios are developed based on different assumptions, estimates and predictions. Due to the complexity and uncertainties of both the composition of the energy system, but also the degree of EC implementation, it is chosen to make two different energy system scenarios, and three sub-scenarios in which the EC capacity is varied. All scenarios are simulated and analysed in a 2030 perspective, as this is the time frame of the 70% CO_2 reduction goal.

4.3.1 Energy system scenarios

Here the two energy system scenarios are presented and the reasoning for choosing the scenarios is outlined. These scenarios govern the amount of onshore and offshore wind power, as well as photovoltaic (PV) capacity in the energy system. The conditions can be found Section 5.2.

According to Energinet [2020b], it is of great importance for the stability of the energy system and transmission grid, whether there is a large penetration of distributed onshore RE units, such as PVs and onshore wind turbines, or if the RE units are offshore-based,

as is the case with offshore wind turbines.
Energinet [2020b] states that larger quantities of offshore wind could potentially be integrated without increasing grid loading, if large flexible loads are placed at the point of connection for offshore wind power plants. These flexible loads, such as ECs, could potentially utilise excess electricity. Thus, increasing domestic utilisation of fluctuating RE, without necessarily increasing grid loading.

To address the pros and cons of implementing various EC capacities in a system based on distributed onshore RE, and a system based on offshore wind, both an onshore and an offshore energy system scenario are developed and investigated.
The exact RE capacity requirements and potentials of these two scenarios are expanded upon later, and can be found in Table 5.4.

The offshore scenario is based on Danish Energy Agency [2020], henceforth referred to as AF20, which entail a significant quantity of offshore wind, as current political plans have pledged to construct two offshore energy islands and increase the offshore wind production drastically [Danish Energy Agency, 2021a]. As this scenario is based on current political plans, it can, to a certain extent, also be considered as a reference scenario.
In order to construct a more explorative scenario, an onshore scenario with increased onshore RE potentials is developed. This is decided in order to address the pros and cons of implementing various EC capacities in an energy system with a higher onshore RE capacity.

In order to adhere to the 70% reduction goal of 2030, each of the scenarios must have a maximum allowed CO_2 emission. According to Regeringens klimapartnerskaber - Energi- og forsyningssektoren [2020], the CO_2 limit for for the utility sector equates to 1 Mt. Therefore, this limit is used to represent the 2030 goal of 70% reduction in this thesis. As a result, all scenarios must adhere to this limit.

4.3.2 EC scenarios

Here the three different EC scenarios are presented. These three scenarios are sub-scenarios for the energy system scenarios described before. This means that all EC scenarios, are simulated for each energy system scenario.

EC-AF20 In this scenario the EC capacity presented by Danish Energy Agency [2020], is used. They estimate a total EC capacity of 1 GW by 2030, with a capacity distribution between DK1 and DK2 of 60% in DK1 and 40% in DK2.

EC-Medium In this scenario the EC capacity is based on the recommendations made by Dansk Energi [2020]. They recommend a total EC capacity of 3 GW by 2030. Again the distribution between DK1 and DK2 is based on Danish Energy Agency [2020].

EC-High Here the EC capacity is based on the recommendations made by Brintbranchen [2020]. They propose a total EC capacity of 6 GW by 2030. Just like the other scenarios, the distribution between DK1 and DK2 is based on Danish Energy Agency [2020].

The stated capacities for the three EC scenarios refer to the ECs electrical consumption capacity. In order to give an overview of the scenarios and their relation to one another, Table 4.1 provides a more visual representation of these relationships.

Table 4.1. The scenarios and sub-scenarios in relation to one another.

Scenarios	Onshore	Offshore
Sub-scenarios	EC-AF20	EC-AF20
	EC-Medium	EC-Medium
	EC-High	EC-High

In order to properly analyse the impacts of implementing ECs in the Danish energy system and transmission grid, more specific methods are developed for both analyses. These methods are presented in Chapter 5 and 6.

5 Method for energy system analysis

The purpose of this chapter is to develop a method for the energy system analysis conducted in this thesis. Here an adequate modelling software for the analysis is chosen, and the working principle of the model is described. Furthermore, different assumptions used for the analysis are described.

As mentioned in Chapter 4 an energy system analysis is carried out, to obtain knowledge about the impacts of integrating different EC capacities in two energy system scenarios. Furthermore, it is the purpose of the energy system analysis, to obtain hourly production and consumption patterns, which can be used in a power flow model, to investigate the impacts of ECs on the transmission grid in DK1.

In this section the methods for setting up and executing this energy system analysis are presented.
According to the synoptic planning approach, which was chosen to investigate the planning objective of integrating ECs in a technically beneficial manner, sophisticated modelling and quantitative data should be utilised to find optimal solutions. Consequently, an adequate energy system modelling software must be selected.

5.1 Selecting an adequate energy system modelling software

To help choose an adequate modelling tool some key analysis parameters of the energy system analysis are defined. These parameters are used to assess the impact of implementing EC plants in different energy systems scenarios. These parameters are listed in the following as questions that, with the help of an an adequate energy system simulation tool, must be answered:

- How does different EC capacities impact the energy system composition with regard to installed power production capacities?
- How do EC plants impact consumption and production dispatch in the the energy system?
- To which extent can ECs mitigate the need for electricity storage in various energy system scenarios?
- How are EC plants dispatched over the course of a year?
- In which way are electricity prices impacted by implementing EC plants?
- What happens to the electricity import/export balance when ECs are integrated in various energy system scenarios?
- Can the 70% CO_2 reduction goal for 2030, be realised when different EC demands must also be satisfied?

Based on the listed analytical questions, a range of criteria for an adequate energy system simulation tool have been developed. These criteria are listed in the following:

- The modelling tool must be able to simulate the dispatch of the electricity and heating utility sector, including the operation and dispatch sector coupling units, such as EC, electric boilers and heat pumps.
- To ensure that energy systems with various constraints, policies and EC demands are constructed and operated adequately, the modelling software must be able to make investments and find optimal capacities for the energy system.
- To enable the use of hourly production and consumption data, in the transmission grid analysis, the simulation tool must at least be able to simulate using an hourly time resolution.
- The tool must be able to simulate electricity transmission between neighbouring countries, as international electricity transmission is an important part of the operation of the Danish transmission grid.
- To increase understanding of the energy system impacts of ECs, the modelling tool must generate hourly electricity prices based on the energy system setup and operation.

Based on the above mentioned criteria multiple energy system modelling tools are assessed. These include: EnergyPRO, EnergyPLAN, Balmorel and Homer Pro.
While Homer Pro also has the ability to make investments and optimise dispatch. Homer Pro is made for modelling systems with a unit specific detail level, such as specific wind turbine models. The model is primarily used for microgrids and smaller energy systems [Homer Energy, 2021].
The EnergyPRO modelling software has a detailed optimisation of both heat and power dispatch. EnergyPRO is a strong tool in terms of optimising dispatch from a business-economic perspective, but it can not optimise capacities for production and consumption units. [EMD, 2021].
The EnergyPLAN software is able to simulate larger national energy systems with international electricity transmission. However, EnergyPLAN was not made to find optimal capacities for production units [EnergyPLAN, 2021].
Balmorel is chosen, as it is a solver-based partial equilibrium model, with the ability to optimise capacity investments and dispatch of both the power and heating sector of an international energy system, while accounting for specific economic, technical and environmental policies. Based on the GAMS modelling language and various powerful solvers, the tool calculates the lowest-cost solution for capacity investments and dispatch, while still complying with the demands of the energy sector, and adhering to e.g. capacity or fuel consumption restrictions and policies such as RE targets. [Balmorel, 2021]
Larger international energy systems can be modelled as national, regional, and area systems interconnected with energy transmission. Electricity and heat markets are represented in the model, where heat and electricity prices can be calculated, down to hourly values, under the assumption of perfect competition. The assumption of perfect competition, also means that the model assumes that producers bid at marginal costs. Furthermore, it should be stated, that large CHP steam-turbine units also have dedicated set of unit commitment values e.g. minimum production, start-up cost, shut-down cost, minimum

down time and ramp rates. These are essential to ensure a proper representation of large CHP units in the model. [Ea Energy Analysis, 2021b]

The model is versatile and completely open-source, thus additional modules and alterations can be made to the source code. Consequently, the model has been developing constantly, since it was released by Hans Ravn in 2001 [Wiese et al., 2017]. Balmorel has been used for supporting energy system related projects in over 35 countries, with geographical scales varying from small island systems in Indonesia to the entire European energy system. This is possible as there is no formal limit on the amount of data inputs, such as countries, regions, fuel types, technologies, etc.. [Ea Energy Analysis, 2021b]
According to Balmorel [2021], Ea Energy Analyses is the leading commercial company that uses the Balmorel model for providing support and consultation of energy system related projects. Ea Energy Analyses has, for this thesis, provided access to the GAMS software, a CPLEX solver, a powerful server and their highly detailed version of the Balmorel model.

5.1.1 The Balmorel model working principle

Being an open source model that has been developing for over 20 years, it is safe to say that there are many versions of the model, with even more extra modules that can be included. However, the operational principle of the models is the same, and can be found in Figure 5.2 on page 25.
A range of exogenous data inputs are needed for the model to run. Before these inputs are explained, it is important to know that the model optimises one year at a time, with a specified time step interval in each year. In the following, a list of common exogenous input data are specified. [Ea Energy Analysis, 2021b]

- **Demand prognoses** specifies all demands for all simulated years in all regions and areas. These demands are e.g. heat demands, electricity demands, EC demands, etc.
- **Technology data** contains technical, economic and environmental data about both specific and generic units. Data for specific units, e.g. for Danish waste plants, are specific for the individual plants, whereas data for generic units are obtained from the Technology Catalogues by Danish Energy Agency [2021b].
- **Generation capacities** provides the model with fixed annual generation and storage capacities for each simulated year. Existing and planned capacities for e.g. heat, electricity, ECs and storage can be specified here.
- **Generation investment options** states the investment options for generation and storage units. Here the options for which production and storage units the model can invest in, are specified for each simulated year. These units are mostly generic units from the Technology Catalogues by Danish Energy Agency [2021b].
- **Transmission capacities and losses** contains data regarding existing and planned transmission capacities and their losses.
- **Transmission investment options** specifies the economic investment options for transmission capacity. Which geographical areas that can be interconnected and in which simulated years, can also be stated here.
- **Policies** can be specified for all geographical areas in the model. These policies can include capacity and fuel use restrictions or minimums, CO_2 emission targets, renewable energy shares, full load hour requirements, etc.

- **Fuel data and prices, taxes, CO_2 prices, etc.** These inputs contains information about prices, energy content and emissions from fuels. Furthermore, data regarding taxes and tariffs can be specified here.
- **Weather data** Contains all weather data for areas, which is used to calculate electricity and heat generation from fluctuating production units.

Another important aspect to understand about the Balmorel model, is the geographical representation in the model, as three different geographic entities exist. An illustration of these geographical dimensions in Balmorel can be seen on Figure 5.1.

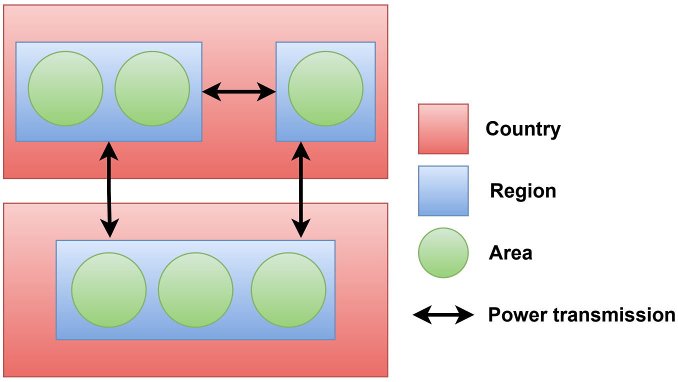

Figure 5.1. Geographical representation in Balmorel. Ea Energy Analysis [2021b].

In the following list the use of the three geographical entities is elaborated:

- **Countries** are the largest geographical entity and are mainly used to define national policies and goals.
- **Regions** are contained inside countries, thus national policies also apply to regions. However, regional policies can also be specified. Furthermore, fuel data and costs, taxes and CO_2 prices can also be specified for both individual countries and regions. Electrical systems are represented on a regional scale, meaning that congestion does not occur inside a region. Thus, electrical demands are specified on a regional level. Regions can be interconnected allowing electricity transmission between regions.
- **Areas** are contained inside regions, meaning that national and regional policies also apply to areas. Areas are used for the representation of data that influences generation units, as variation profiles for wind, solar and hydro are represented on an area level. Heat demands are specified on an area level.

As exogenous input parameters and geographical dimensions have been elaborated, the overall operational principle of the model can be explained. Firstly, a visualisation of Balmorels operation principle can be seen in Figure 5.2.

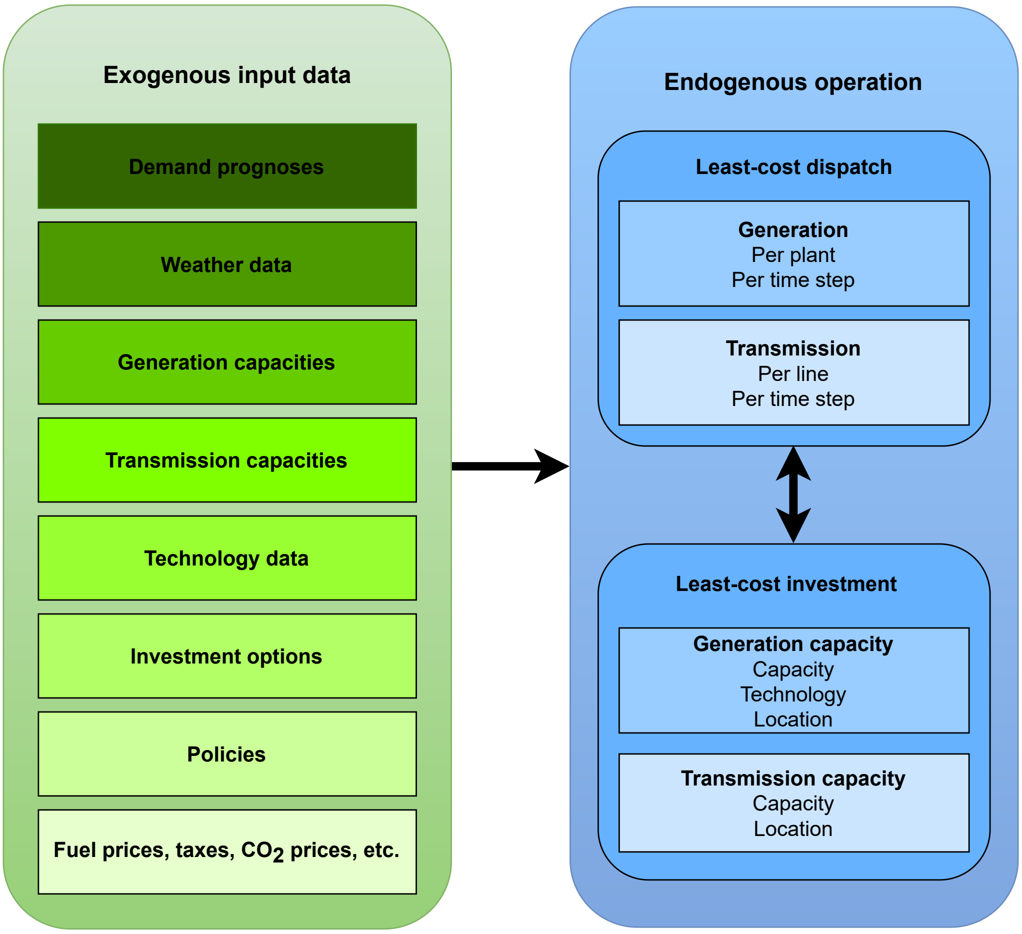

Figure 5.2. Operational principle of the Balmorel model. Based on Ea Energy Analysis [2021b].

From Figure 5.2 it can be understood that once exogenous input parameters are loaded, the model balances demands from all geographical dimensions, while simultaneously optimising dispatch and investment costs. It is important to know that Balmorel has full foresight within each simulation year, meaning that all demands, weather prognoses and other profiles are known. This allows Balmorel to find the optimal dispatch and investment solution. This approach is in line with the synoptic planning approach that was chosen for this analysis in Section 3.1. However, in reality operators do not have full annual foresight, hence dispatch might in practice deviate.
Once the least-cost solution has been found, unit capacities, electricity prices, transmission data, dispatch, economic and environmental data etc. of the least-cost solution is stored. Any errors or warnings are stored. After data is stored, it can be loaded for analysis.

5.2 Populating the Balmorel model for this thesis

In this section, the methods and specific inputs used in the Balmorel energy system analysis in this thesis are presented.

5.2.1 Time resolution setting

As stated in the overall method for assessing EC plants influence on the transmission system in DK1, it is necessary to obtain hourly dispatch simulations from the energy system analysis, as hourly simulations are investigated in a power flow model subsequently to the energy system analysis. Thus, the time resolution of the model should be set to one hour. However, Balmorel operates with two time units, seasons and timesteps. The maximum number of seasons is 52, roughly matching the number weeks in a year. For timesteps the maximum is 168, matching the number of hours in a week. Combined it gives Balmorel a maximum time resolution of 8736 hours annually. This time resolution is used in this thesis.

5.2.2 Simulated countries

As this analysis seeks to simulate and assess the impacts of integrating various EC capacities into the Danish energy system and transmission grid of DK1, it has been deemed adequate to include the countries to which Denmark has electrical interconnections. Thus, Sweden, Norway, Germany, Netherlands and Great Britain are included in the simulation. A graphical illustration of the simulated countries and interconnectors in the model can be found in Figure 5.3.

Figure 5.3. Simulated countries and interconnections in the Balmorel model of this thesis. [Ea Energy Analysis, 2021b]

5.2.3 Main data inputs and policies

As illustrated in Figure 5.2, a list of data inputs and model restrictions should be defined exogenously.

Ea Energy Analysis [2021a] has, for this thesis, provided a Balmorel model that is continuously updated with relevant solar and wind data, projected electricity and heat demands, projected technological developments, policies and RE potentials for the simulated countries. The provision of a populated model has been a tremendous help for this thesis, as the populated model includes specific data regarding demands, production and storage units, weather data, etc. on detail levels down to specific district heating (DH) grids and areas of the simulated countries. As several countries are simulated, the amount of data required to populate this model is significant. Consequently, the provisioned Balmorel model has enabled this thesis to save time and focus more thoroughly on combining the energy system model with the load flow model. Furthermore, it also allowed allocating more time to verify data inputs for the Danish energy system, model EC dispatch and construct useful scenarios for EC integration.
It has been chosen to delimit from making a deeper analysis of how each neighboring country's energy systems are composed and simulated, as the purpose of including neighboring countries in the analysis, is mainly to allow the transmission of electricity, which is why this delimitation is deemed adequate in regards to the adequate level of detail theory described in Section 3.2.

The electricity consumption from various demand types for each country can be found in Figure 5.4. Electricity consumption from ECs is not included as this is specific for each EC scenario. The electricity consumption from the heating sector is not exactly similar for all scenarios, as Balmorel chooses whether the demand is supplied by e.g. electric boilers or heat pumps, which have different efficiencies.
Various Danish electricity demands are based on AF20 by Danish Energy Agency [2020], whereas electricity demands for Sweden, Norway, Netherlands, Germany and Great Britain are based on ENTSO-E [2018].

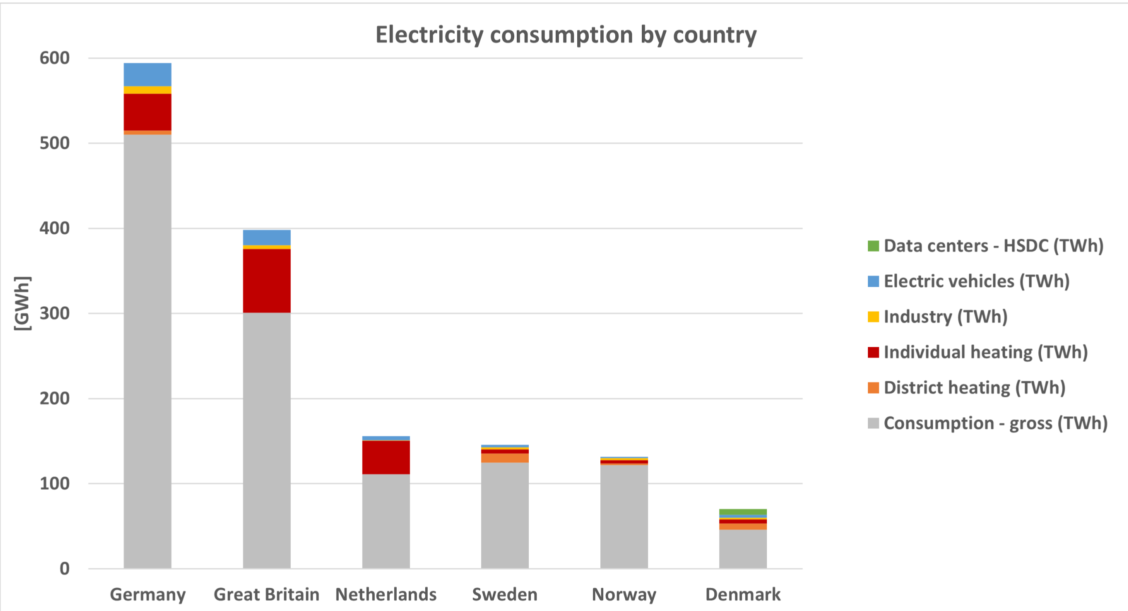

Figure 5.4. Electricity consumption per country in 2030.

The initial composition of electricity generating units in each country split on source, can be found in Figure 5.5. This is the initial capacity inserted into the energy system model. Balmorel is allowed to decommission units during investment optimisation. Data for existing production and storage units in the model are based on ENTSO-E [2018], AF18 and AF20 and Ea Energy Analyses' own projects and internal data.

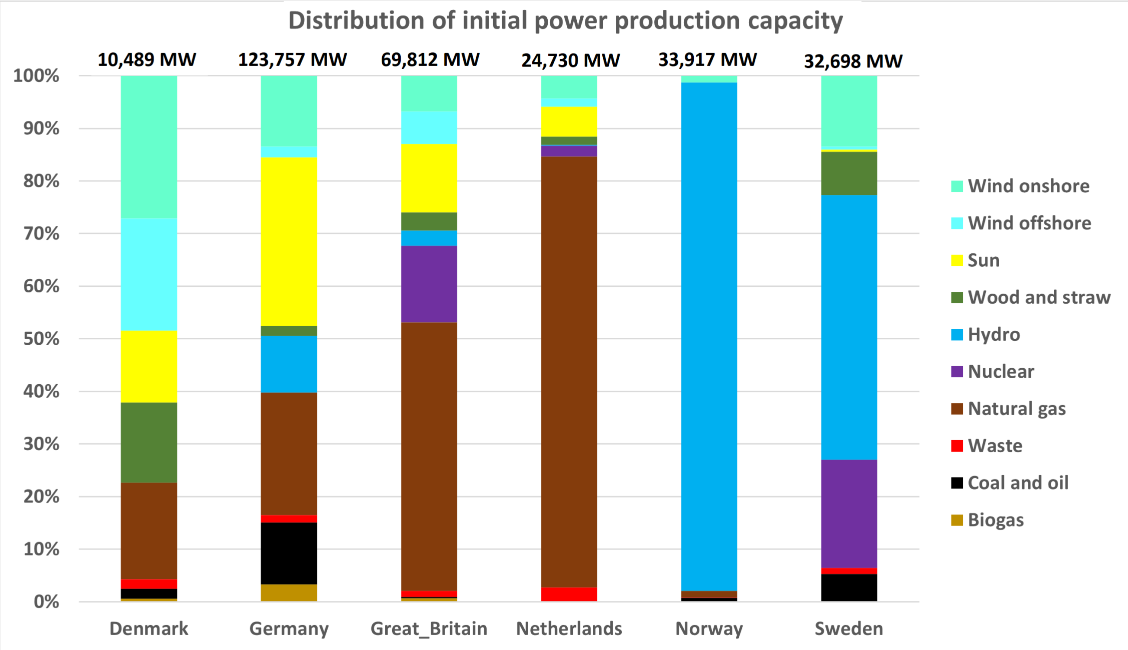

Figure 5.5. Initial 2030 power production capacity split on source.

Various other central input data for the Danish energy system can be found in Table 5.1.

Table 5.1. Input data for the Danish energy system.

Year	Area	Electricity demand [TWh]	DH demand [TWh]	DH losses [TWh]	Individual heat demand [TWh]	Offshore min capacity [MW]
2030	DK1	46.3	23.7	4.3	7.8	4017
	DK2	24.6	16.6	3.1	5.1	3313

5.2.4 Investment and decommission settings

Balmorel is set to enable investments in generic technologies based on data from the Technology catalogues by Danish Energy Agency [2021b]. As mentioned, Balmorel is allowed to decommission existing storage and production capacity.
Balmorel is not allowed to invest in transmission capacity, as the main purpose of the following load flow analysis (described later in Section 6), is to investigate the impacts of EC plants on the existing and planned transmission grid.

According to Danish Energy Agency [2021b] onshore wind is cheaper than offshore. Therefore, it is necessary to ensure that Balmorel does in fact invest in the offshore wind power plants, which are politically approved, instead of covering the demand with onshore wind power. In order to ensure this, a constraint is given for minimum offshore wind power capacities in DK1 and DK2. These minimum capacities are based on AF20 by Danish Energy Agency [2020] and displayed in Table 5.2.

Table 5.2. Minimum capacities for offshore wind

Year	Region	Offshore min capacity [MW]
2030	DK1	4017
	DK2	3313

5.2.5 EC settings

To simulate the operation of EC plants, a demand which specifies how much the ECs must be operated, must be given exogenously. This demand is referred to as the EC demand.

In Section 4.3 EC capacities for each EC scenario are given, and summed up in Table 5.3. Based on predictions by Danish Energy Agency [2020], ECs are assumed to operate around 5000 FLH annually. Based on this prediction, the EC capacities from each EC scenario is multiplied by 5000 FLH to obtain an annual EC demand. An example of the calculation of EC demand is given in Equation 5.1.

$$EC_{demand} = EC_{capacity} \cdot 5000 hours \tag{5.1}$$

It is necessary to define the flexibility of EC production in Balmorel, to allow plants to utilise excess electricity production and low electricity prices. If flexibility is not added the EC operation is constant over the year with a fixed consumption matched to annual demand. On the other hand, full flexibility over the course of a year might not yield the most representative simulated operation either. This is because Balmorel has full annual foresight, while plant owners in practice, only have limited foresight, as they hand in their production plan to the spot market a day before, without knowing the exact electricity price. [Nord Pool, 2021]

Flexibility can be added in Balmorel, by splitting annual demand into weekly bits, while allowing ECs to operate 100% flexible for each hour within each week, as long as weekly demand is met. Thus, the division of annual EC demand into weekly bits reduces Balmorels ability to make perfect dispatch, which in turn is assumed to yield a more realistic production pattern. Consequently, this method of dividing annual demand into weekly parts, is used in this thesis.

In Table 5.3 the most relevant Balmorel settings for ECs are displayed.

Table 5.3. EC settings for each EC scenario for Balmorel. Given for 5000 FLH, as estimated in AF20.

	DK1			DK2		
EC scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
EC capacity [MW]	600	1800	3600	400	1200	2400
EC demand [GWh]	3000	9000	18000	2000	6000	12000

5.2.6 Energy system scenario settings

As mentioned in Section 4.3, three EC capacities are analysed in two energy system scenarios where RE potentials are varied. A main driver for making energy system scenarios with various RE capacities to explore the impacts of integrating ECs, is that EC plants have the ability to act as large flexible loads. According to Energinet [2020b], this can enable higher RE capacities to be beneficially integrated in the energy system, while also reducing loading of the transmission grid. However, these benefits vary depending on how distributed the RE capacity is. Thus, both an offshore and an onshore scenario is made to explore these effects.

For both scenarios, RE potentials are given exogenously for onshore wind and PV. These potentials dictate the maximum capacity that the model can install.

In the Onshore scenario RE potentials for onshore wind is based on Energinet [2015b]. This report investigates the technical onshore wind potential based on a levelised cost of electricity (LCOE) comparison between onshore and offshore wind power. This is displayed on Figure 5.6.

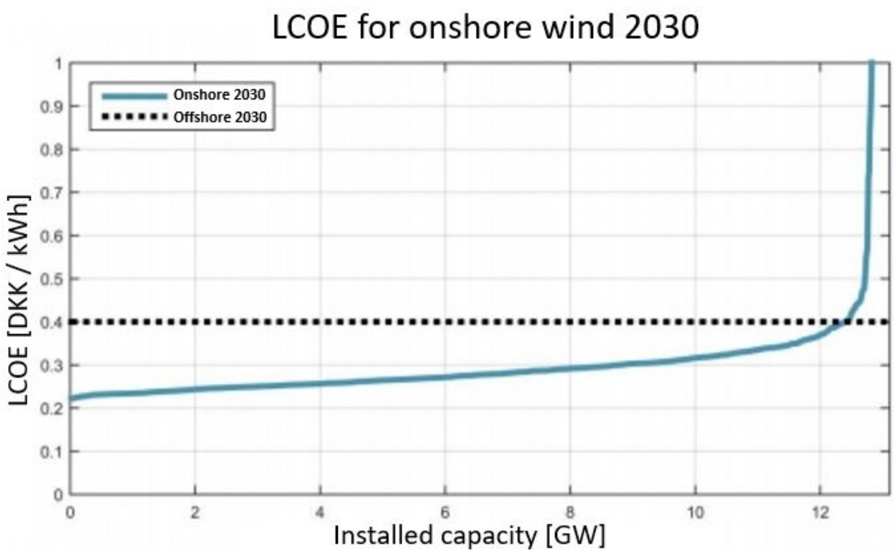

Figure 5.6. LCOE for onshore wind split between expenditures. [Energinet, 2015b]

In Figure 5.6 it can be seen that the technical maximum potential is estimated to be around 13 GW. However, according to Energinet [2015b] the cost of expropriating increases drastically after 12 GW. At around 12 GW the LCOE reaches offshore wind levels. It has been decided to use 10 GW as the onshore wind potential for the Onshore scenario of this thesis, to ensure that economic data from Danish Energy Agency [2021b] is still representative.

The distribution of the onshore wind potential between DK1 and DK2 is based on the expected distribution of onshore wind capacity in AF20. This distribution is approximately 85% - 15% for DK1 - DK2.
The Danish PV potential is estimated to 15 GW for the Onshore scenario, based on Energinet [2020f]. According to Energinet [2020f] the PV potential is based on the capacity

of potential PV projects, which in the beginning of 2020 was above 15 GW.
The distribution of the onshore PV potential between DK1 and DK2 is based on expected PV distribution in AF20, where the distribution is approximately 2/3 - 1/3 for DK1 - DK2.

In the Offshore scenario RE potentials for PV and onshore wind are estimated by using the highest expected installed capacity in AF20 before 2040. The reasoning is that if Danish Energy Agency [2020] expects that a given capacity for a certain RE technology will be installed, it is deemed plausible that this capacity can actually be installed in practice.
Even though requirements for offshore capacities are the same for both scenarios, it is expected that the Balmorel model invests more heavily in offshore in the Offshore scenario, as the potentials for onshore wind and PV are limited in comparison to the Onshore scenario.

In Table 5.4 the RE potentials for the two energy systems scenarios are given.

Table 5.4. RE potentials for the two energy system scenarios.

Year	Energy system scenario	Location	Onshore wind max capacity [MW]	Onshore PV max capacity [MW]
2030	Onshore	DK 1	8500	10000
	Onshore	DK 2	1500	5000
	Offshore	DK 1	5608	5823
	Offshore	DK 2	819	3484

5.2.7 Balmorel model operation settings

Balmorel has three modes of operation called BB1, BB2 and BB3. These are briefly explained in the following list.

- **BB1** is used for annual optimisation of dispatch. No investment optimisation option.
- **BB2** is used for annual optimisation of dispatch and investments.
- **BB3** is used for detailed hourly optimisation of dispatch based on inputs from BB1 or BB2. No investment optimisation option.

For this energy system analysis it has been chosen to utilise the BB2 model run for optimisation of investments, and transfer the result data to a BB3 run, which is used for detailed hourly dispatch optimisation.
This combination of model runs is utilised to ensure a detailed representation of hourly dispatch, while also allowing Balmorel to optimise investments.
It should be stated that a detailed hourly optimisation requires large amounts of computing power. Hence, this analysis could not have been completed without the provided server from Ea Energy Analyses.

6 Method for transmission grid analysis

In this chapter the method used to conduct the transmission grid analysis are described. Here a modelling tool for the analysis is chosen, and load flow analysis is introduced. Furthermore, the development of the DK1 transmission grid model and the assumptions used are described. Moreover, the EC locations used for analysis are introduced.

The aim of this analysis is to assess the transmission grid in a future perspective with both increased electrification and EC capacities. This aim of the analysis is to identify any overloading in the transmission grid, for different energy systems and EC scenarios. This analysis takes its point of departure from the scenarios presented in Section 4.3 and the hourly consumption and production data of the energy system analysis, described in Chapter 5.

6.1 Selection of modelling tool for grid analysis

In order to properly conduct the grid analysis, an adequate simulation tool must be chosen. Therefore, a set of criteria for the modelling tool are developed. These criteria are listed below:

- The tool must be able to conduct a load flow analysis, as this will allow for identification of overloaded components in the transmission grid of DK1.
- In order to obtain the most accurate results, the tool must be able to accommodate the entire transmission grid of DK1. Based on Energinet [2021c] 100 busses are needed to incorporate the transmission grid of DK1.
- It is strongly desired that data for loads and power generation at each bus can be setup in a manner that allows for simulation of multiple scenarios.

Multiple load flow analysis tools, such as PowerFactory and PowerWorld fit the criteria listed above. Both of the tools are leading in the field and are used by Energinet [Energinet, 2021b]. However, due to previous experience with PowerFactory, this tool has been chosen for the grid analysis in this thesis. In order to accommodate the entirety of the transmission grid in DK1, a thesis license has been provided by DIg Silent.

6.2 Load flow analysis

In order to conduct an analysis of the transmission grid in DK1, it is important to understand what a load flow analysis is. Therefore, a short introduction to load flow analysis is given.

A load flow analysis can be carried out as an AC or DC model. In an AC load flow analysis the voltage magnitude and the phase angle is calculated for each bus in the system. These calculations are done assuming a steady state condition, which is defined by DIgSILENT [2020] as a state in which all variables are assumed to be constant. When calculating the load flow of an AC system simulation, the power flows of both active and reactive power in the systems components are also calculated. As a result, the component loading and losses can be calculated [Glover et al., 2016]. When performing a load flow analysis the different busses in the system are split on three different bus types. These bus types are:

- Slack bus: The slack bus is also called the reference bus, and is the bus that supplies the power required to cover system losses. In a slack bus the known parameters are the voltage magnitude and the phase angle, which are normally specified as 1.0 per unit and 0 degrees, respectively.
- PV bus: Also known as a voltage controlled bus, this bus has active power (P) and voltage magnitude (V) as the known parameters. Generators are often regarded as PV busses.
- PQ bus: Also called a load bus, as it commonly used to model loads in the system. The known parameters are P and reactive power (Q). PQ busses are the most common busses in power systems.

In load flow analysis, transmission lines are represented using the nominal π circuit, which can be seen in Figure 6.1. Here Z is the line impedance and Y is the shunt admittance, they can be expressed using the following equations:

$$Z = R + jX$$

$$Y = \frac{1}{Z} = G + jB$$

Where R is the resistance, X is reactance, G is conductance and B is susceptance [Glover et al., 2016].

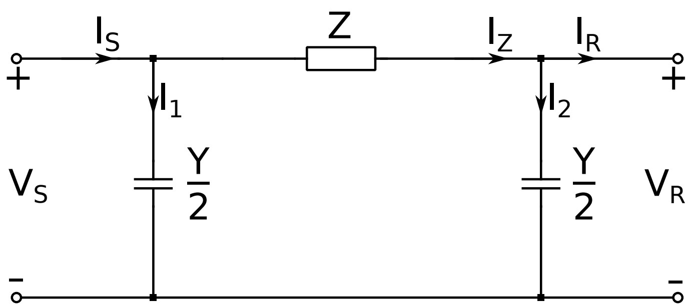

Figure 6.1. Nominal π model. Based on Glover et al. [2016].

If the excitation current is small compared to the rated current, the excitation current can be neglected. Thereby, the reactive power required for core magnetisation and the core losses can be neglected. Doing this and the equivalent transformer model shown in Figure 6.2 can be used. Here R_{eq} is the resistance and Xeq is the leakage reactance [Glover et al., 2016].

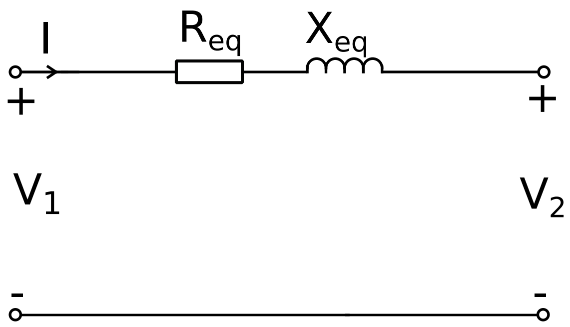

Figure 6.2. Equivalent transformer circuit. Based on Glover et al. [2016].

AC load flow models can provide more accurate results than DC models, however this requires that Q compensation is correctly accounted for in the model. However, Q compensation studies significantly increases complexity of the system. Furthermore, convergence is not guaranteed.

In DC load flow models the equations for Q and V are neglected, by constant V magnitude at 1.0 per unit (corresponding to nominal bus voltage) throughout the system. Assuming that active line losses can be neglected and that sine of angles is the angle itself (in radians), active power between bus j and k can be obtained using the following equation [Glover et al., 2016]:

$$P_{jk} = \frac{\theta_j - \theta_k}{X_{jk}}$$

For DC power flow the real power balance equations becomes linear and can be expressed as follows:

$$\mathbf{P} = \text{-}\mathbf{B} \cdot \boldsymbol{\theta}$$

A DC load flow analysis offers an approximate simulation of component loading in an AC system, with no need for iterative computing. As the equations are linear in DC load flow, the risk of convergence issues is mitigated, and the required computing power is decreased [Glover et al., 2016].

The aim of the load flow analysis in this thesis is to analyse the component loading of the transmission grid in DK1, based on different energy systems, EC capacities and EC locations. As the focus of this thesis is to investigate component loading and not Q compensation or voltage regulation, the transmission grid analysis is conducted using DC load flow analysis. However, it is acknowledged that including reactive power would likely increasing component loading. Thus, one could argue that when overloading issues are found using a DC load flow analysis, an AC load flow analysis would likely yield even higher loading.

According to DIgSILENT [2020], the DC load flow in PowerFactory is conducted using the same assumptions as has been described above.

6.3 Model development

In order to conduct the intended analysis, a model of the transmission grid in DK1 is constructed. This model is constructed based on data from Energinet [2021c] and Figure 6.3, which represents the current transmission grid and approved alterations by 2025. Energinet [2021c] represents a balanced load flow case of the Danish transmission grid for 2020.

Figure 6.3. The grid reference for 2025, as shown in Energinet [2020b].

The different components, such as cables, overhead lines, transformers, production and consumption units and DC interconnectors, shown in Figure 6.3 are inserted in PowerFactory and assigned the parameters defined in Energinet [2021c]. Some of the components which are not yet in operation, are not specified in Energinet [2021c]. However, in an interview with Maria Broe from Energinet (see Appendix A), some generic capacities, which Energinet use in their simulations were disclosed.
For 400 kV overhead lines the rated current used is 2.4 kA, giving them a capacity of roughly 1660 MW, while the rated current for 150 kV is 1.5 kA. However, as the rated voltage of the cables are slightly higher at 165 kV, the capacity is approximately 425 MW. By considering the data from Energinet [2021c], it can be seen that there is both a 400 kV line and a 150 kV cable with the exact dimensions described above. As a result, the electrical parameters given per km for this line and cable, are used as the parameters for the generic overhead lines and cables.

As multiple countries are simulated in the energy system analysis, described in Section 5, the interconnectors to these countries also have to be included in the transmission grid analysis. As a result, the interconnectors from DK1 to DK2, Norway, Sweden, Germany, Great Britain and Netherlands are included in this model.
Import is modelled using generators and export is modelled as loads. In Table 6.1 an overview of the interconnectors from DK1 is given. Here the country or region to which DK1 is connected and the capacities of these connections are given.

As there are two 400 kV connections from DK1 to the German border. It is necessary to make a proper distribution between these two connections. According to Energinet [2021a], the new connection between Endrup and the German border will increase the interconnection capacity between DK1 and Germany from 2500 MW to 3500 MW. In order to adequately simulate this difference between the two connections to Germany, the total import/export capacity is multiplied with a distribution factor. This distribution is obtained by dividing the specific connection capacity with the total interconnection capacity. Consequently, 28.6% of import/export capacity from Germany is assigned to the Endrup connection, while the remaining 71.4% is assigned to the connection in Kassø.

Table 6.1. Overview of the interconnections from DK1 as used for simulation in Balmorel.

Interconnectors	Country/Region	Capacity [MW]
COBRAcable	Netherlands	700
German border	Germany	3500
Konti-Skan	Sweden	740
Skagerrak	Norway	1632
Storebælt	DK2	600
Viking Link	Great Britain	1400

In the paper by Energinet [2020e], the potential long term developments in the transmission grid are outlined. However, most of them are associated with a high degree of uncertainty. In this thesis, only grid reinforcements with a high certainty of being realised by 2030 are included.

With the introduction of Thor wind power plant, expected by AF20 to be fully operational in 2026. Energinet [2020e] expects that a 400 kV dual system between Endrup and

Idomlund replaces the existing 150 kV line. To do so, changes must be done in order to maintain an operational 150 kV grid in the area. Energinets potential solution can be seen in Figure 6.4. In this thesis the line between Stovstrup and Askær is not included in the model, as Energinet [2020e] associate this connection with a high degree of uncertainty.

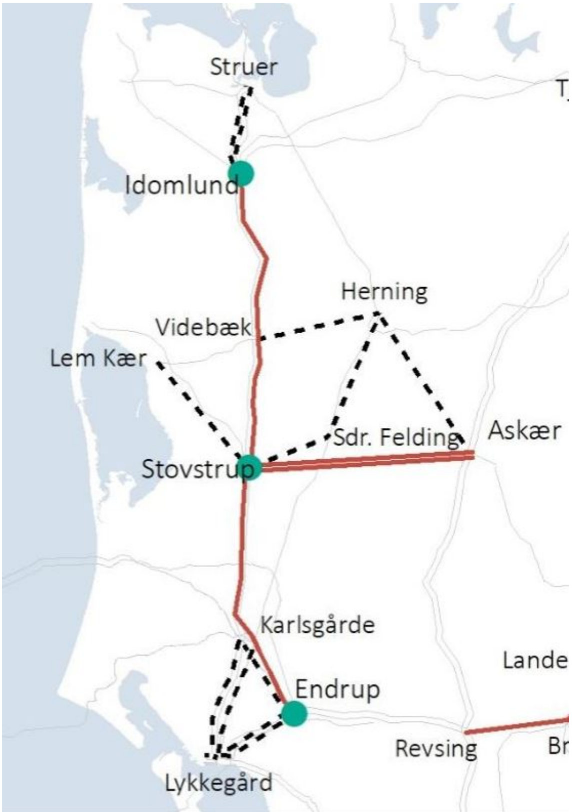

Figure 6.4. Changes in Vestjylland as proposed by Energinet [2020e].

As described in Section 6.2, it is necessary to choose a slack bus in order to simulate the system. As DK1 is connected to Europe through Germany, it is chosen to use the interconnection to Germany from Kassø as the slack bus in this model. This means that, besides being an interconnector to Germany, this connection also supplies system losses at all times.

6.3.1 Distribution of loads and generation in the transmission grid

In order to obtain useful transmission grid results, it is of importance to ensure that the loads and generators are accurately distributed from a geographical point of view.

In Energinet [2021c], all consumption units are aggregated and assigned to each bus in the transmission grid. Therefore, this data is used as a distribution key for the electricity consumption in the different scenarios. However, this method is not considered adequate for all loads. Consumption data for ECs and import/export is not distributed using the distribution key for the general electricity demand from Energinet [2021c]. Moreover, import/export is country specific and differ significantly for each hour in each scenario. Thus, import and export data, obtained from the energy system analysis results, is individually specified for each interconnection.

As mentioned, import is modelled as generators at busses of interconnection, whereas export is modelled as loads at busses of interconnection. Consequently, these loads and generators supply the electricity import and exports at the given hour.

Similarly, using the distribution key from Energinet [2021c], generation units have been aggregated and assigned to their respective transmission grid bus. This means that production from various electricity generating units, such as PV, onshore wind and decentral power plants, are aggregated before their production is fed into the grid. In practice most generation units are aggregated in the same manner in the distribution grid prior to the connection to the transmission grid. This method is considered adequate for all land based production units, as it is assumed that any additional units will be distributed in a similar manner as today. However, central power plants which will be decommissioned by 2030, are removed from the data.

Central power plants

According to Danish Energy Agency [2020], the 357 MW block 4 at Studstrupværket, accounting for half of the total plant capacity, is scheduled for decommission when the heat agreement for block 4 expires ultimo 2022. In order to account for this, half of the production at Studstrupværket is removed and distributed along other generators in DK1. Esbjergværket is also scheduled for closure primo 2023. Therefore, the production from Esbjergværket is also split on the remaining generators in DK1. Furthermore, Nordjyllandsværket is scheduled for decomission in 2028. Thus the same method is applied to Nordjyllandsværket.

Offshore wind power plants

Due to their capacity, offshore wind power plants have a significant impact on the grid. Therefore, it is necessary to consider the point of connection of the wind power plants. As the cables connecting the offshore wind power plants to the transmission grid are case specific, they are assumed to be dimensioned correctly. Therefore, it is chosen to neglect these cables and connect the offshore wind power plants directly to the point of connection bus. During the interview with Maria Broe from Energinet (seen in Appendix A), the points of connection for upcoming wind power plants were discussed. In the interview Broe disclosed that Energinet conduct their analyses using the points of connection shown in Table 6.2, for the offshore wind power plants, which AF20 expects after the introduction of the energy island.

Table 6.2. Point of connection of extra offshore wind power plants, as used for analysis by Energinet. Based on interview with Maria Broe from Energinet Appendix A.

Wind power plant	Point of connection	Capacity [MW]
Extra 1	Stovstrup	1000
Extra 2	Endrup	1000
Extra 3	Idomlund	1000
Extra 4	Stovstrup	1000
Extra 5	Endrup	1000

According to Energinet [2021e,d], Vesterhav Syd (170 MW), Vesterhav Nord (180 MW) and Thor (900 MW), will be connected in Stovstrup, Idomlund and Idomlund, respectively [Energinet, 2021e,d]. These wind power plants must also be taken into account when making a distribution key for offshore wind power plants. Therefore, a distribution key is developed using these and the offshore wind power plants shown in Table 6.2.
This distribution can be seen in Table 6.3. This distribution is used for any new offshore wind power capacity invested in during the energy system optimisation. It is acknowledged that the connection of the Energy Island could potentially alter this distribution. However, according to Maria Broe, it is not yet decided where the Island will have its point of connection, or if it will have multiple points of connection. Therefore, it is in this thesis assumed that the Island will be connected with a similar distribution to what is seen in Table 6.3.

Table 6.3. The distribution factor for new offshore wind power plants.

Location	Capacity [MW]	Distribution
Endrup	2000	32%
Idomlund	2080	33%
Stovstrup	2170	35%

A spreadsheet with all distribution keys for loads and generators is constructed. In the spreadsheet production and consumption values are assigned to generators and loads at each bus. The hourly consumption and production data obtained from the energy system analysis, is the input in this spreadsheet. The spreadsheet serves as a link between the two analyses conducted in this thesis and can be found in Appendix C.

The PowerFactory model developed for this thesis can be seen in Figure 6.5. Here the different interconnectors can be seen. Furthermore, the slack bus is marked by a red dot. It can be seen that there are several round sites in the model. These sites represent transformer stations between the 400 kV and 150 kV grid. Additionally, they are also used to model cables and lines in areas with a high number of cables and lines. Hence, they can be interpreted as a visual simplifications. If one wishes to take a look inside these sites, the full PowerFactory model can be found in Appendix D.

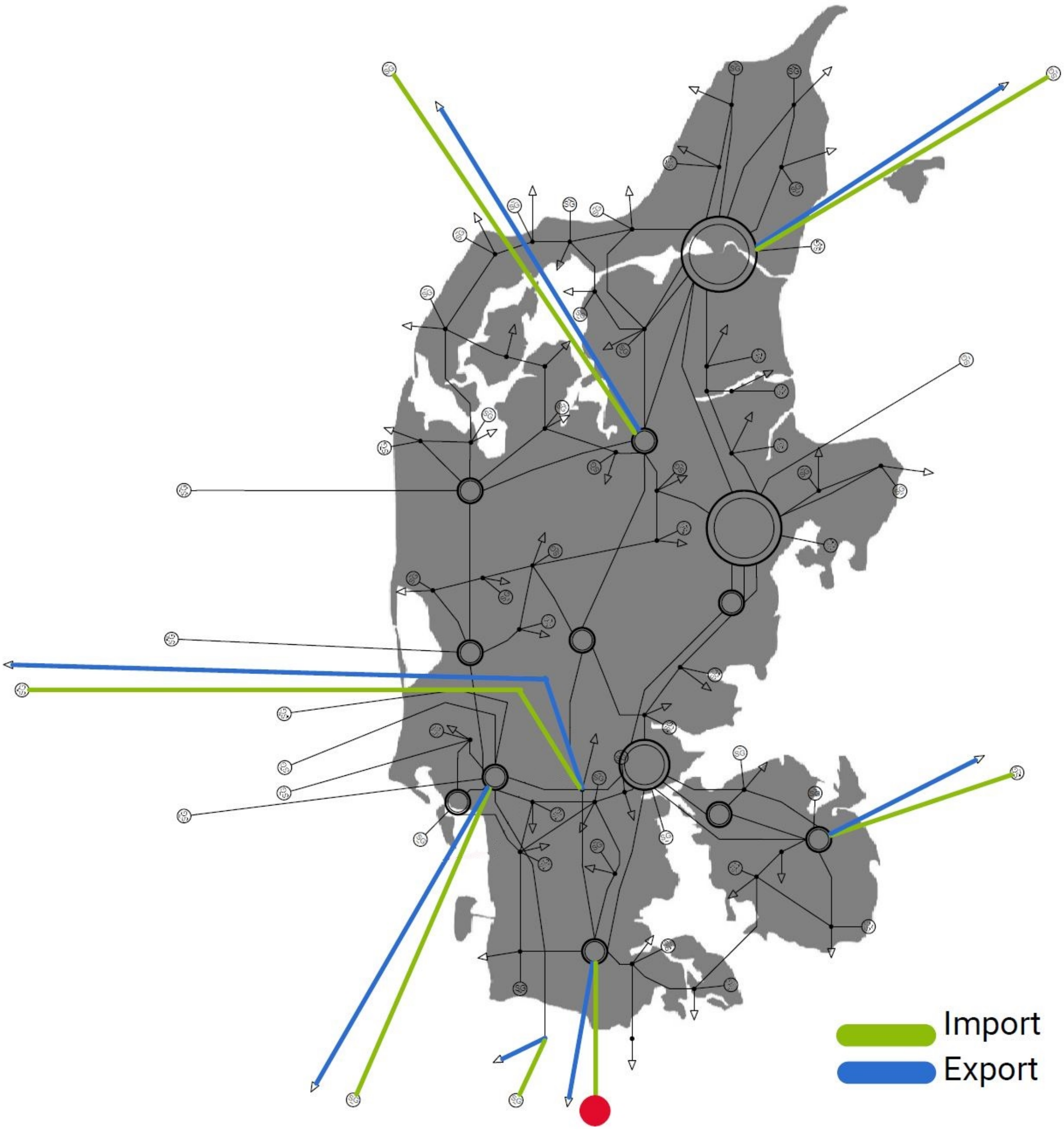

Figure 6.5. The PowerFactory model developed in this thesis. The slack bus is marked by a red dot.

In order to simplify and ensure that the reader can obtain an overview, all generators and loads are graphically removed before the presentation of results, leaving only the lines/cables which, are the main focus of this analysis. This simplification is used in Figure 6.6 where the voltage levels of overhead lines and cables can be seen. The interconnectors are not graphically represented in the simplified model seen in Figure 6.6, nor are they included in the results shown in Section 8.3, as the capacities of the interconnectors in the model are equal to those used in the energy system analysis, described in Section 6.3. Hence, they cannot be overloaded in this model.

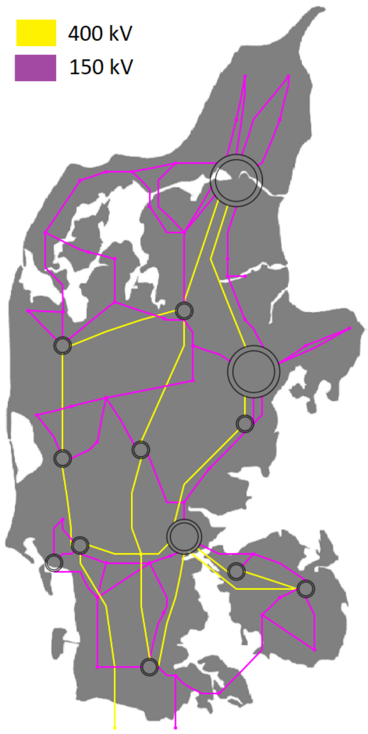

Figure 6.6. The simplified model used for result presentation in Section 8, here displayed with with voltage levels.

As a friendly reminder, it is recommended to keep Figures 6.5 and 6.6 at hand when going through the transmission grid analysis in Section 8.2.

6.3.2 EC plant locations

For EC plants, various locations are tested for all scenarios in the simulation. This is done as it enables the possibility to analyse the impacts of ECs, when placed at different locations in the transmission grid of DK1.

In this thesis the EC plants are placed at different 400 kV busses, as it is assumed that large-scale EC plants will be connected in central locations with access to the 400 kV grid. The busses at which ECs are connected can be seen in Figure 6.7. The locations shown are chosen in order to represent different cases regarding EC placement.

The different locations are selected mainly based on three focus perspectives: key locations from a transmission grid perspective, potential for delivering surplus DH and access to CO_2 point sources. However, as mentioned in the delimitation, Section 1.3.1, this thesis does not dive further into the complex details surrounding the surplus heat and access to CO_2 perspective, as it in itself entails detailed analyses of solutions, potentials and infrastructure. That being said, the perspectives are, to some extend, included in the selection of EC locations for the load flow analysis.

Locations along the west coast, Endrup, Idomlund and Stovstrup, are chosen as they are feed-in zones for offshore wind power plants. Feed-in zones are identified by Energinet [2020c], as areas where large-scale EC plants can assist in balancing the grid. Thereby, mitigating the need for grid reinforcements.

Revsing, Kassø and Tjele are chosen as they are import / export points for international power transmission. Aalborg, Landerupgård, Odense og Trige are added as they are located near potential CO_2 point sources [Energinet, 2021f]. Furthermore, they are included as they are located in a high consumption area with potential for utilising surplus heat from ECs.

Figure 6.7. Grid reference with EC locations marked in orange. Map based on Energinet [2020b].

From Figure 6.7 it can be understood that if all EC points and combinations of these are to be simulated for each scenario, it would require a significant number of simulations. It is not possible within the frame of this project to run all these simulations. Consequently, it has been decided to select a number of locations, and combinations of locations, to simulate. These are illustrated on Table 6.4.

Firstly, it has been decided to run simulations where the entire EC capacity is added to each individual location, without being distributed over several locations. This is chosen to investigate how well suited each location is for integrating ECs with regard to grid loading. Secondly, a series of simulations are used to test how well suited offshore wind feed-in zones are for integrating ECs.
Following, are the simulations which are meant to test how the transmission grid would be loaded, if ECs are placed in areas with CO_2 point sources and high DH consumption. These are called *DH and CO_2 areas* on Table 6.4.
Next up is simulation 19, which seeks to understand the grid impacts of placing ECs at central import/export locations. Simulation 20 to 23 are made to investigate how the grid is affected, if ECs are placed in different regions of Denmark. Lastly, in simulation 24 the EC capacity is distributed amongst all loads in the transmission grid of DK1, using the distribution key from Energinet [2021c]. Consequently, this simulation is called the

Distributed.

Table 6.4. EC locations which are tested for each scenario.

Simulation number	**EC load bus**	**EC load bus**	**EC load bus**	**Note**
1		Endrup		Individual location test
2		Idomlund		Individual location test
3		Revsing		Individual location test
4		Tjele		Individual location test
5		Trige		Individual location test
6		Landerupgård		Individual location test
7		Aalborg		Individual location test
8		Kassø		Individual location test
9		Odense		Individual location test
10		Stovstrup		Individual location test
11	Endrup		Idomlund	Feed-in zones
12	Endrup	Stovstrup		Feed-in zones
13	Endrup	Stovstrup	Idomlund	Feed-in zones
14		Stovstrup	Idomlund	Feed-in zones
15	Landerupgård	Odense	Trige	DH and CO_2 areas
16	Aalborg	Odense	Trige	DH and CO_2 areas
17	Aalborg		Trige	DH and CO_2 areas
18	Aalborg	Endrup	Trige	DH and CO_2 areas
19	Tjele	Kassø	Revsing	Import / central grid line
20	Endrup	Kassø	Landerupgård	Southern Denmark
21	Endrup	Kassø	Odense	Southern Denmark
22	Tjele	Stovstrup	Trige	Central Jutland
23	Tjele	Idomlund	Aalborg	Western / northern Jutland
24	All	All	All	Distributed

In Energinet [2020b] the grid is assessed under three different conditions when Energinet make long term planning of the grid. These conditions are N-analysis, N-1, and N-2. Here N-analysis means intact grid, N-1 means that there is one fault in the grid, and N-2 means that there are two faults in the grid.
As mentioned in Section 1.1, EC and PtX plants will seek to obtain lower tariffs by accepting the possibility of being shut down during hours with overloading or grid faults. Thus, it is assumed that ECs would not be allowed to operate under faulty conditions. Using this assumption, the EC plants will not operate under N-1 nor N-2 conditions. Therefore, it is not relevant to analyse the EC impact on the grid under these conditions. Hence, the EC impacts on the grid are only analysed for intact grid conditions.

Energy system analysis 7

In this chapter the results obtained from simulating different energy systems and EC scenarios are presented and analysed. The presentation and analysis of results follows the methods presented in Chapter 5. In order to give the reader an overview of the main findings in this analysis, a summary is given in the end of this chapter.

7.1 Analysis questions

In Section 5 a list of analysis questions were presented. This section seeks to answer these questions. The analysis questions are repeated in the following list:

- How does different EC capacities impact the energy system composition with regard to installed power production capacities?
- How do EC plants impact consumption and production dispatch in the the energy system?
- To which extent can ECs mitigate the need for electricity storage in various energy system scenarios?
- How are EC plants dispatched over the course of a year?
- In which way are electricity prices impacted by implementing EC plants?
- What happens to the electricity import/export balance when ECs are integrated in various energy system scenarios?
- Can the 70% CO_2 reduction goal for 2030, be realised when different EC demands must also be satisfied?

These analysis questions are answered in chronological order throughout the remainder of this chapter. The background data used to answer the analysis questions can be found in Appendix E.

7.2 How does different EC capacities impact the energy system composition with regard to installed power production capacities?

As mentioned in Chapter 5, the Balmorel energy system modelling tool optimises investments in power production capacities. The power production capacities optimised by Balmorel are presented in Table 7.1.

Table 7.1. Optimised power production capacities from each energy system and EC scenario split on DK1 and DK2.

Installed capacity DK1	**Onshore**			**Offshore**		
	EC-AF20	**EC-Medium**	**EC-High**	**EC-AF20**	**EC-Medium**	**EC-High**
Wind offshore [MW]	4017	4017	4150	4017	5008	7575
Wind onshore [MW]	5433	7110	8500	5608	5608	5608
Sun [MW]	8270	10000	10000	5823	5823	5823
Wood [MW]	143	144	194	165	195	191
Wood pellets [MW]	214	201	315	234	328	95
Waste [MW]	57	51	57	59	62	60
Biogas [MW]	92	93	96	96	96	96
Straw [MW]	66	66	66	66	66	66
Natural gas [MW]	1677	1669	1643	1636	1636	1621
Oil [MW]	155	155	155	155	155	155
Installed capacity DK2	**Onshore**			**Offshore**		
	EC-AF20	**EC-Medium**	**EC-High**	**EC-AF20**	**EC-Medium**	**EC-High**
Wind offshore [MW]	3313	3313	3313	3313	3313	4062
Wind onshore [MW]	718	832	1500	491	819	819
Sun [MW]	2682	3593	5000	2971	3484	3484
Wood [MW]	240	244	264	254	261	267
Wood pellets [MW]	728	746	860	771	860	860
Waste [MW]	127	128	128	126	124	128
Biogas [MW]	12	12	12	12	12	12
Straw [MW]	3	3	3	3	3	3
Natural gas [MW]	342	344	328	326	324	322
Oil [MW]	42	42	42	42	42	42

When compared to Table 5.4, on page 31, of PV and onshore wind potentials, Table 7.1 discloses that Onshore EC-AF20 and Onshore EC-Medium does not reach the national capacity limits, however the maximum PV capacity is met in DK1 for EC-Medium. Onshore EC-High, on the other hand, reach limits for both onshore wind turbines and PVs. Furthermore, Onshore EC-High also invests in additional offshore wind power capacity.

In DK1, all Offshore scenarios maximum PV and onshore wind capacity are reached, and investments in additional offshore wind power capacity are even made. In DK2 maximum capacities are utilised in EC-Medium and EC-High, while 133 MW additional offshore wind capacity is necessary in EC-High. From the table it is clear that model invests more heavily in power production capacity in DK1, which is logical as DK1 accounts for 65% of the general electricity demand, while DK2 accounts for the remaining 35%.

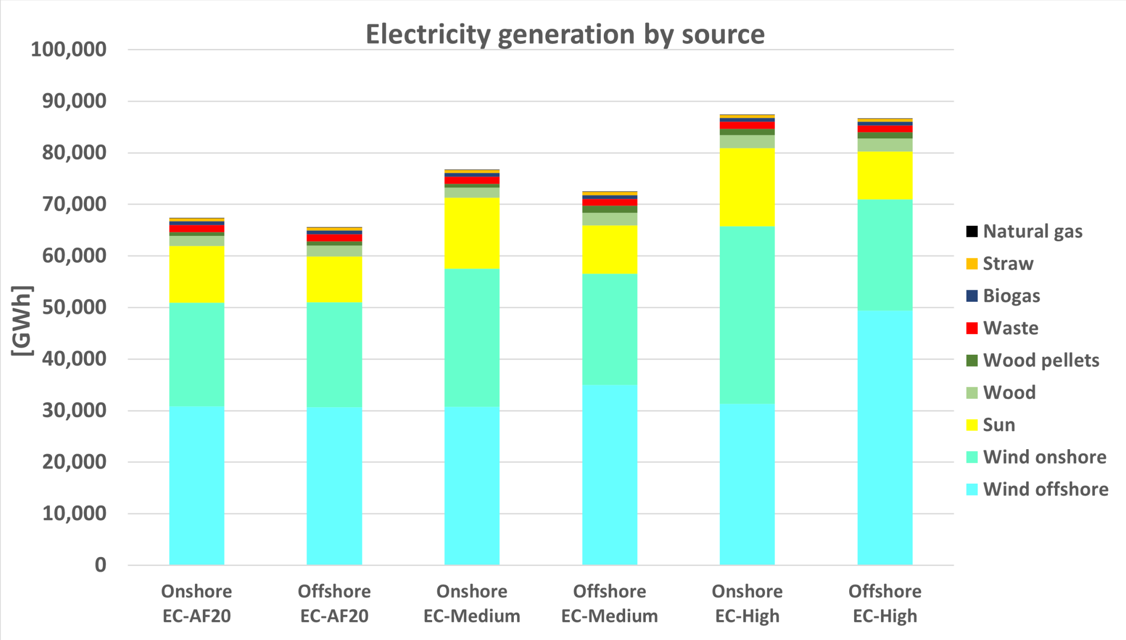

Figure 7.1. Electricity generation in both DK1 and DK2 for each scenario, based on source.

As can be seen on Figure 7.1 large shares of the electricity is produced from RE sources such as onshore wind, offshore wind and PV. An interesting point that can be drawn from this figure is that there is a larger electricity generation in the onshore scenarios, as compared to the offshore scenarios. This is likely due to the lower cost associated with onshore wind and PV, as compared to offshore wind. The lower cost could, amongst others, increase exports, hence the higher electricity production in the Onshore scenarios. The import export balance is elaborated in Section 7.7.
An interesting tendency from Figure 7.1 is that the share of electricity generation from fluctuating sources (wind and PV) slightly increases along with high EC capacities.

7.3 How do EC plants impact consumption and production dispatch in the the energy system?

As mentioned in Energinet [2020b], ECs might be able to increase integration of fluctuating RE production capacity, as they can act as flexible loads that can be adapted to RE production. In practice EC plant operators likely operate their plant according to the electricity price, as it would be most profitable. However, as the electricity price usually fluctuates according to the RE production, EC plant operators might unintentionally utilise their plants as flexible loads that follows RE production.
This is simulated in Balmorel by forcing the model to ensure that the EC demand is met while minimising system costs. This makes it relevant to investigate how different production and consumption units are operated in regard to the electricity price. Furthermore, consumption patterns vary depending on the seasons, especially in a future scenario where the electrification of the heating sector is more developed. This makes it relevant to consider EC dispatch in both warmer and colder months. To find relevant weeks for the investigation, the average weekly electricity prices are presented in Figure

7.2.

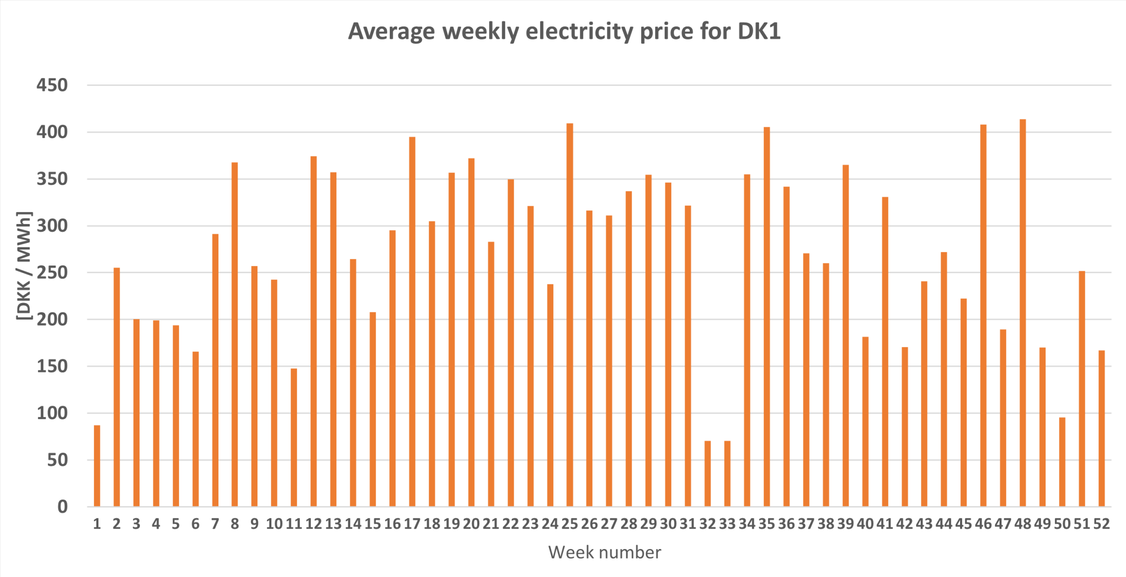

Figure 7.2. Average weekly electricity price for DK1 in the Offshore EC-High scenario.

From Figure 7.2 the lowest electricity prices, in these simulations, are found in week 32, while the highest are found in week 48. Figure 7.2 presents results from the Offshore EC-High scenario, however all scenarios had the lowest and highest average electricity prices in the same weeks. Weeks 32 and 48 are also assumed to be useful for illustrating the seasonal demand changes from e.g. heating demands. Thus, it has been chosen to investigate electricity production and consumption dispatch for weeks 32 and 48.

It has been deemed adequate to only present dispatch figures for the Offshore energy system scenarios, as the relationship between EC production dispatch and electricity price is assumed to be similar for both energy system scenarios. The Offshore energy system scenario has been selected in favor of the Onshore scenario, as the Offshore scenarios is based on predictions made by Danish Energy Agency [2020], whereas the Onshore scenario is more explorative.
Moreover, it has been decided that analysing EC dispatch patterns by comparing only the EC-High and EC-AF20 scenarios is sufficient, as this is deemed adequate for obtaining knowledge about dispatch patterns. Thus, EC dispatch patterns from the EC-Medium scenario are not be represented in the following Figures 7.3, 7.4, 7.6, and 7.7, as they are assumed similar.

To understand how EC plants are dispatched in relation to other electricity demands and the electricity price, the electricity consumption in week 48 is plotted in Figure 7.3 along with the electricity price.

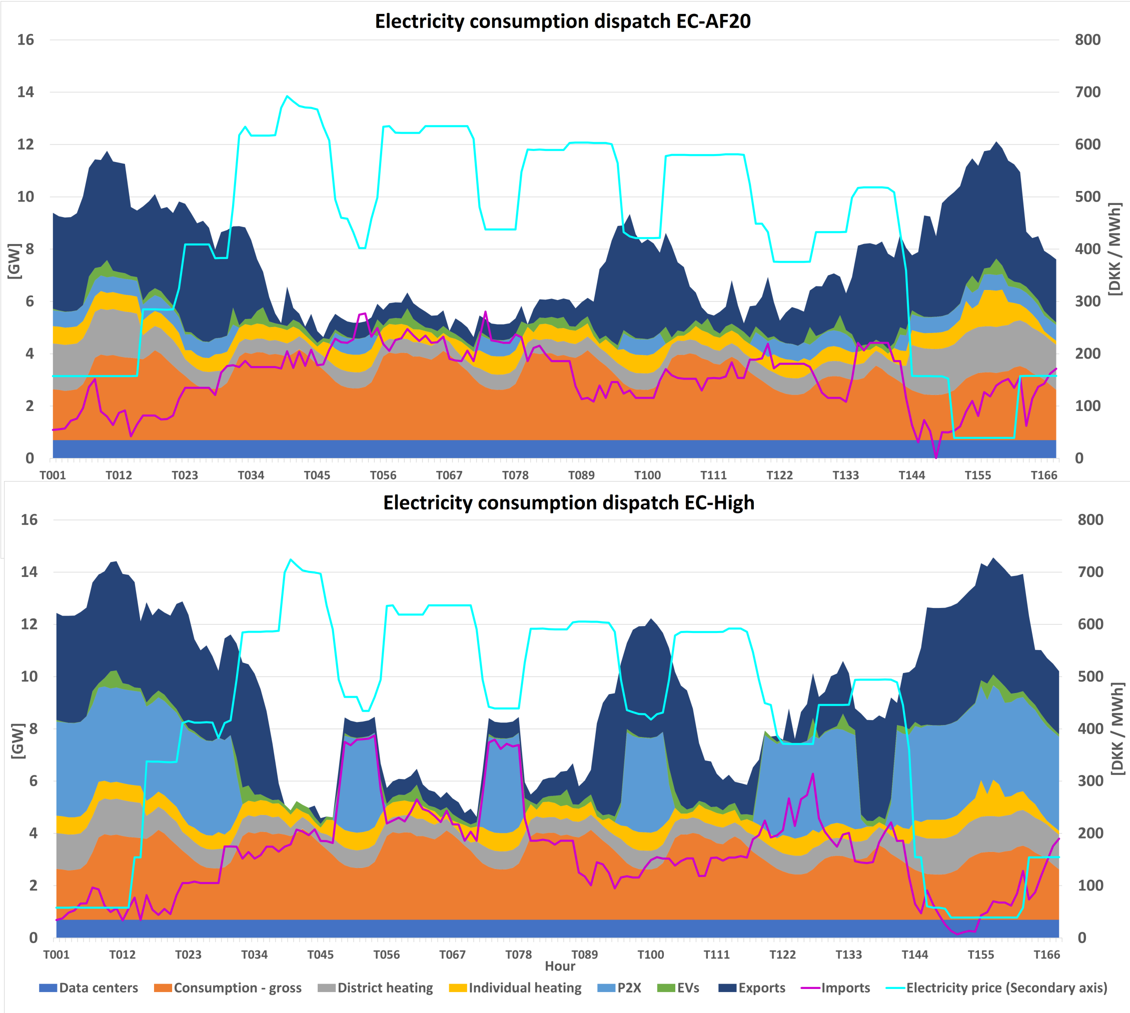

Figure 7.3. Electricity demand and export dispatch for DK1 in week 48.

From Figure 7.3 it can be understood that EC plants completely turns off production when the electricity price peaks. However, the EC plants are operated at electricity prices above 400 DKK/MWh, which could seem infeasible, as the cost of green hydrogen is expected to be 200-300 DKK/MWh by 2030 [Dansk Energi, 2020]. On the other hand, one must remember that, according to the method, the EC plants are forced to produce every week. As week 48 has the highest weekly average electricity price, it can be understood why the EC plants are operated at such relative high electricity prices.
In week 48 ECs seem to be the most flexible load in the system. EV charging is also modelled with some flexibility, but the daily electricity consumption from EVs is almost constant, with slightly lower demand in the weekend. It should be noted that the EV electricity demand is the same for all scenarios. In week 48 the electricity demand for individual and district heating fluctuates between 0.5 and 3.2 GW with an average of 1.4 GW for both the EC-High scenario and EC-AF20 scenario. These fluctuations also seem to follow the electricity price.

Across the week, it can be seen that electricity is imported and exported at the same time. From a deeper dive into the data it is evident that the transmission connections to DK1 are often being utilised to transfer power from e.g. Norway to Germany. An example from the data is around hour 90 to 110 in the EC-AF20 scenario. Here approximately 2 GW is being imported from Norway and Sweden, while 2-4 GW are begin exported to DK2, Germany, Netherlands and Great Britain. Table 7.2 reveals how much electricity is being transmitted in week 48 in relation to the maximum weekly interconnection capacity.

Table 7.2. Percentage of maximum weekly interconnection capacity between DK1 and neighbouring countries utilised in week 48.

To/from:	DK2	Germany	Great Britain	Netherlands	Norway	Sweden
EC-High	59%	42%	78%	81%	95%	76%
EC-AF20	50%	37%	78%	78%	95%	77%

Now that consumption figures have been presented, it would be relevant to take a glance at how production units are operated in relation to EC dispatch. In Figure 7.4 the dispatch of electricity generating units, and the corresponding electricity prices, are plotted for the Offshore EC-AF20 and EC-High scenarios.

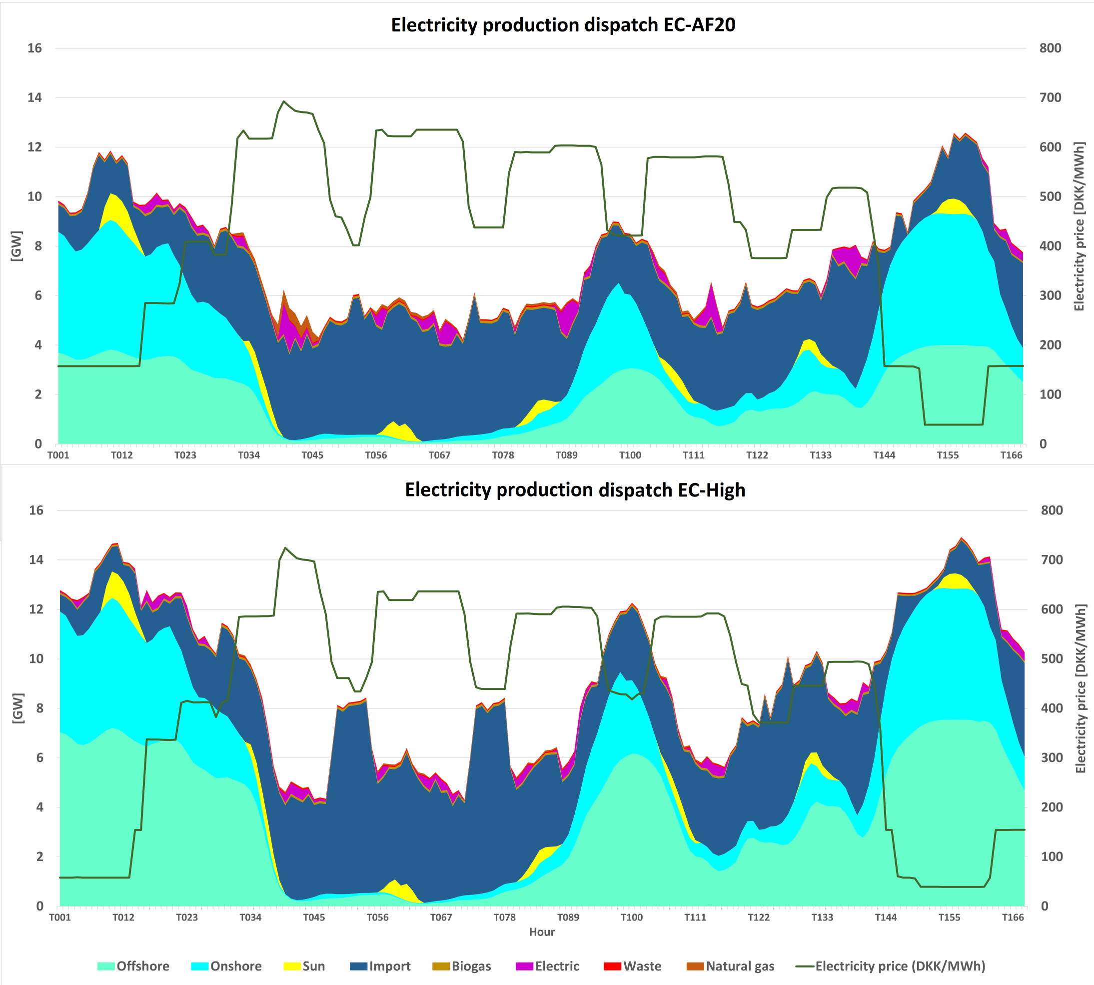

Figure 7.4. Dispatch of electricity generation and import for DK1 in week 48.

From Figure 7.4 it can be seen that the vast majority of the electricity demand is supplied by wind and imports. When comparing the EC-AF20 and EC-High scenarios, it does not seem that EC plants affects the electricity price significantly. However, this is probably

because there is more wind and PV installed in EC-High, thereby mitigating the impact of the higher demand from ECs. This can be supported by the fact that even when ECs are operated at full capacity, the electricity prices are lower around hours 144-148 in the EC-High scenario compared to EC-AF20. Thus, the figure indicates that electricity prices drop as production from wind and PV units increase.
As the relatively large electricity price fluctuations occurring during the week are fairly similar for both EC scenarios, it is unlikely that the fluctuations are caused by import of electricity, even tough it could seem to be the case for the EC-High scenario. It is more likely that the electricity price alternates in relation to electricity consumption and production patterns in neighbouring countries. To obtain knowledge about how the imported electricity affects the electricity price in DK1, the aggregated electricity generation from all simulated countries is presented in Figure 7.5.

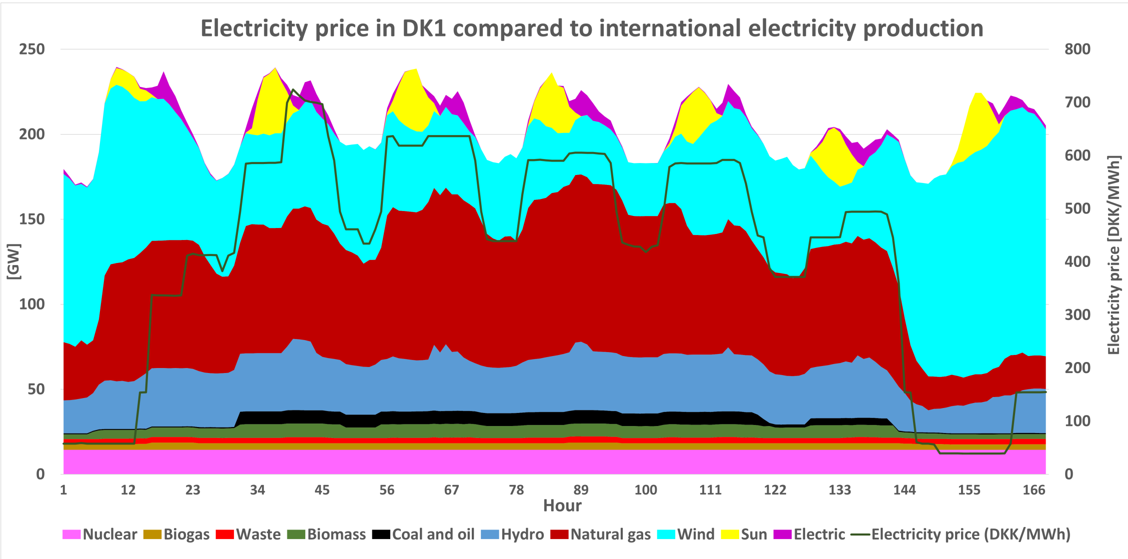

Figure 7.5. Aggregated electricity generation in the EC-High scenario based on source for all simulated countries (Denmark, Norway, Sweden, Netherlands, Great Britain, Germany). Electricity price in DK1 on secondary axis.

According to Danish Energy Agency [2021b] wind turbines and PVs have lower marginal costs than fuel-based units. Thus, electricity prices should decrease when production from wind- and solar-based units increase. This is again evident in Figure 7.5 from hour 144 to 167, as the electricity price drops when wind-based production increases. The discrete production from PV panels also seem to be the reason for the smaller reductions in the electricity price during the week.

In Figure 7.3 it seemed that when EC plants started to produce based on imported electricity, the electricity price in DK1 would drop. However, as the consumption from EC plants in DK1 is relatively small in an international perspective, it is more likely that the decreasing electricity prices occur due to lower demand during the night. As the demand decreases over night, the natural gas-based production follows proportionally, which is the reason for the drop in electricity prices.

As week 48 had the highest weekly average electricity prices, it is also relevant to investigate how EC plants impact consumption and production dispatch in week 32 where average electricity prices were lowest.

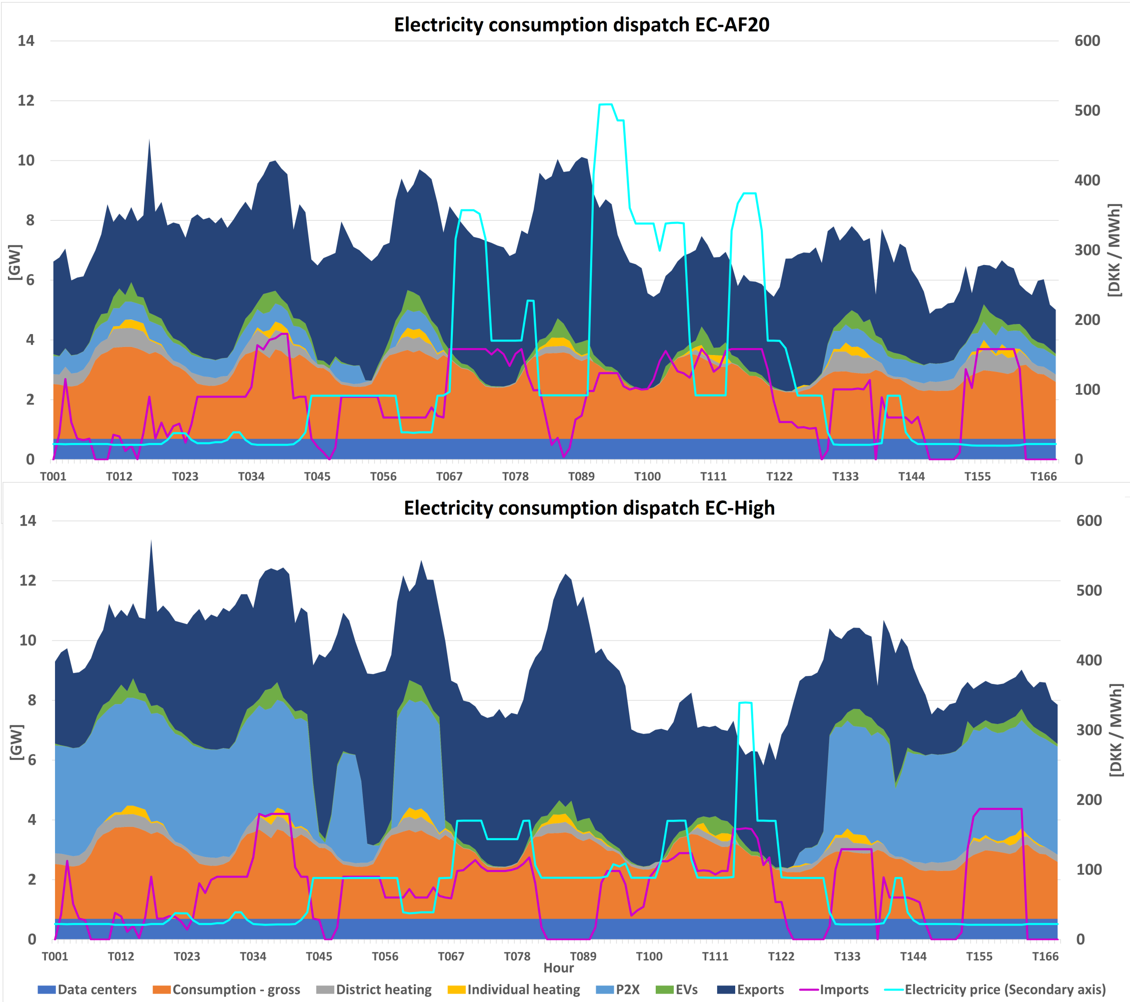

Figure 7.6. Electricity demand and export dispatch for DK1 in week 32.

When comparing Figure 7.6 to 7.3 it is evident that the combined consumption from data centers and gross consumption is somewhat similar. However, consumption from heating is significantly higher in week 48. Especially electricity to individual heating is rather insignificant in week 32 when compared to week 48.

The import/export patterns seem similar, however total exports are 9% higher and imports are 14% lower for the EC-High scenario in week 32, as compared to the EC-AF20 scenario. This is likely due to the higher RE capacity in the EC-High scenario. These higher RE capacities in the EC-High scenario also seem to reduce the electricity price in hours 67-78, 95-105 and 122-130.

In terms of assessing the impact of EC on dispatch patterns of other consumption units, it seems that these impacts are minimal. Even so it can be observed that consumption from individual and district heating in some instances are reduced in favor of ECs. This can be explained by the higher installed capacity of flexible DH production units in the EC-AF20 scenario which are displayed in Table 7.3 on page 55. Thus, it can be stated that EC plants do not significantly impact the consumption pattern for other demands,

however they do impact investments in production units. Furthermore, electricity prices seem to be affected as a knock-off-effect from the changes in production unit capacities.
To investigate if production units are dispatched in a similar manner at various EC capacities, Figure 7.7 presents electricity production for week 32 for both EC-AF20 and EC-High.

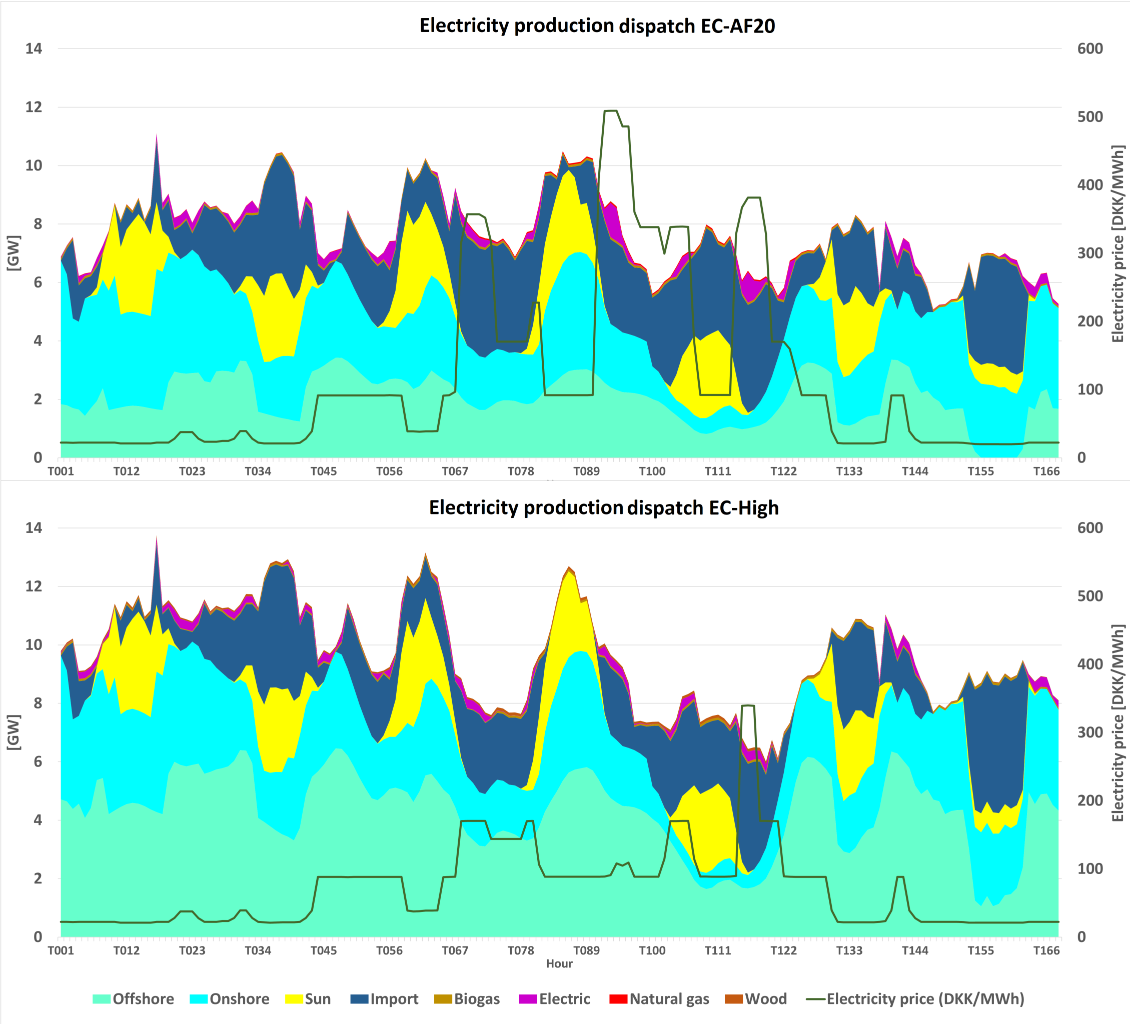

Figure 7.7. Electricity production and import dispatch for DK1 in week 32 of 2030.

From Figure 7.7 it becomes evident that the larger EC capacity also yields significantly higher production from wind turbines. This is hardly a surprise as the higher EC demand must be supplied. What might be more interesting is considering the dispatch of fluctuating RE production units (wind power plants and PV).
As the model is deterministic and weather data is identical for both scenarios, it is evident that offshore wind is shut down in the hours 155 to 162 in the EC-AF20 scenario. This means that excess offshore wind is not being utilised, even though it is available. Onshore wind turbines and PV have lower marginal costs than offshore wind [Danish Energy Agency, 2021b]. So if demands can be met by onshore wind and PV and there is not sufficient capacity on flexible loads, electricity production ramps down. This can mean that ECs increase the utilisation of excess RE production.
Another example of EC plants ability to maximise utilisation of fluctuating wind and PV

can be found in the background data for the figures. In these data it has been found that fuel-based units are utilised more in the EC-AF20 scenario. This is illustrated, along with the utilisation of electricity storage, in Figure 7.8.

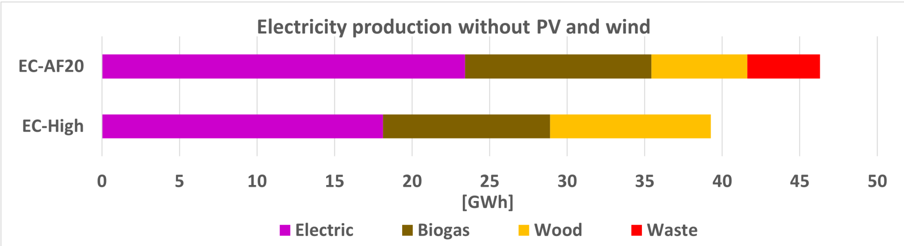

Figure 7.8. Electricity production without wind and PV for DK1 in week 32.

When comparing the two scenarios directly it is evident that fuel-based units along with storage are utilised around 18% more in the EC-AF20 scenario. Furthermore, it should be noted that the relative usage of these units is even higher for EC-AF20, as the total electricity production is 38% lower than in EC-High. From these data it can be stated that EC plants can increase utilisation of fluctuating RE units, such as wind and PV. Figures 7.8 and 7.7 indicated that the increased utilisation of fluctuating RE has led to lower electricity prices in the EC-High scenario. To verify these statements Figure 7.9 presents a comparison of the electricity price against the PV and wind share.

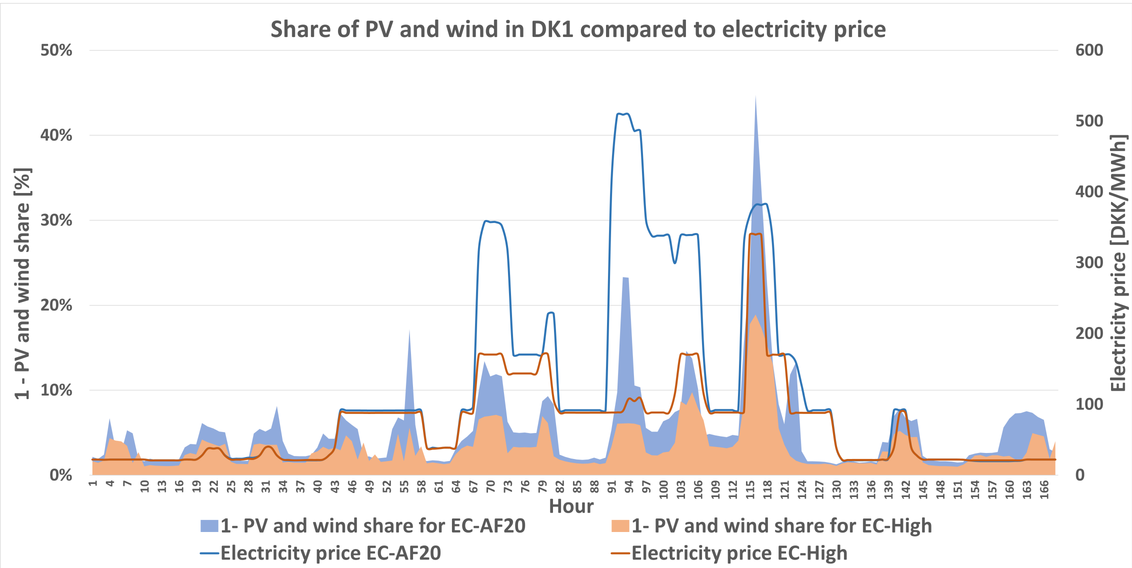

Figure 7.9. Share of PV and wind in electricity production compared to electricity price. The left y-axis illustrates 1 minus the share of PV and wind.

In Figure 7.9 the relationship between the share of wind and PV and the electricity price seems to confirm that electricity prices rise, as the share of wind power and PV decrease and vice versa.

7.4 To which extent can ECs mitigate the need for electricity storage in various energy system scenarios?

It is desired to investigate how ECs impact the need for storage and other flexible consumption units.
The use of flexible charging of electric vehicles is included in the model. However, as the amount of EVs is fixed, there is no difference between the scenarios. Therefore, flexible charging of electric vehicles is not considered.

In Table 7.3 the technologies that provide flexibility and their capacities are shown. For electricity storage it can be seen that there is a rather significant difference between installed capacity for both the energy system scenarios and the EC scenarios. Generally, the need for electricity storage drops, when increasing EC capacities. However, the drop is more significant in the offshore scenarios than the onshore scenarios. Considering the capacities for electric boilers, similar tendencies can be seen. Here there are differences between installed electric boiler capacity for the different energy system scenarios, but also between the EC scenarios. Again the installed capacity drops as the EC capacity increases.

Table 7.3. Capacity for units that provide additional flexibility to the system.

EC scenario	System scenario	Electricity storage [MWh]	Electric boilers [MW]
EC-AF20	Offshore	6,104	1,826
	Onshore	5,470	2,258
EC-Medium	Offshore	6,746	991
	Onshore	4,963	2,092
EC-High	Offshore	2,295	951
	Onshore	4,849	1,208

The tendencies seen for electric boilers indicate that there is a higher excess electricity production in the Onshore scenarios, as compared to the Offshore scenarios. Considering the EC-High scenarios, the capacities of both electricity storage and electric boilers are significantly lower for the Offshore scenarios. This indicates that the offshore scenarios have a more stable production, as compared to the onshore scenario. This is also in line with the FLH estimations for PV, onshore- and offshore wind power made by Danish Energy Agency [2021b]. The capacity differences caused by increased EC capacities, indicate that ECs provide flexibility to the system. Thereby, reducing the need for other flexible loads in the system.

7.5 How are EC plants dispatched over the course of a year?

To understand how ECs are operated over the course of a year, a distribution curve of EC production is made. This distribution curve can be seen in Figure 7.10.

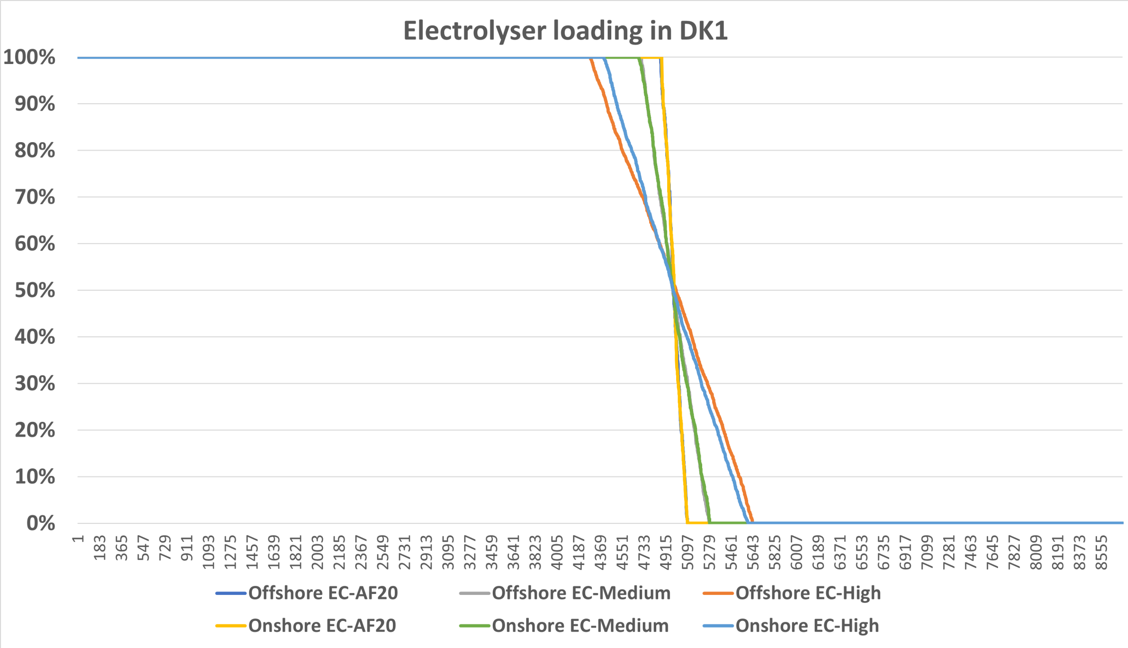

Figure 7.10. Distribution curve of EC dispatch.

Here it can be seen that the EC dispatch is fairly similar across all scenarios, as they are all more inclined to produce at full capacity, than in the intermittent area. This likely happens due to several reasons, the first being that the energy system compositions are optimised for those exact scenarios. Another reason is that the Balmorel model has full foresight, meaning that the model is able to look across the full week and determine which hours are best suited for EC operation. However, there is a tendency that the number of hours at full capacity decrease, when EC capacities increase. This is likely due to the fact that the capacity of PV and wind turbines does not increase at the same rate as the EC capacity. Thereby, the ratio between GWh produced from cheap renewable units and GWh required for EC production decreases. As Balmorel must satisfy all demands, the ECs are forced to produce more in the intermittent area. This ratio between electricity produced by PV and wind turbines, and EC demand can be seen in Table 7.4.

Table 7.4. Ratio between electricity production from PV and wind turbines, and EC demand for different scenarios.

System scenario	EC scenario	(Wind and PV production) / EC demand [GWh/GWh]
Onshore	EC-AF20	20.65
	EC-Medium	7.92
	EC-High	4.50
Offshore	EC-AF20	19.96
	EC-Medium	7.32
	EC-High	4.46

An overview of the EC production hours are given in Table 7.5. Here the average electricity price for EC production hours are given along with number of production hours in different price intervals.

Table 7.5. Average and maximum electricity price when EC plants are operated in DK1. The number of hours ECs are operated at various electricity prices is also presented in this table.

System scenario	**Offshore**			**Onshore**		
EC scenario	EC-AF20	EC-Medium	EC-High	EC-AF20	EC-Medium	EC-High
Average elec. price [DKK/MWh]	185	196	203	184	188	203
Max elec. price [DKK/MWh]	498	495	494	498	493	499
EC hours at >0 DKK/MWh	5,101	5,283	5,645	5,098	5,284	5,606
EC hours at >100 DKK/MWh	3,594	3,790	3,993	3,548	3,686	4,000
EC hours at >200 DKK/MWh	1,977	2,215	2,516	1,940	2,085	2,511
EC hours at >300 DKK/MWh	1,294	1,597	1,960	1,268	1,461	1,823
EC hours at >400 DKK/MWh	98	141	217	96	129	316

From Table 7.5 it can be seen that the average electricity price when ECs are operated is higher for EC scenarios with higher EC capacity. On the other hand there does not seem to be any relation between maximum electricity price of EC operation and EC capacity. The reason for the higher average electricity price in the scenarios with higher EC capacities, is that the higher EC demand forces ECs to operate in hours where electricity supply, is based on imports or more expensive production units. This can again be explained by the lower RE generation per EC demand ratio presented in Table 7.4.

When considering the number of EC production hours at various electricity prices, it again becomes evident that higher EC demands also yield more production hours. The EC-High scenarios have around 10% more EC production hours than EC-AF20. It should be noted that these production hours are in the intermittent area, as displayed on Figure 7.10. As the electricity price increases, the percentual difference between the number of EC production hours for EC-AF20, EC-Medium and EC-High increases too. The EC-High scenarios have approximately 35% of its production hours at electricity prices above 300 DKK/MWh, while the percentage is roughly 25% for the EC-AF20 scenarios. Again, this is likely due to lower RE generation per EC demand ratio for EC-High scenarios, shown in Table 7.4.

7.6 In which way are electricity prices impacted by implementing EC plants?

As it has been illustrated earlier, the ECs adapt their production to the price signal, and as they represent a relatively large demand, it is desired to investigate how the ECs impact the electricity price.

In Table 7.6 the average electricity price for all scenarios can be seen. Here it is evident that the average electricity price is generally higher in the Offshore scenarios, as compared to the Onshore scenarios. Another tendency present in the average electricity prices, is that the price is decreasing with increased EC capacities. However, for the Onshore scenarios, it can also be seen that there is a slight price increase from Onshore EC-Medium to Onshore EC-High. The reason that the Offshore EC-High scenario has the lowest average electricity prices, is likely that offshore wind yields more FLH compared to onshore wind and PV. Thus, more hours with high shares of RE throughout the year.

Table 7.6. Average electricity prices for DK1.

System scenario	EC scenario	Average electricity price [DKK/MWh]
Onshore	EC-AF20	276.8
	EC-Medium	273.1
	EC-High	274.1
Offshore	EC-AF20	277.6
	EC-Medium	277.1
	EC-High	272.6

In order to visualise the distribution of the electricity prices throughout the year, a distribution curve for the electricity prices in the different scenarios is constructed. This distribution curve can be seen in Figure 7.11. The figure illustrates that the price across the year is generally similar. However, there are some slight differences between the scenarios. The price difference between the scenarios likely occur as the marginal costs for offshore wind turbines are higher than those for onshore wind turbines and PVs [Danish Energy Agency, 2021c].

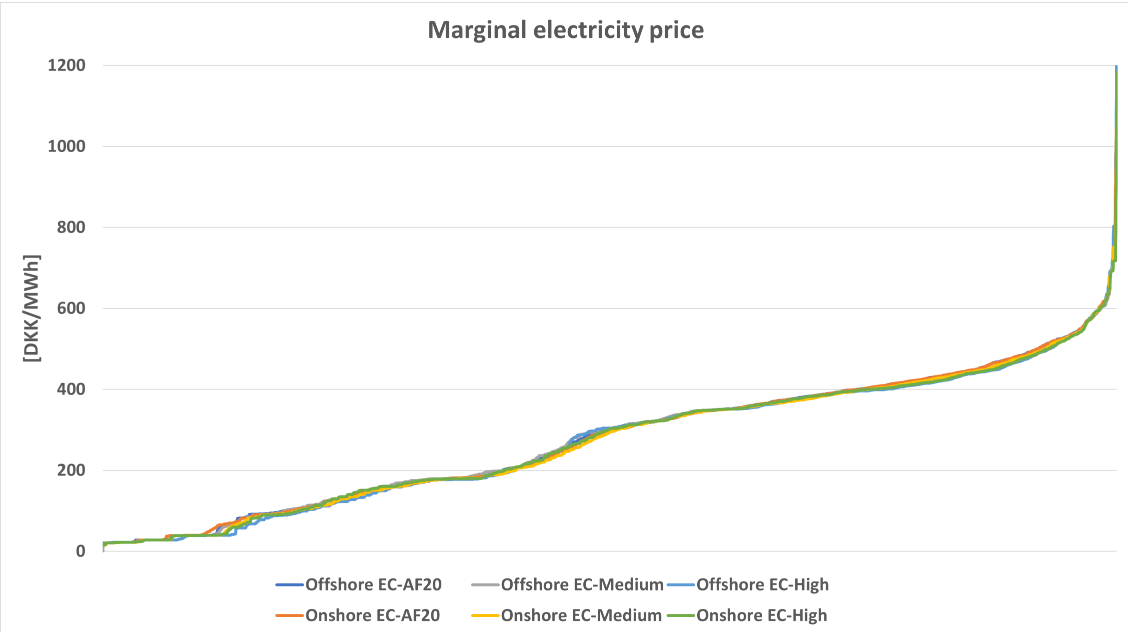

Figure 7.11. Distribution curve for DK1 electricity prices for each scenario.

Considering Table 7.6 and Figure 7.11, it can be seen that the different energy systems impact the electricity price. However, it can also be seen that increasing EC capacities decrease the average electricity price. This happens as a larger share of RE can be integrated in the system, thereby reducing the need for fuel-based electricity generation.

7.7 What happens to the electricity import/export balance when ECs are integrated in various energy system scenarios?

It is desired to investigate how the implementation of EC plants impact the import/export balance. This is done in order to analyse to what degree the ECs impact the self sufficiency of the Danish energy system.

In Figure 7.12 a duration curve of net exports from Denmark can be seen. Here a negative value represents import, while positive values account for export.
It seems that export is higher for Onshore scenarios, than for Offshore scenarios. Especially for EC-AF20 and EC-Medium scenario, while this difference seems less for the EC-High scenarios.

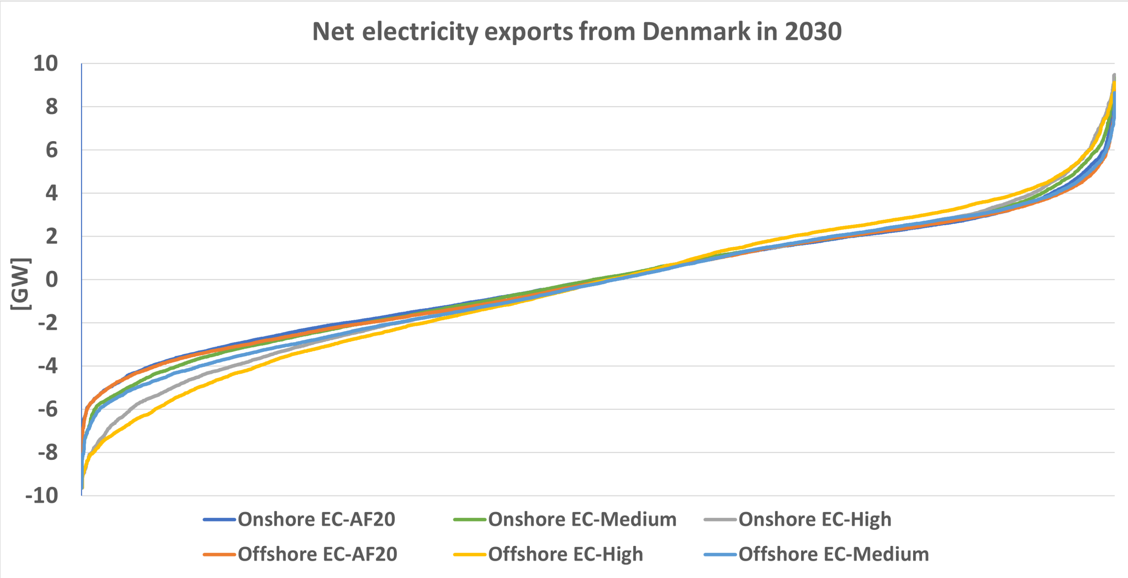

Figure 7.12. Net electricity exports from Denmark to neighbouring countries.

In Table 7.7 the tendencies observed in Figure 7.12, can be verified. Here it can be seen that there are generally higher imports in the offshore scenarios. However, it is also evident that the differences between Onshore EC-High and the other Onshore scenarios are rather significant. The observed tendencies likely stem from the ratio between RE production and EC demand, see Table 7.4.
Furthermore, it can be seen that there is a link between the amount of import and the EC capacity. The higher the EC capacity, the more electricity is imported. Hence, it can be said that Denmark is more reliant on import from neighbouring countries, with higher EC capacities.

Table 7.7. Net export for Denmark.

System scenario	EC scenario	Net export [GWh]
Onshore	EC-AF20	-210
	EC-Medium	-578
	EC-High	-2,678
Offshore	EC-AF20	-951
	EC-Medium	-2,207
	EC-High	-2,903

As the transmission grid analyses in Chapter 8, is concerned with DK1, it is desired to investigate the electricity import/export balance on a more regional level. As a result, the electricity import/export balance is given for both DK1 and DK2 in Table 7.8.
Here the net export from the two regions are split on the countries to which they are interconnected. Exchange between the two regions are shown as net export to DK.

In Table 7.8 it can be seen that DK2 is dependent on imports in all scenarios. Again, it is clear that the import is significantly increased for higher EC capacities.
Considering DK1, it is evident that this region has high net exports. Interestingly, the general tendency for DK1 is that the net exports slightly increase as the EC capacity increase from EC-AF20 values. This is likely because large shares of the RE capacity is located in DK1, see Table 7.1.

Table 7.8. Net exports from DK1 and DK2 to neighbouring countries in GWh. A negative number means that import exceeds exports.

Net exports [GWh]	DK	DE	GB	NL	NO	SE	Sum
				DK2			
Onshore EC-AF20	-213	620				-3,880	-3,473
Offshore EC-AF20	-114	607				-3,911	-3,418
Onshore EC-Medium	-995	173				-4,812	-5,634
Offshore EC-Medium	-436	294				-4,246	-4,388
Onshore EC-High	-1,151	-263				-4,991	-6,405
Offshore EC-High	-1,381	-322				-5,043	-6,746
				DK1			
Onshore EC-AF20	218	5,200	1,552	3,180	-4,698	-2,189	3,263
Offshore EC-AF20	119	4,710	1,419	3,096	-4,766	-2,111	2,467
Onshore EC-Medium	1,001	5,677	1,690	3,192	-4,527	-1,977	5,056
Offshore EC-Medium	441	4,245	1,354	3,026	-4,824	-2,062	2,181
Onshore EC-High	1,156	4,522	1,538	3,012	-4,567	-1,934	3,727
Offshore EC-High	1,387	4,445	1,432	2,881	-4,494	-1,808	3,843

As this thesis investigates the influence of ECs on the Danish energy system, it is decided to examine the utilisation of the interconnector between DK1 and DK2. In Figure 7.13 the loading of the interconnector is presented. Here it can be seen that increased EC capacities does increase the amount of hours in which the interconnector is utilised. However, it is not as obvious as indicated in Table 7.8. Instead the interconnector in the scenarios with higher EC capacities, is likely used more unidirectional than in the EC-AF20 scenarios. This is caused by the fact that the RE capacity is significantly higher in DK1 than in DK2.

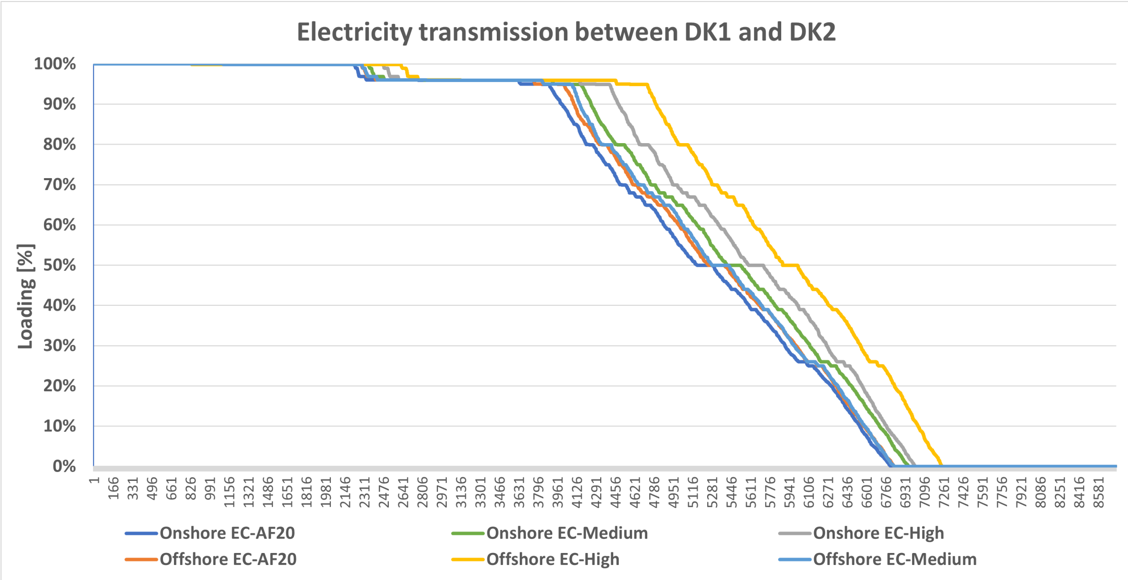

Figure 7.13. Duration curve of electricity transmission between DK1 and DK2.

The results shown in Table 7.8 and Figure 7.13, can indicate that the transmission capacity between DK1 and DK2 could benefit from being increased, as this might enable increased utilisation of domestically produced electricity. Alternatively, EC capacity could be moved from DK2 to DK1, which would also reduce loading on the interconnector between DK1 and DK2.
However, moving all EC capacity from DK2 would, from an energy system perspective, not necessarily be wise, as hydrogen from EC plants can be used to produce e-fuels when combined with a carbon source e.g. waste incineration or biogas plant. Furthermore, excess heat from ECs can be utilised in large DH areas. Both carbon point sources and large DH areas exist in both DK1 and DK2, and as especially carbon point sources are limited, it is essential to utilise all available resources in order to produce the required amount of e-fuels and gasses. [Energinet, 2021f]

7.8 Can the 70% CO_2 reduction goal for 2030, be realised when different EC demands must also be satisfied?

In order to ensure that the different scenarios all adhere to the 70% reduction goal of 2030, corresponding to a maximum allowable emission of 1 Mt, the emission level must be analysed.

In Table 7.9, the total emissions for each scenario are presented. Here emissions are split on fuel type, in order to create an overview of the source of CO_2 emissions.
It can be seen that waste accounts for the highest amount of emissions, while natural gas accounts for the rest. Overall, the emission level actually does not comply with the requirement of maximum 1 Mt CO_2. The differences arise due to the different time-step resolutions of the BB2 (investment run) and the BB3 (dispatch run) of the Balmorel simulations. The BB2 run has a timestep resolution of 624 steps per year, while the BB3 run has a full Balmorel year of 8736 steps.

The results shown are based on the BB3 run. However, had the results of the BB2 instead been shown the total emissions would instead have been 1 Mt, and as the limit is only exceeded by a maximum of 0.05 Mt CO_2 in the BB3 run, the error is considered negligible. Therefore, all scenarios are considered to adhere to the 70% reduction goal.

Table 7.9. CO_2 emissions from different scenarios in 2030, given per fuel type.

Energy system	**Offshore**			**Onshore**		
EC scenario	**EC-AF20**	**EC-Medium**	**EC-High**	**EC-AF20**	**EC-Medium**	**EC-High**
Waste [Mt]	0.97	0.95	0.95	0.97	0.96	0.95
Natural gas [Mt]	0.07	0.06	0.06	0.08	0.08	0.06
Sum [Mt]	**1.04**	**1.01**	**1.01**	**1.05**	**1.04**	**1.01**

7.9 Summary of energy system analysis

Using the methods and assumptions presented in Chapter 5, two energy system scenarios and three EC scenarios have been optimised and simulated, with the intention of assessing how different EC capacities impact the Danish energy system. Furthermore, the intention with these energy system simulations was to obtain data for how production and consumption units are dispatched in the different scenarios, as this data is needed to assess how large-scale ECs affect the transmission grid. Hence, these data are the foundation of the transmission grid analysis conducted in Chapter 8.

From this energy system analysis it became evident that it is possible to integrate large EC capacities in the two different energy system scenarios, while still adhering to the 70% reduction goal of 2030. However, integrating large EC capacities does yield both pros and cons.
A key advantage of increasing EC capacity, is that it enables the integration of higher PV and wind turbine capacities, along with a increased utilisation of the fluctuating RE production. The higher capacities and increased utilisation of RE also yield a slight decrease in the electricity price. Furthermore, ECs provide flexibility to the system, meaning that the need for other flexible units, such as electric boilers and electricity storage, decreases along with increasing EC capacities.
Conversely, the are also cons associated with integrating high EC capacities. The higher EC capacities results in decreased self-sufficiency, meaning that Denmark will be more reliant on electricity import from neighbouring countries.

Transmission grid analysis 8

In this chapter the results of the transmission grid analysis of DK1 are presented and analysed. The analysis is conducted based on the method developed in Chapter 6.

The focus of this analysis is on line/cable loading caused by EC integration. This also means that loading of transformers is not considered, as it is assumed that it is less complex and costly to upgrade transformer capacity, opposed to cables and lines. Furthermore, it is assumed that large loads of approximately 1 GW, have a dedicated transformer. In order to conduct this analysis, certain hours of interest are selected based on the results from the Energy system analysis, presented in Section 7.

8.1 Selection of relevant simulation hours for the transmission grid analysis

As mentioned in Section 5, this analysis uses the hourly production and consumption data obtained from the energy system analysis. These data are inserted and distributed in the load flow model, using the distribution keys developed in Chapter 6, see Appendix C.

This load flow analysis is conducted in order to investigate potential benefits and issues from integrating ECs in the transmission grid of DK1. Therefore, the hours selected for simulation are chosen based on the assumption that these yield the highest grid loading. To understand how various EC capacities impact grid loading, it has been decided that ECs should produce at full load in the selected hours.
Alternatively, one could also simulate load flows at hours when ECs were not producing or producing at a reduced loading. However, this is neglected, as it is assumed that tendencies and potential issues from operating at low or none EC load, can be derived from the EC-AF20 scenarios where the EC capacity is relatively low.

To give an overview of which hours that could be relevant, different hours of interest are presented in Table 8.1.

Table 8.1. Potential hours for transmission grid analysis. (S) indicate weeks, while (T) indicate the hour of a given week. E.g. S04-T060 is hour 60 of week 4.

Energy system scenario	**Offshore**	**Onshore**	**Offshore**	**Onshore**	**Offshore**	**Onshore**
Electrolyser scenario	**EC-AF20**	**EC-AF20**	**EC-Medium**	**EC-Medium**	**EC-High**	**EC-High**
Max con. excl. export	S04-T060	S09-T012	S04-T060	S06-T083	S06-T083	S06-T083
Max con. incl. export	S15-T037	S15-T036	S15-T037	S15-T036	S15-T036	S15-T036
Max prod. ex. import	S15-T036	S15-T036	S15-T036	S15-T036	S15-T036	S15-T036
Max prod. incl. import	S08-T013	S15-T036	S09-T012	S15-T036	S15-T036	S15-T036
Max onshore prod	S15-T036	S15-T036	S15-T036	S15-T036	S15-T036	S15-T036
Max offshore prod	S49-T052	S49-T052	S49-T052	S49-T052	S49-T052	S49-T052
Max import	S08-T130	S08-T130	S08-T130	S08-T130	S48-T054	S48-T050
Max export	S15-T038	S15-T037	S15-T038	S20-T086	S15-T038	S15-T035

In Table 8.1 various criteria are stated in the far left column of the table. Furthermore,

a criterion ensures that ECs are producing at full capacity. For each scenario, the hours that live up to the set criteria are displayed.
In order to understand how different EC capacities and energy system compositions impact grid loading, it has been decided to use the same hours for all scenarios. Only hour 36 of week 15 and hour 52 of week 49 live up to this. Thus, these two hours are selected for load flow simulations. In order to easily separate the results of the two hours selected for analysis, hour 36 in week 15 is henceforth be referred to as *max production hour*, while hour 52 of week 49 is referred to as *max offshore hour*.

In order to ensure that the hours selected for further analysis can adequately describe the grid impacts in the different scenarios, it is necessary to ensure that the hours are representative. Therefore, it is chosen to investigate how often hours with similar production patterns occur during the year. In this investigation, hours that are within 90% of the production of the two hours are deemed similar. The number of similar hours can be seen in Table 8.2, where the number of hours, which have 90%, 95% and 99% similar production levels of the selected hours, are presented.

Table 8.2. Distribution of similar hours based on electricity production.

Hour	**Max production hour**					
Energy system scenario	**Onshore**			**Offshore**		
Electrolyser scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
90% similar production [hours]	9	17	16	12	14	18
95% similar production [hours]	3	3	4	3	3	4
99% similar production [hours]	1	1	1	1	1	1
Hour	**Max offshore hour**					
Energy system scenario	**Onshore**			**Offshore**		
Electrolyser scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
90% similar production [hours]	1452	1404	1371	1407	1385	1479
95% similar production [hours]	845	795	763	795	774	717
99% similar production [hours]	191	163	152	170	155	113

As presented on Table 8.2, the max production hour is a rather extreme case, as very few hours reach similar electricity production levels, as only 9-18 hours have a 90% similar electricity production level. In contrast, the max offshore hour has 95% production similarities in 717-845 hours, corresponding to 8-9% of the year, and 1371-1479 hours have 90% similar electricity production levels, corresponding to 16-17 % of the year.
In order to assess how the rather extreme max production hour impacts grid loading, it is still decided to simulate this hour. However, to increase understanding and make the analysis representative for more hours throughout the year, it has been chosen to select an additional hour, which shares production similarities with more hours annually.
In order to ensure that this hour is more representative, it is chosen to pick an hour for which, around 5% of the year has a higher electricity production, as this is assumed to mitigate the extreme cases. To elaborate, this means that the electricity production is higher than this hour during 5% of the year. 5% of a Balmorel simulation year (8736 hours) equates to 437 hours. 5% is chosen as not being able to operate the ECs during 437 hours each year due to grid overloading, is considered a significant loss for EC plant operators, as well as a socio-economic loss due to the lack of hydrogen production needed

for essential PtX products.

Table 8.3. Overview of which hour has the 95% highest annual production in each scenario. Meaning the electricity production is higher than in this hour during 5% of the year. The hour is identified according to week (S) and hour in week (T).

Hour with 95% highest annual production for each scenario.		**Percentage of year with higher production than the 95% hour.**					
		Offshore EC-AF20	**Offshore EC-Medium**	**Offshore EC-High**	**Onshore EC-AF20**	**Onshore EC-Medium**	**Onshore EC-High**
Offshore EC-AF20	S10-T115	5.0%	5.0%	3.3%	7.7%	6.7%	7.3%
Offshore EC-Medium	S49-T059	3.5%	5.0%	3.1%	5.5%	6.3%	4.7%
Offshore EC-High	S06-T071	5.9%	5.7%	5.0%	8.8%	7.6%	8.3%
Onshore EC-AF20	S02-T158	3.6%	3.5%	8.4%	5.0%	4.5%	4.9%
Onshore EC-Medium	**S52-T110**	**5.0%**	**7.8%**	**5.8%**	**6.2%**	**5.0%**	**4.9%**
Onshore EC-High	S14-T156	18.4%	16.0%	26.1%	15.9%	17.7%	5.0%

From the data presented in Table 8.3 hour S52-T110 is selected, as it is the hour which matches the 5% criteria closest for all scenarios. Thus this hour is added to the list of simulation hours, as it is a less extreme hour than the max production hour. Hour S52-T110 is henceforth referred to as the *95% hour*.

As mentioned earlier, the hourly consumption and production data from the energy system analysis is used as the input data for the grid analysis. Therefore, data is extracted from Balmorel for the hours selected for the grid analysis. This data can be found in Tables 8.4 and 8.5, which respectively shows load and production data used in the grid analysis. This data shows the average load and production data across the selected hours.

Table 8.4. Load data from Balmorel for the selected hours.

			Max production hour			
System scenario		**Onshore**			**Offshore**	
Electrolyser scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
General consumption [MW]	7549	7510	7047	6583	6742	6917
EC consumption [MW]	602	1805	3610	602	1805	3610
Export Germany [MW]	1901	3159	3159	1239	1056	1499
Export Norway [MW]	1637	1637	1637	1637	1637	1637
Export Sweden [MW]	742	742	742	742	742	742
Export DK2 [MW]	409	409	409	409	49	409
Export Netherlands [MW]	491	491	491	491	491	491
Export Great Britain [MW]	1404	1404	1404	1404	1404	1404
			Max offshore hour			
System scenario		**Onshore**			**Offshore**	
Electrolyser scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
General consumption [MW]	6460	6411	5898	6190	5753	5750
EC consumption [MW]	602	1805	3610	602	1805	3610
Export Germany [MW]	0	0	0	0	0	0
Export Norway [MW]	1637	1637	1637	1637	1637	1637
Export Sweden [MW]	371	371	371	371	371	371
Export DK2 [MW]	602	602	602	602	602	602
Export Netherlands [MW]	702	702	702	702	702	702
Export Great Britain [MW]	1404	1404	1404	1404	1404	1404
			95% hour			
System scenario		**Onshore**			**Offshore**	
Electrolyser scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
General consumption [MW]	6688	6642	6125	6419	5978	5991
EC consumption [MW]	602	1805	3610	602	1805	3610
Export Germany [MW]	0	0	0	0	0	0
Export Norway [MW]	1587	1587.4	1587	1587	1587	1587
Export Sweden [MW]	327	326.5	327	327	327	327
Export DK2 [MW]	578	577.6	578	578	578	578
Export Netherlands [MW]	702	701.9	702	702	702	702
Export Great Britain [MW]	1404	1403.8	1404	1404	1404	1404

Table 8.5. Production data from Balmorel for the two selected hours.

	Max production hour					
System scenario	**Onshore**			**Offshore**		
Electrolyser scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
Production excl. Offshore [MW]	11777	14700	15951	10062	10091	9999
Import Germany [MW]	0	0	0	0	0	0
Import Norway [MW]	0	0	0	0	0	0
Import Sweden[MW]	0	0	0	0	0	0
Import DK2 [MW]	0	0	0	0	0	0
Import Netherlands [MW]	0	0	0	0	0	0
Import Britain [MW]	0	0	0	0	0	0
Offshore General [MW]	2797	2797	2921	2791	3717	6115
Offshore Anholt [MW]	385	0	0	385	385	385
Offshore Hornsrev [MW]	483	335	335	483	483	483
	Max offshore hour					
System scenario	**Onshore**			**Offshore**		
Electrolyser scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
Production excl. Offshore [MW]	5520	7199	8717	5739	5829	5705
Import Germany [MW]	2823	2316	1782	2162	2045	776
Import Norway [MW]	0	0	0	0	0	0
Import Sweden[MW]	0	0	0	0	0	0
Import DK2 [MW]	0	0	0	0	0	0
Import Netherlands [MW]	0	0	0	0	0	0
Import Britain [MW]	0	0	0	0	0	0
Offshore General [MW]	3008	3008	3142	3008	4002	6575
Offshore Anholt [MW]	401	401	401	401	401	401
Offshore Hornsrev [MW]	618	618	618	618	618	618
	95% hour					
System scenario	**Onshore**			**Offshore**		
Electrolyser scenario	**AF20**	**Medium**	**High**	**AF20**	**Medium**	**High**
Production excl. Offshore [MW]	6442	7980	9497	6387	6215	6189
Import Germany [MW]	2104	1649	1287	1815	1756	1026
Import Norway [MW]	0	0	0	0	0	0
Import Sweden[MW]	0	0	0	0	0	0
Import DK2 [MW]	0	0	0	0	0	0
Import Netherlands [MW]	0	0	0	0	0	0
Import Britain [MW]	0	0	0	0	0	0
Offshore General [MW]	3008	3008	3141	3008	4001	6574
Offshore Anholt [MW]	0	0	0	0	0	0
Offshore Hornsrev [MW]	408	408	408	408	408	408

8.2 Grid loading results

In this section the results of the transmission grid analysis are presented. Here the chosen hours have been simulated with the different EC locations, as described in Section 6.3.2. These results are used to examine both the impacts of EC capacities, but also the influence of EC locations.

As mentioned earlier, it might be useful for the reader to keep Figures 6.5 and 6.6, at hand when reading this section, as they might give the reader a better overview. In the text, EC locations where EC capacity is split on multiple locations are referred to using

parentheses. e.g. (Endrup, Stovstrup, Idomlund) means that EC capacity is distributed equally between Endrup, Stovstrup and Idomlund.
The transmission grid of DK1 consists of both 400 kV and 150 kV overhead lines and cables, with most of the 150 kV grid being cables. However, in order to simplify the presentation of overhead line/cable loading, both overhead lines and cables are referred to as lines. The grid loading data for all scenarios in the three simulated hours, can be found in Appendix F, G and H. The most relevant results are presented in the following.

The results for the 400 kV grid can be seen in Figure 8.1. Here the maximum line loading and the number of overloaded 400 kV lines in the max production hour can be seen.

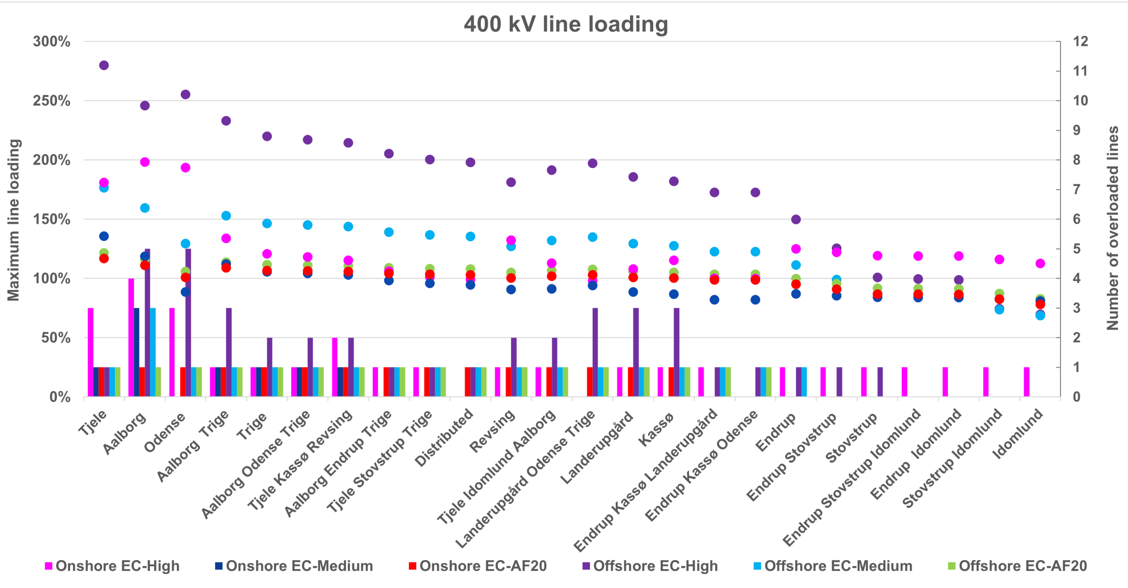

Figure 8.1. Loading of 400 kV lines for the max production hour depending on EC location. The bar chart refers to the number of overloaded lines on the secondary axis, whereas the line chart refers to the maximum loading of a single line.

It can be seen that the Offshore scenarios yield the highest maximum loading and highest number of overloaded lines. However, they also yield the lowest maximum loading and most locations with no overloaded lines. Interestingly, Offshore EC-Medium and EC-High yield lower maximum loading than EC-AF20. The reason could be that ECs are able to utilise a larger part of the power generated by the offshore wind power plants. Thereby, reducing power flowing through the system.
The Onshore EC-High scenario has no overloading if the EC capacity is located in (Landerupgård, Odense, Trige), (Endrup, Kassø, Landerupgård) and in the distributed case. For Offshore EC-High there is no overloading if the ECs are placed in (Endrup, Stovstrup, Idomlund), (Endrup, Idomlund), (Stovstrup, Idomlund) and Idomlund.

In Figure 8.2 the amount of overloaded 150 kV lines and the maximum loading found in the 150 kV grid during the max production hour, can be seen for different EC locations.

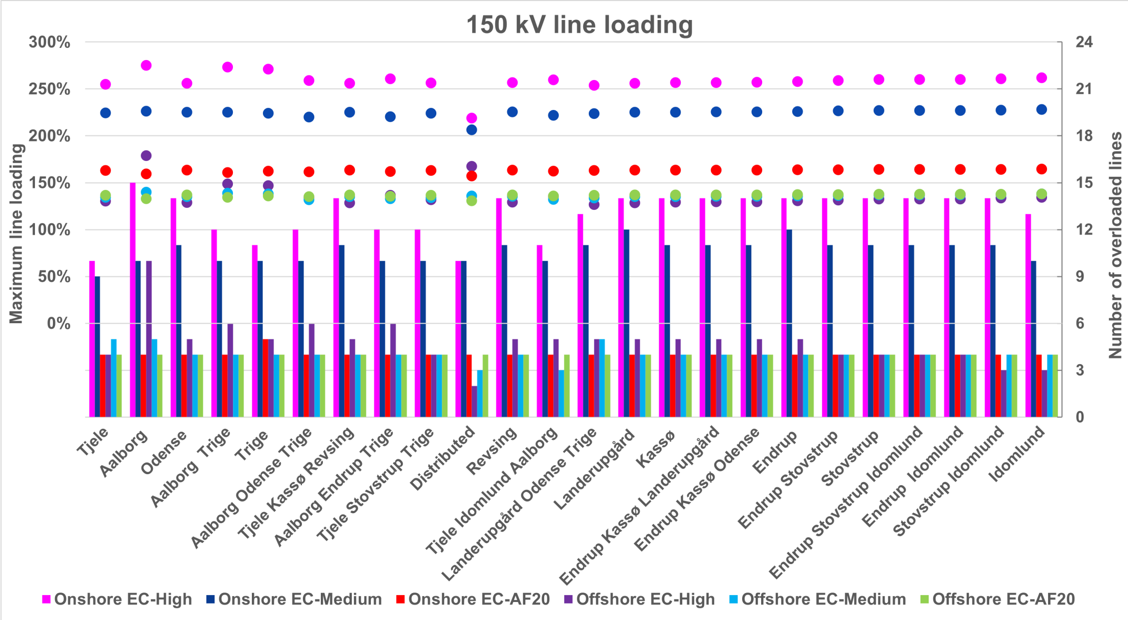

Figure 8.2. Loading of 150 kV lines for the max production hour depending on EC location.

By considering the maximum line loading, it can be seen that the Onshore scenarios have significantly higher maximum loading, as compared to the Offshore scenarios. This is likely due to the higher decentralised production in the 150 kV grid for the Onshore scenarios. Furthermore, it can be seen that for the Onshore scenarios the maximum loading increases along with EC capacity. Considering the maximum loading of the Offshore scenarios, the maximum loading is less dependant on EC capacity. In fact, the Offshore scenarios are fairly similar with regard to the number of overloaded lines, and even has a lower maximum loading for EC-High at multiple locations.

By considering the number of overloaded lines, the same tendencies are evident. Again Onshore EC-Medium and EC-High cause a significantly higher numbers of overloaded lines than other scenarios. Conversely, Offshore EC-High, is the scenario with the lowest number of overloaded lines. However, as the lowest number of overloaded lines are still different from zero, some reinforcements in the 150 kV grid seem unavoidable.

Now that the general tendencies have been presented, the EC locations should be considered. As the tendencies are most visible in the two EC-High scenarios, they are elaborated. For Onshore EC-High it can be seen that the general tendency is that more central locations, like Tjele and Trige, yield the lowest amount of overloaded lines. Additionally, the distributed case also yielded less overloading for the Onshore scenario. For the Offshore scenario, the distributed case yields the least overloading. However, Idomlund and (Stovstrup, Idomlund) also result in a low number of overloaded 150 kV lines.
The differences between the Onshore and Offshore scenarios seen in Figure 8.2 was expected as PV and onshore wind turbines, dominating the Onshore scenarios, are located in the 150 kV grid.

Summarising the results of the max production hour described in the above, it can be said that the Onshore scenarios generally result in more overloading, and therefore require more grid reinforcements than the Offshore scenarios.

Location of the EC capacity is of great importance. In this regard the results have shown that central grid locations seem to yield the best result for the Onshore scenarios. However, it is not the same EC locations that yield the best results in both the 150 kV and 400 kV grid. The best locations for the Offshore scenario are (Stovstrup, Idomlund), Idomlund and the distributed case.
From Figure 8.2 and 8.1 it can be stated that if placed correctly, higher EC capacities can lead to reduced overloading for the Offshore energy system scenario.

In Figures 8.3 and 8.4 the line loading during the 95% hour is presented for all scenarios.

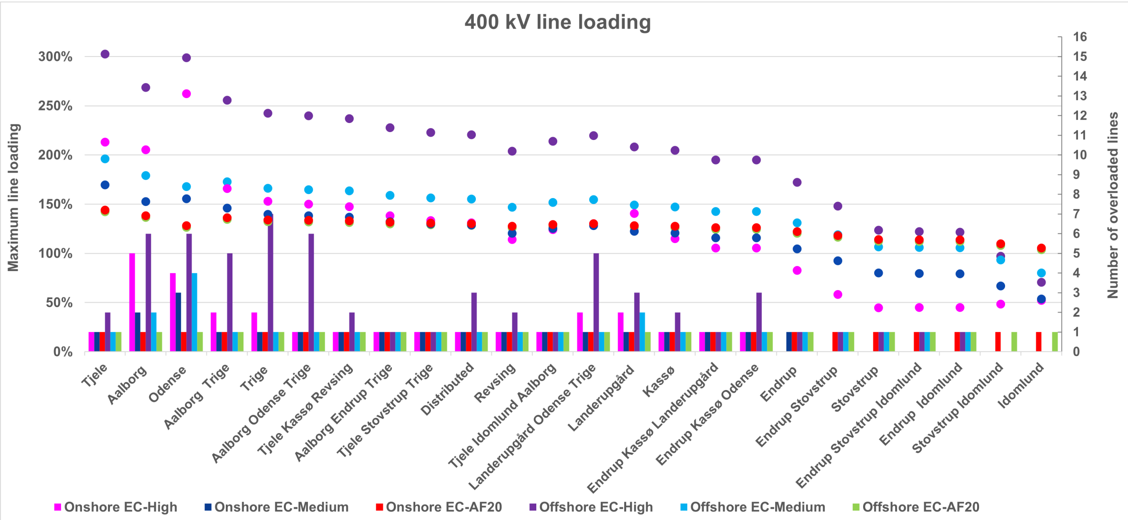

Figure 8.3. Loading of 400 kV lines for the 95% hour depending on EC location. The bar chart refers to the number of overloaded lines on the secondary axis, whereas the line chart refers to the maximum loading of a single line.

In Figure 8.3, the line loading on the 400 kV grid can be seen. Here it can be seen that significant line loading can occur in all scenarios. Interestingly, only the two EC-AF20 scenarios are not capable of mitigating overloading. Hence, it can be understood that increased EC capacity can mitigate overloading if placed properly.
In this hour the Onshore EC-High scenario yields the lowest possible line loading, and also yields the highest range of locations without overloading. This is opposed to the max production hour, where Onshore EC-High is the only scenario that cannot completely mitigate overloading of the 400 kV grid.

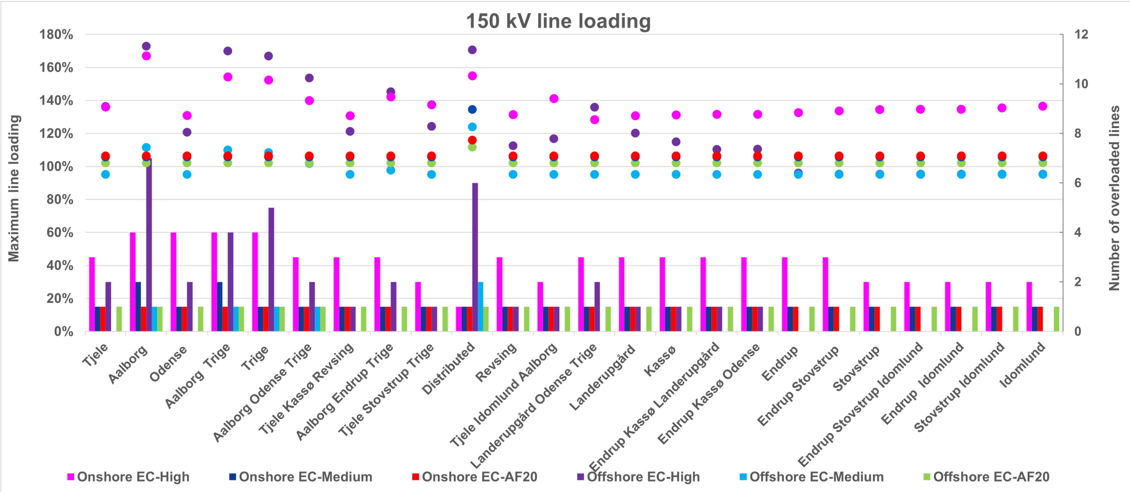

Figure 8.4. Loading of 150 kV lines for the 95% hour depending on EC location.

In Figure 8.4, the line loading on the 150 kV grid is presented. For the 150 kV grid, the EC-AF20 scenarios are again not able to mitigate overloading. Furthermore, the Onshore EC-High cannot mitigate overloading in the 150 kV grid, and has a minimum of two overloaded 150 kV lines for all scenarios. Conversely, the Offshore EC-High scenario is able to mitigate all overloading in the 150 kV grid during the 95% hour.

Based on the results of the 95% hour it can be said, that the best results are obtained for all scenarios, when placing ECs in the feed-in zones. Here especially Idomlund and (Idomlund, Stovstrup) yield promising results, as overloading of both the 150 kV and the 400 kV grid can be avoided altogether, in the Offshore EC-Medium and EC-High scenarios. Considering the two EC-High scenarios, it is evident that the Onshore scenario performs better than the Offshore scenarios when considering the loading of the 400 kV grid, while the roles are reversed when considering the 150 kV grid. This is, again, likely due to the higher decentral onshore wind and PV production in the Onshore scenario, as opposed to the more centralised offshore wind power production in the Offshore scenario, as seen in Table 8.5.

In Figure 8.6 and 8.5, the line loading results for the max offshore hour are presented for all scenarios at various EC locations.

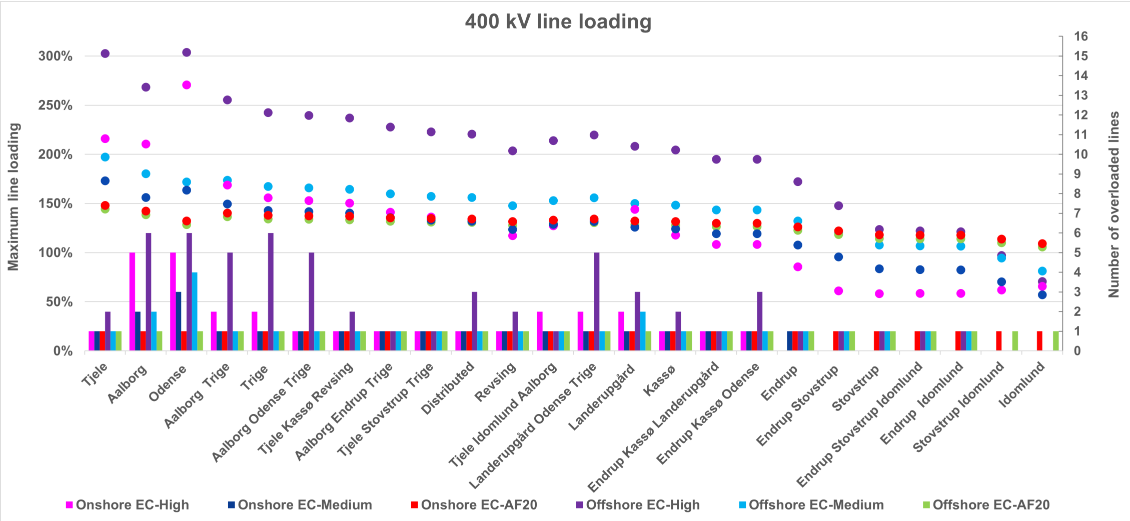

Figure 8.5. Loading of 400 kV lines for the max offshore hour depending on EC location. The bar chart refers to the number of overloaded lines on the secondary axis, whereas the line chart refers to the maximum loading of a single line.

The lower EC capacity in the EC-AF20 yields a maximum line loading between 106-148%, which means that one line is always overloaded. It is possible to decrease the maximum line loading to levels between 66 and 70% if the EC capacity of the EC-High scenarios is placed correctly. If ECs are located in Idomlund or (Idomlund and Stovstrup), overloading only occurs in the EC-AF20 scenarios. Thus, it can be stated that overloading can be completely eliminated for 400 kV lines by integrating higher EC capacities. Even so, it must be stated that higher EC capacities generally yields more overloading if EC capacity is not placed correctly, especially for the Offshore energy system scenarios.
An example to support these statements is given on Figure 8.5. EC-High capacity placed in Aalborg, Odense or Trige in e.g. for the Offshore scenario, yield six overloaded lines and a maximum line loading of 240-300%. If EC is placed in Idomlund, no lines are overloaded and maximum line loading is around 70%.

For all scenarios, the lowest 400 kV line loading can be achieved when EC capacity is located in feed-in zones (Endrup, Idomlund and Stovstrup). To demonstrate how EC capacity and placement affects the 150 kV grid, line loading of the 150 kV grid is presented in Figure 8.6.

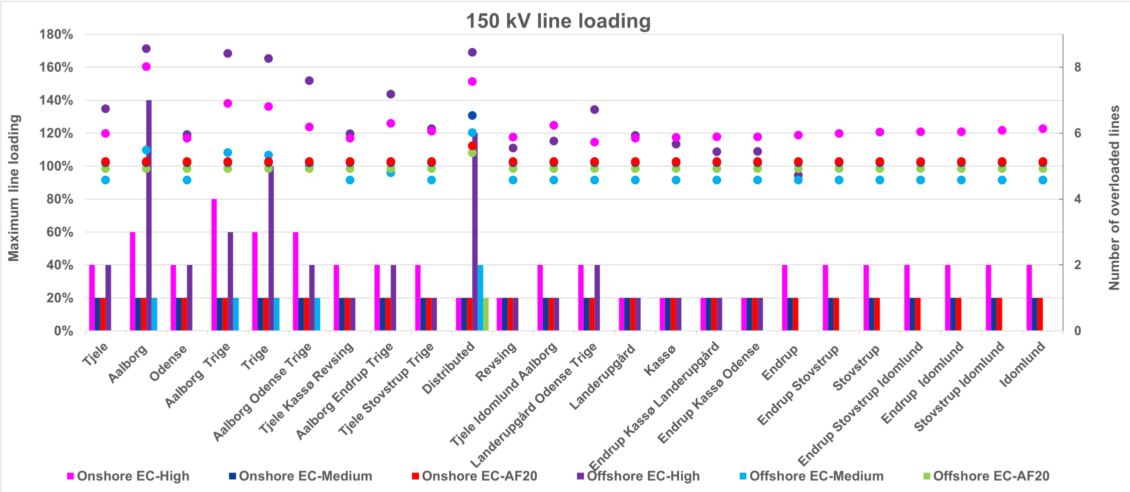

Figure 8.6. Loading of 150 kV lines for the max offshore hour depending on EC location.

When considering the loading of 150kV lines, it is again clear the higher EC capacities yield the potential to obtain lower maximum line loading for the Offshore scenarios, if EC capacity is connected at feed-in zones. In contrast to the max production hour, the distributed case, yields more overloading of both 150 kV and 400 kV lines for the Offshore scenario in the max offshore hour. It should be stated that overloading of the 150 kV grid generally does not occur for Offshore EC-AF20 and is rare for Offshore EC-Medium.
On the contrary, the Onshore energy system scenario yields at least one overloaded line no matter the EC capacity or EC placement. However, it can be seen that the overloaded line in the Onshore scenario is generally only overloaded by 1-2%, which is rather insignificant. Thus, it can be understood that these figures can only provide a simplified overview of line loading in relation to EC capacity and placement. Consequently, a deeper dive into the background data is needed.

8.3 Detailed simulation results for selected locations

In this section, a significant quantity of detailed figures of the transmission grid in DK1 are presented, in order to analyse how ECs affects grid loading.
Two different energy system scenarios have been developed and simulated in this thesis. Therefore, it is necessary to investigate the resulting grid loading affects from ECs for each energy system scenario. Hence, this more detailed analysis is conducted for each of the two energy system scenarios.

8.3.1 Onshore scenario

From Figure 8.1 and 8.2 it is evident that the Onshore energy system scenario yields significant overloading for the 150 kV grid. Furthermore, increasing EC capacity only increases the number of overloaded lines in the Onshore scenario. However, it is still relevant to investigate, to which extent, ECs can be integrated in the Onshore energy system scenario with the lowest possible grid loading. Thus, simulations of all three EC scenarios are presented for the EC locations that yielded the lowest number of overloaded lines. In order to do so, the average number of overloaded lines from the max offshore hour, the 95% hour and the max production hour is calculated for each location. Here the distributed case and Idomlund yield the two lowest averages, while four EC locations in the feed-in zones shared the third place. Therefore, only the two EC locations with the lowest averages are shown in detail.

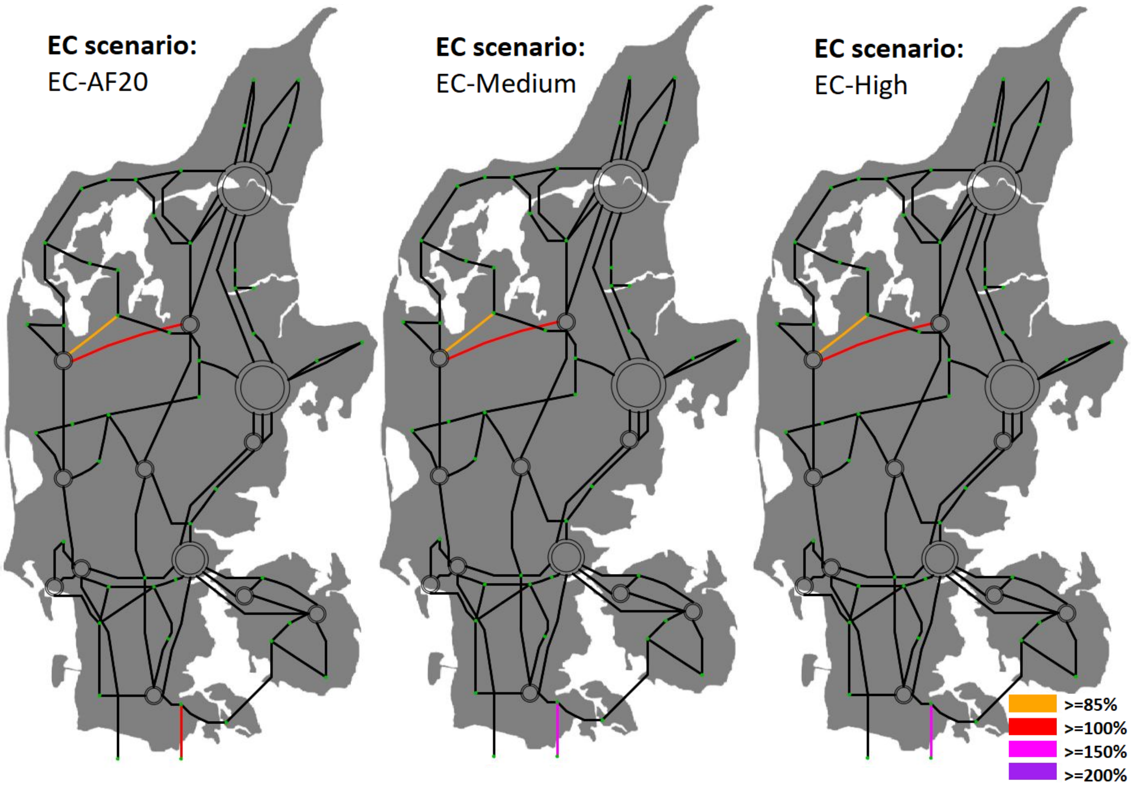

Figure 8.7. Grid loading from EC capacity distributed amongst all busses, using the distribution key for general loading, for the three EC-scenarios in the max offshore hour.

In Figure 8.7 grid loading for the Onshore scenario with different EC capacities during the max offshore hour is presented. Here the EC capacities are distributed on each load bus in the system. It can be seen that the loading is similar for all EC capacities, as there are only slight changes in component loading. As a result, the same two lines are overloaded for all three scenarios.

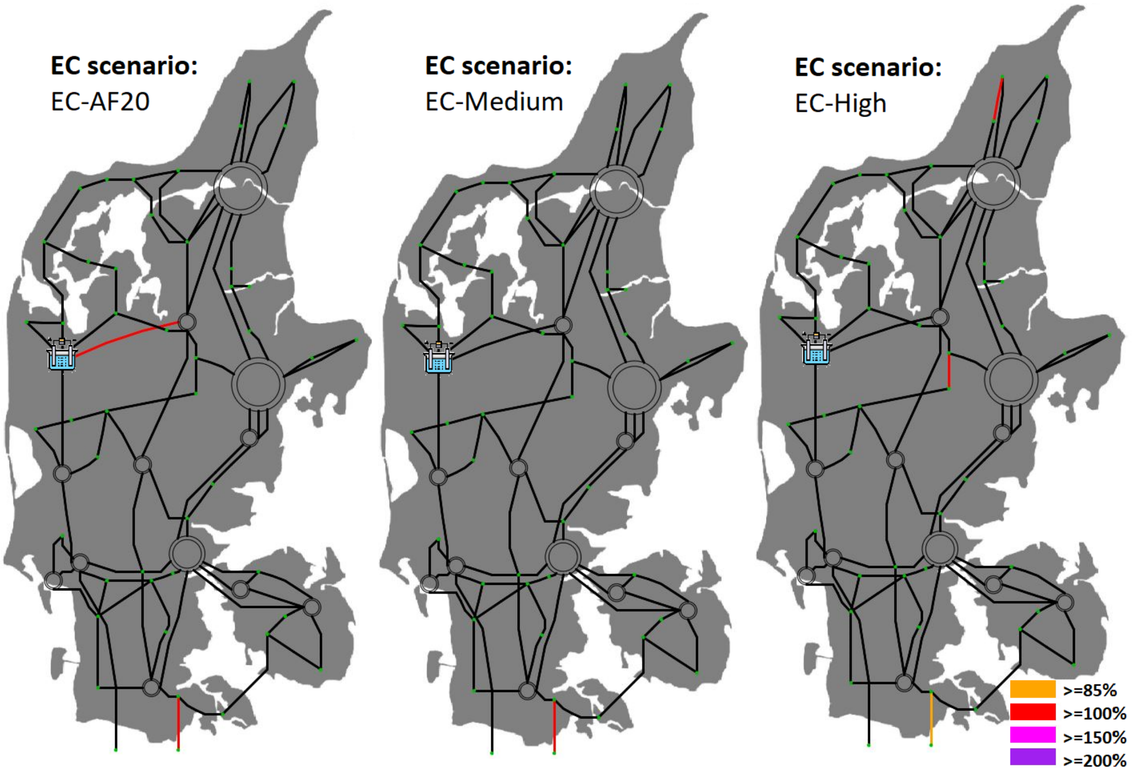

Figure 8.8. Grid loading from EC capacity in Idomlund for the three EC-scenarios in the max offshore hour.

Figure 8.8 shows the Onshore scenario with the different EC capacities placed in Idomlund. Here it can be seen that for EC-Medium and EC-High, the overloading on the line between Idomlund and Tjele can be mitigated, as the EC capacity is sufficient to consume enough production from offshore wind power plants. Hence, there is less power flowing through the line from Idomlund to Tjele. Furthermore, it can be seen that the loading of the 150 kV grid for EC-High changes, as compared to two other EC scenarios. Looking back at Tables 8.4 and 8.5, it can be seen that this happens, as there is a significantly larger production from onshore units and a lower general demand in the EC-High scenario. This makes sense as the EC demand is larger in the EC-High scenario.

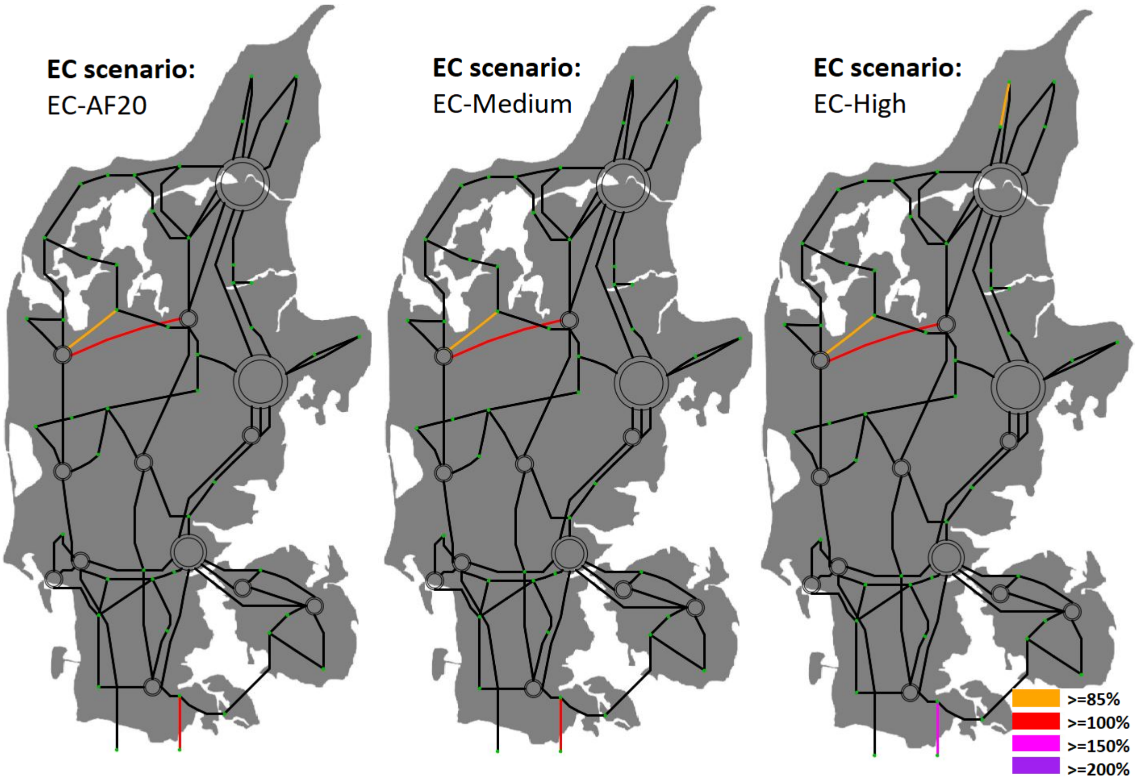

Figure 8.9. Grid loading from distributed EC capacity for the three EC-scenarios in the 95% hour.

In Figure 8.9 the grid loading when distributing different EC capacities on all busses can be seen, for the Onshore scenario. It can be seen that the same lines are overloaded at all EC capacities. However, it can also be seen that the line loading increases for high EC capacities. Indicating that increased EC capacities will further increase line loading in the distributed onshore scenario.

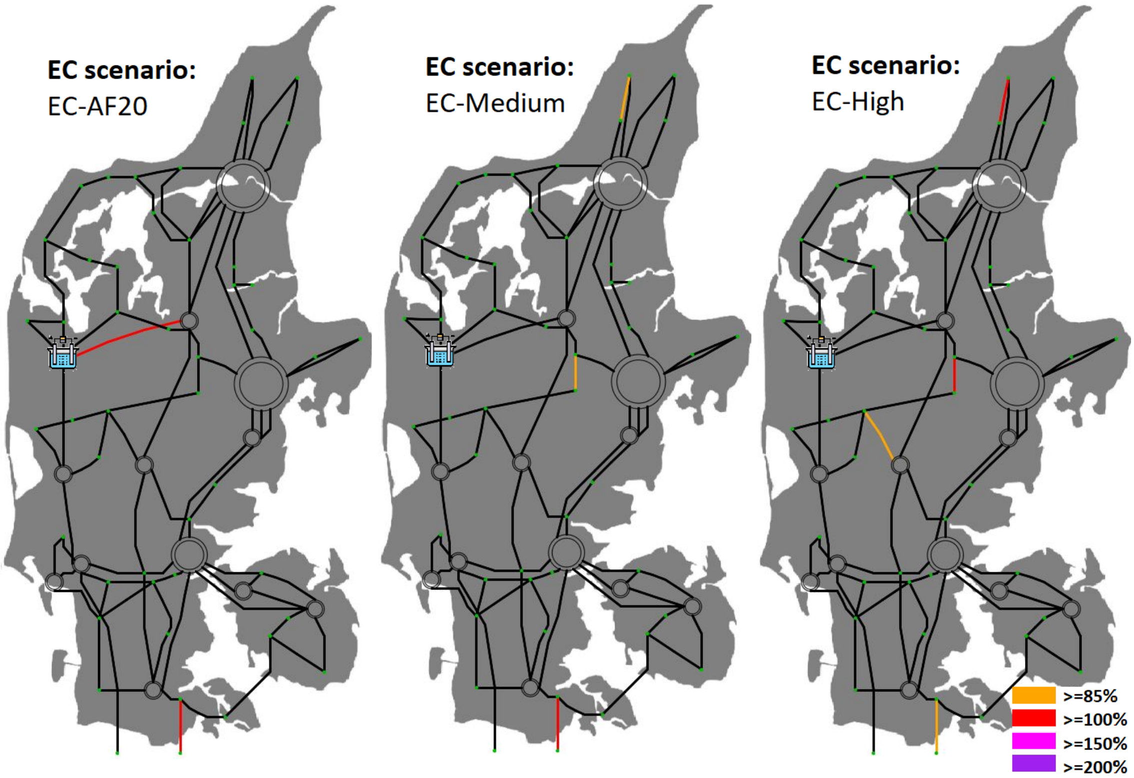

Figure 8.10. Grid loading from EC capacity in Idomlund for the three EC-scenarios in the 95% hour.

Figure 8.10, shows grid loading for the Onshore scenario with different EC capacities placed in Idomlund. Here it can be seen that increased EC capacities can mitigate overloading on the 400 kV grid, while increasing line loading in the 150 kV grid. The 400 kV overloading is mitigated as a load is placed in the feed-in zone, thereby reducing the amount of power flowing in the line between Idomlund and Tjele. However, as this is an onshore based scenario, the increased power production required in the EC-High scenario is produced by onshore based units, which are distributed in the 150 kV grid. Thereby, increasing loading in the 150 kV grid.

Comparing Figures 8.7, 8.8, 8.9 and 8.10, it can be seen that the results are fairly similar. This is due to the similarities in production, as seen in Table 8.5. Here it is clear that the production from offshore wind power is fairly similar, while onshore-based power generation is increased in the 95% hour, as compared to the max offshore hour.

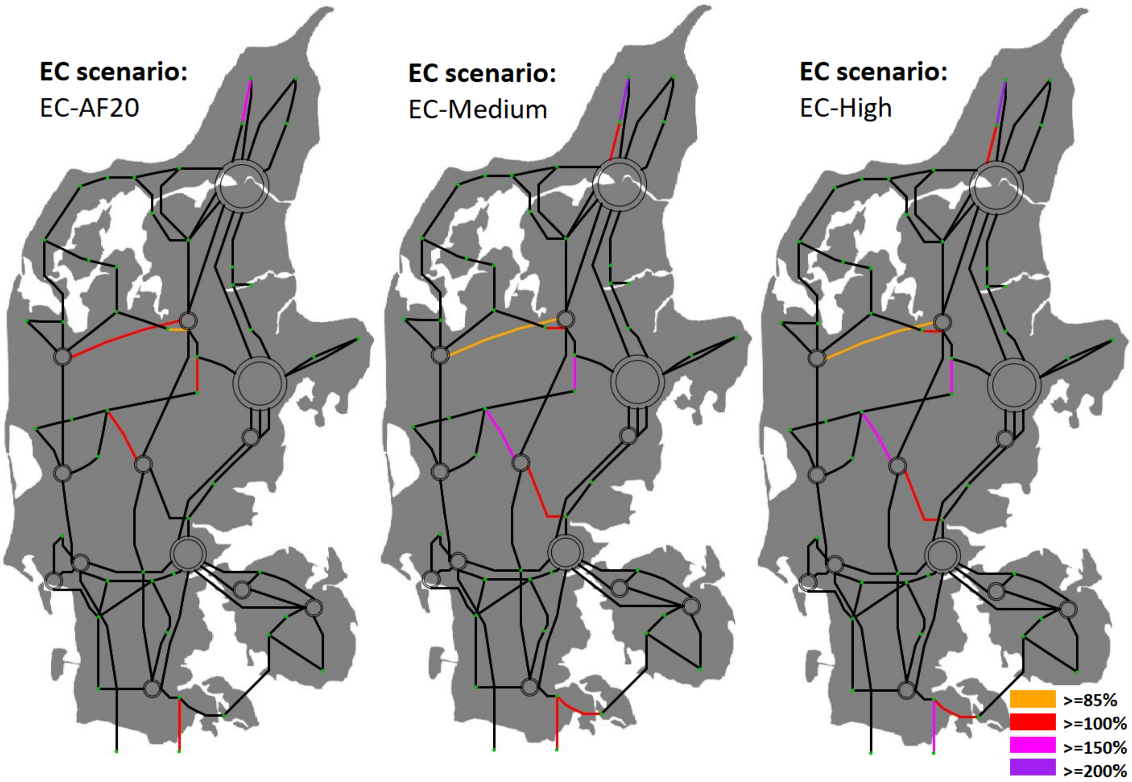

Figure 8.11. Grid loading from EC capacity distributed amongst all busses for the three EC-scenarios in the max production hour.

The grid loading for the max production hour of the Onshore scenario with different distributed EC capacities are shown in Figure 8.11. Here it can be seen that the overloading on the 73 km 400 kV line between Idomlund and Tjele can be mitigated with higher EC capacities. However, increased EC capacity comes at the cost of increased overloading in the 150 kV grid. In the 150 kV grid three to four lines are loaded above 150% in EC-Medium and EC-High respectively, while only one line is loaded above 150% in EC-AF20. Moreover, one line is loaded above 200% in both EC-Medium and EC-High.
It should be noted that it is possible to control power flows by using flexible AC transmission system (FACTS) which can, amongst other, distribute power between transmission lines in order to reduce overloading on specific lines. [Rashid, 2014]

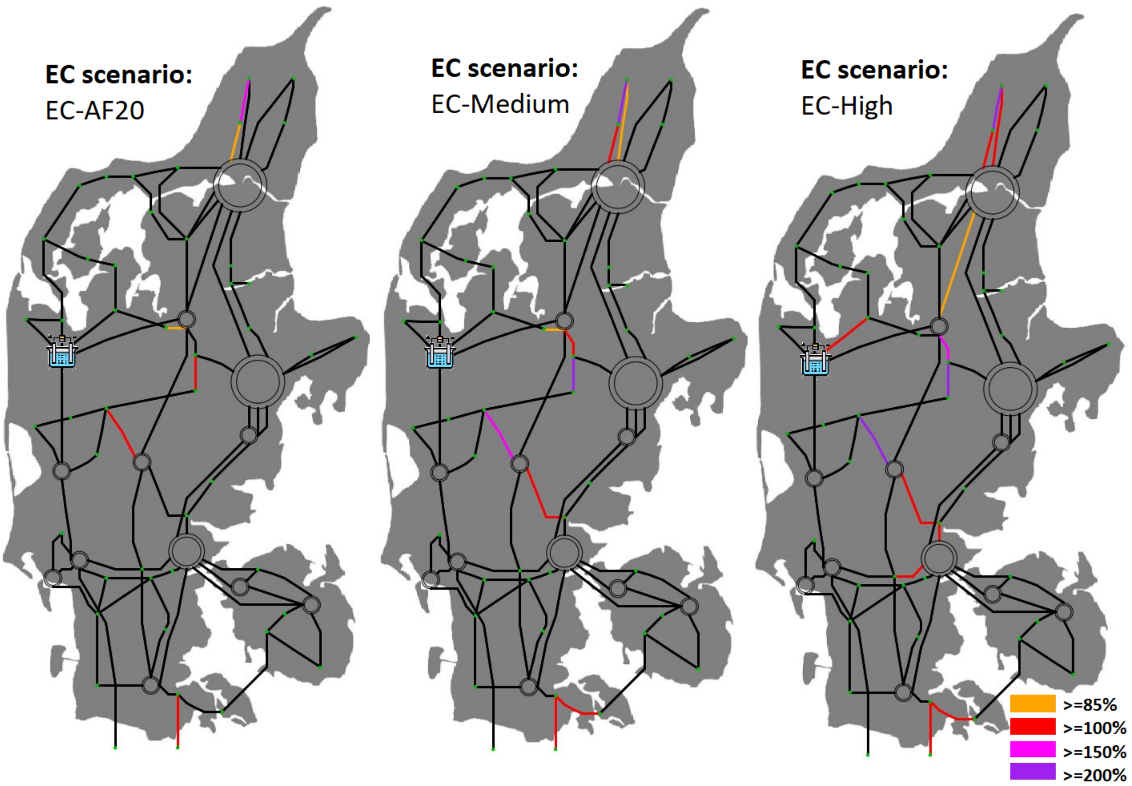

Figure 8.12. Grid loading from EC capacity in Idomlund for the three EC-scenarios in the max production hour.

Figure 8.12 shows the grid loading in the max production hour with EC capacities placed in Idomlund. Here the same tendencies, as shown in Figure 8.8, are present. However, for the max production hour the difference between EC-AF20 and EC-High is more significant, as 10 more lines are overloaded in EC-High compared to EC-AF20, of these, three lines are loaded more than 200% in EC-High.

The increased loading seen in the max production hour was expected, as the amount of power flowing in the system is significantly increased compared to the max offshore hour, and even the 95% hour. In Table 8.5, it can be seen that the extra production is onshore-based, meaning that the production is distributed in the 150 kV grid. Thereby, causing additional strain on the 150 kV grid. The same can be used to explain the large differences between the EC scenarios, as the EC demand increases, a larger electricity production is needed to satisfy the demand. This results in more power flowing through the system, and eventually leads to increased overloading.

In the results shown for the onshore scenarios the line between Flensburg and Ensted is overloaded in 16 out of 18 cases, and has an average loading for all 18 cases of 123%. As EC capacity is only added to Flensburg in the two cases with distributed EC location and that there is no power generation in Flensburg. This indicates that this line have difficulties coping with the increased electricity demand, caused by increased electrification alone. Furthermore, adding distributed EC capacity only increases this issue.

In the max production hour presented in Figures 8.11 and 8.12, it has been shown that there is significant loading in especially the 150 kV grid. Placing EC capacity in Idomlund results in 4-14 overloaded lines, while distributed EC location yields 5-10 overloaded lines, depending on the EC scenario. Of the overloaded lines a maximum of one is in the 400 kV grid. This indicates that the 150 kV grid is not dimensioned for a significant amount of distributed onshore production. Consequently, it can be said that the 150 kV grid requires significant reinforcements, if the grid should be able to accommodate the different EC capacities for all hours, in an onshore-based energy system. Considering only more representative hours, such as the max offshore hour and 95% hour, the results has shown that fewer reinforcements are needed. However, this would mean that some production units must down regulate during peak hours, in order to mitigate grid overloading. Thereby, flexible loads, such as EC, must also reduce their consumption or even shut down during these hours. Hence, removing what will likely be the most profitable production hours for EC plant owners, which in turn might also result in socio-economic losses.

8.3.2 Offshore scenario

It has already been shown that the integration of larger EC capacities can reduce grid overloading if the energy system is based on higher quantities of offshore wind. Therefore, it is the intention of this section to investigate which location yield the least overloading.

The offshore energy system scenarios yielded the least grid loading when ECs were placed in feed-in zones. Consequently, three feed-in zone locations are investigated in order to find the must suitable location.

The locations are chosen based on the results obtained in Figures 8.2, 8.1, 8.3, 8.4, 8.6, and 8.5. The locations with the lowest average number of overloaded lines are selected. These are respectively: Idomlund, (Idomlund, Stovstrup), (Idomlund, Stovstrup, Endrup).

To further investigate the statement that higher EC capacities yield lower line loading, a comparison of the EC-AF20 and the EC-High is presented for the three locations. It is decided to delimit from presenting the results from the EC-Medium scenario, as the correlation between EC capacity and line loading can be explored, using the highest and the lowest EC capacities.

In Figure 8.13 the grid loading for EC-High can be seen with different EC locations.

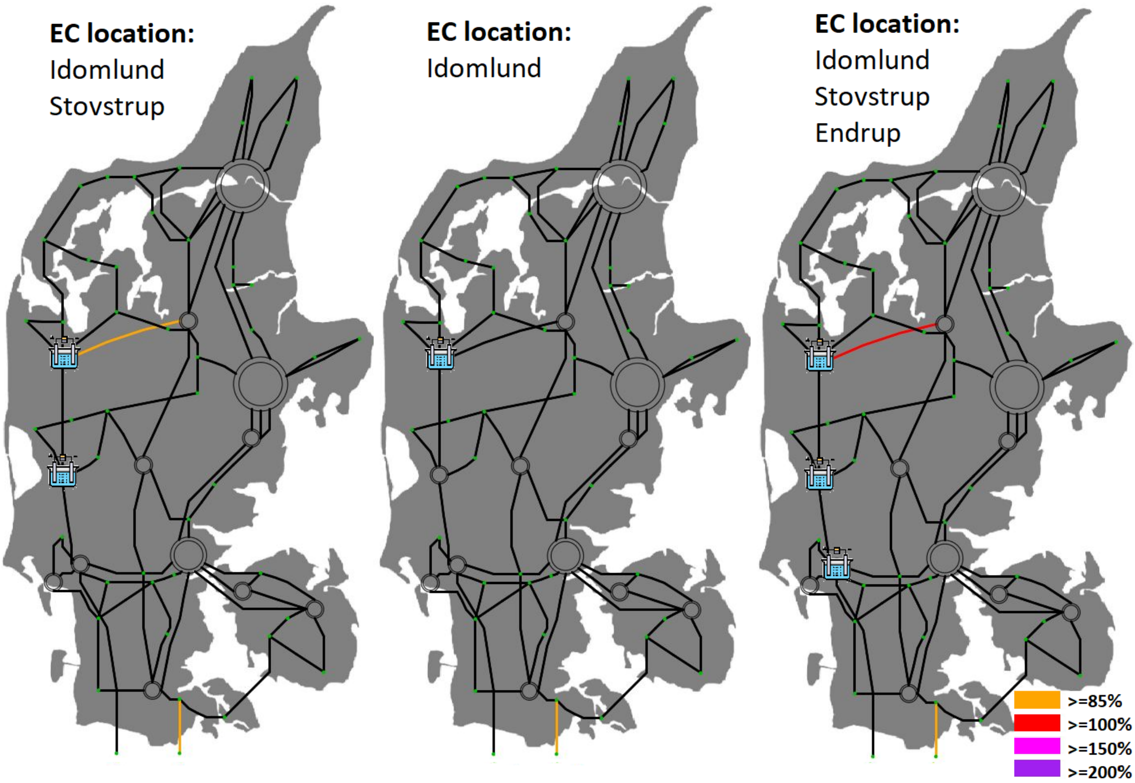

Figure 8.13. Grid loading with EC placed at three different feed-in zones for the Offshore EC-High scenario in the max offshore hour.

It can be seen that there is one overloaded line if EC capacity is located in (Idomlund, Stovstrup, Endrup), while there are no overloaded lines when placing ECs in Idomlund and (Idomlund, Stovstrup). However, it is also evident that there is higher loading on the line between Idomlund and Tjele if the EC capacity is placed in (Idomlund, Stovstrup). Therefore, it can be said that Idomlund is the optimal EC location in the max offshore hour for EC-High.

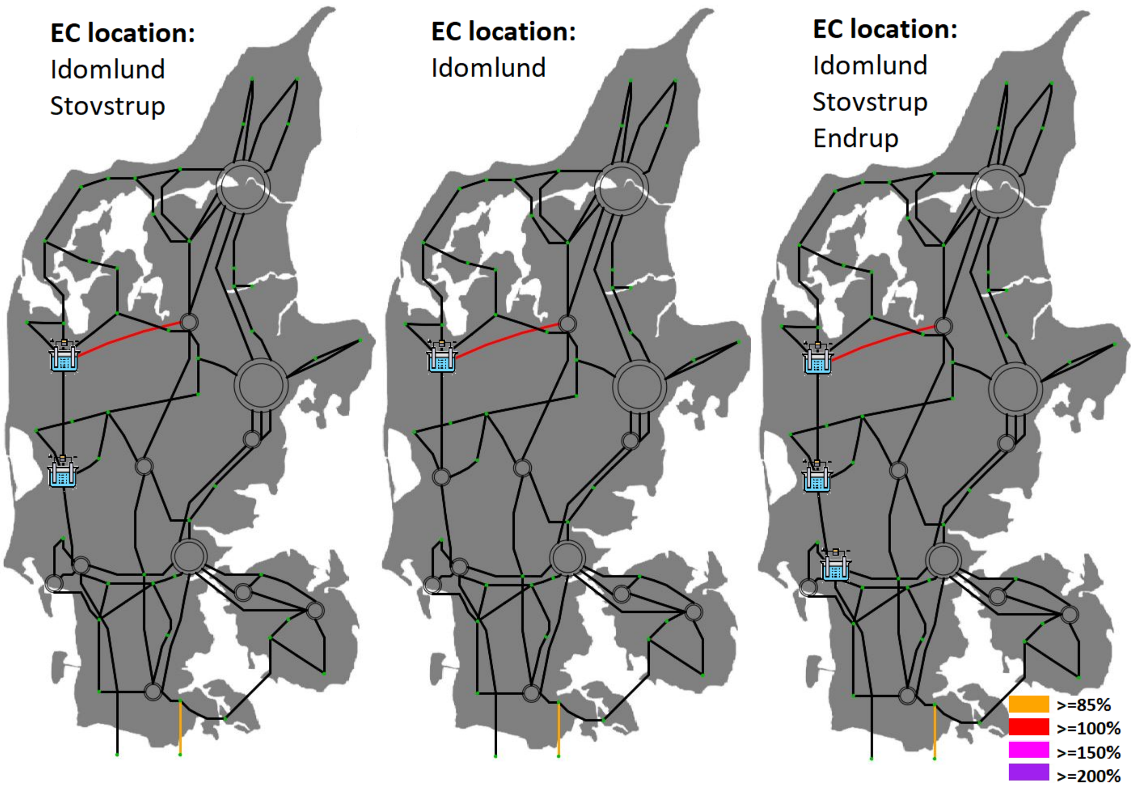

Figure 8.14. Grid loading with EC placed at three different feed-in zones for the Offshore EC-AF20 scenario in the max offshore hour.

When comparing Figure 8.13 and 8.14 it is evident that increasing EC capacity in hours with large offshore electricity production can reduce transmission grid loading. This is evident, as the 73 km long 400 kV line from Idomlund to Tjele is overloaded no matter where the EC capacity is placed in the EC-AF20 scenario, as opposed to the EC-High scenario.

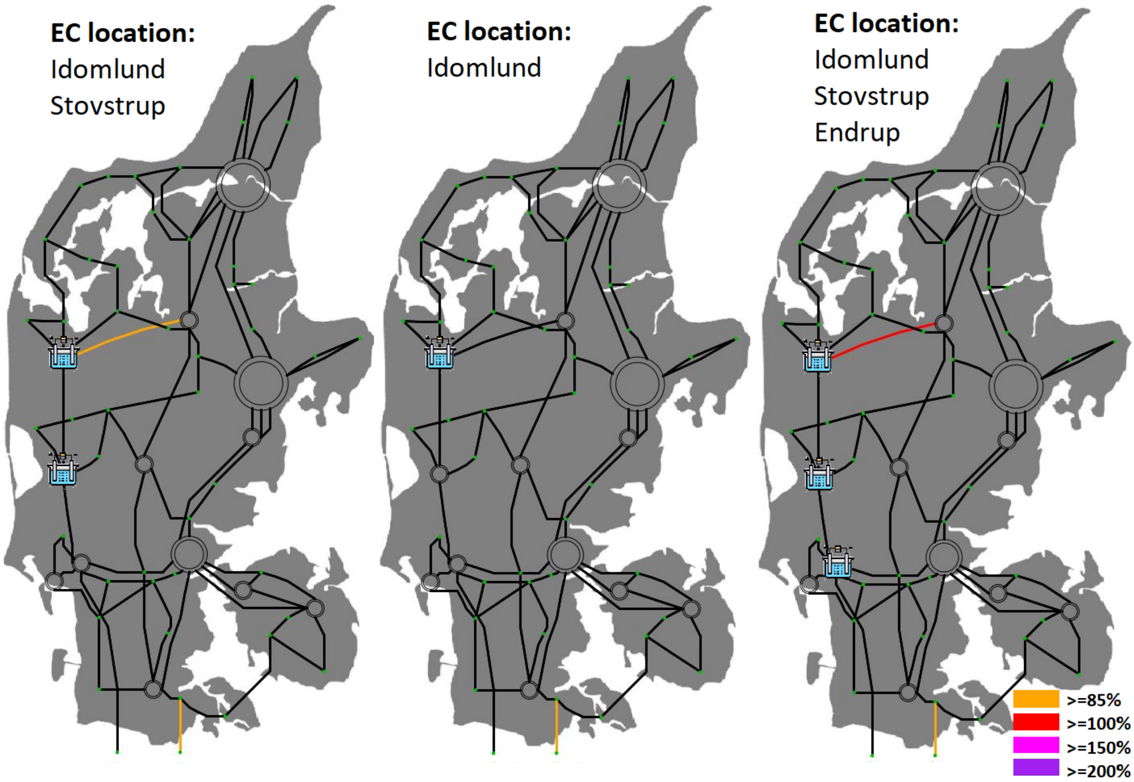

Figure 8.15. Grid loading with EC placed at three different feed-in zones for the Offshore EC-High scenario in the 95% hour.

In Figure 8.15 the overloading caused by placing ECs at different feed-in zone locations can be seen for Offshore EC-High. Here it can be seen that Idomlund and (Idomlund, Stovstrup) has no overloading, while the line between Idomlund and Tjele is overloaded when placing the EC capacity in (Idomlund, Stovstrup, Endrup). This happens as the production is significantly larger than the loading in the area. Thereby, there is more power flowing into the system, leading to overloading on the line.

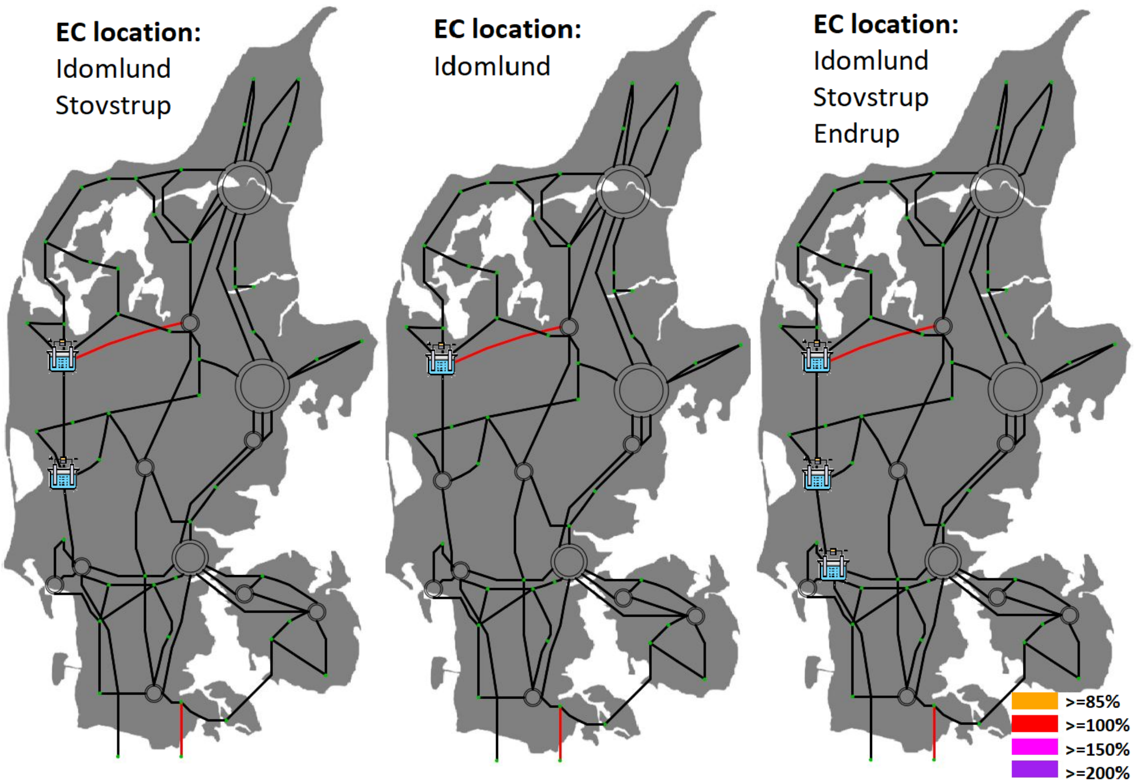

Figure 8.16. Grid loading with EC placed at three different feed-in zones for the Offshore EC-AF20 scenario in the 95% hour.

Figure 8.16 shows grid loading results at different feed-in zones in the Offshore EC-AF20 scenario. Here it can be seen that the transmission line between Idomlund and Tjele is overloaded for all EC loacations. Comparing with the EC-High results shown in Figure 8.15, it can again be stated that increased EC capacity can mitigate overloading in the grid when placed properly in this Offshore energy system. Furthermore, it can be seen that the line to Flensburg is overloaded for all EC locations. This is caused by an increased general load in the Offshore EC-AF20 scenario in the 95% hour, as compered to the Offshore EC-High scenarios, see Table 8.4. Hence, it can also for the Offshore scenario be said that this overloading happens as a result of increased general electrification and not as a result of EC integration.

Comparing the results of the max offshore hour shown in Figures 8.13 and 8.14, with those of the 95% hour shown in Figures 8.15 and 8.16 it can be seen that the results are quite similar. This is likely due to the similarity of the electricity production in the two hours, as both have a large offshore-based production, as can be seen in Table 8.5.

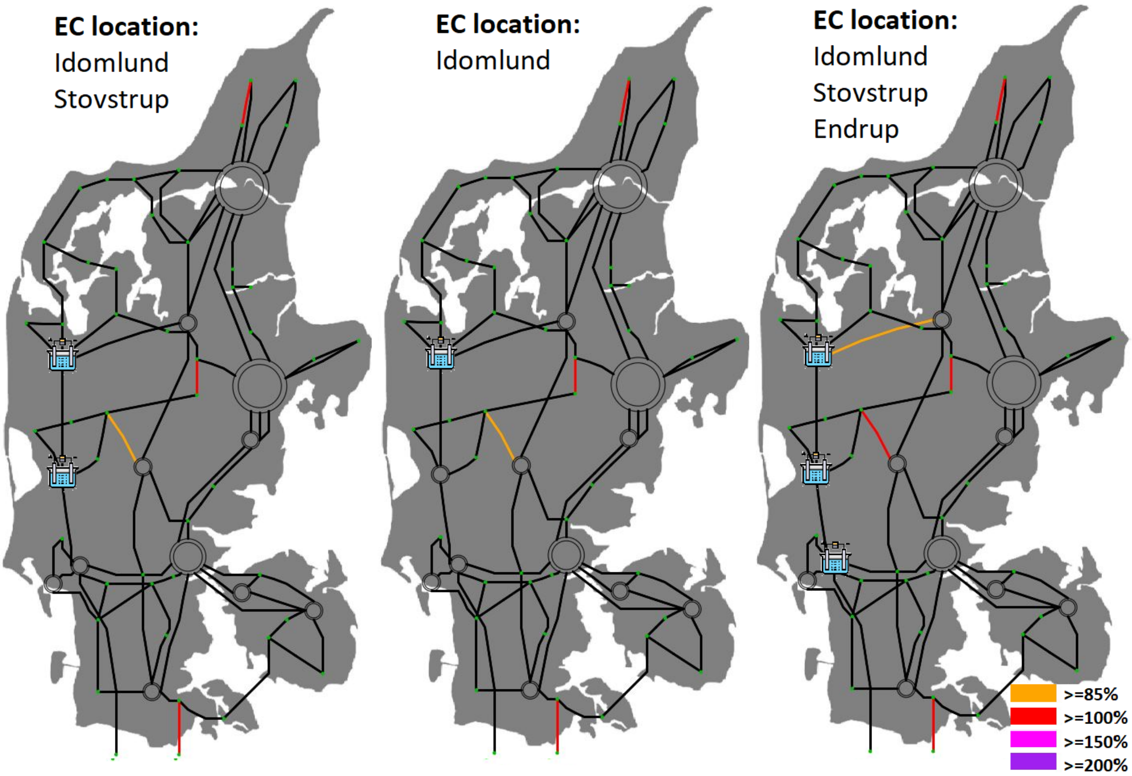

Figure 8.17. Grid loading with EC placed at three different feed-in zones for the Offshore EC-High scenario in the max production hour.

In Figure 8.17 different EC locations are simulated for Offshore EC-High during the hour of maximum production. Compared to Figures 8.13 and 8.15 it can be seen that several 150 kV lines are overloaded. This happens as the overall production is higher in the maximum production hour, seen in Table 8.5. As this increased production is not offshore-based, it is produced by onshore units placed in the 150 kV grid. Additionally, the general electricity demand is also higher in the hour of maximum production, which can also increase loading of the 150 kV grid.

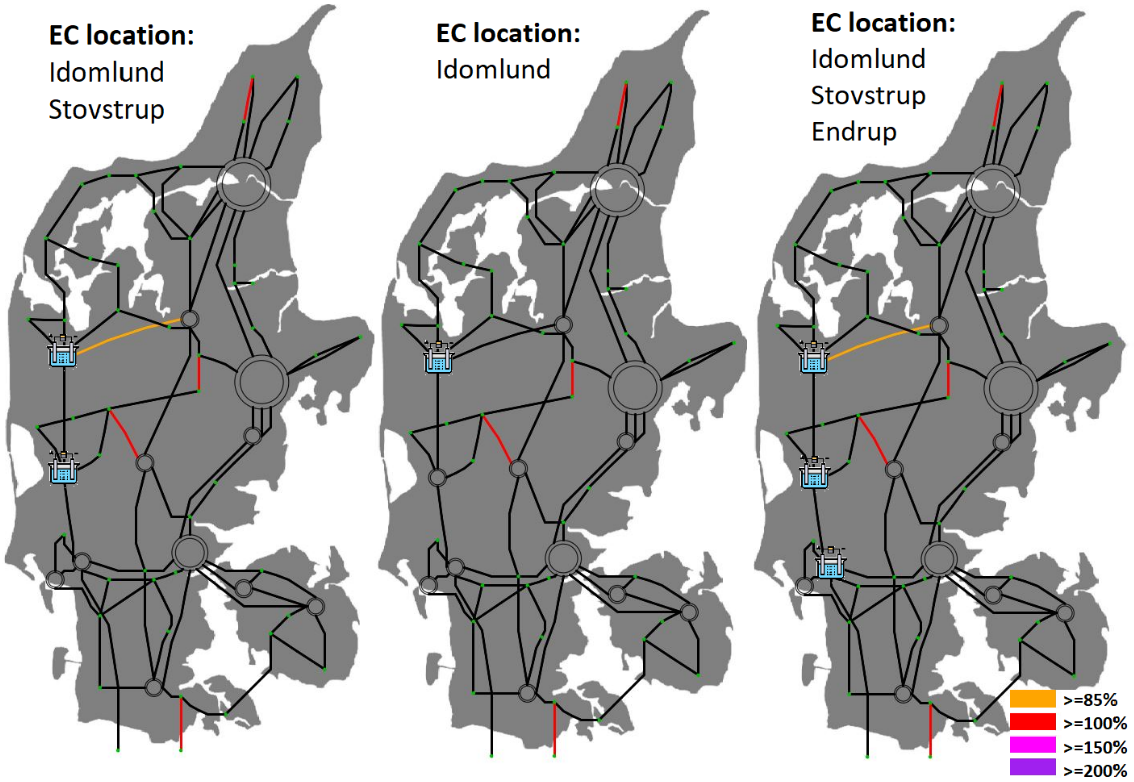

Figure 8.18. Grid loading with EC placed at three different feed-in zones for the Offshore EC-AF20 scenario in the max production hour.

Again it is evident that lines which are not overloaded in the EC-High scenario in Figure 8.17 are overloaded in the EC-AF20 scenario in Figure 8.18.
The loading of the 150 kV line from Askjær to Herning decreases by 9-14% in the EC-High scenario compared to the EC-AF20 scenario in this hour. Furthermore the loading of the 400 kV line from Idomlund to Tjele can be reduced by up to 35%, depending on EC location, in the EC-High scenario compared to the EC-AF20 scenario.

The number of overloaded 150 kV lines are the same for all 24 potential EC-locations in the EC-AF20 scenario. Also the maximum line loading is similar at 131-138%. This can indicate that the location of the lower EC capacity in the EC-AF20 scenario does not significantly affect the loading of the 150 kV grid.

Even though the EC location seemed to have a rather insignificant impact on the EC-AF20 scenario, placing EC capacity in Idomlund did yield the least line loading in all simulations. As for EC-High the location was more influential, as it did affect the number of overloaded lines. Both Idomlund and (Idomlund, Stovstrup) yielded the same number of overloaded lines in the three hours. However, the line loading was lower in Idomlund, again making Idomlund the optimal location. Thus, it can be stated that the optimal EC location for the Offshore energy system scenario in the max offshore hour, the 95% hour and the max production hour is Idomlund.
It is likely that the reason Idomlund is the best location, from a line loading perspective, is the distribution between the offshore wind production. Certainly, if the points of connection for offshore wind power plants were different, it would be preferred to distribute the EC capacity accordingly.

Comparisons between EC-AF20 and EC-High has made it possible to state that increasing EC capacity in the feed-in zones, can reduce transmission grid loading in a system based on offshore wind power. However, it should be stated that these results only indicate that ECs reduce grid loading during hours where offshore wind turbines are producing. If offshore wind turbines were not producing and ECs still operated at full capacity, the power flowing to the ECs could cause overloading. Consequently, if ECs are placed at feed-in zones, their production should, to some extend, follow the production of the offshore wind turbines. For the plant operators located in feed-in zones, this could mean that they are not allowed to produce during hours without offshore wind production. Conversely, in practice the plant operators might only produce during hours with significant offshore production, as these hours would likely yield lucrative electricity prices.

8.3.3 Electrolysers in DH and CO_2 areas

Reports by Ea Energy Analysis [2020], Energinet [2021f] and Dansk Energi [2020] recommend that surplus heat from ECs should be utilised and ECs should be placed near larger CO_2 point sources. Consequently, it has been chosen to present a series of detailed results of how the transmission grid would be affected if the EC capacity was distributed amongst large DH and CO_2 areas. In the report by Ea Energy Analysis [2020] surplus heat from PtX is utilised in Aarhus, Aalborg and Esbjerg. In this thesis, this corresponds to EC capacity split on Trige, Aalborg and Endrup. Therefore, a simulation with these locations is conducted. Furthermore, it has been decided to present simulation results of EC placement in (Landerupgård, Odense, Trige) and (Aalborg, Odense, Trige) as these locations are near the largest CO_2 point sources in DK1 [Energinet, 2021f].

It has, for this part of the analysis, been chosen to simulate the EC impact on the transmission grid using the EC-High scenario for both energy system scenarios, as the EC-High scenario would provide the highest surplus heat output. Thus, yielding the highest contribution to the DH sector.

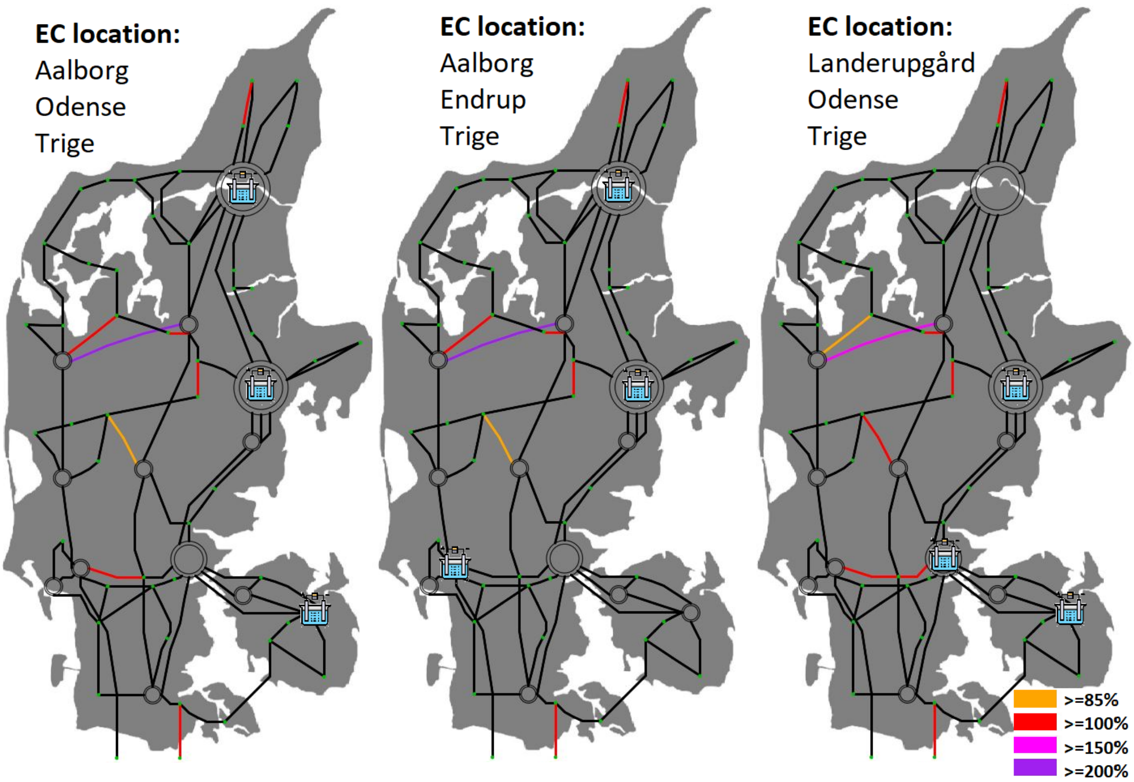

Figure 8.19. Grid loading with EC placed at different larger DH and CO_2 areas for the Offshore energy system scenario in the max production hour.

In Figure 8.19 ECs are located in different DH and CO_2 areas for the Offshore EC-High scenario, during the max production hour. From the simulations it is evident that 7 to 8 lines of both 400 kV and 150 kV are overloaded. The 73 km long 400 kV line from Idomlund to Tjele is loaded between 197% and 217%.

In this simulation it seems locating EC in (Aalborg, Endrup, Trige) yield less overloading than the other two simulations, as the 30 km 400 kV line from Endrup to Revsing is not overloaded. This could be beneficial as this line has a relatively large capacity of around 3.8 GW.

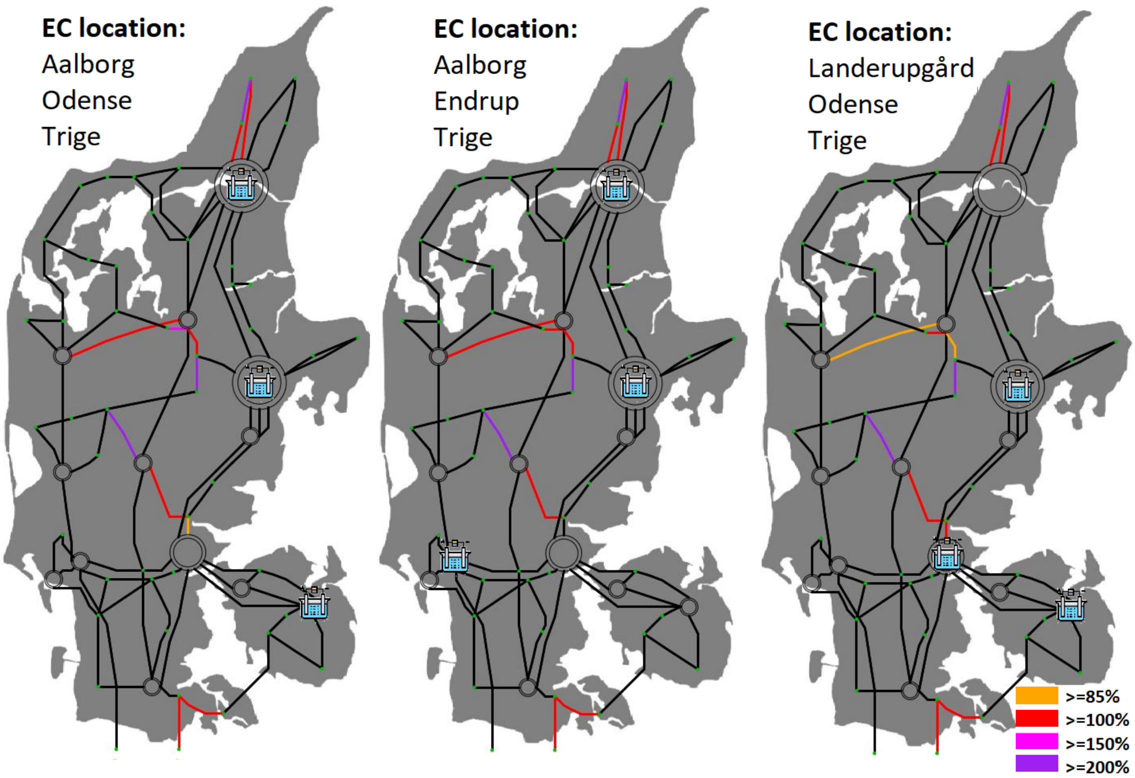

Figure 8.20. Grid loading with EC placed at different large DH and CO_2 areas for the Onshore energy system scenario in the max production hour.

Figure 8.20 shows the grid loading of Onshore EC-High in the max production hour, with ECs located in the large DH and CO_2 areas. Here the 400 kV line from Endrup to Revsing is no longer overloaded for any of the cases. This is likely due to the larger decentral production of onshore units.

In each of the three EC location simulations 13 lines are overloaded. Most of these are 150 kV, which makes sense as most onshore production units are connected at this voltage level. On the figure, only 10-11 overloaded lines are visible, as the remaining overloaded lines are shorter ones, located inside transformer sites.
In all three simulations, three 150 kV lines are loaded above 200% and all of them have peak line loading above 250%.
The only overloaded 400 kV line is the one from Idomlund to Tjele. However, this line is not overloaded if EC capacity is distributed amongst (Landerupgård, Odense, Trige).

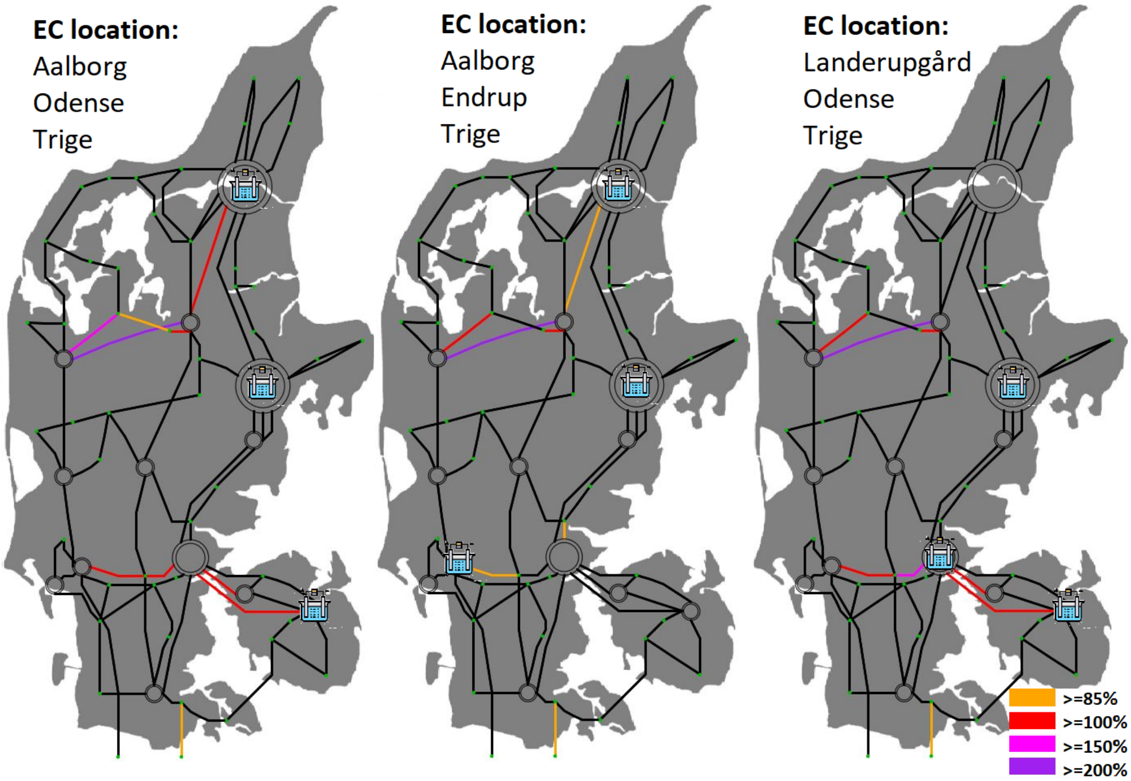

Figure 8.21. Grid loading with EC placed at different large DH and CO_2 areas for the Offshore energy system scenario in the 95% hour.

Figure 8.21 presents the grid loading from distributing 3.6 GW of EC capacity on large DH and CO_2 areas in the Offshore energy system scenario during the 95% hour. If no EC capacity is placed at feed-in zones, overloading of 400 kV lines becomes severe, as 240-301 km of 400 kV line is overloaded in the cases without EC capacity in Endrup. By placing 1/3 of the EC capacity in Endrup, 167-228 km of overloaded 400 kV line can be mitigated. However, the 73 km 400 kV line from Idomlund to Tjele is overloaded in all three cases by between 220% and 240%.

The reason for the significant overloading is that 6.4 GW of offshore-based wind feed into the system from the offshore wind power plants on the west coast, and the transmission grid is not dimensioned to transport such capacities across DK1. Again, it can be stated that with large Offshore capacities, ECs must be placed in feed-in zones.

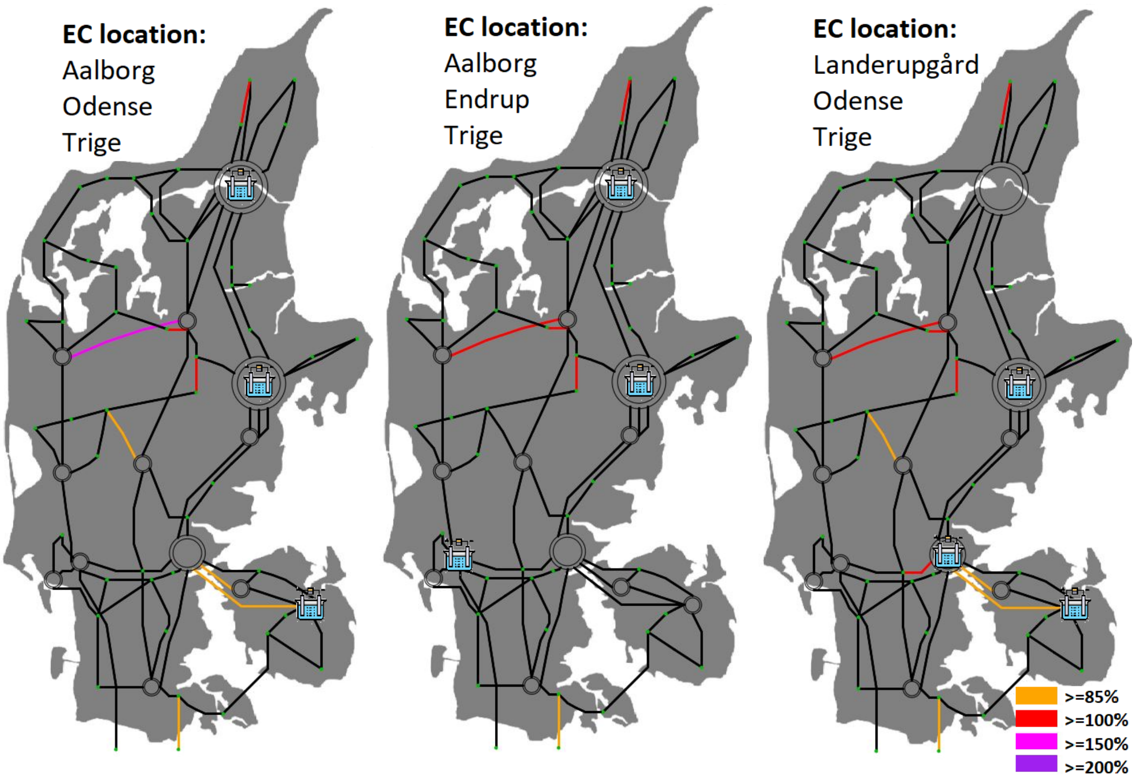

Figure 8.22. Grid loading with EC placed at different large DH and CO_2 areas for the Onshore energy system scenario in the 95% hour.

The grid loading in Figure 8.22 is less significant for the Onshore energy system when compared to the Offshore energy system in 8.21. This is because offshore wind only accounts for 25% of the total electricity production in the Onshore scenario, whereas it accounted for 49% in the Offshore scenario during the this hour. Consequently, less electricity is transported from feed-in zones to the large DH and CO_2 areas. Even so, it must still be noted that placing EC capacity in feed-in zones does yield the least line loading. This is true because if all EC-High capacity was placed at any feed-in zone or distributed amongst feed-in zones, all 400 kV line overloading would be mitigated and 12 km of 150 kV overloaded line would be avoided in the 95% hour.

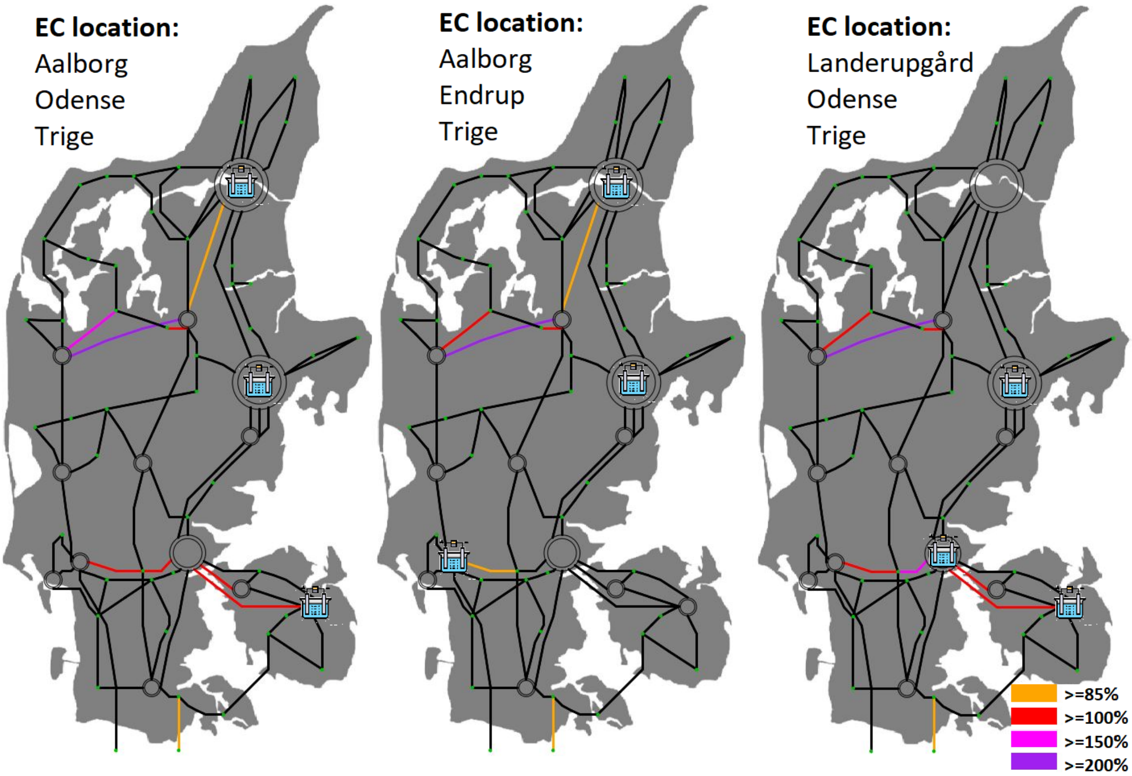

Figure 8.23. Grid loading with EC placed at different large DH and CO_2 areas for the Offshore scenario in the max offshore hour.

In Figure 8.23 the EC capacity is located in the DH and CO_2 areas for Offshore EC-High during the max offshore hour. The results are very similar to those presented on Figure 8.21 for the 95% hour.

When EC capacity is distributed amongst larger DH and CO_2 areas, it is evident that the Offshore energy system scenario causes significant loading of both 400 kV and 150 kV lines in the max offshore hour.

If 1200 MW of EC capacity is placed in Odense, the power transmission leads to four overloaded 400 kV lines in the southern part of DK1, while the 400 kV line from Idomlund to Tjele is loaded between 220-240%.

On the contrary, if this 1200 MW of EC capacity is placed in Endrup instead of Odense, only the 400 kV line from Idomlund to Tjele is overloaded, meaning that overloading 167 km of 400 kV lines is avoided. Again, this illustrates that when offshore electricity production is transmitted across the country to a large EC plant, significant loading of the transmission grid can occur.

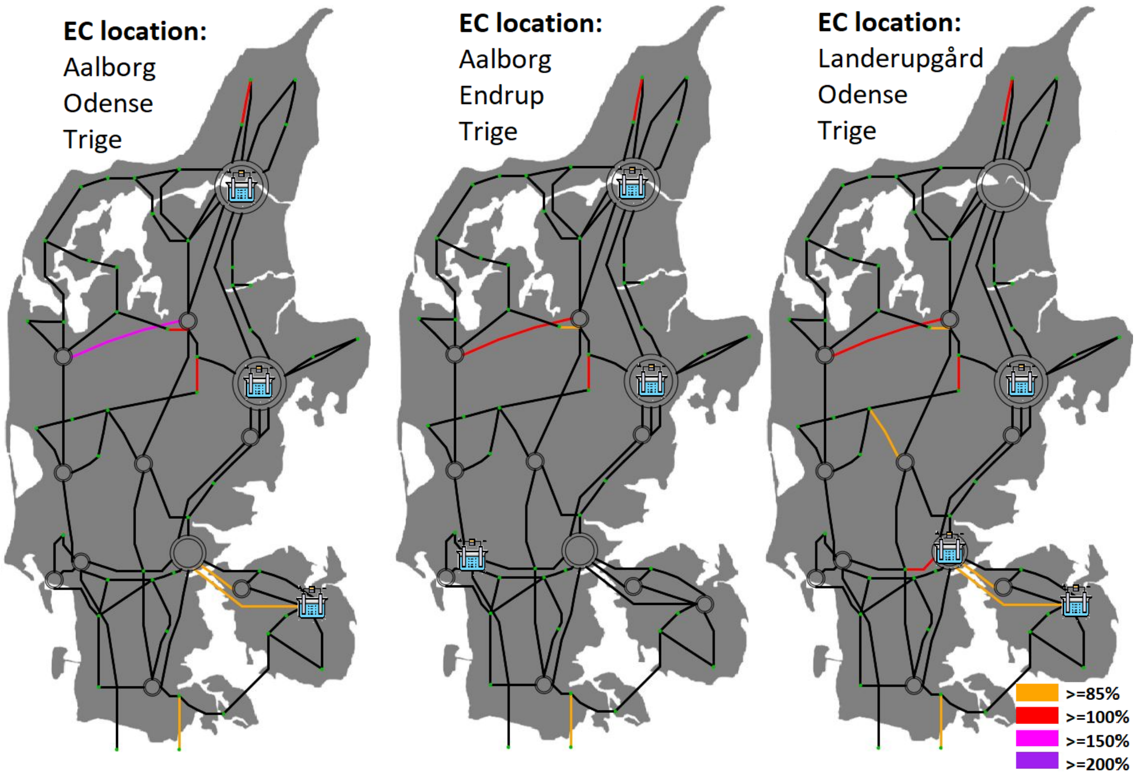

Figure 8.24. Grid loading with EC placed at different large DH and CO_2 areas for the Onshore energy system scenario in the max offshore hour.

In Figure 8.24 the EC capacity is again located in the large DH and CO_2 areas, this time shown for the Onshore EC-High scenario during the max offshore loading.
Again it is still evident that distributing EC capacity amongst the larger DH and CO_2 areas, yields a number of overloaded lines, with e.g. the 400 kV line from Idomlund to Tjele loaded between 133 and 153% depending on EC location.

From analysing the Figures 8.19, 8.20, 8.21, 8.22, 8.23 and 8.24 it can be stated that placing EC capacity in large DH and CO_2 areas leads to a number of overloaded both 400 kV and 150 kV lines. On average, roughly 7 lines were overloaded in these 18 simulations, with the Onshore energy system yielding 13 overloaded lines in the max production hour.

The 73km 400 kV line between Idomlund and Tjele was overloaded in 17 out of 18 simulations and had an average line loading of 176%. Furthermore, placing 1/3 of the EC capacity from the EC-High scenario in Odense overloaded the dual system 400 kV line from Endrup to Revsing in the offshore scenarios. When the EC capacity was moved from Odense to Endrup, which is both a large DH area and an offshore feed-in zone, the overloading was mitigated. Again, this proves that when integrating larger offshore wind and EC capacities, some EC capacity must be placed in the feed-in zones. Alternatively, the feed-in zones must be located closer to larger DH and CO_2 areas. According to the interview with Marie Broe from Energinet, this is still an option, as point of connection for the planned energy island in DK1 is still undecided, see Appendix A.

8.4 Indicative economic perspective

It is relevant to obtain an overview of how much it would cost to reinforce the transmission grid, so that it can adequately sustain the loading of each simulation. Thus, reinforcement costs are estimated based on EC location, EC capacity and simulation hour for both energy system scenarios.

Grid reinforcement costs are based on Energinet [2015a], which estimates investment costs based on previous transmission grid projects. It must be stated that every project is different, as e.g. expenditures to economic compensation for property owners vary significantly between projects. Thus the investment costs obtained from Energinet [2015a] should be taken with some reservation. However, it is assumed that they are adequate for providing a rough cost estimation.
Additionally, it should be noted that this indicative economic cost calculation is based on the assumption that an additional transmission line is added in parallel to an existing overloaded line. It is recognised that it is not necessarily the solution used in practice. However, this method is applied to obtain a comparable estimate of the reinforcement cost for the different simulations.

According to Energi-, Forsynings- og Klimaministeriet [2016], all new 150 kV projects must be made as cable solutions. Consequently, costs of increasing capacity of the 150 kV grid are calculated using the investment costs of 132-150 kV cables. According to Energinet [2015a], a 1.1 kA cable, with a capacity of roughly 300 MW, has an investment cost of 3 MDKK per km with all expenditures included.

For the 400 kV grid, the reinforcement costs are based on a single line system, as these systems have a rated capacity of around 1.9 GW, which is deemed adequate for eliminating overloading in the simulations of this analysis.
Single system 400 kV lines have an investment cost of 6 MDKK per km. Alternatively, one could argue that upgrading certain grid structure to a 400 kV double system, which has a rated capacity of roughly 3.7 GW at the cost of 8 MDKK per km, would increase security of supply and could be a more future oriented solution.

In Table 8.6 the estimated grid reinforcement costs associated with integrating various EC capacities at different locations are presented for both energy system scenarios in the three simulated hours.

Table 8.6. Cost associated with reinforcing the grid to accommodate various EC capacities and locations for each system scenario in the three simulated hours.

Line upgrade cost [MDKK]	Max offshore hour						Max production hour						95% hour					
Energy system scenario	**Onshore**			**Offshore**			**Onshore**			**Offshore**			**Onshore**			**Offshore**		
EC scenario / **EC location**	**EC-AF20**	**EC-Medium**	**EC-High**	**EC-AF20**	**EC-Medium**	**EC-High**	**EC-AF20**	**EC-Medium**	**EC-High**	**EC-AF20**	**EC-Medium**	**EC-High**	**EC-AF20**	**EC-Medium**	**EC-High**	**EC-AF20**	**EC-Medium**	**EC-High**
Aalborg	517	640	1738	218	519	1779	747	1738	2338	747	1375	2329	517	701	1809	517	678	2245
Odense	517	1177	1717	218	629	1379	747	602	1687	747	747	1785	517	1177	1637	517	1258	1947
Trige	517	517	784	218	458	1576	782	1036	1168	747	684	985	517	517	868	517	556	2689
Aalborg Trige	517	517	740	218	458	1061	747	1036	1211	747	684	1311	517	578	740	517	556	1568
Aalborg Odense Trige	517	517	603	218	458	1030	747	1036	1211	747	684	1000	517	517	603	517	556	1963
Landerupgård Odense Trige	517	517	730	218	218	1030	747	621	811	747	782	1126	517	517	766	517	436	1594
Landerupgård	517	517	670	218	299	630	747	679	1035	747	747	1126	517	517	828	517	599	900
Tjele Kassø Revsing	517	517	567	218	218	548	747	1078	1453	747	747	963	517	517	665	517	436	736
Tjele	517	517	567	218	218	619	747	973	1638	747	782	684	517	517	603	517	436	772
Distributed	517	517	517	381	621	1156	747	606	606	747	649	637	517	517	517	517	637	1163
Tjele Idomlund Aalborg	517	517	1120	218	218	458	747	627	1312	747	649	1252	517	517	567	517	436	556
Kassø	517	517	506	218	218	548	747	621	1181	747	747	1290	517	517	665	517	436	736
Revsing	517	517	506	218	218	548	747	621	1017	747	747	963	517	517	665	517	436	736
Endrup Kassø Odense	517	517	506	218	218	787	311	621	854	747	747	782	517	517	665	517	436	1215
Aalborg Endrup Trige	517	517	567	218	218	528	747	600	1211	747	684	820	517	517	603	517	436	591
Tjele Stovstrup Trige	517	517	567	218	218	458	747	600	1211	747	747	684	517	517	567	517	436	556
Endrup Kassø Landerupgård	517	517	506	218	218	458	311	621	1035	747	747	782	517	517	665	517	436	556
Endrup	517	517	132	218	218	218	311	664	1017	311	747	782	517	517	229	517	436	436
Endrup Stovstrup	517	82	132	218	218	218	311	642	1017	311	311	747	517	82	229	517	436	436
Stovstrup	517	82	132	218	218	218	311	642	1017	311	311	747	517	82	132	517	436	436
Endrup Idomlund	517	82	132	218	218	218	311	642	1017	311	311	311	517	82	132	517	436	436
Endrup Stovstrup Idomlund	517	82	132	218	218	218	311	642	1017	311	311	311	517	82	132	517	436	436
Stovstrup Idomlund	517	82	132	218	0	0	311	642	1102	311	311	213	517	82	132	517	0	0
Idomlund	517	82	132	218	0	0	311	607	1080	311	311	213	517	82	132	517	0	0

Considering Table 8.6 it is evident that the offshore wind feed-in zones on average yield the lowest grid reinforcement costs, while large consumption areas such as Aalborg, Odense and Trige yield the highest costs. There seems to be a clear tendency between increasing EC capacity and reducing grid reinforcement costs for all Offshore scenarios, when placing ECs in the feed-in zones. However, the same trend can also be observed for the Onshore scenarios in the max offshore hour and the 95% hour, as grid reinforcement costs decrease when EC capacity is increased from AF20 levels. The only simulations where increasing EC capacity above AF20 levels increases reinforcement costs, are the Onshore scenarios in the max production hour. However, as presented in Table 8.2 on page 64, only 9-18 hours had a 90% similar electricity production magnitude. Consequently, it is not deemed an issue if the ECs plants has to shut down production 9-18 hours during the year.

Based on the data in this table, it would be most economically feasible to integrate ECs in feed-in zones, with Idomlund and (Stovstrup, Idomlund) being the most suitable locations. This corresponds well with the results seen in Sections 8.2 and 8.3, as Idomlund and (Stovstrup, Idomlund) were also singled out as ideal EC locations in these sections.

The reinforcement cost for mitigating overloading have been calculated from Table 8.6. This is done for the EC and energy system scenarios, and the locations with the lowest reinforcement are presented on Figure 8.25.

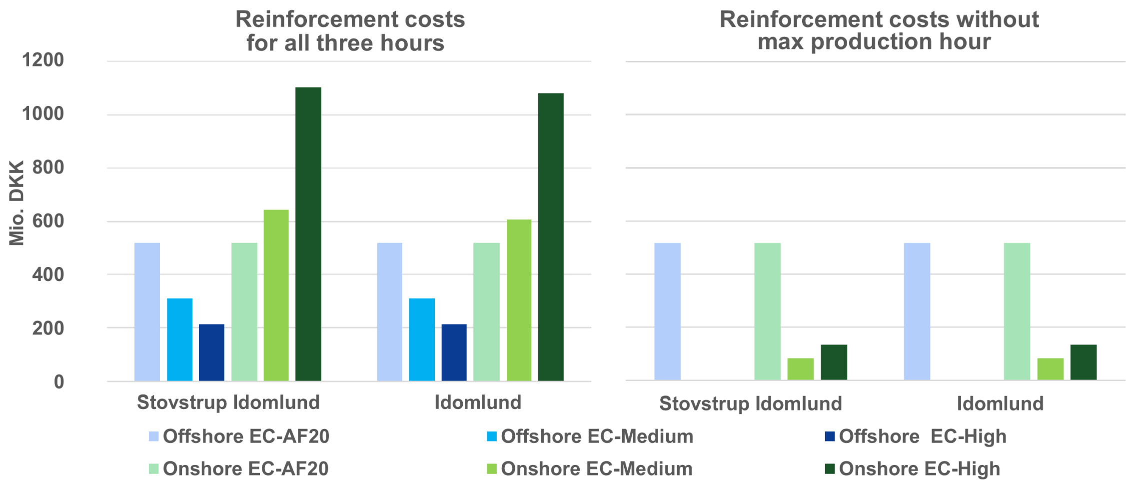

Figure 8.25. Reinforcement costs for mitigating overloading. On the left chart the cost of reinforcing is presented for all three hours, whereas the right chart presents the cost of reinforcing, without taking the max production hour into account.

In Figure 8.25 it can be seen that if the grid must be reinforced to avoid overloading in all hours including the max production hour, the reinforcement costs are significantly higher than if the max production hour is not accounted for.
If it is possible to reduce electricity consumption and production during the max production hour, reinforcements are not needed for Offshore EC-Medium and EC-High. Consequently, between 436 and 386 MDKK in reinforcement costs can be saved for Onshore EC-Medium and EC-High respectively. However, EC-AF20 scenario has a minimum indicative reinforcement cost of 517 MDKK whether the max production hour is accounted for or not. Consequently, it can be stated that between 386 and 517 MDKK in reinforcement

costs can be avoided if EC capacity is increased above EC-AF20 levels and the extreme case of the max production hour is not considered.

8.5 Summary of transmission grid analysis

In Figures 8.11, 8.12, 8.17 and 8.18 it was shown that that several 150 kV lines were overloaded. Especially the three lines between Ensted-Flensburg, Bjørnholt-Tange and Bredkær-Nibstrup (see Figure 6.3 for bus names) showed a clear tendency. All three are overloaded in the majority of the simulations, no matter the EC capacity, EC location or energy system scenario. Therefore, it can be said that the capacity of these lines has to be increased. Hence, these three lines are not considered to be overloaded as a result of the EC integration, but more likely due to increased general electrification in the simulation.

In the problem formulation Section 1.3 it was stated that ECs are essential in the transition towards a 70% CO_2 reduction goal. The results and analysis of this transmission grid analysis has illustrated, that it is possible to integrate high EC capacities in DK1 without overloading the grid. However, the energy system composition, EC location and EC capacity have a significant impact on grid loading, and thereby also the costs associated with the needed grid reinforcements.

Transmission grid simulations were made for three different EC capacities at 24 varying EC locations for both an Onshore and and Offshore energy system scenario of DK1.
The Offshore energy system scenario, which resembles the current offshore wind strategy used in Denmark, proved well suited for implementing large EC capacities, without causing grid overloading. In fact, it has been illustrated that increasing EC capacity can mitigate grid overloading in an offshore-based energy system, if EC plants are placed in feed-in zones. Hence, it can be said that increasing EC capacity allows for higher offshore wind power integration. It must however, be stated that the reduced loading from placing ECs in feed-in zones, stems from the reduced power flow through the system. Consequently, if ECs are operated at full capacity, without offshore wind turbine generation, power would instead flow towards the ECs in the feed-in zones. This power flow would likely cause overloading, if the loading of the ECs is not reduced. Thus, if ECs are also used to reduce strain on the transmission grid, then ECs placed at feed-in zones must, to some extend, follow the production of offshore wind turbines. However, it was also stated in this analysis, that as EC plant owners operate their plant according to spot market prices, they would likely not operate at hours with low or no offshore production, as electricity prices follow the RE production in high RES energy systems.

As described, several reports such as Ea Energy Analysis [2020] and Dansk Energi [2020] recommends placing ECs in areas where the surplus heat from the EC plants can be utilised in the DH grid. Furthermore, Energinet [2021f] states that access to CO_2 is important for developing PtX. Therefore, results of simulations where EC capacity was placed in large DH and CO_2 areas have also been shown. From these, it was evident that placing the ECs in these areas would lead to significant overloading of both 150 kV and 400 kV transmission grid. In order to overcome this challenge, and reduce costs needed for grid reinforcements, it should be considered to have the point of connection from future offshore wind power plants, near large DH and CO_2 areas. The same approach could beneficially be used when connecting the upcoming Energy Island in the North Sea.

A more explorative energy system scenario with higher onshore wind, and PV electricity production capacity was also simulated, to investigate how EC capacity impact the transmission grid loading in such a scenario. Three hours with high electricity production were simulated and presented in detail. A rather extreme hour with the highest annual production yielded significant overloading in the transmission grid for all three EC capacities. In this hour, increasing EC capacity had the potential to reduce loading of the 400 kV grid. However, increasing the EC capacity also yielded significantly more overloading in the 150 kV grid. On the contrary, the other two simulated hours, max offshore hour and 95% hour, yielded only limited overloading of 150 kV grid at higher EC capacities, when EC capacity was placed in Idomlund. Interestingly, when EC capacity was increased above EC-AF20 levels, the overloading of 400 kV lines was mitigated, which significantly reduced the estimated grid reinforcement costs.
Even though the Onshore energy system yielded significant overloading during the max production hour, it must be remembered that only 9-18 hours had 90% similar electricity production levels. Thus, it is not deemed an issue if the ECs can not be operated during these 9-18 extreme hours.

A comparison of the reinforcement costs necessary to avoid transmission grid overloading, was calculated and presented in Figure 8.25. This figure clearly illustrated the potential for reducing grid reinforcement costs by utilising ECs. For the Offshore energy system, with ECs placed in Idomlund and (Idomlund, Stovstrup), the higher the EC capacity, the lower grid reinforcement cost.
The reinforcements costs for the Onshore energy system could also be reduced significantly by increasing EC capacity above EC-AF20 levels. However, this is only true if the extreme max production hour is neglected.

As these results are obtained using a DC load flow analysis, it is again emphasised that the grid loading shown throughout this chapter would likely be higher, had the analysis been conducted using AC load flow analysis. This is the case, as reactive power flows have not been considered in this analysis. However, this strengthens the results shown throughout this analysis, as the overloading issues found, will likely be worse in practise.

9 Discussion

This chapter entails reflections and discussions regarding the methodological choices and assumptions behind the analyses conducted in this thesis. Furthermore, the results and the operation of the modelling tools are discussed. The discussion is divided up, based on the two underlying research questions.

How do large-scale electrolysers affect the dispatch and capacities of electricity production, consumption and storage units in the energy system?

When considering the underlying research question, it can be understood that the objective is to shed light on how ECs impact the composition and dispatch of different units in the energy system. In order to reach the objective, the top-down oriented synoptic planning approach was selected, but it might be worthwhile to discuss, how and whether the objective could be reached if a bottom-up oriented approach had been used instead.

Once the synoptic planning approach was selected, it became clear that solutions for reaching the objective should be investigated using a macro-economic energy system modelling tool. As the tool has a macro-economic energy system perspective, it is adequate for investigating how ECs impact the energy system and how the energy system should be composed to integrate ECs from a top-down oriented system perspective.
An alternative solution could be to investigate solutions from a bottom-up perspective. This could both be done from a technology or plant specific perspective, by assessing how electrolysers in general or individual plants would fit into the a given energy system and market. This strategy would surely be useful for understanding how framework conditions affect ECs ability to be economically viable. Furthermore, a bottom-up-based perspective could likely also generate EC dispatch data, which would closely resemble a production plan from an EC plant, as the dispatch would be based on the economic perspective of the a plant owner and the framework conditions of a given system. Additionally, the analysis could even point to policy changes, needed to make EC plants economically viable.

As this thesis takes the position that ECs are essential enablers for reaching the 70% reduction goal, it is considered the first priority to assess whether the system is prepared for integrating ECs, and how it should be composed to allow this integration. The bottom-up-based approach is not ideal for assessing how a given technology impacts a system, but rather how the technology fits in to a given system. Consequently, the bottom-up perspective can yield several additional insights and solutions, but it should be used after the proper energy system composition has been identified. Meaning that the economic framework conditions needed for ECs to be profitable can be identified subsequently to the identification of the adequate energy system composition.
Altogether, it is still believed that top-down oriented synoptic planning approach is best suited for shedding light on the objective of assessing EC impact on energy system composition and dispatch. An outcome of this belief was that a partial-equilibrium energy system optimisation tool, called Balmorel, was used. The validity of selecting this tool for

the assessment can also be discussed.

The operating principle of a partial-equilibrium (PE) model is that it optimises dispatch and calculated electricity prices by balancing electricity demands and production. This does, however, yield some complications, as the dispatch optimisation of consumption units, is not based on the same perspectives and objectives that individual plant owners have. In practice plant owners should only focus on operating their plant in the most economically viable way. Thus, they would follow the price signals available to them. This would most likely be electricity prices on the different markets, and their marginal production cost. Electricity price forecasts are only available a short time period ahead based on e.g. weather forecasts, while the exact spot market price is not available before plant owners hand in their production plan one day ahead of production. When electricity prices are below their marginal cost, they would produce.
In contrast to the plant owners, the PE model has full-annual-foresight. Meaning that the PE model knows all demands and production patterns, which in a sense enables it to make perfect dispatch. In order to reduce the models ability to make perfect dispatch, ECs were forced to operate every week, by splitting the annual EC demand into 52 weekly bits.
An unintended consequence of this was that, because the model always has to meet the specified demand, it would sometimes have to operate the plant during situations, which does not make sense from a practical point of view. This can be stated from the fact that EC plants were sometimes operated during hours where the electricity price was above the expected green hydrogen price. Conversely, the model also stopped EC production once the weekly demand was met, even though the electricity prices were favorable. These situations should, and probably would, never happen in practice. A solution that could reduce these issues would be to split the annual demand into larger bits e.g. monthly. Thus, the ECs would, to a smaller degree, be forced to operate during hours with high electricity prices. Therefore, it must be stated that the entirety of the dispatch patterns from the PE model should not be used to make an exact production plan for EC plant owners. However, all hours where ECs are operated and RE production is high are still deemed representative, as the electricity prices are consequently assumed low.

With regard to understanding how ECs impact capacities of electricity production, consumption and storage units, it was clear that differences in EC capacities have a significant impact. It was blatantly obvious that increasing EC capacities also increased optimal RE capacity. However, whether the ECs made this increased RE integration possible or it was due to import/export possibilities can be discussed.
As the Danish energy system has significant interconnection capacities to neighbouring countries, exchange of excess electricity production from fluctuating RE-based units is possible. Thus, one could argue that the ability to increase RE capacities is merely due to the possible electricity exchange. While this may be true, increasing EC capacities proved useful for increasing the utilisation of fluctuating RE in the system. This was evident from dispatch figures of week 32, where available offshore wind was shut down when EC capacities were low, but offshore wind was utilised during the same hours, once higher EC capacities were integrated. Furthermore, the share of fuel-based electricity production was actually decreased at high EC capacities, which in turn also decreased average electricity prices.

Considering the investments in flexible consumption units, e.g. electric boilers and electricity storage, ECs also have an influence. In the scenarios with higher EC capacities, the capacities of electric boilers and electricity storage were decreased, as excess electricity production would instead be consumed by ECs. Especially the Offshore energy system scenario seemed to be less dependent on other flexible consumption units, once EC capacities were increased. It should be noted that other technologies, which might exist in the system anyways, could also provide flexibility, e.g. EVs. However, as the amount of EVs are fixed for all scenarios, this is not the case.
Along these lines, it is worth mentioning that the whole perspective about how the hydrogen should be utilised post production is neglected in this thesis. This perspective is diverse, as hydrogen can be used for methane production, e-fuels, stored, send directly into to gas network etc. This multitude of options could affect whether the ECs can produce flexibly or the further handling of the hydrogen entails bottlenecks. Having said that, one could argue that plant owners would likely not dimension their plants in a way that makes the further processing a bottleneck, as this could prove costly during prolonged periods of favorable production conditions e.g. low electricity prices. This assumption can be backed by the fact that EC projects are generally PtX projects, which intend to produce e-fuels and gasses. Consequently, it is assumed they will dimension their synthesis plant and hydrogen storage adequately in relation to the EC plants capacity.

A relevant aspect, which was not covered in detail in this thesis, is surplus heat from ECs. The reason that surplus heat from large-scale ECs was not modelled in the Balmorel model, was that it was not certain that ECs would be placed in areas where surplus heat could be utilised, as a multitude of EC locations would first have to be investigated in the transmission grid analysis.

The reason that surplus heat from ECs was not modelled in the Balmorel model, was that it was not certain where ECs would be placed, as a multitude of EC locations would first have to be investigated in the transmission grid analysis. Consequently, if surplus heat from ECs supplied heat in a given area, it would completely change the energy system optimisation if the EC plant was moved to another location. Hence, the energy system analysis would have to be conducted for each of the 24 EC locations analysed in the transmission grid analysis. As, the simulation time alone would be roughly 700 hours, it was chosen to delimit from including surplus heat from ECs in the energy system analysis. However, if surplus heat from ECs had been included in the simulations, it would probably have meant that an even lower capacity for electric boilers and heat pumps was needed. Additionally, this would likely have decreased the electricity and fuel consumption for DH, and thereby also impacted optimal RE production capacities.
Along with reflections on the location of ECs, the distribution key for splitting EC capacity between DK1 and DK2 can be discussed. The used 60% / 40% distribution for DK1 / DK2 was based on expectations from the Danish Energy Agency [2020]. Other distribution keys could surely have been utilised, but this one was chosen, as DEA is a trusted source, thus their expectation was used. Even so, the used distribution key was able shed light on some perspectives regarding the location of ECs. One being the significant electricity import in DK2, which could indicate that, from an electricity production capacity perspective, some EC capacity should be moved to DK1.
Meanwhile, this led to the realisation that when deciding which locations are ideal for ECs,

several important perspectives plays a role. These include: distance to CO_2 point sources, gas storage, transmission grid capacity, large DH areas, gas infrastructure etc. The ideal solution for identifying relevant EC locations would be to conduct a detailed geographical analysis of the before mentioned perspectives. Having said that, such an analysis, however useful, would have resulted in an additional analysis with high complexity. Hence, focus and resources would have been removed from the other analyses of this thesis. Consequently, such an analysis was deemed outside the scope of this thesis.

Another consideration regarding the energy system simulation made to assess EC impact on the system, is the number of countries included in the simulations. In the model Norway, Germany, Netherlands, Great Britain and Sweden are included, as they are expected to be directly electrically connected to Denmark by 2030. Had more or less countries been included in the model, it could have impacted the results. One consideration is that, if more countries were included, increased electricity exchange could have been made between other countries. This could mean that the electricity exchange with Denmark was higher in the model that it would be in practice, as some countries could have made electricity exchange with Denmark, as other options were limited. Consequently, the electricity production capacity in Denmark might have been lower if more countries were included. On the other hand, Denmark had net import, meaning that additional capacity was not bought in Denmark to supply neighbouring countries. Furthermore, it must again be stated that the primary focus of this thesis is to assess EC impact on the Danish energy system. Hence, the reason for including other countries in the simulation is merely to allow for electricity exchange with neighbouring countries.

How do electrolyser plant locations and capacities impact transmission grid loading, and how should electrolysers be integrated in the transmission grid to minimise these impacts?

During the transmission grid analysis, it was found that ECs can both significantly increase and decrease transmission grid loading, depending on EC location and capacity. In regards to location, it was evident that placing ECs in the feed-in zones from offshore wind power plants yield the least grid loading. From this it can be generalised that ECs can decrease grid loading, if placed at the point of connection for large centralised RE capacities, whether offshore or onshore.
Interestingly, it was found that, when placing ECs in the feed-in zones, grid loading could be reduced by increasing EC capacity. This was evident as EC-AF20 capacities generally caused overloading for all EC locations, while this overloading could be either reduced or completely mitigated for EC-High capacities. As it was shown that overloading could be mitigated, in hours of high RE production, by increasing EC consumption, this raises the question what would happen if the situation was reversed. Meaning what would happen if EC consumption remain high, but RE production drops. In such a case it is fair to assume that it would cause overloading, as the flow would be reversed, meaning that power would instead flow towards the ECs, most likely causing overloading.
These situations actually do happen in the PE model as it, as discussed earlier, has to supply a weekly EC demand. Consequently, the PE model shuts down ECs when weekly demand is met. Conversely, it also forces the EC plants to produce when electricity prices are high, indicating that RE production is low. It was shown in Table 7.5 that ECs

produce in 96-316 hours at electricity prices above 400 DKK/MWh. Furthermore, it was illustrated in Figure 7.6, that ECs are shut down in hours with electricity prices below 100 DKK/MWh. Thereby, it can be said with almost absolute certainty that the PE model sometimes shuts down ECs when RE production is high, but also has EC production when RE production is low, most likely causing grid overloading.
This could have been verified by conducting annual simulations, as this would have yielded precise grid loading results for all hours during the simulated year. However, it is expected that EC plant owners will in practice operate their plant according to the electricity price, meaning that the EC plants will operate their plants when prices are low, and shut down production when prices are high. Thereby, most likely following the RE production. Hence, it is not deemed relevant to simulate these hours of suboptimal dispatch.

In the PE model the EC demand is split across DK1 and DK2. However, had e.g. DK1 been simulated using several modelling regions with a given transmission line capacity between them, then the EC demand would also be split across this increased amount of regions. The transmission line capacity restrictions between each region would not only yield more representative dispatch for ECs, but also take the distribution of electricity production into account. Moreover, the model would also be capable of identifying economically viable transmission grid capacity expansions between the regions in DK1.
As of now the PE model treats the power system in DK1 as a copperplate model, meaning there is no possibility of congestion inside the region, this increases the need for a load flow analysis. However, by splitting DK1 into more regions, the model would have to account for potential congestion between these regions. It is acknowledged that splitting DK1 into more regions would increase both complexity and computing power required, to run the model. However, splitting DK1 into enough regions could reduce the need for conducting a load flow analysis, similar to the one of this thesis. Consequently, making the PE model a stronger tool, by allowing for both more realistic dispatch. Furthermore, it would make the PE model more compatible with tools such as PowerFactory.

In this thesis it was chosen to conduct the transmission grid analysis using DC load flow. DC load flow only offers an approximate solution of an AC load flow. However, as AC load flow introduces the need for reactive power compensation it significantly increases complexity and computing power needed for the analysis. As DC load flow was deemed adequate for the aim of this thesis, it was selected in favor of the AC load flow.
Had the transmission grid analysis instead been conducted using AC load flow, it would most likely have increased line loading, as reactive power would be present in the system. Hence, it can be stated that the overloading seen in the DC load flow analysis, would also be present for an AC load flow analysis. Thereby, strengthening the results obtained in this analysis.

The transmission grid analysis conducted in this thesis is done for an intact grid. For long term grid planning the Danish TSO Energinet, normally also analyse the grid under faulty conditions, namely the N-1 and N-2 analyses. Here N-1 and N-2 means that there are respectively one and two faults in the transmission grid. In this thesis it was not chosen to analyse the grid under N-1 or N-2 conditions. Had this been done, it would likely change the results and observations significantly. However, as it was expected that EC plants will seek to obtain lower tariffs by giving Energinet the possibility to shut down their plants during faulty conditions. Consequently, ECs would not operate under faulty conditions, rendering the N-1 and N-2 analyses redundant.

In this thesis it was assumed that the distribution of onshore power production capacity, would remain the same going forward. However, the production from central power plants, scheduled for decommission by 2030, was removed from the distribution key. Thereby, further increasing the production placed at the remaining generators in the system. Due to increased RE production from onshore-based units by 2030, the actual distribution might deviate from the one used in this analysis. However, as the onshore-based production in 2020, which is the year for which the steady-state distribution is obtained, was already well developed, it was assumed that onshore-based power production will likely be increased in a manner that corresponds to the distribution of 2020.
Again this uncertainty could have been mitigated by splitting DK1 into multiple regions in the PE model, as power production capacities would then have been optimised for each region, based on local demand and interconnection capacity to the surrounding regions.

As the feed-in zones yielded the least overloading, it was stated that the point of connection for the offshore wind power plants is of importance. If the planned offshore wind power plants and the energy island ends up being connected with distribution and points of connection similar to the ones used in this project, then Idomlund, and (Idomlund, Stovstrup) can be singled out as the ideal EC locations. The points of connection and the distribution of the offshore wind power capacities used in the analysis was based on an interview with Maria Broe from Energinet. However, Broe did disclose that the points of connection from future offshore wind power plants and the energy island, is not set in stone. Therefore, it would be beneficial to conduct an analysis of where these offshore wind power plants should be connected. However, as the general tendencies found in this analysis are clear, it is expected that placing ECs in the feed-in zones will most likely yield the lowest grid loading. Hence, it could, from a system perspective, make sense to move these points of connection into areas with DH and CO_2 point sources, as this would increase overall system efficiency.

Indicative prices

In order to make a comparison of all EC capacities for every location, it was decided to present indicative grid reinforcement expenditures for all EC locations in each scenario. These expenditures were calculated for each of the three simulated hours. It was chosen to increase the capacity of overloaded lines by adding a parallel line to any overloaded line. The calculation was made using generic cost per length for 150 kV cables and 400 kV overhead lines, as this enabled the possibility to create a table where the reinforcement costs required for all scenarios could be equally compared. It is however acknowledged that grid reinforcements costs would, in practice, be case specific. Thereby, the reinforcement costs could vary significantly for all scenarios. Hence, these reinforcement costs should not be considered actual reinforcement costs, but indicative costs which can be used to equally compare different EC locations and capacities for the two energy system scenarios. Thereby, indicating which EC locations and capacities could result in extra expenditures for the TSO, but also which could be used to mitigate reinforcement expenditures.

It is acknowledged that there are other ways to reduce grid loading, these include lowering consumption, shutting down production or utilising FACTS to distribute loading between lines. However, these solutions are also associated with costs, whether for the TSO or socio-economic costs. As it is assumed in this thesis that EC are essential to reach the 70% reduction goal, it can be stated that it would be unwise not to utilise ECs to mitigate transmission grid overloading, as they have the ability to do so, if adequate EC capacity is placed at the point of connection from large RE production plants.

Conclusion 10

This chapter concludes on the research question, based on the methods, assumptions and analyses conducted in this thesis.

"How should large electrolyser capacities be integrated in Danish transmission grid and energy system, from a technical point of view, while still complying with the 70% CO_2 reduction goal of 2030?"

Based on the methods, assumptions and analyses of this thesis, it can be concluded ECs can, depending on EC placement, capacity and dispatch, cause significant overloading of the transmission grid. However, it can also be concluded that large EC capacities can reduce transmission grid loading, if placed at points of connection for large RE plants, and EC dispatch is proportional to the electricity production of these RE plants. If these conditions are satisfied, then increasing EC capacity can mitigate grid overloading, which would be present in a system with lower or no EC capacity.
Furthermore, it can be concluded that increasing EC capacity enables increased integrating and utilisation of RE. Moreover, the need for other flexible electricity consuming units can be reduced by increasing EC capacity.
These conclusions were derived while complying with the 70% CO_2 reduction goal for 2030.

The conclusions were obtained by investigating how large EC capacities impacted the Danish energy system and the transmission grid of DK1.
The partial-equilibrium model Balmorel was used to simulate and optimise the energy system of Denmark in a 2030 perspective. Balmorel was used to optimise both the capacities and dispatch of consumption and production units. This was done for both offshore- and onshore-based energy system scenario, with three different EC capacities of 1 GW, 3 GW and 6 GW, using a 60%/40% distribution for DK1/DK2.
Through the energy system analysis it was shown that increased EC capacities would yield both higher optimal RE capacities, but also a higher utilisation of the RE production. Furthermore, it was found that all scenarios were capable of adhering to the 70% CO_2 reduction goal.

The conclusions regarding EC impact on the transmission grid were derived from DC load flow simulations, using hourly production and consumption data, obtained from the Balmorel dispatch optimisation. These simulations were conducted using PowerFactory, and led to the conclusion that feed-in zones for offshore wind power plants were ideal locations for integrating ECs.
Using the assumptions and distribution keys from this thesis, it can be concluded that an EC capacity of 3.6 GW can be integrated in DK1 without the need for transmission grid reinforcements. The scenario that yielded the lowest grid loading was the offshore-based scenario with an EC capacity of 3.6 GW placed in Idomlund or distributed between Idomlund and Stovstrup.

11 Recommendations

This chapter entails recommendations for decision-makers and for further research of the subject. These recommendations are developed based on the results and analyses of this thesis.

In this thesis, it was found that ECs can facilitate increased integration of RE production. Furthermore, it was demonstrated that, if certain criteria are satisfied, high EC capacities can be integrated without overloading the transmission grid. These criteria dictate that ECs must be placed at the point of connection for large RE plants, and dispatch proportionally to the RE production. Based on the findings and reflections in this thesis, the following recommendations are given:

- **Synergy between RE and ECs**. ECs should be placed at points of connections for large RE plants to mitigate overloading of the transmission grid, while increasing RE integration and utilisation. Therefore, it is recommended to make an analysis of potential points of connection for future large-scale RE plants and energy islands.

- **Using ECs to improve system efficiency**. As ECs have thermal losses, it is recommended to use the surplus heat from ECs to supply DH, in order to improve overall system efficiency. Therefore, it is recommended to analyse the possibility of placing the point of connection for future large RE plants, into areas with a large DH demand.

- **Framework conditions for ECs**. As it was concluded that ECs can be integrated from an energy system perspective, it is recommended to conduct an analysis of the framework conditions for EC, in order to ensure that ECs can be become economically feasible in Denmark. This analysis should entail an assessment of the transmission grid tariff for large flexible consumers.

- **AC load flow simulations**. It is recommended to conduct a full year AC load flow analysis to obtain more accurate transmission grid loading results.

- **Socio-economic assessment of ECs in the energy system**. As it was concluded that it would be technically beneficial to include ECs in the energy system, it is recommended to conduct an energy system analysis that emphasises on the socio-economic perspective of integrating ECs.

- **Transmission grid reinforcement costs**. It is recommended to conduct a thorough analysis, using case specific expenditures, of transmission grid reinforcements needed to integrate ECs. In this analysis other potential transmission grid expansions could also be assessed.

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Interview with Maria Broe from Energinet A

An interview was conducted with Maria Broe, a project leader on long term grid planning at Energinet. The interview was made in order to obtain additional knowledge about Energinets perspective regarding PtX, point of connection for offshore wind power in DK1, and capacities of overhead lines and cables. The following is a condensation of the interview. The full interview can be found in Appendix B.

When asked about pros and cons on integrating PtX from a transmission grid perspective, Maria Broe replied that based on how the PtX plants are incorporated in the grid they can, if located close to RE sources, assist in incorporating even more RE. However, if they are placed at points of high consumption, such as larger cities, they are likely to increase the demand for grid expansions.

PtX plants should utilise the ancillary service market, however the important driver, from a net planning perspective, is their security of supply. This is why Energinet offers their "begrænset netadgang" tariff product, which offers lower tariffs, but also enables Energinet to reduce the load or turn off the plant entirely if necessary, meaning that security of supply is reduced. Energinet have made this product to integrate large consumers in the grid, without necessarily having to reinforce the grid. Maria Broe does state that only the part of loading which makes the grid unstable will have to be shut down, meaning that shut downs might in practice just be partial.
Several of the details of the "begrænset netadgang" tariff product are still under development, as the tariff product is undergoing public hearing. Currently, Energinet does not offer a minimum number of full load hours. However, she states that when large consumption units applies for grid connection, Energinet evaluates the likelihood of being switched off. Based on this information, the consumer can decide if they would like to utilise the reduced tariff product with the risk of having to shut down production in hours with grid issues.
Maria is also asked about whether utilising placement dependent tariffs based on e.g. the municipal RE capacity factor is an option Energinet has considered. Here she states that Energinet currently does not have such a tariff under development. However, she points to the fact that consumers utilising the "begrænset netadgang" product, would maximise their security of supply by placing their load in a location with high RE capacity factor.

When asked about the point of connection for offshore wind power, she mentions that are no real decisions made on where the planned offshore energy island will be connected. However, she states that the energy island could be connected in several points if it is deemed beneficial. Furthermore, she goes on to say that after the realisation of the energy island, new offshore wind power plants, denoted Extra 1-5 in AF20, will likely be constructed in the North Sea and could be connected to the three feed-in zones on the west coast (Endrup, Idomlund and Stovstrup).

When asked about how Energinet dimensions overhead lines and cables in their transmission grid assessments, she states that they normally use a generic standard for connections based on voltage level (see Figure A.1). Furthermore, she says that when replacing older connections they normally increase the connection capacity, due to the uncertainties regarding the future development of the energy system.

For longer perspective grid planning, Maria Broe states that it would be adequate to use standard grid data for high voltage cables and overhead lines. Furthermore, she states that as a rule of thumb large 400 kV projects take about 10 years from idea to operation ready, while smaller projects like 150 kV take about 5 years.

Maria Broe <meo@energinet.dk>
to 08-04, 15:28
Tim Løgsted; Marco Rosenkrands Hansen

Hej Marco og Tim,

Det lykkedes vidst både at finde svar på det hele og afklare at jeg gerne må dele det med jer 😊

I kan bruge følgende standardværdier for den kontinuerte overføringsevne for nye forbindelser:

- 150 kV-kabler: 1500 A – svarende til ca. 425 MW – for kablerne i Sønderjylland kan I anvende 1400 A
- 132 kV-kabler: 1500 A – svarende til ca. 340 MW
- 400 kV-luftledninger: 2400 A – svarende til ca. 1660 MW (for et system) - dette passer også med 400 kV Idomlund-grænsen.

Derudover kan der tillades en større belastning i kort tid (15 minutter eller 40 timer) som det også fremgår af metodebeskrivelse i behovsanalysen. I kan finde nogle standard procentsatser for hvor meget forbindelserne kan belastes ift. deres kontinuerte belastningsevne her på vores hjemmeside – i det øverste dokument til højre på siden.

For de 5 havvindmølleparker der forudsættes i AF20 efter energiøen kommer vi til i den behovsanalyse vi laver i år at forudsætte at de tilsluttes i følgende stationer i den nævnte rækkefølge: Stovstrup, Endrup, Idomlund, Stovstrup, Endrup. Der ligger ikke nogle dybere analyser bag denne antagelse endnu andet end at parkerne er forudsat placeret langs vestkysten og så har vi fordelt det sådan rimeligt jævnt på de tre 400 kV-stationer i området. Det er selvfølgelig noget vi kommer til at kigge nærmere på hvis/når parkerne skal etableres.

For energiøen i Nordsøen kommer vi, som jeg nævnte, til at undersøge en lang række mulige tilslutningspunkter i den kommende tid. De primære punkter vi undersøger er Endrup, Revsing, Tjele og Kassø, men også andre stationer eller kombinationer af de fire kan komme i spil. Tilsvarende for energiøen ved Bornholm dog med udgangspunkt i stationerne Hovegård, Bjæverskov og Avedøreværket. Analyserne omhandler i første omgang at undersøge hvad der giver mening ud fra en knudepunktsbetragtning. Dernæst skal det undersøges hvad der er muligt rent fysisk ift. plads i eller omkring stationerne.

Held og lykke med projektet. Hvis I ender med et projekt der ikke er for hemmeligt til at I må dele det, må I da gerne sende det til mig når I er færdige.

Venlig hilsen

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Figure A.1. Screenshot of follow up mail from Maria Broe.