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Smart expansion of offshore wind and Power-To-X for a sustainable future electricity market

Master thesis

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Shuo-Hsing Chang
Nicklas Müller Thrimar

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Department of Planning
Rendsburggade, 14
9000 Aalborg
http://www.plan.aau.dk/

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Authors:
Nicklas Müller Thrimar
Shuo-Hsing Chang

Supervisor:
Andrei David Korberg

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Synopsis:

During the green transition, the offshore wind sector and the Power-to-X sector are recommended to balance development and expansion, instead of one sector overdeveloping. This recommendation, as well as smaller recommendations on development of other renewable, flexibility, storage, and infrastructure technologies, are found through a game-theoretical approach and simulations in the software, EnergyPLAN. The purpose is to avoid potential market failures, as the electricity market is not designed to settle the electricity price around renewable supply technologies. Another risk is the electricity demand from Power-to-X increasing the electricity prices immensely. But together the sectors behind these risks of decreasing and increasing electricity prices are in simulations used to counteract one another, instead keeping a steady electricity market during the green transition. Usually, in a game-theoretical perspective, players (in this project the offshore wind and Power-to-X sector) actions maximise their own profit but hurt the other players situation. In the scenarios explored, players actions can economically hurt themselves and potentially the society and energy system. The results of individual sector development are also evaluated against the concept of a smart energy system to discover if the wrong actions cause the system to fail as a smart energy system.

Preface

Reading guide

- This report chronologically structured with the problem field, research questions, concepts, theories, methods and analyses, divided into numbered chapters, sections, subsections and at times subsubsections.
- The primary knowledge source is own research using simulations, calculations and analysis, but otherwise validated scientific knowlegde or official documents constitute the sources. A few articles have been used.
- All sources are cited by the Harvard standard style, including at least; author and the year published.
- There are numerous figures and some tables that have all been chronologically numbered and have a short caption text.
- There are no appendices.

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Intro 1

With both national and international carbon reduction goals, planned shifts occur in the primary technologies in the composition of energy systems. In Denmark, power generated from offshore wind turbines will have an immense role in the green transition. To take advantage of cheap green electricity and provide a green alternative to liquid fossil fuels in the transport sector, a process and industry known as Power-to-X is slowly expanding and is expected to also play a major role in the green transition. Power-to-X, explained briefly, is the production of hydrogen from electricity and water, then used to produce green fuels. In research, it is speculated that if offshore wind and other renewable electricity determine the electricity price, the market will fail and technologies will become infeasible businesses. However, in research, it has also been speculated that electrolysis for Power-to-X will, in fact, have the opposite effect of renewable supply on the price of electricity. This project investigates the possibility of having the two sectors, offshore wind and PtX, expand in a balanced way to ensure a steady electricity market during the green transition, without changing the market design or regulations.

Based on game theory, the EnergyPLAN software is used to simulate more than 28 scenarios to test the impact of individual sector development and balanced development. From the results, important trends are highlighted and in the end will be recommendations for supply, demand, and infrastructure technologies.

Problem analysis 2

2.1 Overall carbon neutrality intro

Within a decade, Denmark, as many other countries, is obligated to meet a carbon reduction goal of 70 pct. compared to the year 1990. In the year 2050 Denmark has to be carbon neutral. Transitioning away from fossil use necessitates actions and alterations in multiple energy-consuming sectors, since carbon emissions are a consequence of energy use in multiple sectors. Figure 2.1 shows how the Danish Climate Council expects the emissions to be distributed in percentages across sectors in 2025 and 2030, considering the current initiatives taken to reduce emissions.

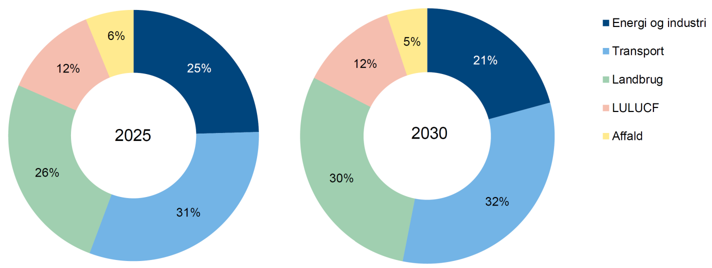


Figure 2.1. Emissions across sectors in pct. [The Danish Council on Climate Change, 2022]

The Danish Council on Climate Change [2022] reviews five sectors that cause emissions in 2025 and 2030; energy and industry (dark blue), transport (light blue), farming (green), change in area use (LULUCF, light red) and garbage (yellow), the three main emitters being energy and industry, transport, and agriculture in both years.

Having established an overview of the polluting sectors, an overview of progress toward the 2030 climate goal has also been made. The two grey pillars in figure 2.2 show the reductions in carbon emissions using data from two government documents, the dark grey pillar being the newest government projection, visualising a reduction of 54.0 pct. compared two the year 1990.

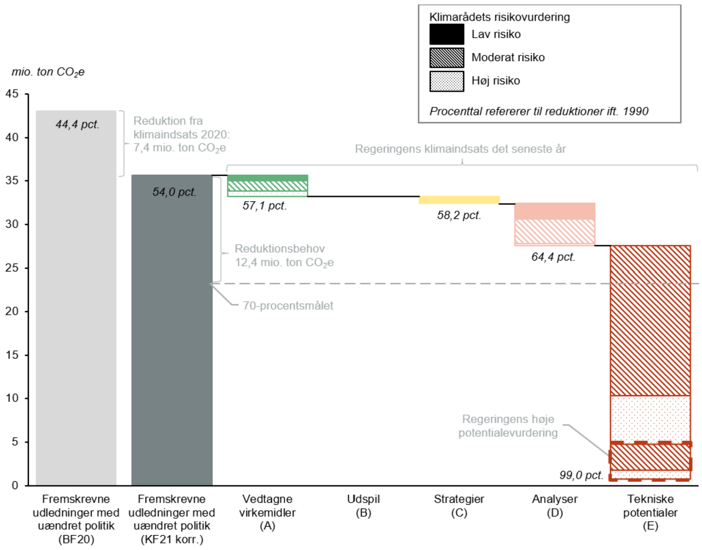


Figure 2.2. Climate council assessment of anticipated reductions. [The Danish Council on Climate Change, 2022]

The grey stippled line points at the 70 pct. carbon reduction goal. To get there, a reduction of 3.1 pct. can be found through agreed governmental initiatives, 1.1 additional pct. can be found from strategies, and 6.2 pct. extra reduction is possible according to analyses. From a 64.4 pct. reduction to 99.0 pct. reduction is simply potentially possible and therefore deemed highly risky in terms of realisation.
For the Danish carbon emissions, there are several plans, strategies, and more across multiple sectors, discussing internal steps for reduction and intersectoral steps. The energy-consuming sectors are increasingly linked.

2.1.1 Sector coupling - district heating, biogas, PtX and electricity

When analysing sector strategies, connecting sectors, also known as sectorcoupling, become evidently more clear as an important part of the green transition. The district heating sector is planning higher use of electricity-based heating supply such as heat pumps and electrical boilers, and when electrical supply is not suitable, biogas instead can be used. Biogas production and use is on the rise, and with CO_2 captured during production, it is possible to make electrofuels - more specifically electromethane - that use electricity when produced.

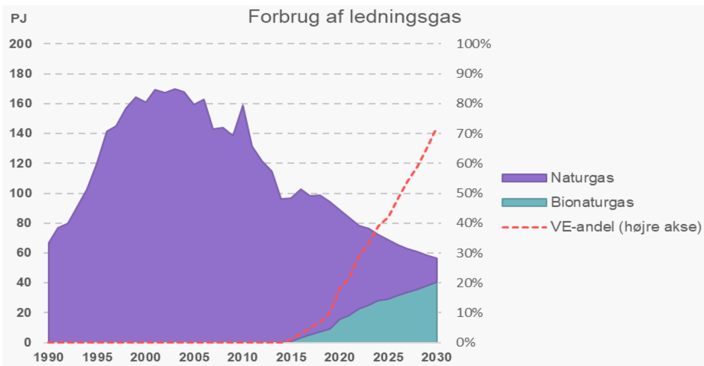


Figure 2.3. Development of biogas use compared to natural gas use in Denmark in UNIT and percentage. [Biogas Denmark, 2021]

As can be seen in figure 2.3 there is already an increasing use of biogas compared to natural gas. The red stippled line further shows that the renewable percentage of gas usage will be around 70 pct. in 2030.

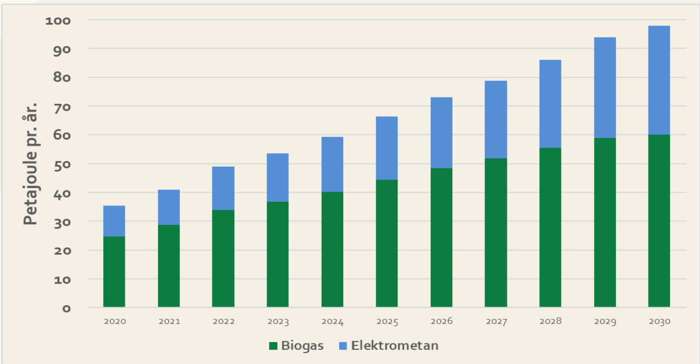


Figure 2.4. The potential available energy from biogas and electromethane. [Biogas Denmark, 2021]

The growing production and use of biogas is potentially increasingly linking the gas sector with the electricity sector. Due to the CO_2 capture during the biogas production, Biogas Denmark [2021] points out that CO_2 can be combined with hydrogen by using excess electricity from renewable energy sources such as the emerging energy islands. This creates an interaction where gas is not only used to produce electricity, but electricity is also used to produce gas, coupling the sectors more closely. Figure 2.4 shows the potential for electrofuel production as biogas production increases. Biogas Denmark [2021] estimates that two GW excess electricity can be used in this process.

Increasing interaction between energy sectors is also a trend in the heating sector. The Danish District Heating Association [2020] has done an analysis and an overview of how to obtain a CO_2 neutral district heating sector in 2030. In so the Danish District Heating Association [2020] has examined potential technologies to replace fossil fuel technologies by three different categories; baseload, middle load and peak load. Electricity-based technologies are planned to be used in each category. Heat pumps have a high investment cost (CAPEX) but low operation cost (OPEX); thus, they are suitable and expected to be a large part of the base load of district heating, with many operating hours. Electrical boilers have far lower efficiency than heat pumps but are a cheap investment in comparison. The Danish District Heating Association [2020] describes that electrical boilers will be the main technology to cover the middle and peak load, as they are cheaper, with a higher running cost, but will have fewer running hours.
The Danish District Heating Association [2020] recommends removing any regulations that force district heating plants to use combined heat and power supply - thus removing a link between the heat and electricity sector - but by integrating heat pumps and electrical boilers, another coupling between sectors is established.

Having examined the planned progress in the biogas and district heating sector, it is evident that there is going to be a clear connection between energy sectors and the electricity sector will play a significant role in the green transition. Full utilisation of carbon capture from biogas production depends on a major amount of electricity, and the district heating sector plans to rely mainly on electrical heat pumps for base load, meaning a lot of operation hours. Next is therefore a deeper dive into the electricity sector plans.

2.2 Electrification essential to green transition

For the country to transition towards reduced carbon emissions, the government plans to rely heavily on the electricity sector. In the summer of 2021, The Danish Climate, Energy and Supply ministry [2021] released a vision of how the Danish government aims to transition away from fossil fuel use and emissions, outlining policies, milestones, potentials, and scenarios. These are primarily focused on the electrification potentials in different energy consuming sectors, describing the amount of energy able to be covered by electricity, the emission savings and rising electricity demand. Additionally, it is in the vision only loosely described how the surging electricity demand will be met to maintain the high security of supply.

2.2.1 Rising demand as a consequence of electrification

The vision of The Danish Climate, Energy and Supply ministry [2021] is based on the demands found in the analysis of The Danish Energy Agency [2021a], which can be seen in figure 2.5. From the figure, it can be seen that the electricity demand will increase significantly due to the green transition, the demand entails increase of power to; individual and large heat pumps, electric boilers, Power-to-X (PtX), transport and large data centres as well.

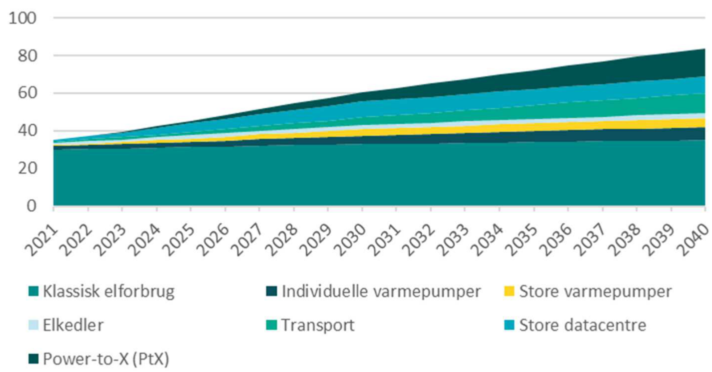


Figure 2.5. Expected development of Electricity demand split between different sectors. [The Danish Energy Agency, 2021a]

Figure 2.5 shows a possible increase to around 60 TWh electricity demand in 2030 and 80 TWh in 2040. To achieve the climate goals in 2030 and 2050, the electricity demand could increase even further due to additional potential emission reductions in the different sectors found by The Danish Climate, Energy and Supply ministry [2021]. Three sectors are highlighted for having an extra carbon reduction and electrification potential; households, transport, and industry.

Toward 2030, the electricity demand from households is expected to increase from around 1.6 TWh to around 3 TWh. With the additional potential being around 0.5 TWh, as can be seen in figure 2.6. This increase is due to a rising implementation of individual heat pumps that might occur. However, the demand increase will likely be smaller since district heating can also be beneficial when going away from individual fossil-based boilers, so some will instead choose district heating over individual heat pumps.

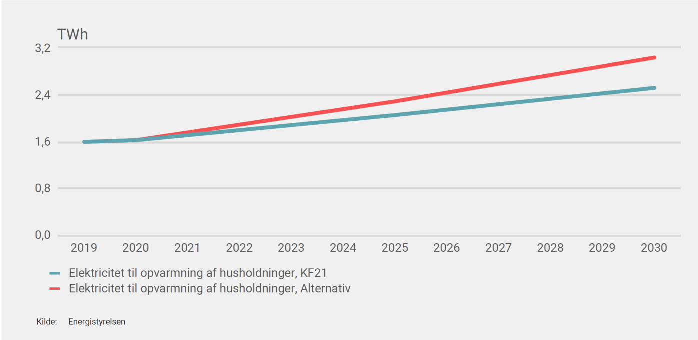


Figure 2.6. Additional electrification potential of households. [The Danish Climate, Energy and Supply ministry, 2021]

The analysis of the transport sector shows a major increase in electricity demand, going from close to zero in 2022 to an estimation of 6.4 TWh in 2030, see figure 2.7. The Danish Climate, Energy and Supply ministry [2021] however assumes a strict political focus on getting more electrical vehicles on the roads for this to happen, meaning that the electricity demand of charging electrical vehicles can vastly range from around 2.0 TWh to 6.4 TWh. This potential increase does not include hydrogen transport, in which the fuel demand can also increase the electricity demand.

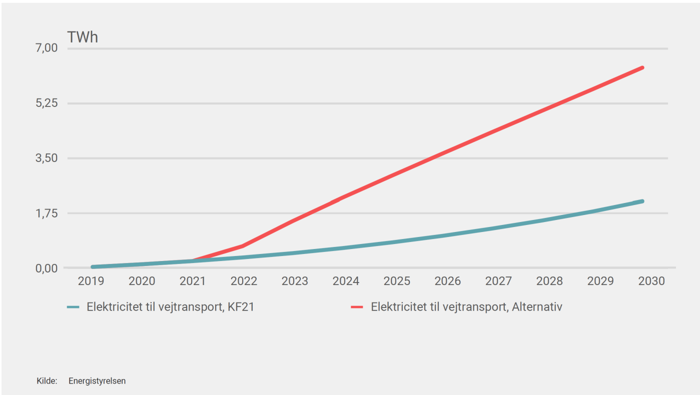


Figure 2.7. Additional electrification potential of transport. [The Danish Climate, Energy and Supply ministry, 2021]

Lastly, figure 2.8 visualises a potential increase to either around 29 TWh or 33 TWh electricity demand in the industry. It is highlighted by The Danish Climate, Energy and Supply ministry [2021] that electrification of this sector is set back by numerous barriers, with industrial machines not necessarily being replaceable by an electrical alternative. The surge in demand can vary depending on technological development.

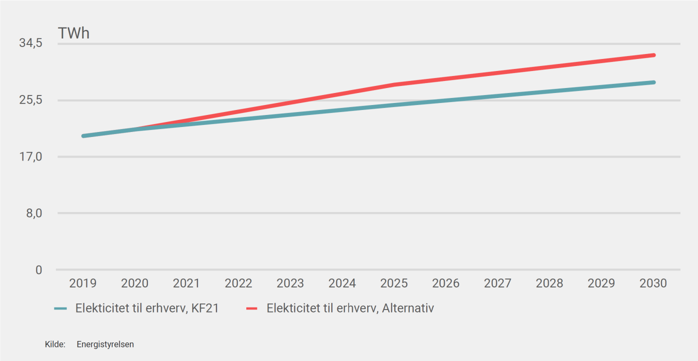


Figure 2.8. Additional electrification potential of industry. [The Danish Climate, Energy and Supply ministry, 2021]

In the analysis of these three electrification potentials, only *direct electrification* is mentioned. In The Danish Climate, Energy and Supply ministry [2021], electrification of the different sectors is divided into *direct electrification* and *indirect*, as not all energy-consuming sectors are viable for directly using electricity. The transition towards the use of green electricity will thus require different technologies to work together. Most of the Danish energy system is viable for direct electrification, but especially heavy transport and parts of the industry are deemed fuel dependent by The Danish Climate, Energy and Supply ministry [2021]. These are planned to be covered by Power-to-X, using green gasses, green fuels, or hydrogen. Biogas or carbon, together with water and electrolysis and powered by renewable electricity, has the potential to make fuel users renewable, but will also increase the electricity demand.

2.3 Power-to-X demand and plans & increase of RES supply

In December 2021, The Danish Climate, Energy, and Supply ministry [2021] published policies on the Danish approach to develop PtX to achieve the climate goals. The government aims to develop the PtX industry to achieve an electrolysis capacity of four to six GW in 2030. There are several reasons behind this commitment, first of all, outphasing fossil fuels in transport and industry. Also, The European commission has deemed PtX a necessity in reaching carbon neutrality, and Denmark has good conditions to support this policy, technically and economically. Denmark already has a suitable gas infrastructure, a huge potential for wind power, and a trade partner in Germany. But The Danish Climate, Energy, and Supply ministry [2021] also describes how the establishment of a PtX industry will also greatly increase the demand for electricity, which must be renewable to have a positive effect on carbon neutrality. One GW of electrolysis will roughly need the power of one GW offshore wind farm.
Although there are plans to increase the renewable electricity supply, the Danish government denies setting a firm goal for the share of renewable electricity in the system by 2030 [Lindqvist and Bernth, 2021b]. This is met by criticism from the Climate Council in the article of Lindqvist and Bernth [2021a], highlighting that with the potential surging demand from PtX, Denmark risks importing electricity generated from fossil fuels and having a negative impact on the global climate emissions.
Achieving the 2030 climate goal is critically described as more about producing less black energy than producing more green in the article of Lindqvist and Bernth [2021b], which means that there is a danger of pushing a significant amount of emissions across Denmark's borders, considering the possible increase in PtX demand and the vision of electrification.

To cover the increasing electricity demand, the Danish offshore wind capacity will continue to expand and is expected to increase approximately three times in 2030 compared to now, if not including the planned energy islands, see figure 2.9. As the yellow line in figure 2.9 shows, the offshore wind capacity should be around seven GW in 2030, but The Danish Energy Agency [2022b] describes that the capacity will decrease slightly because four wind turbine farms will shut down thereafter.

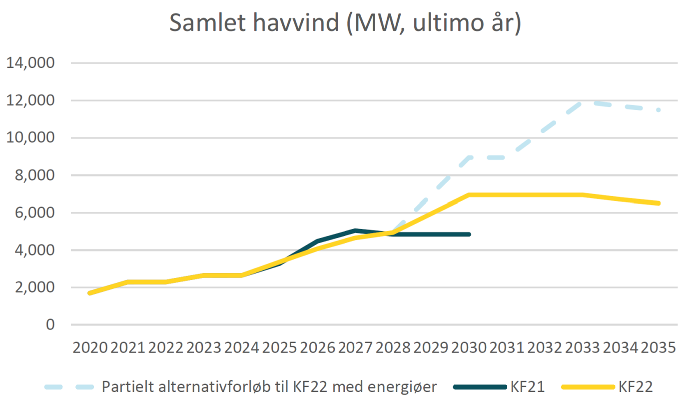


Figure 2.9. Predicted offshore wind capacity with and without energy island. The yellow line visualises the latest prognosis of offshore wind capacity without the planned energy islands, and light blue stippled line shows the same prognosis but with the energy islands. [The Danish Energy Agency, 2022b]

As described in The Danish Climate, Energy, and Supply ministry [2021], the PtX capacity is planned to be four to six GW in 2030, corresponding to the use of four to six GW of offshore wind power, which means that most of the offshore wind capacity could be used for PtX in 2030 if the PtX increases as planned. In addition to offshore wind turbine farms, a major source of renewable electricity supply will be energy islands, which should be operational in 2030 and 2033 [The Danish Energy Agency, 2022b]. They will add five GW capacity internationally, but it is unknown how much electricity will be traded between the connected countries, which depends on the market design [Tosatto et al., 2021; European Commission, 2020].

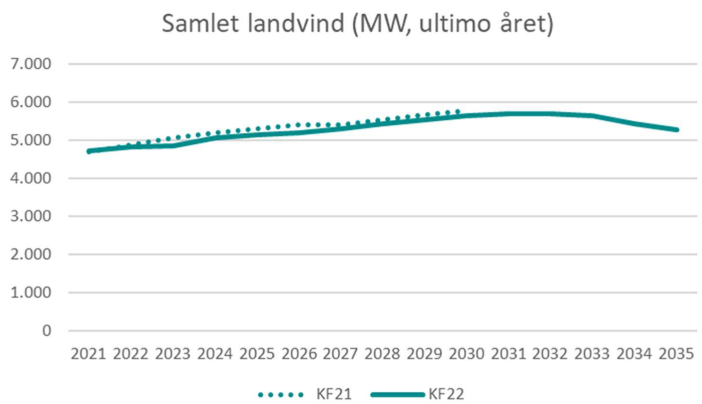


Figure 2.10. Predicted land wind capacity. [The Danish Energy Agency, 2022a]

Figure 2.10 shows a prognosis of the land wind-power capacity. Unlike offshore wind, it is expected to increase very little in comparison by going from approximately five GW in 2022 to six GW in 2030, and then falling slightly.
Of offshore and land wind power supply, offshore seem to get a significantly greater role in the green

transition. Especially given the fact that the electricity demand will increase vastly both with and without the uncertain electricity demand from PtX.

To achieve climate goals, Denmark will rely on three factors, which are either direct electrification or indirect, which means electrification of energy sectors, increasing electricity supply, and developing the PtX industry. The electricity demand is expected to increase significantly, with both electrification and PtX being heavy consumers. Furthermore, since electricity is not suitable in all sectors, the upcoming PtX industry plays a major role in the green transition. Development of the supply side is crucial as there is a risk of otherwise pushing the carbon emissions across the borders through import from fossil-based sources. This requires a scope on the supply side, primarily offshore wind, the electricity market, and the PtX demand. As Djørup et al. [2018] covers, the current electricity market design is not suitable for a major penetration of renewables into the market, and the PtX industry is still in the early stages of development.

2.4 Technical impact in the present system and market effect of RES and PtX

As per the previous paragraph, the expansion and integration of renewable electricity supply (RES) and PtX into the system is crucial, as covered in the Danish government's policy for a green transition. It is worth to be aware that to fulfil the planning and policies, a technical breakthrough and economic feasibility of applying PtX are not the only barriers. Changes in the energy mix of the system associated with a new technology on the demand side are expected to affect the market to some extent. Also, there is an existing problem regarding the design of the electricity market; the market does not coincide with high penetration of RES. There are market flaws and support schemes that has negative influence when increasing RES capacity in the long term. This will be explored, and afterwards will follow exploration of the effect of PtX in the present market setup.[Hu et al., 2018].

2.4.1 Challenges from a high RES share

As mentioned in section 2.3, consistent development of Danish renewable energy supply is shown in figure 2.11, where in 2020 50 pct. of the electricity supply of the Danish energy sector was covered by RES, which is four times higher than in 2000, where RES only covered 12 pct. of electricity consumption. [Christian Nepper-Rasmussen et al., 2021]

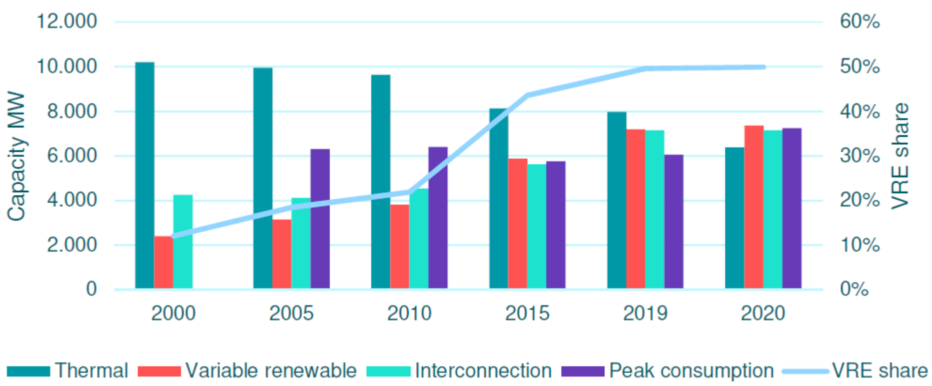


Figure 2.11. Development of VRE share from 2000-2020 [Christian Nepper-Rasmussen et al., 2021]

However, certain problems have been brought up considering the increasing RES capacity in the energy market. The energy market in use as of now was designed based on the dominating suppliers being adjustable and flexible fuel-based power plants, meaning that there would be a running cost for producing one additional unit of electricity. Hence, it is logical to have the market designed for suppliers to compete with their marginal costs with earlier gate-closure time, as supply is controllable. The characteristic of RES is principally opposite in the design, with intermittent but zero-cost energy resources, where the unit production costs almost zero but is relatively unstable and more difficult to predict. The advantage of low marginal cost results in RES most often being selected as suppliers and gradually rule out noncompetitive plants, which with time will mean ordinary power plants. There is a risk that the security of the energy supply is compromised with an incomplete number of flexible plants and storage systems.
Discrepancy between the investment characteristics of RES, the operation of RES, and the merit order mechanism used in the electricity market (DAM) has brought obstacles on the path to green transition, which will be elaborated in the next section. [Hu et al., 2018]

2.4.1.1 Merit order effect and suppliers' profitability

To begin with, in the setup of the electricity trading market in the EU, there are the; Day ahead market (DAM), Intraday market (IDM), and real-time balancing market, that are in use for short term period electricity trading as shown in figure 2.12.

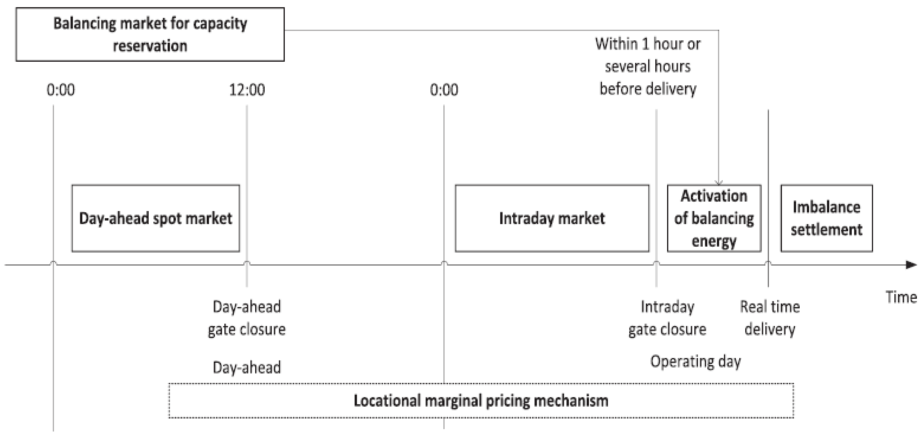


Figure 2.12. Electricity markets in use during different timeline [Hu et al., 2018]

As electricity can only be delivered in real time when there is a demand, the Day-ahead Market (DAM) and the Intraday Market (IDM) operate to secure a sufficient supply of electricity in real time. The bidders in the DAM schedule the supply and demand of electricity one day ahead, with gate closure time at 12 pm. In the DAM, electricity trading is conducted one day ahead with the bidding prices segmented into hourly basis. Following the merit order mechanism, all suppliers and buyers are screened by their respective marginal cost/willingness to pay unit price, and winners of the supply are those with a marginal cost cheaper or equal to the last chosen supplier. Therefore, the supply curve forms with a merit order in an ascending marginal cost. Vice versa for the demand curve with the willing to pay prices sorted in descending tendency, the interaction point of the demand and supply curve is viewed as the market clearing price for each unit of hour. The winning bidders, both suppliers and buyers, will then pay or sell with this uniform clearing price for electricity, as shown in figure 2.13. [Resch et al., 2012; Scharff, 2015]

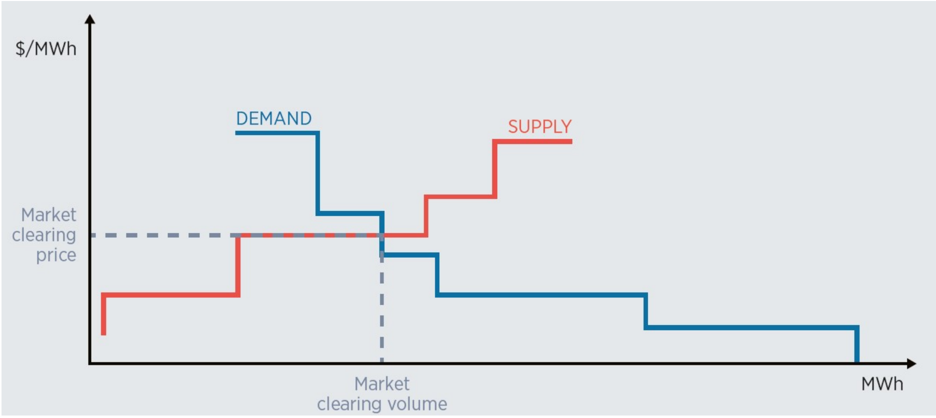


Figure 2.13. Clearing price of demand and supply curve.[Pérez-Arriaga et al., 2017]

By having the advantage of a low marginal cost due to a fuel cost of zero, RES most often successfully bid into the electricity supply and feed into the left-hand side of the supply curve, potentially ruling out the plants whose marginal cost is above the lowest willing to pay price in the hour. The merit order effect on figure 2.14 shows the impact on the electricity price of feeding in RES, where the supply curve shifts downward. Practically, it showcases how the merit order effect rules out the more expensive plants and result in a price drop when RES feed into the system. Figure 2.15 indicates the significance of the merit order effect with different values in the demand. Depending on the level of demand, reliance on different technologies as the last acceptance supplier can lead to a different level of clearing price. When the demand is lower, the clearing price would settle at a relative lower end, so the effect of using e.g. RES and excluding conventional plants is thus less significant. [Collins et al., 2015; Benhmad, 2014]

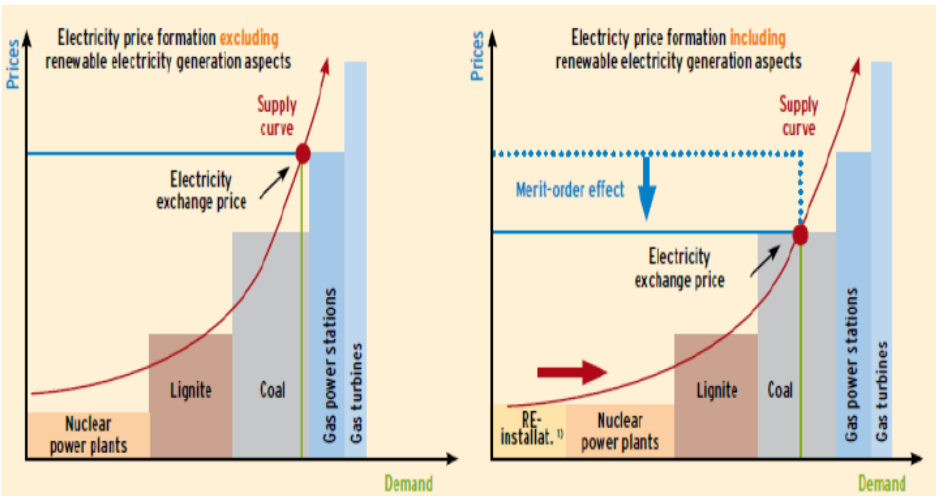


Figure 2.14. Merit order effect result by RES. [Benhmad, 2014]

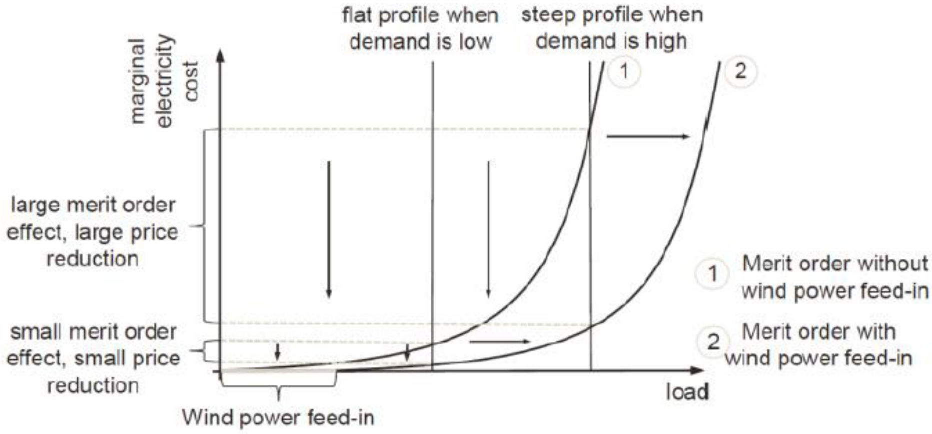


Figure 2.15. Right shifted supply curve. [Collins et al., 2015]

Therefore, when RES becomes predominant in the energy system, the electricity price should follow the decreasing tendency with non-competitive plants gradually being ruled out. As less competitive plants get fewer hours of operation, they make less profit, potentially only having marginal cost recovered. Such plants would gradually be crowded out. Meanwhile, considering that the clearing price is determined by the highest marginal cost among the accepted suppliers, the revenue of RES suppliers will also decline considering the merit order effect. It is concerned that with RES as a capital intensive technology, the low marginal price will not reflect the real cost of RES investment, undermining the market value by potentially endangering RES profit, once government support is lifted and RES transition to being the predominant type of electricity supply. [Sorknæs et al., 2020] Especially when nearing the 2030 or highly likely 2050 climate goal, the percentage of RES could increase to the point where economic problems begin to occur.

2.4.1.2 RES subsidies distort price signal

Instead of establishing a level playing field by defining a standard carbon emission tax quantifying and adding an additional tax directed towards conventional plants, the current EU ETS scheme has been criticised as a loose economic sanction in compensating the climate externality. Instead, benefits from support schemes to encourage investment in RES have been carried out by EU and EM. Among different support schemes, Feed-in premium (FIP), which is in use in Denmark, has been recognised as a more market-compatible subsidy type, which is characterised with mitigation of overcompensation, and compromise suppliers with a complementary to the market price, which differs from the flat-price Feed-in tariff (FIT) scheme. [Council of European Regulator, 2016] However, with the support scheme and above mentioned market design flaws, high shares of RES may distort the price signal in the electricity market, making the market incapable of accurately reflecting the market condition. In addition, as more conventional plants become crowded out, the low value price bidding of RES might impact the revenue of its own in the short run, especially when the technology matures, leading to difficulty to minimise extra cost with degressive support schemes. [Resch et al., 2012; Hu et al., 2018] The negative economic effect of the increase in RES in the system can occur merely by more RES suppliers winning bids and pushing traditional plants out. In addition, this trend can be strengthened by the subsidy schemes that are currently in use.

2.4.1.3 Limitation of scarcity price

With the market operating with a merit order mechanism, additional cap regulation with regard to electricity scarcity situations may require adjustment when the system gets RES increases. The last power plant's earning would only be the marginal cost and merely covering operational cost but not fixed cost. Also, expanding RES generation only lowers the frequency of spike price occurrence. The cap of the spot price, so-called scarcity price, is set to be lower than the value of lost load (VOLL), which is an average acceptance price level of the consumer's willingness to pay for electricity and avoid involuntary curtailment of consumption. However, if the scarcity price is set too low below the VOLL, it can cause a missing money problem where the scarcity price-dependent plants could earn more but are limited due to cap regulation. [Hu et al., 2018]

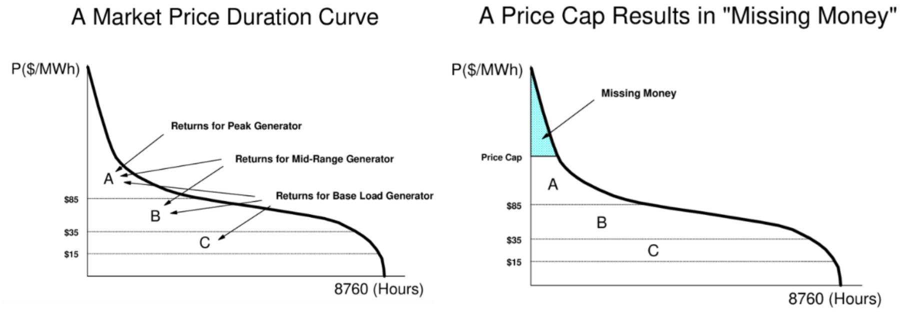


Figure 2.16. Missing money problem under regulated price cap.[Hogan et al., 2005]

Intermittent electricity production calls for more flexibility, but potentially falling electricity prices endanger the economic feasibility of backup power plants. Thus, it would seem that there is a risk that all electricity suppliers suffer without a market overhaul, as the green transition progresses.

The total spot market price (lifetime revenue) should be able to compromise the lifetime cost of the RES, so that both CAPEX (capital expense) and OPEX (operational expense) of the RES are covered. However, the spot market price can differ due to various reasons from both the demand and supply side. Therefore, it is interesting to further explore the effect and impact of the operation mechanism when there is a high level of RES in the energy mix and a new demand technology, PtX. Furthermore, search for a strategy to develop these technologies in an efficient manner.

2.5 Power-to-X and the electricity market

Section 2.4 describes the challenges of a major increase in RES in the electricity market. But instead of researching how to completely restructure the electricity market, there is a small amount of research that instead analyses the interactions between different markets and synergies between technologies across sectors. The analysis of Sorknæs et al. [2020] focusses on the impact of the electricity price on fuel prices and vice versa. In this paper, the energy system is a completely carbon neutral system, which means there is a high share of wind and photovoltaic (PV), with biomass and biogas-driven plants as well.
Sorknæs et al. [2020] links energy markets in various ways, e.g. through CHP that uses gas to produce heat and electricity, but also by using electricity to produce gas, known as PtX or electrofuels. This type of gas adds a product to the gas market, affecting competition and, thereby, price.

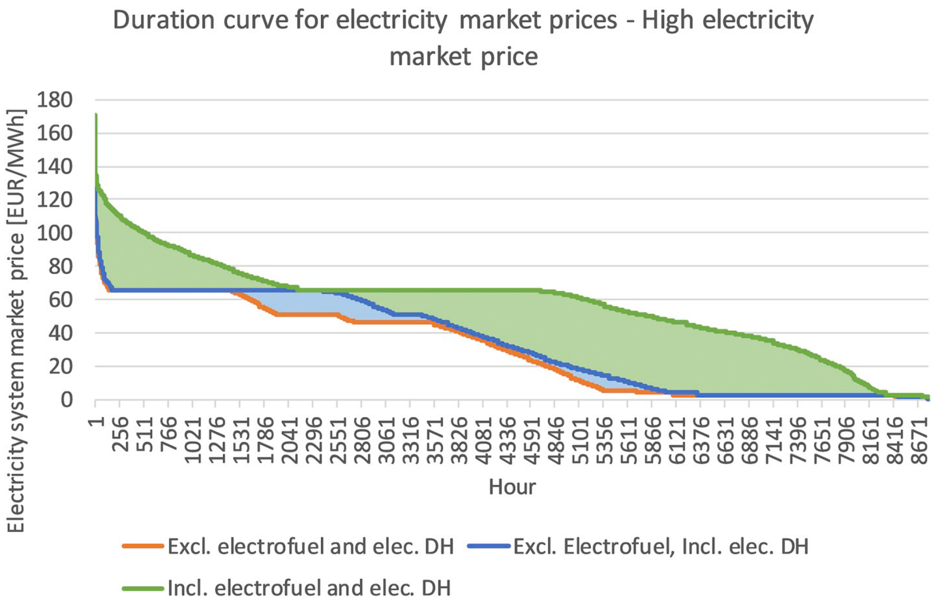


Figure 2.17. Visualisation of elctrofuels (PtX) influence of electricity prices using duration curves. Line is without electricity to heat or PtX, green is including power to heat in DH, and the blue line is with PtX and Power to heat. [Sorknæs et al., 2020]

The important results from this paper and the figure are not the specific changes in fuel prices, but rather the **trend** of using electricity to produce fuel, from a market perspective. Figure 2.17 visualises the results found by Sorknæs et al. [2020], showing three scenarios in a duration curve figure. The orange line demonstrates the electricity price without PtX production or large-scale electrical heat pumps in district heating, thus without connection to the gas sector. As can be seen in figure 2.17, a price of 0 or close to 0 occurs for more than 3000 hours, and the price peaks around 200 hours in a year. Adding electrical sources to district heating decreases the number of hours with a price of around 0 to approximately 2500, and about the same number of peak hours occurs. A major change follows when using PtX (electrofuel) production in the system; see the green line and field on figure 2.17. The number of hours with an electricity price close to 0 or 0 EUR/MWh is reduced to around 500. Also, the price rises to above 60 EUR/MWh in more than 2000 hours, which is a major difference from the other scenarios.

On the other hand, Sorknæs et al. [2020] also shows the impact on the production cost of green fuels with different levels of electricity price, in which green fuels produced with the hydrogenation process have an obvious increase in production cost when the price of electricity increases, as shown in figure 2.18. Based on figure 2.12, a rough calculation shows that there is an about 37 to 50 pct. increase in the green fuel production cost as the electricity price increases about 2.5 to 3.0 times depending on the fuel level, shown in 2.19.

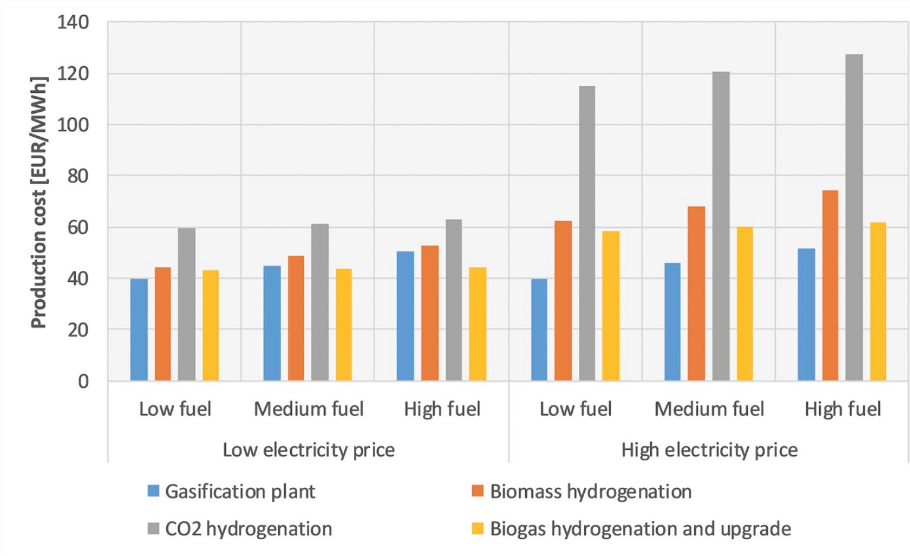


Figure 2.18. Fuel prices under different electricity prices. [Sorknæs et al., 2020]

Table 5
Data from the IDA2050 scenario at the two different electricity market price levels and three different fuel price levels.

[EUR/MWh]	Low electricity price level			High electricity price level		
	Low fuel	Medium fuel	High fuel	Low fuel	Medium fuel	High fuel
Average electricity price in Denmark	19	20	21	53	57	61
Average electricity price for electrolysers	19	20	21	53	56	60
Value of produced district heating	7.9	11.5	13.0	10.6	10.3	10.5

Figure 2.19. Fuel prices in numbers under different electricity prices. [Sorknæs et al., 2020].

Although the analysis of Sorknæs et al. [2020] has been carried out using a carbon neutral system, it shows a large number of hours with very low electricity prices when the system relies heavily on RES. The results also show that PtX production pushes up the electricity price due to the significant increase in electricity demand. Therefore, the use of PtX could have the potential to counteract the issue of the decline in electricity prices under current market conditions, potentially balancing the economics of the system.

The Danish energy system is getting ever increasing renewable supply to reduce carbon emissions and eventually become carbon neutral. As the renewable share increases, more and more fossil-based power plants are being ruled out by renewable technologies in the electricity market according to the merit order effect. With a high enough production of electricity from renewable sources, there is a possibility of a low, zero, or negative electricity price. A prolonged occurrence of low to negative electricity prices can mean that investing in RES becomes an unsustainable business case. PtX has shown the opposite effect on the electricity price, namely, it is increased with the immense demand that follows. However, there is uncertainty as to how much will be invested in PtX and when the facilities will be in operation. Therefore, this project will investigate whether RES in a Danish energy system model lowers the electricity price, whether PtX increases it, and whether there can be created synergy effects from adding both. In addition, economic and market parameters will be the main evaluation area.

3 Research question and subquestions

- *How can a strategic development of offshore wind supply and Power-to-X contribute to a steady commercial and technical green transition in a multi actor situation, with a goal of finding a balance around individual profits and social welfare?*

To answer the research question, it is practically divided into two subquestions, each of which will be answered through a respective analysis. The first subquestion concerns knowledge building, and the second is focused on using the knowledge.

- How will individual development of offshore wind supply and Power-to-X production impact the energy system on self-sufficiency, private and socioeconomics, and carbon emissions, under three possible external market prices?
- What are the relative optimal market economic, socioeconomic and environmental benign balance strategies when using the interactive development of offshore wind and PtX?

Research design 4

This project follows a classic structure, from the problem field to research questions to analyses. As can be seen in figure 4.1 two subquestions support answering the main research question. A game-theoretical approach is part of both analyses. The first analysis only uses simulation, whereas the second analysis contains both simulation and optimisation. EnergyPLAN is the chosen simulation tool. Analysis one and two lead to a discussion of the results in different perspectives and then follow a conclusion. The conclusion consists of an answer to the main research question, and before that are recommendations, practically also a summary of the analyses results.

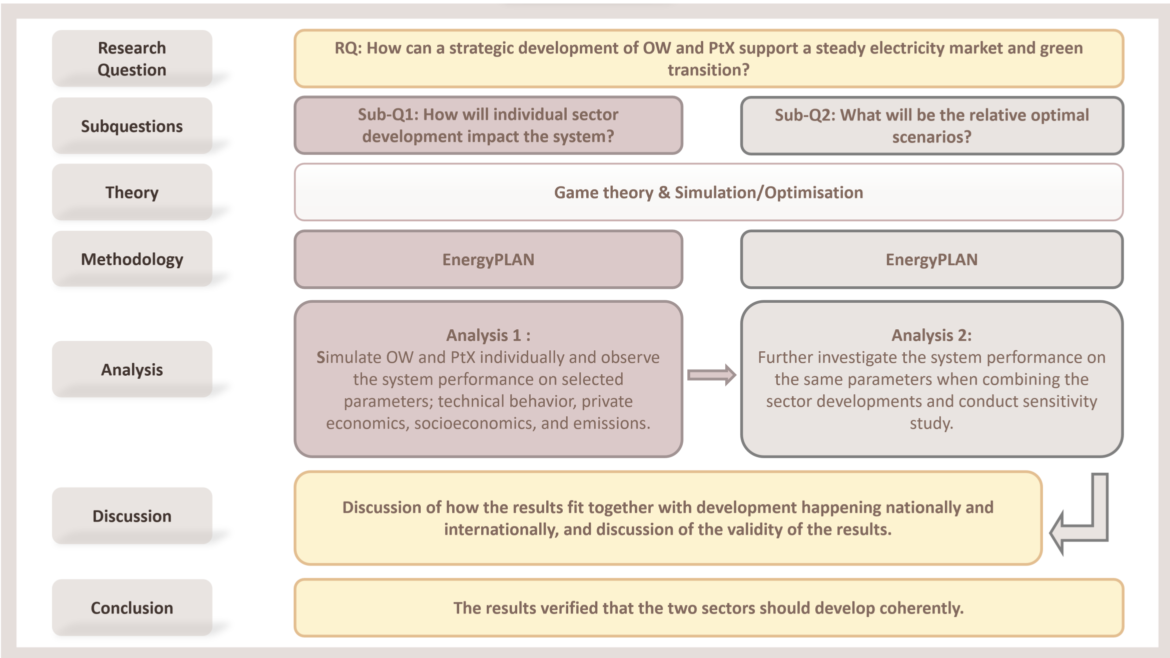


Figure 4.1. The structure of the thesis.

Concepts 5

The concept of smart energy systems will provide some areas of focus for the analyses. Additionally, the energy systems analysed will be evaluated in relation to this concept.

5.1 Smart energy system concept as an analytical basis

Dincer and Acar [2017] presents eight constituents of a smart energy system, see figure 5.1. These are described by the authors as expectations of a smart energy system in the development of the system *smart*. In so, the development of the energy supply is expanded further than focussing strictly on renewability, but address issues of being competitive with the current supply and being realistically integrable as well. This view of a smart energy system and the progression towards carbon neutrality is linked with the findings of chapter 2, on the problems of keeping renewable technologies competitive and the system flexible.

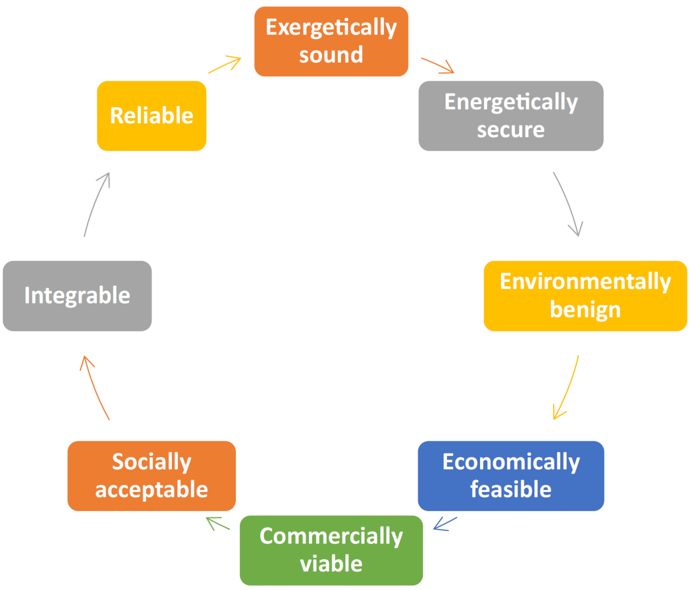


Figure 5.1. Aspects of a Smart Energy System. [Dincer and Acar, 2017]

As seen in figure 5.1 there are a total of eight expectations for a smart energy system:

- Exergetically sound; the system should uphold a high efficiency when converting from primary energy to usable secondary energy.
- Energetically secure; the system needs to be reliable, secure and self-sufficient from locally available energy sources.

- Environmentally benign; the core of a smart energy system, it should be as clean as possible throughout the whole value chain, minimising emissions and resource use.
- Economically feasible; rather than being a socioeconomic burden, the system should be affordable, efficient and provide economic benefits to the society.
- Commercially viable; the technologies constituting the system should rely on available resources and be competitive under the market conditions rather than relying on import and subsidies.
- Socially acceptable; using new technologies should be accepted by the communities, not compromising daily lives.
- Integrable; shifting towards use of different technologies means that they need to be integrable without having to substantially changing the existing system, but instead constructing synergy effects between different technologies.
- Reliable; though local renewable energy sources vary in type and pattern, a smart energy system needs to have a reliable level of service.

The eight different expectations will function as points of investigation in the analysis chapter 8, but not all expectations are relevant focus areas as per chapter 2 and the research question, section 3. Four expectations explain goals related to the issues found in the sections 2.4 and 2.5; economically feasible, commercially viable, integrable and reliable. These revolve around making the energy system technically and economically feasible, market competitive, and flexible, which reflects the obstacles of increasing RES for renewability and PtX for flexibility, without also getting immense investment costs and an electricity price so low investors cannot get a return. These will be further specified.

Economically feasible: Section 2.4 explains the issues of implementing renewable energy to the point where the electricity price might fall. The obstacles may not be finding funding for renewable energy projects, but keeping the system economically feasible as the RES share increases. Economic feasibility is expected of a smart energy system and therefore keeping RES projects affordable throughout the green transition is crucial. This expectation by Dincer and Acar [2017] leads to the analysis of the impacts of increasing RES and keeping a steady market.

Commercially viable: An uncertainty and potential barrier in transitioning to a high-renewable energy system is the current electricity market design as per section 2.4. As highlighted by Dincer and Acar [2017], an important part of a smart energy system is renewable technologies that can compete in the electricity market. A crucial challenge presents itself through this dilemma. For the Danish energy system to undergo a major *renewabilization*, as Dincer and Acar [2017] defines the substitution of fossil-based supply; technical and market system behaviour, performance, and synergies needs to be analysed. The results from the problem analysis and the concept of commercial viability being a core of smart energy systems serve to underline exploration of performance in the electricity market and in so steer the first and second analysis.

Integrable: Dincer and Acar [2017] describes the importance of integrating new technologies without radically changing the energy system. To achieve the 2030 goal, the energy system is planned to rely more heavily on renewable supply according to section 2.2, thus facing an obstacle in the potential electricity price issues and thus risking integration issues. The importance of integration points to explore both the supply side and the demand side for a feasible integration of RES. PtX adds flexibility to exploit large amounts of cheap renewable electricity, and thus has the potential to counteract the falling electricity price. The *integrable* aspect of a smart energy system denotes the incorporation of RES *and* PtX analysis, so both the supply and demand side, to investigate *hydrogenization* to achieve integration. That is, using hydrogen production to achieve economic and environmental benefits.

With a conceptual overview of a smart energy system and these three expectations, the progress and challenges of transitioning to a green system are clear. Dincer and Acar [2017] provides this project with an understanding of how to a smart energy system and, thereby, what targets to prioritise in the analyses.

Theory 6

Game theory, simulation and optimisation theory constitute the theoretical skeleton of this project. These three theories are key factors as to how the analyses will be conducted and knowledge built, and so will first be explained in general, with how they are used specifically following.

6.1 Game theory

Undergoing the green transition, the energy system will undeniably become more interlinked. However, the system will also become more complex, with many technologies working together to maintain a high level of security, flexibility, and affordability. This project has through chapter 2 highlighted two industries as key factors in reaching the 2030 and 2050 climate goal; the offshore wind industry and the PtX industry. These industries, although linked, are separate industries and will be treated as different actors in the energy system with individual objectives. This view is a result of the uncertainty around the development of OW and PtX as found in chapter 2, where each sector might increase the capacity within a certain range, but there is criticism floating around concerning concrete steps of development. Perceiving the industries as individual actors means taking individual objectives into account, meaning their actions will prioritise their own benefit rather than overall welfare. Such individual strategising can be explained and explored using game theory, namely; cooperative and non-cooperative game theory [He et al., 2020]. As explained by Basar et al. [2010], herein actors are seen as players playing the game for their own sake, with choices affecting other players. Practically, this is about the OW and PtX sector maximising their own welfare through development.
In the following subsections, the difference between cooperative and non-cooperative game theory will be explained, likewise how the two variations of game theory explain strategy making of different actors in the energy system, and the connection to the analysis and benefit of using game theory.

6.1.1 Cooperative and non-cooperative game theory to explain actor strategies

General game theory concerns strategy and decision making when there are two or numerous actors trying to maximise benefits or minimise losses through some choices. Actors, also called decision makers, are perceived as players playing a game and their actions influence each other [Basar et al., 2010]. Before going into *game rules*, it should be noted that there are at least two distinctive game theories to be aware of; cooperative game theory and non-cooperative. The essential of cooperative game theory is maximising individual profit by forming an alliance or alliances, thereby acting together in a coalition and splitting the benefits [Elkind and Rothe, 2016]. Although a coalition is formed and the benefit is shared, cooperative as well as non-cooperative game theory both centre around maximising individual profit. For both game theories, this is achieved by reaching a form of equilibrium, which can differ depending on the game being cooperative or non-cooperative. The equilibrium is understood as a solution in which the payoff for each player (actor) cannot change for the better by taking any further actions - often defined as the Nash equilibrium. [Basar

et al., 2010].
Three main elements that must be defined when using the Nash equilibrium are the number of players (N), strategies (S), and utilities (U). Any number of players can be included in a game theory analysis as per He et al. [2020] and is by expression denoted as:

$$\{N = 1, 2, ..., n\} \tag{6.1}$$

Where N is the number of players, each of the players can form their own set of strategies which can be finite or infinite depending on the case and is hereby expressed as:

$$\{S = S_1, S_2, ., S_n\} \tag{6.2}$$

With S being the strategy and the number representing the respective player carrying out set strategy. At last each player will have individual profits or losses as products of the total:

$$\{u = u_1, u_2, ., u_n\} \tag{6.3}$$

An important aspect when diving into game theory is determining whether the situation (game) is cooperative or non-cooperative. One way to decide this is to look into whether the actors (players) are competing or not, yet it is not the deciding element. For a situation to be cooperative, a coalition has to be formed and joint actions taken, as mentioned by Elkind and Rothe [2016]. From the planning documents investigated in Chapter 2, there is no evidence showing official agreements and planned coordinated actions to be taken between the OW industry and the PtX industry and therefore no real coalition shown, this suggests the current situation between the industries being non-cooperative. However, chapter 2 also shows opposite effects on the electricity price and market, thereby making the two industries non-competitive. This leads to another part of the final game situation; if the respective players stand to lose if another wins, that is, the classification of the game as *zero-sum game* or *nonzero-sum game*. A zero-sum game means that the profits of one player are equivalent to the loss of another, meaning that the game is in a state of competition with non-cooperating players. Vice versa, a nonzero-sum game is less restricted in which one player's gain will not necessarily be equivalent to another player's loss. All players can profit or lose. Given that the OW and PtX industries are on the supply and demand side, respectively, and do not compete, the situation is *nonzero-sum game*. [Basar et al., 2010].

6.1.2 Non-cooperative game theory for investigating the OW and PtX sector interaction

Game theory clarifies certain aspects of the multiple technology development of the green transition, by explaining that there are then also multiple actors with individual objectives and strategies to reach them. This first and foremost points towards not seeing the green transition as one big whole but taking into consideration technological and actor complexity. Game theory thus provides a clear view that is; **green transition takes actions from multiple players**. According to chapter 2, a significant part lies in the electricity sector, but not all sectors are suitable for direct electrification. Therefore, green fuels are also needed, which requires more actors. The penetration of renewable electricity could have a *"damaging"* effect on the electricity price, in that the electricity market is not built for renewable supply to set the electricity price, but PtX can inversely raise the electricity price. There is a multi-actor situation with different actions to take. OW The purpose of using game theory is thus to explore an uncoordinated development in two sectors, to determine if it is actually in the actors' own interest to develop industries simultaneously.

6.2 Simulation to build knowledge, and optimisation to balance it

This project will follow two theoretical approaches in the analyses, simulation and optimisation. Each approach deals with constructing a model that can show *future*, but they have different purposes and benefits, and therefore using both will create a more holistic analysis. Simulation offers an exploratory investigation, highlighting certain outcomes of the choices made. Alternatively, optimisation is target-orientated, typically searching for a future around a single constraint such as lowest cost. Both are relevant because the two analyses will be different in nature; where the first analysis is centred around building knowledge and discovering tendencies, the second instead searches OW and PtX balancing around economic parameters. Although both will be included, the working method will lean more towards simulation, mixing in elements of optimisation. In the following subsections, general descriptions of the two theoretical processes will follow and how these tie into the analyses and what they offer the project.

6.2.1 Simulation in general

Simulation concerns discovery, exploring futures, and specifically for energy planning, investigating how an energy system behaves under certain conditions. The focus is not necessarily on using simulation to build a model but rather on testing how the model performs. This makes simulation great for building knowledge, as it allows for a thorough learning process of testing how conditions impact a system, potentially giving a transparent overview of numerous important factors. The approach is also suited for making comparisons between models. This theoretical process is a more open analytical way, with the possibility of including several criteria, rather than building around a single constraint. If the analysis is complex in nature, with numerous parameters to be included, simulation provides an open method that can balance each parameter. However, openness also means that many decisions are taken outside the model, which has pros and cons, since the model greatly depends on the modeller and decision makers. [Lund et al., 2017]

6.2.2 Simulation to discover technical and economic impacts

Through chapter 2 it was found that increasing the capacity of OW and PtX can have *negative* market effects individually, by either lowering the electricity price to a not profitable level, or increasing the demand, and thus price and possibly import from fossil-based supply. However, hypothetically, increasing the capacity of both technologies should balance the effects and decarbonise the system by implementing more renewable energy in the system. To validate these potentials, the first analysis will be based on simulation. The hypothesis is that OW and PtX will have the mentioned effects in a Danish energy system model, but simulation and testing will validate this and make the effects numerical and concrete. Methodologically, a Danish energy system model will be used as a basis, and the two technologies will be progressively increased. The reason for choosing simulation is the purpose of the approach and the benefits it brings. With it, technical tendencies and economic trends can be discovered when changing capacities of either technology, and two systems with significant differences in OW and PtX can be compared. Additionally, this project concerns both the market and the environment, meaning that there are numerous parameters to be aware of rather than a single constraint. Decision-making around several economic parameters and carbon emissions can and will be balanced outside of the chosen model software. [Lund et al., 2017] Simulation is thus the primary theoretical approach and will be fully dominant in the first analysis. In the second analysis, the approach changes.

6.2.3 Optimisation in general

Optimisation concerns building towards a goal under one or a few constraints, where it is understood that there is a single optimal future to work towards. Rather than exploring, a range of input is used for a software to construct a configuration of technologies and capacities. Decision making lean more towards the initial part of the process, when choosing inputs and modelling, rather than later. Often, economic considerations are the most important choices of optimisation modelling, choosing a single (often economic) value to model around and the discount rate to account for. Optimisation separates from simulation in being highly goal orientated and less suited for comparison between results. [Lund et al., 2017]

6.2.4 Optimisation for strategy making

The optimisation process comes into play in the second analysis, but rather than an optimisation tool, it is the goal and purpose of it, that is interesting and beneficial. Denmark and the Danish energy system face potential obstacles, meaning that solutions to these might become requirements, according to chapter 2. The idea of searching for solutions will be adopted in the second analysis and built upon the first. After verifying *powers* in the market of OW and PtX, the technologies will be used to search for a range of *optimal* alternatives, balancing the two technologies around several parameters. An optimisation software building around a chosen input is not the selected approach, rather it is simulating, understanding, and simulating again, to be able to create a strategy of development in the OW and PtX sector. The belief is that there is perhaps not a single optimal strategy, but strategies that are more optimal than others. Concentrating on a single or few constraints is in this project too narrow a focus. When multiple actors are involved in a game-theoretical-based analysis with multiple parameters as well, optimisation theory sets a path towards a desired scenario where the electricity market is balanced and carbon reduction goal fulfilled. The second analysis thus arrives at a highly mixed simulation and optimisation approach, with the mindset of optimisation, but using simulation to understand, learn and continuously optimise on past results.

6.3 Theoretical framework

One concept and a number of theories are presented that each contribute something different to the project. There will be two analyses, and these will have different goals and starting points. The theoretical framework will present how the chosen theories build the background for the analyses, show how everything is connected, and help provide a structured analytical investigation of OW and PtX in the energy system.

6.3.1 From a theoretical starting point to answering subquestions

Conceptual knowledge of a smart energy system is the offset of the analysis. Moving closer to the climate goals, the energy system becomes increasingly more sectorcoupled, and thus transitions towards what is defined as a *smart energy system*. To gain an understanding of what will be modelled towards in the analyses, the smart energy system concept serves as background knowledge in this project, pointing out important parts of an the energy system. In the concept, eight aspects are highlighted as crucial. Herein three are chosen; economically feasible, commercially viable and integrable, as they match the barriers presented in chapter 2. Knowing the key areas of a smart energy system, game theory enters the picture. Economic feasibility, commercial viability, and integration point towards economics, the market, and complexity in the system. Game theory can help investigate in a structural matter, and thus shapes the starting points and foundation of the analysis. Game theory concerns economics and is additionally used to divide the energy system into a form of multiple actors, with the OW sector as one and the PtX sector as another. It builds upon the conceptual key areas from smart energy systems and is used to structure the analysis into a multiple actor and strategy analysis, with the goal of deriving optimal economic strategies. The actions taken by the actors are seen as separate based on the knowledge of chapter 2 and the explanations of game theory.

Simulation and optimisation are used, similarly to game theory, for constructing the analyses. Knowledge of game theory will be used to create a starting point for the first analysis, and then first simulation and since optimisation will be used to carry out the analyses. The theory explains the benefits of either approach. Simulation and optimisation theory are means to answer the two subquestions in chapter 3.

Methods 7

To explore an optimal energy planning strategy with a focus on the development of OW and PtX, the project is designed based on the concept of non-cooperative theory through two analytical phases. The first analysis involves a different development strategy for each of the technologies, OW and PtX. This phase provides a closer and transparent observation into how selected parameters are affected, and the corresponding outcomes. Followed by the second analysis where the system will be tested out with the demonstrated strategies from the previous analysis, in order to search for the optimal planning strategies which fulfil green transition as well as investor benefits.

7.1 Analysis one and two

Herein the methods of the two analyses will be presented. Most methods will be used in both analyses, but analysis two will have some additional methods.

7.1.1 Simulation of OW in EnergyPLAN

With the two analyses having differences in the theoretical basis, they will be presented individually, but with the methodology of the second analysis being based on the first and therefore referring to the methodology of the first. Starting off, a description of the exploratory analysis will be provided in which the increase in OW and PtX is separated. Herein, the connection to the theory is explained, and the following will be the presentation of the base scenario choice, how OW and PtX are increased, how a sensitivity will be carried out, and the purpose it serves.

7.1.1.1 EnergyPLAN as the tool

Section 6.2 describes how simulation is the primary theoretical basis for conducting the two analyses. A fitting software is EnergyPLAN. The software is an exogenous simulation tool that is primarily designed for a national or regional scale, executing a one-year simulation that shows the behaviour of an energy model under a predetermined set of conditions. Based on these characteristics, EnergyPLAN is chosen; as per section 6.2, the first analysis seeks to discover how two sectors influence the whole system and earnings individually. The purpose, at first, is not to refine the model and make decisions through EnergyPLAN, but to discover tendencies when altering the OW and PtX - an exogenous simulation tool thus makes sense as it is also fitting for exploration. Moreover, the scope of this project is the Danish energy system and the relation to the electricity market primarily, and also to the hydrogen fuel market. A one-year simulation is easily treated as a milestone year. This project concerns a transition period, where the energy system goes from containing some fossil-based energy production to more renewability; in the energy planning in this project, this translates into a given year between 2030 and 2045. [Lund et al., 2017]

To evaluate the importance of developing offshore wind and PtX sectors individually, certain parameters are selected to provide a deep insight into the potential consequences. These will be a mixture of technical performance, private economics, socioeconomics, and environmental impact. These also closely link to the selected requirements for a smart energy system; economically feasible, commercially viable, and integrable, as covered in the chapter 5.1. The parameters are:

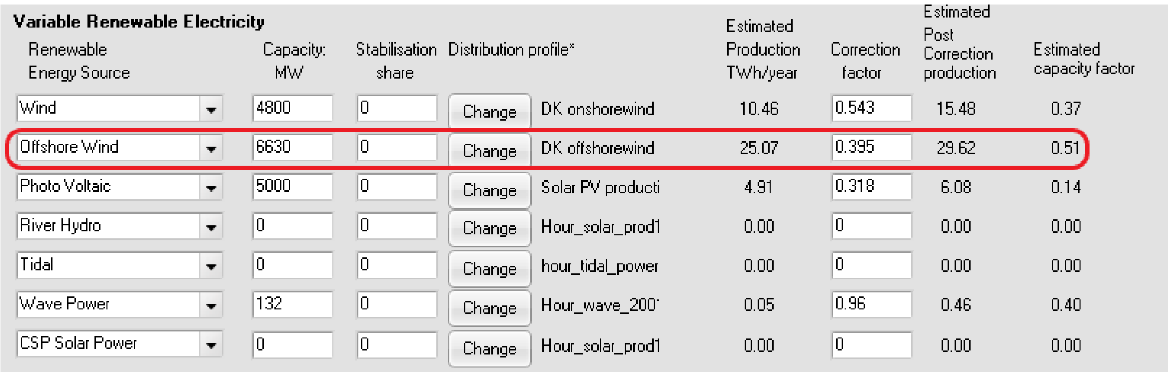
- **Technical performance** as import/export, to evaluate the infrastructural realism of developing the sectors separately: This will be analysed through extracting the import and export flow in TWh, and comparing the two to each other, and investigating if there is an economic gain or loss.
- **Private economics**
  - Investigate the long-term profits of offshore wind investors to determine the long-term feasibility and business case: Using LCoE, production, and the inmarket electricity price, this will be analysed by calculating the revenue and subtracting the total annualized cost.
  - Investigate short-term profits of offshore wind investors to determine short-term feasibility and business case: The short term profit will be analysed by instead extracting the O&M cost and use the electricity inmarket price and production.
  - Investigate the increase in PtX fuel costs to determine the feasibility of producing green fuels.
- **Socioeconomics**
  - Investigate the total annual cost to determine the overall socioeconomic impact of increasing offshore wind or PtX individually. This will be analysed using the total annual cost from EnergyPLAN and compare across all scenarios, to investigate how the cost develops.
  - Investigate the bottleneck cost to determine how much individual development pressure transmission and balancing: The analysis of the bottleneck cost will follow the same method as the total annual cost.
  - Investigate the electricity price to gain insight into the consequences for the consumers. To investigate the electricity price, the annual average inmarket electricity price will be the main source of investigation, where all prices will be sorted from the first scenario to the last, using all external market prices. The inmarket price spikes will similarly be included.
- **Environmental impact**
  - Investigate CO_2 emissions to determine the progression toward carbon neutrality: Carbon emissions will be extracted from EnergyPLAN to determine whether carbon emissions increase or fall as the energy system changes.
  - Investigate CO_2 emissions impact on the society as an external cost: A cost of 60 EUR/ton will be multiplied with the carbon emissions to also determine the carbon emissions' external cost.

7.1.1.2 The base scenario, a pessimistic IDA 2030 scenario

In the problem analysis, specifically in sections 2.4 and 2.5, potential issues with rising OW and PtX are brought forth. These issues may only arise as the energy system progresses toward renewable sources dominating the electricity supply and become dominant under the current design of the electricity market. Another problem might be the lack of sufficient amounts of renewable electricity as the electricity demand from PtX increases. This happens if either OW or PtX increases without the other, as there is a potential for the sectors to balance out the potential issues. As the findings indicate that there must be a larger amount of renewable electricity and some demand from PtX, the IDA 2030 energy system model is chosen. An IDA

2030 and 2045 model is freely available to EnergyPLAN users, and the 2030 model will be the base model. The important parts of the 2030 base model are highlighted below, in figures 7.1, 7.2, 7.3, 7.4, and 7.5.

Figure 7.1 shows a starting point of 6,630 MW offshore wind, which is slightly less than what The Danish Energy Agency [2022b] estimates i 2030, perhaps making the IDA 2030 model more of a 2027 - 2030 model. Offshore wind will represent the renewable electricity supply sector. According to The Danish Energy Agency [2022b] and as can be seen in 2.9, offshore wind is the fastest growing renewable electricity supply, and in the IDA 2045 it is still the most dominant in 2045.

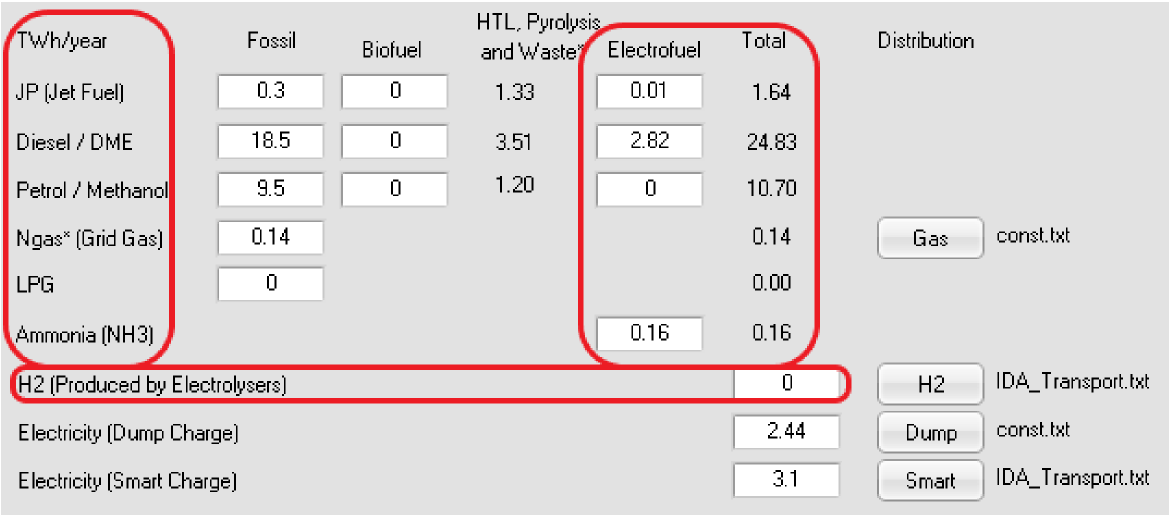


Variable Renewable Electricity

Renewable Energy Source	Capacity: MW	Stabilisation share	Distribution profile*		Estimated Production TWh/year	Correction factor	Estimated Post Correction production	Estimated capacity factor
Wind	4800	0	Change	DK onshorewind	10.46	0.543	15.48	0.37
Offshore Wind	6630	0	Change	DK offshorewind	25.07	0.395	29.62	0.51
Photo Voltaic	5000	0	Change	Solar PV producti	4.91	0.318	6.08	0.14
River Hydro	0	0	Change	Hour_solar_prod1	0.00	0	0.00	0.00
Tidal	0	0	Change	hour_tidal_power	0.00	0	0.00	0.00
Wave Power	132	0	Change	Hour_wave_200	0.05	0.96	0.46	0.40
CSP Solar Power	0	0	Change	Hour_solar_prod1	0.00	0	0.00	0.00

Figure 7.1. Highlight of offshore wind capacity.

The following figure 7.2 points out the PtX transport demand in a more pessimistic 2030 model. Although 2.82 TWh of E-diesel is used, the PtX sector is still in very early development in this model.



TWh/year	Fossil	Biofuel	HTL, Pyrolysis and Waste*	Electrofuel	Total	Distribution	
JP (Jet Fuel)	0.3	0	1.33	0.01	1.64		
Diesel / DME	18.5	0	3.51	2.82	24.83		
Petrol / Methanol	9.5	0	1.20	0	10.70		
Ngas* (Grid Gas)	0.14				0.14	Gas	const.txt
LPG	0				0.00		
Ammonia (NH3)				0.16	0.16		
H2 (Produced by Electrolysers)					0	H2	IDA_Transport.txt
Electricity (Dump Charge)					2.44	Dump	const.txt
Electricity (Smart Charge)					3.1	Smart	IDA_Transport.txt

Figure 7.2. Highlight of fuels that can be converted to E-fuels through PtX.

To meet the demand for E-fuels in the last figure, figure 7.3 shows the required production of combining CO_2 with H_2, in TWh. With CO_2 hydrogenation liquid E-diesel and other E-fuels can be produced, ammonia (NH_3) is independent, however. The figure also shows a required CO_2 storage.

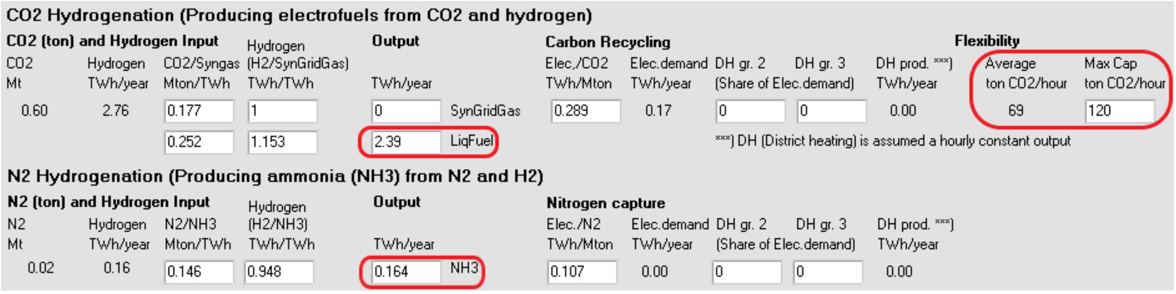


Figure 7.3. Highlight of CO_2 hydrogenation, NH_3 production and carbon storage.

Figure 7.4 simply shows the difference between demand and production. In the 2030 model there is slightly higher production than demand.

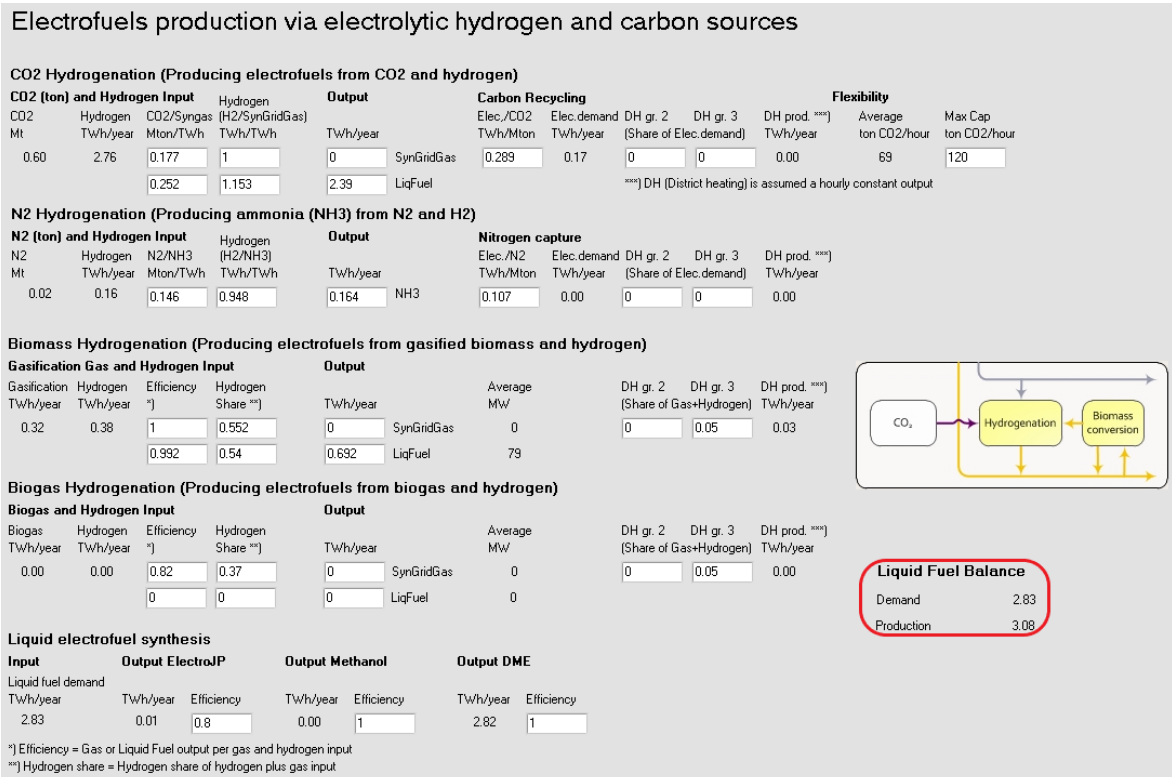


Figure 7.4. The E-fuel total demand and production.

The last figure 7.5 shows the needed electrolyser capacity. In subsection 2.3 the planned electrolyser capacity as of now is four to six GW, meaning the IDA 2030 also seems to be pessimistic in the PtX sector, as well as the wind.

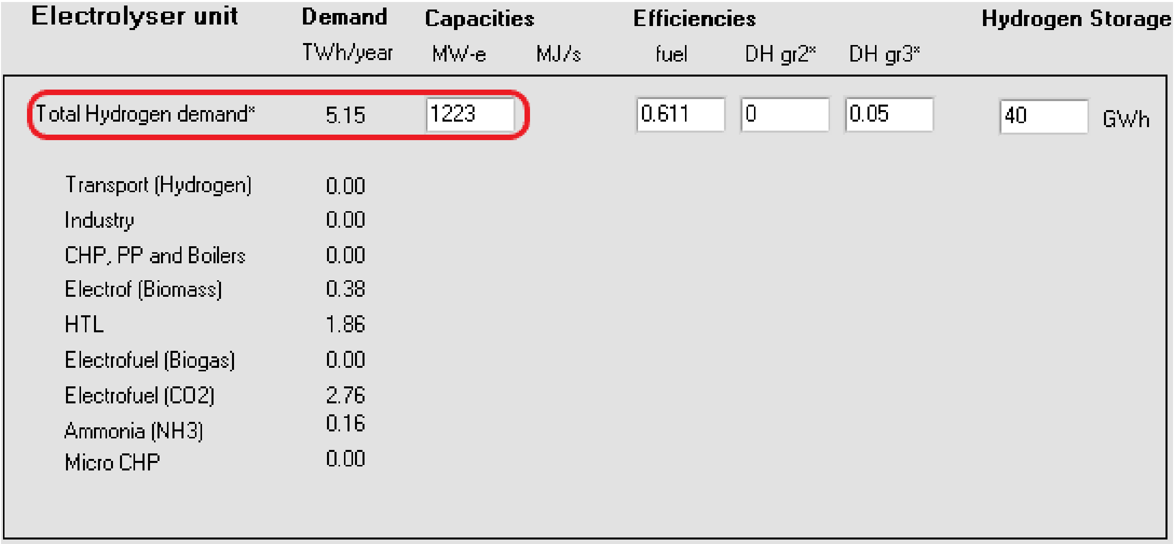


Figure 7.5. Needed electrolyser capacity.

In the 2030 base the transmission line capacity had not been defined; therefore, the transmission line capacity will be set to 7,000 MW, which is around the same as another IDA 2050 model and close to the real Danish transmission line capacity. The next subsubsection describes the choice of system price.

7.1.1.3 System price EnergyPlan

Energyplan requires a single external market price; therefore, the Nord Pool system price is used, which represents the spot price for the entire Nordic Area hourly. The external price in the reference scenario is based on the 2021 hourly system price as it is the latest year with all hours available, and with the factors; political instability and operation of a new transmission line from Norway to Germany (Nordlink cable) and UK (North Sea Link cable) included. The average system price is settled at around 62 EUR/MWh. Although the chosen price is relatively higher than in previous years, it is realistic, since the surge may be partially caused by raising natural gas price caused by invasion of Russia toward Ukraine, and the two new operating transmission lines. Zakeri et al. [2015, 2018] has carried out simulations for the two projects and both show that there will be an increase in the Nordic system price. In addition, according to Nord Pool data, as per Nord Pool [2022a], the system price has surged in 2021, and even more intensely in the first quarter of 2022. Zakeri et al. [2018] also states that the impact on the system price will be reduced as VRE capacity increases in the UK. The application of the system price of 2021 is considered to best reflect the real situation. Furthermore, looking back at historical data since 2002, as can be seen in 7.1, the average volatility of the price change is around 33%, besides from 2020 to 2021, with major changes in the cable connection and political instability. To calculate a high and low system price to use in the sensitivity study, the reference price of 62 EUR/MWh will be used as a basis and upscaled/downscaled by 33%, which makes the high and low prices 82 EUR/MWh and 43 EUR/MWh respectively.

Year	Price	Price change from former year in pct.
2021	62.31	4.70
2020	10.93	0.72
2019	38.94	0.11
2018	43.99	0.50
2017	29.41	0.09
2016	26.91	0.28
2015	20.98	0.29
2014	29.61	0.22
2013	38.1	0.22
2012	31.2	0.34
2011	47.05	0.11
2010	53.06	0.52
2009	35.02	0.22
2008	44.73	0.60
2007	27.93	0.43
2006	48.59	0.66
2005	29.33	0.01
2004	28.92	0.21
2003	36.69	0.36
2002	26.91	
Avg pct. change between years		**0.33**

Table 7.1. Price volatility from 2002 - 2021

7.1.1.4 Simulating offshore wind increase up until a 2045 aim

To investigate the economic and technical severity of the offshore wind sector increasing capacity without adding a PtX demand, there will be seven capacity increases, each using the three external market prices as just described. To find an ending point, the IDA 2045 model will be used to define a final threshold for the offshore wind sector, in which the capacity increases no further. The IDA 2045 is a model of a renewable energy system, where the system no longer transitions. In subsubsection 7.1.1.5 an export demand of E-fuel is found and added, implying a greater need for renewable electricity. However, considering a potential additional demand, an offshore wind sector capable of providing a fully renewable energy system in 2045 is, for the purpose of this project, deemed a logical target point for offshore wind capacity, since this project only targets a transition period and not a fully renewable scenario in both analysis one and two. The IDA 2045 model capacity is 14075 MW. Investigating the newer offshore win farms, the capacities are generally quite large, ranging from 300 MW to 1,200 MW a project [Energistyrelsen, N.A.]. Each step-wise increase of offshore wind will follow a larger size new offshore wind farm with a capacity of a 1,000 MW. The final simulated capacity will be 13,630 MW, is it nears the IDA 2045 capacity, and another step would exceed it.

To clarify the steps, they are as following;

- Ref > base model with 6630 MW offshore wind, no PtX
- First increase > 7630 MW offshore wind, no Ptx

- Second increase > 8630 MW offshore wind, no Ptx
- Third increase > 9639 MW offshore wind, no Ptx
- Fourth increase > 10630 MW offshore wind, no Ptx
- Fifth increase > 11630 MW offshore wind, no Ptx
- Sixth increase > 12630 MW offshore wind, no Ptx
- Seventh increase > 13630 MW offshore wind, no Ptx

The maximum capacity to be simulated can be seen on figure 7.6.

Variable Renewable Electricity

Renewable Energy Source	Capacity: MW	Stabilisation share	Distribution profile*		Estimated Production TWh/year	Correction factor	Estimated Post Correction production	Estimated capacity factor
Wind	4800	0	Change	DK onshorewind	10.46	0.543	15.48	0.37
Offshore Wind	13630	0	Change	DK offshorewind	51.53	0.395	60.88	0.51
Photo Voltaic	5000	0	Change	Solar PV producti	4.91	0.318	6.08	0.14
River Hydro	0	0	Change	Hour_solar_prod1	0.00	0	0.00	0.00
Tidal	0	0	Change	hour_tidal_power	0.00	0	0.00	0.00
Wave Power	132	0	Change	Hour_wave_200'	0.05	0.96	0.46	0.40
CSP Solar Power	0	0	Change	Hour_solar_prod1	0.00	0	0.00	0.00

Figure 7.6. Highlight of the maximum simulated capacity.

7.1.1.5 Simulating PtX with both inland demand and export

Similarly to the offshore wind capacity increase, the IDA 2045 model is used as an upper threshold for PtX demands. However, to significantly test to system and get a clearer view of the impact of PtX, an analysis with PtX scenarios from Rambøll [2022] is also used, as it provides some different transport demands that will be included in the EnergyPLAN PtX simulations. Rambøll [2022] has in their analysis made four scenarios for achieving the 2030 carbon reduction goal:

- Scenario 1 > 55 pct. carbon reduction
- Scenario 2 > 70 pct. carbon reduction; conversion of 15 pct. of the road transport demand to be covered by hydrogen and conversion of national ship fuels to E-fuels
- Scenario 3 > Scenario two plus conversion of international ship fuels to E-fuels
- Scenario 4 > Scenario three plus export of hydrogen and E-fuels

To get more of an overview, the scenario calculations from Rambøll [2022] will be visualised in TWh from PJ.

	Road transport	National ships	Export	Conversion factor
H_2 (PJ)	20	2	14	3.6
H_2 (TWh)	5.6	0.6	3.9	**10.0 TWh H_2**
	National ships	**International ships**	**Export**	**Conversion factor**
MeOH (PJ)	2	4.7	6	3.6
MeOH (TWh)	0.6	1.3	1.7	**3.5 TWh MeOH**
	National ships	**International ships**	**Export**	**Conversion factor**
NH_3 (PJ)	1	2	6	3.6
NH_3 (TWh)	0.28	0.6	1.7	**2.5 TWh NH_3**

Table 7.2. Overview of Rambøll scenario transport demands in PJ and TWh.

Table 7.2 visualises the scenarios created by Rambøll by converting certain fuel uses for transport to E-fuel use. What is noteworthy is that Rambøll see potential in converting road transport to pure hydrogen, exporting pure hydrogen and using methanol (MeOH) as ship fuel. These are not included or not included to this level in IDA 2030 or 2045. IDA 2045 has a H_2 demand of 1.2 TWh and at least a demand for methanol (DME) of 2.97 TWh for heavy road transport. IDA in Lund et al. [2021] does not specify how much of the DME goes into ship or heavy transport. The scenario analysis by Rambøll [2022] and the IDA 2045 EnergyPLAN model will both be used to construct a model and development of the PtX sector, as they offer different possible developments of the E-fuel demands. Rambøll expects H_2 use and export, MeOH use and export, and adds an NH_3 export demand. IDA 2045 provides a development of E jet fuel demand, E diesel demand and NH_3 demand. Lund et al. [2021] explicitly expects an export of 3.6 TWh biomethane, but otherwise does not highlight export of electrically generated fuels. In this project it is therefore the export demand of E-fuels from the analysis of Rambøll [2022] that will be used as an export demand.

To investigate how PtX impacts the Danish energy system, the simulations are constructed by mixing the possible futures from Rambøll and IDA 2045. Although the scenarios by Rambøll [2022] are all in 2030, the most ambitious scenario is quite far from the IDA 2030 and 2045 models and will therefore not be implemented in the EnergyPLAN modelling to the full extent from the beginning. Instead the modelling will be in more balanced steps that still tests and pressures the energy system. The modelling will follow a progression in E-fuel demands from IDA 2030 to IDA 2045 in four steps;

- 25 pct. of the way there
- 50 pct.
- 75 pct.
- and finally the transport demands from IDA 2045.

In addition to the demands, the demands by Rambøll [2022] in the form of; all road and ship E-fuel demand and no export, plus 50 pct. export, plus 75 pct. export and finally the full export demand. The E jet fuel and E diesel progression goes as follows.

	E diesel (TWh)	NH3 (TWh)
2030 base model demands	2.8	0.2
25 pct. of the way to 2045	2.9	1.0
50 pct. of the way to 2045	3.0	2.0
75 pct. of the way to 2045	3.0	2.8
2045 demands	3.1	3.7

Table 7.3. An overview of the initial E diesel and E jet fuel demands to the final

Added to the NH3 will be the first 50 pct. export, 75 pct. export and the full export from Rambøll [2022]. The H_2 and methanol demands will be the initial demands with the export demand following the same steps.
Table 7.4 shows the transport fuel demands.

Scenario	25 pct. No export	50 pct. 50 pct. Export	75 pct. Full export	100 pct. Full export
E jet fuel (TWh)	2.5	5.1	7.6	10.2
E diesel (TWh)	2.9	3.0	3.0	3.1
MeOH (TWh)	1.9	2.7	3.5	3.5
H2 (TWh)	6.1	8.1	10	10
NH3 (TWh)	1.0	2.7	4.4	5.3

Table 7.4. Constructed scenarios for PtX sector development

Figure 7.7 shows the second increase scenario in EnergyPLAN, where the new inputs from IDA 2045 and Rambøll [2022] has been included.

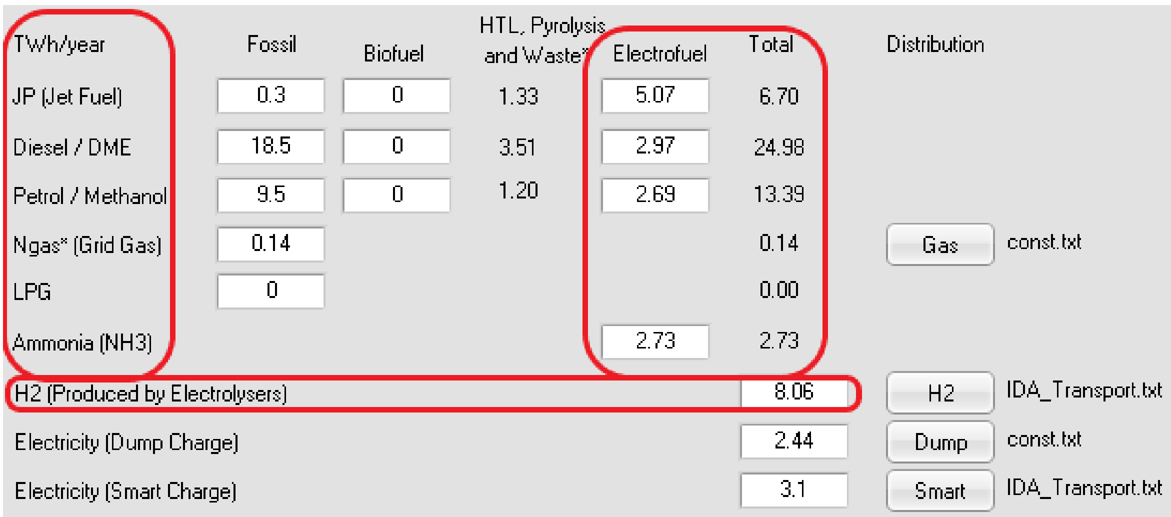


Figure 7.7. Figure showing all the electrofuel transport demands in the second increase scenario.

Figure 7.8 shows the hydrogenation required from the combination of CO_2 and hydrogen, the production of ammonia, and the required carbon storage. The carbon storage has been kept at the same ratio as the base 2030 model: In the base model the ratio is calculated by $120/69 = 1.74$
In figure 7.8 the carbon storage is the found by $324 * 1.74 = 563\ max\ cap\ ton\ CO_2/hour$.

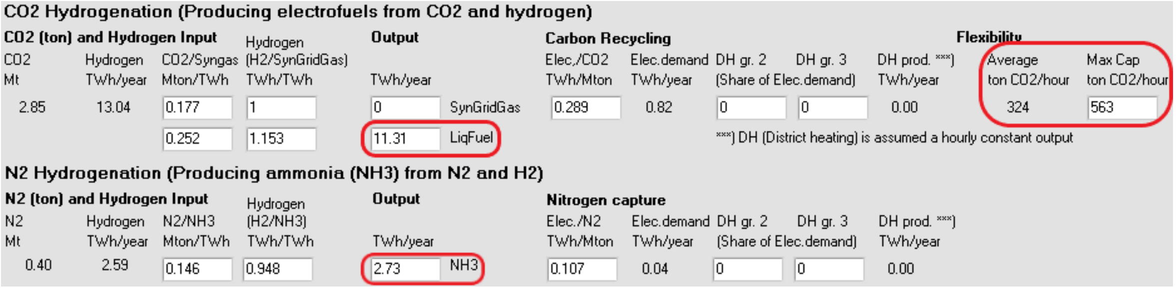


Figure 7.8. Visualisation of the required hydrogenation and carbon storage to fulfil the demand.

Figure 7.9 simply shows that demand and production have been chosen to match.

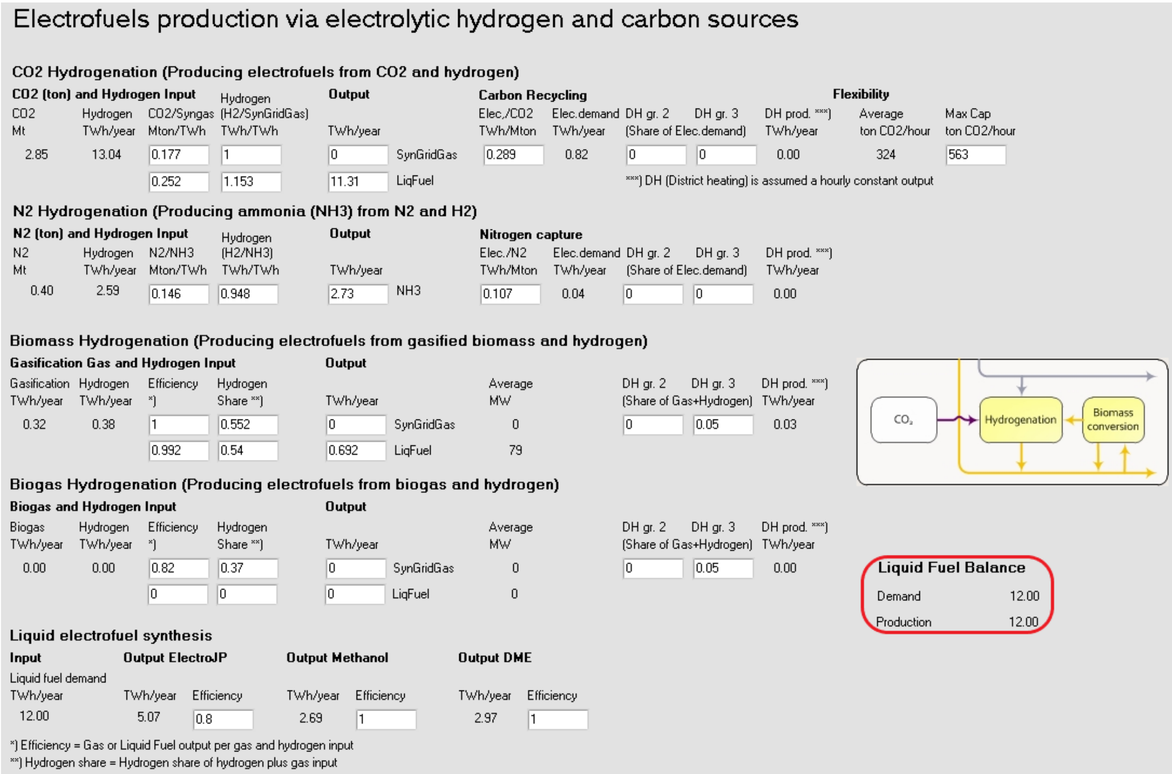


Figure 7.9. Figure showing demand and production matching.

The last figure 7.10 shows the required electrolyser capacity. For flexibility, the electrolyser has been kept at the same ratio between the required capacity and the input capacity as in the base 2030 model: $1223MW/959MW = 1.28$

In figure 7.10 the calculation is $4830MW * 1.28 = 6160MW$

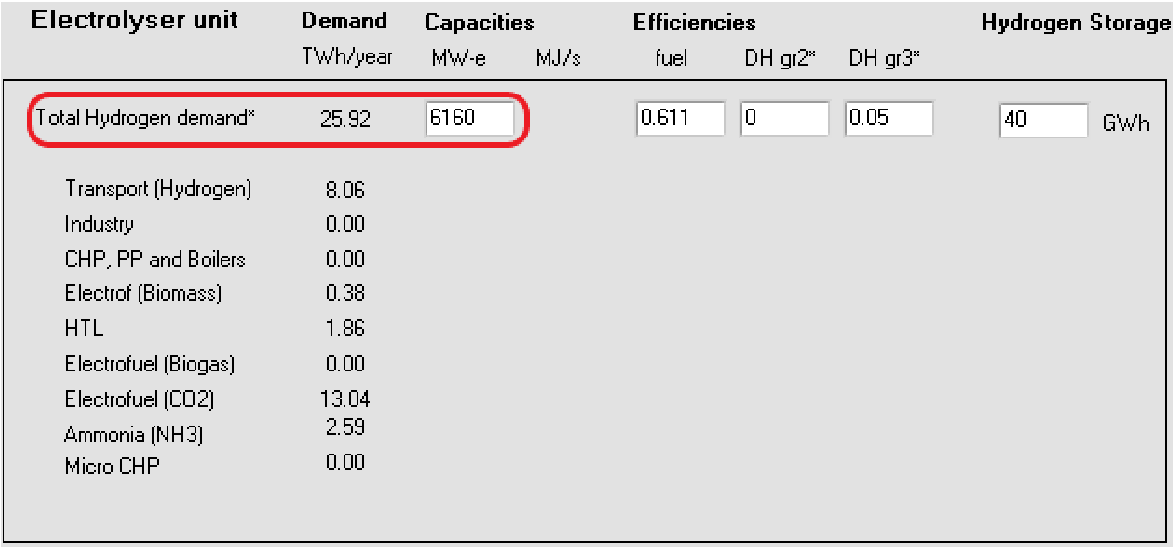


Figure 7.10. Figure showing the required electrolyser capacity.

7.1.1.6 Calculation of private economics

The utility for OW supplier is profit, more specifically, from a business perspective, it would be the investment of return under the agreement with the government, contract for difference, which can be differ from project to project. Since this project view the technology development as a whole; therefore, for the private economics of OW supplier, a short term and long term profitability are brought in as two indicators for accessing the tendency of OW suppliers' profitability in a general level. Differences between long and short term profit is by having the annual revenue deducts either marginal cost (MC) or levelised cost of electricity (LCoE), and further details will be elaborated in the following sections. The idea of having the two profitability indicator is due to MC, normally as a bidding price, cannot truly reflect the actual cost for producing the electricity. Therefore, hereby also bring in the concept of LCOE to showcase that an additional cost, that are normally underestimated due to the flaw of the market mechanism.

OW short-term profit:
The main focus of monitoring this parameter is to ensure the security supply of the system while scaling up OW capacity. Besides utilising MC for the knowing short term profit of OW suppliers, it also showcases the market tendency of producer's surplus and non-competitive producer with only fixed cost get paid.

$$Profit_s = SMP \times P_e - MC \times P_e \tag{7.1}$$

$Profit_s$	Short term profit of OW
SMP	Spot market price
P_e	Electricity production
MC	Marginal cost

Marginal Cost (MC):
Marginal cost is a term for the additional cost of generating on additional unit of electricity, see the MC

formula in the equation Afework et al. [2021]:

$$MC = \frac{change\ of\ total\ cost}{change\ of\ total\ electricity\ production} = \frac{\Delta TC}{\Delta Q} \tag{7.2}$$

ΔTC	change of total cost
ΔQ	change of total electricity production

OW long term profit:
By using LCoE as an annual cost to formulate profit, it can be used in a business perspective to determine whether the strategy is worth investing in, since LCoE considers the overall life-cycle cost, including CAPEX and OPEX, of the investment.

$$Profit_l = SMP \times P_e - LCoE \times P_e \tag{7.3}$$

$Profit_l$	Long term profit of OW
SMP	Spot market price
P_e	Electricity production
$LCoE$	Levelised cost of electricity

LCoE:
Levelised cost of electricity is a measurement for the total net present cost of a given electricity generation plant, unit or technology over the expected lifetime. It can provide a benchmark for the needed revenue to recover all capital expenditure (CAPEX) and operation expenditures (OPEX), which is how it will be utilised in this project. See the following formula in equation 7.4. Kenneth [2018]

$$LCoE = \frac{sum\ of\ costs\ over\ lifetime}{sum\ of\ energy\ produced\ over\ lifetime} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{7.4}$$

I_t	investment expenditures in the year t
M_t	operations and maintenance expenditures in the year t
F_t	fuel expenditures in the year t
E_t	electricity generated in the year t
r	discount rate
n	expected lifetime of system

Production cost of hydrogen electrolysis:
For PtX case, instead of figuring out the profit and revenue of the suppliers, focusing on the on-site

production cost of electrolytic hydrogen is considered as a more suitable indicator due to reflection of the cost finding affected by the electricity sector. Reference is made to Hurskainen and Ihonen [2020], and modified as below formula 7.5:

$$
\begin{aligned}
&Production\ cost\ of\ hydrogen\ (EUR/kg) \\
&= \frac{Annualized\ investment\ cost + Annual\ electricity\ cost}{Total\ produced\ hydrogen} \\
&= \frac{IC_{electro} * CRF_{electro} + FC_{electro} + Demand_{elec} * Price_{elec}}{Demand_{elec} * \eta_{electro} * EC_{hydrogen}}
\end{aligned}
\tag{7.5}
$$

$IC_{electro}$	Investment cost of electrolysis plant
$CRF_{electro}$	Capital Recovery Factor
$FC_{electro}$	Fixed cost of electrolysis plant
$\eta_{electro}$	electrolysis efficiency
$Demand_{elec}$	Electricity demand of hydrogen production
$Price_{elec}$	Inmarket electricity price
$EC_{hydrogen}$	Energy content of hydrogen

7.1.1.7 Theoretical connection

The offshore wind sector and the PtX sector increase separately from each other. This is to discover the behaviour of the system, economic development, and environmental impact. Using simulation, the underlying meanings of the industries acting individually will become clear, thus relating to the strength of simulation theory, as per 6.2, and considers the consequences of actors not always developing coherently as per 6.1. The consequences of acting individually can be positive or negative and will be analysed in chapter 8.

7.2 Additional analysis two methods

To discover and test possible synergies between the offshore wind and PtX sectors, as production increases, the second analysis will undergo simulations combining the previous scenarios and evaluations will be performed to find the more *optimal* combinations of offshore wind and PtX.

7.2.1 Testing for optimisation approach

Rather than completely optimising, the approach will mainly be to test for optimality, which means to simulate all possible combinations of offshore wind and PtX increases. Table 7.5 visualises the approach in a table style; the X'es are just for examples.

Scenarios	25% & no export	50% & low export	75% & mid export	100% & high export
7630 MW OW				
8630 MW OW				
9630 MW OW				
10630 MW OW	X			
11630 MW OW				
12630 MW OW		X		
13630 MW OW			X	X

Table 7.5. Table with all combinations between offshore wind steps and PtX scenarios. The X'es are simply possible optimal combinations, **not** the final combinations.

To find these combinations, the same evaluation parameters as described earlier; self-sufficiency, private economics, socioeconomics, and carbon emissions will be used. Given that the study is set to dig into the situation of the renewable energy market, private and socioeconomics will be the main parameters to balance when determining optimality, but the remaining two parameters will also be analysed.

7.2.2 Sensitivity study

As a last investigation, for the final four combinations of offshore wind and PtX production a form of sensitivity will be conducted. Hydrogen storage, transmission line capacity, external market, and the NordPool price caps all have the potential to create flexibility and otherwise alter the optimality of the systems.

Transmission capacity:
Figure 7.11 illustrates the anticipated transmission capacity across the borders of Denmark. Transmission capacity will receive three major increases, bringing the maximum capacity significantly higher than the starting capacity in the IDA 2030 model. However, two of the increases are in connection with the coming energy islands, meaning there is uncertainty regarding how those will be used to export electricity.

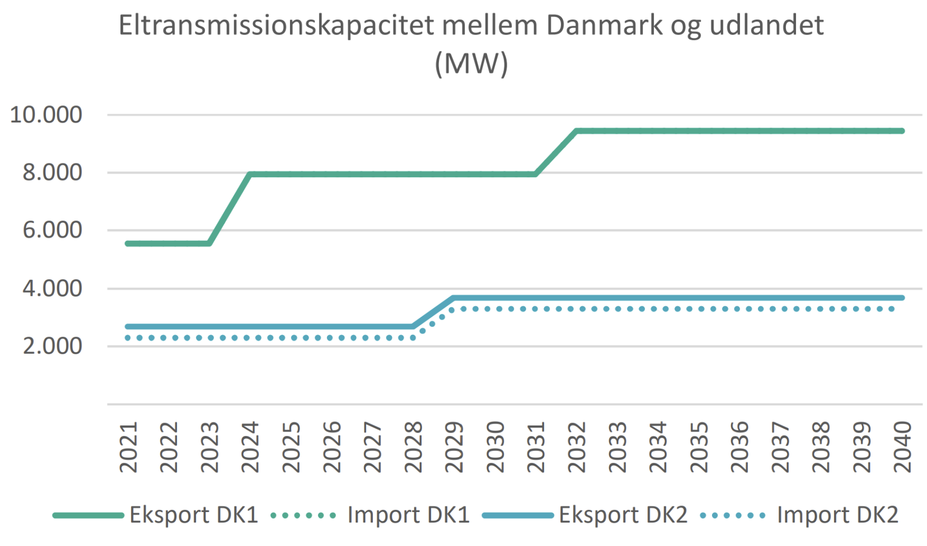


Figure 7.11. Figure showing the anticipated transmission line capacity from Denmark to other countries. [The Danish Energy Agency, 2021b]

In the sensitivity study the first major increase will be included, bringing the transmission capacity to 10,400 MW, see figure 7.11. Finally, in the sensitivity study it will be assumed that the energy island transmission freely transports electricity across the borders, increasing the capacity to 13,000 MW.

Hydrogen storage:
The energy system model start with a hydrogen storage of 40 GWh, which will not be altered throughout the first analysis and a large part of the second analysis. To investigate whether hydrogen storage is significant to the system, it will be turned up in the sensitivity analysis to be ten times larger, equal to 400 GWh. The aim of this is not realism, but to get and investigate energy system models where hydrogen storage never limits the system.

External market price:
The final simulations will use all the prices of the external market on the final four sector increase combinations. Using three external prices from the beginning would generate an abundant amount of data for analysis, and therefore reintroducing an external market price range will only reoccur after evaluation and selection of four scenarios.

NordPool price caps:
At a later stage in this project, it became apparent that no maximum or minimum price cap were defined in the energy system simulations. Critical overload of the transmission lines from either import or export therefore turns the internal electricity prices to zero in the majority of the scenarios. It turned out that the simulated systems were not able to handle the potential electrical flow across borders, and therefore many zero-price hours occurred in some scenarios, obscuring the results. The general trends and conclusions were not affected. But to test the severance of overloading the transmission lines and not finding an equilibrium between supply and demand, a sensitivity study incorporating the maximum and minimum price caps from Nord Pool will be conducted for the final five combinations between OW capacity and PtX demand. The maximum electricity price will be 4,000 EUR/MWh, and the minimum price will be -500 EUR/MWh [Nord Pool, 2022b]. In EnergyPLAN the electricity price rightly jumps to 4000 EUR/MWh when supply does not meet demand, including import, meaning when the transmission lines are sought overused and there is a lack of electricity in the system. The same principle applies for the minimum price, albeit prices oddly jump from 0 to -500 EUR/MWh rather than decreasing to a range between 0 and -500 EUR/MWh.

Analysis one - investigating separate sector development 8

This analysis will carry out a deep dive into futures where offshore wind capacity and electrofuel production will not increase in a balanced way. Instead, the offshore wind will continue to develop independently in seven steps, each step with a capacity increase of 1,000 MW. Similarly, the production of electrofuels increases in steps, adding both internal demand and export demand. Therefore, the consequences of separated development will be discovered and analysed.

8.1 Offshore wind expanding individually

First knowledge will be built on how offshore wind impacts the system and how offshore wind increase impacts the earnings of offshore wind turbine owners. The analysis will range from private economic to socioeconomic.

8.1.1 Offshore wind increases export

First a deep dive into the import/export of the system. Given that the scenarios are built on market simulations, the connection to the external market and the external market prices are significant factors in some of the following parameter analyses.

Among all external prices, a low external market price results in the most *even* relationship between import and export throughout the increase steps; see figures 8.1, 8.2, and 8.3.

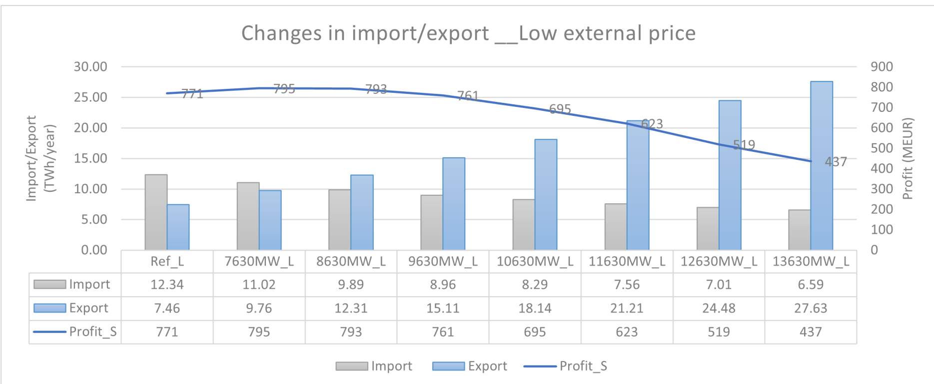


Figure 8.1. Import/export in the low external price scenarios.

The common feature of all figures 8.1, 8.2, and 8.3 is that more renewable electricity production equals a higher amount of export and a lower amount of import. This is a natural occurrence, with more production capable of covering demand and allowing more trade across borders.

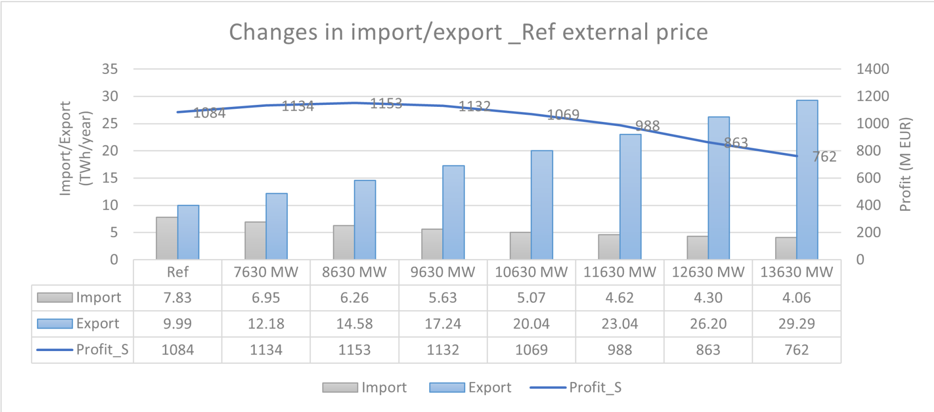


Figure 8.2. Import/export in the reference external price scenarios.

When investigating the figure 8.3 and comparing it with the previous one, it is clear that a higher external price results in more exports. The system seems highly reliable with plenty of electricity production, able to export very high amounts and import little in comparison, already in the early increase steps. What this means to the system will be highlighted in the following subsections.

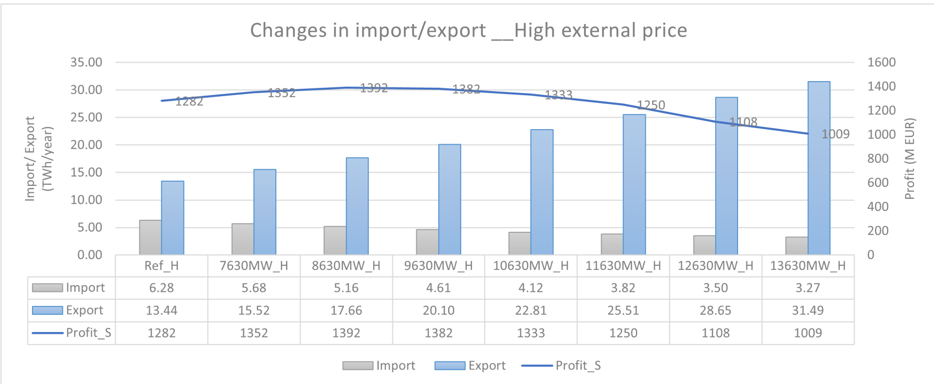


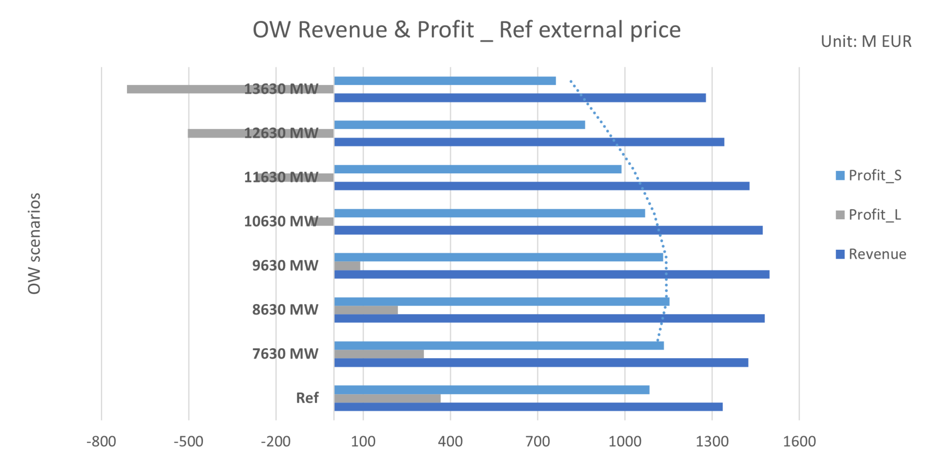
Figure 8.3. Import/export in the high external price scenarios.

High outflow and, at times, inflow carry the risk of putting pressure on transmission lines and risking a bottleneck cost.

8.1.2 Continuously increasing OW can cause decreasing profits

The section presents the long and short term profitability of offshore wind suppliers by increasing offshore wind capacity. The following charts show a consistent tendency that long-term profit is constantly decreasing, whereas short-term profit climbs upward until the offshore wind capacity reaches a certain level and then declines afterwards. It also concludes that offshore wind expansion will reach maximum profitability, though the value can differ depending on the external electricity price.

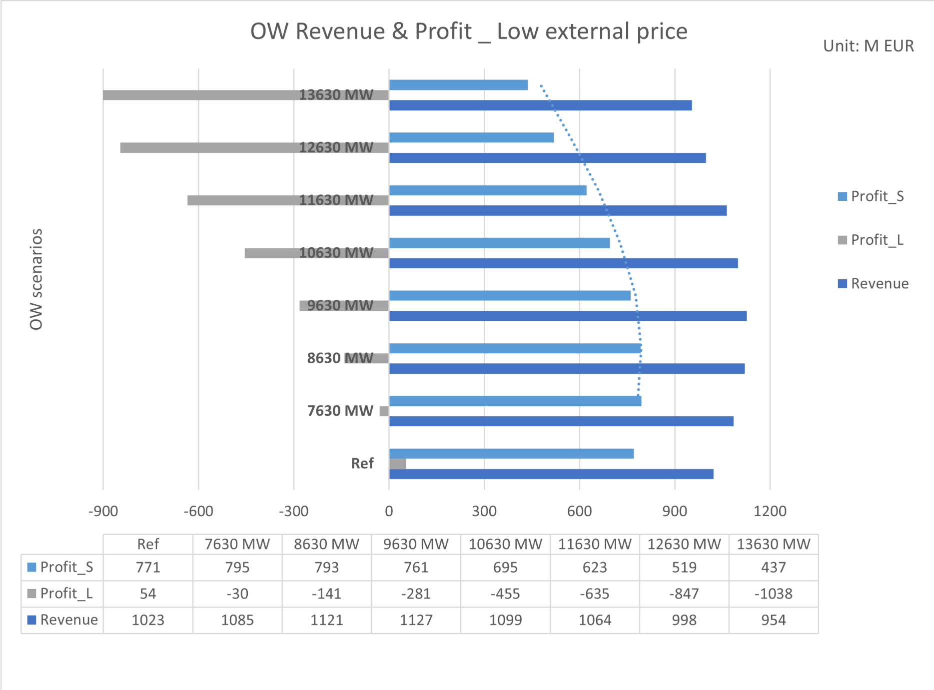
In figure 8.4, offshore wind investment remains profitable in the long term, as it scales up to 9,630 MW and has the highest short-term profit in scenario 8,630 MW.



	Ref	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Profit_S	1084	1134	1153	1132	1069	988	863	762
Profit_L	367	309	219	90	-81	-270	-503	-713
Revenue	1336	1424	1481	1498	1473	1429	1342	1279

Figure 8.4. OW profit in Ref external price

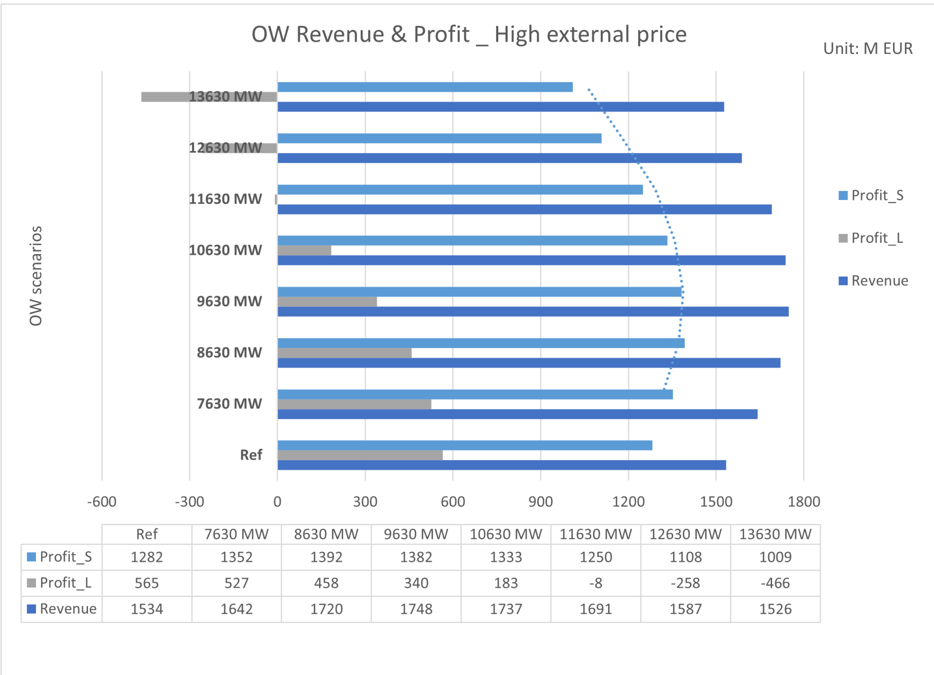
In all figures 8.5, 8.4 and 8.6 the profitability trend is mostly on the same track; what changes when applying different prices in the external market is the amount of profit. Under the condition of a lower external price, market coupling affects the electricity flow, and therefore the energy system imports more than in the reference scenario, resulting in long-term non-profit from the 7,630 MW scenario in figure 8.5. In addition, although scenario 8,630 MW still continues to have the maximum short-term profit, the value has shrunken by about 30 pct. compared to the corresponding scenario with the external reference price.



	Ref	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Profit_S	771	795	793	761	695	623	519	437
Profit_L	54	-30	-141	-281	-455	-635	-847	-1038
Revenue	1023	1085	1121	1127	1099	1064	998	954

Figure 8.5. OW profit in low external price

On the contrary, in figure 8.6 with a higher external price, long-term profit remains positive until the capacity expands to 10,630 MW. However, 8,360 MW is still the most profitable scenario in the short term with about 200 M EUR higher than the corresponding reference price scenario.



	Ref	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Profit_S	1282	1352	1392	1382	1333	1250	1108	1009
Profit_L	565	527	458	340	183	-8	-258	-466
Revenue	1534	1642	1720	1748	1737	1691	1587	1526

Figure 8.6. OW profit in high external price

Figure 8.7 shows that the short-term profit has relatively stable changes compared to the long-term profit among the three clusters of external price levels. Additionally, among these clusters, the long-term profit drop becomes steeper in the low external price cluster. Furthermore, offshore wind suppliers make more long-term profits when the external price increases and quickly turn to financial loss in the lower external price scenario while scaling up the capacity.

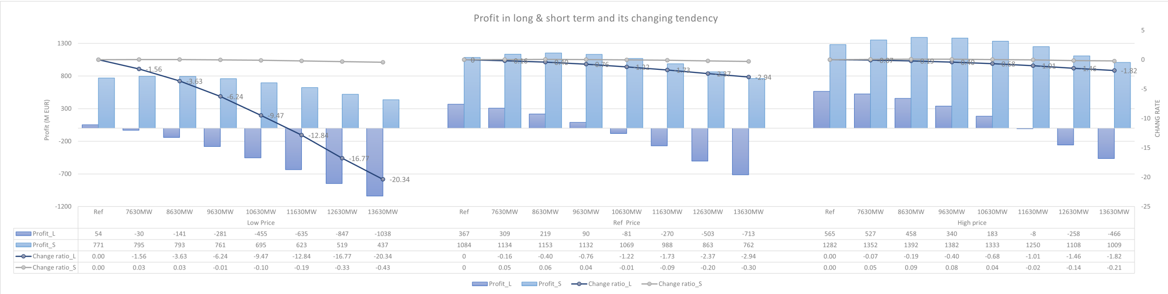


Figure 8.7. Long and short term profitability in different external price level

In this section, it was shown that the reference scenario (6,630 MW) obtains the highest value in long-term profit; whereas, the maximal profit in short term occurs when the capacity increases 1,000 or 2,000 MW. The result reflects the fact that the increase in short-term profit (producer surplus) while scaling up the capacity is insufficient to cover the additional investment cost from constructing the wind turbines. However, having a higher level of external price would increase offshore wind profitability in both the long-term and the short term. Therefore, it is worth being aware of the importance of securing the status of a low-price zone by maintaining the development of offshore wind and enabling profitability during the process. The high external price and export are crucial to feasible investment according to these results; becoming a high-price zone could make investments unfeasible. However, as the external price level differs due to various factors related to the market coupling, analysis two will take short-term profit as the primary indicator as for the private sector while determining the preferable increasing range of OW and PtX.

8.1.3 Offshore wind causing rising socioeconomic expenses

Moving on to the socioeconomic perspective of increasing offshore wind capacity, three parameters will be analysed; the total annual cost, the bottleneck cost, and the electricity price. These reflect the benefits or burdens for society and private consumers, as systemic savings or payments will influence electricity bills and taxes.

In figure 8.8 there are three graphs showing the total annual cost as the offshore wind capacity increases. The three graphs show that continuously increasing offshore wind will eventually just increase the socioeconomic expenses, and not benefit the system in a socioeconomic perspective.

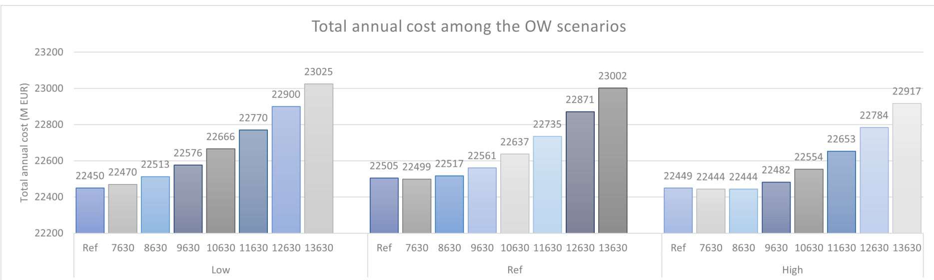


Figure 8.8. The total annual costs of increasing offshore wind across three price levels

However, the external electricity price is an important factor, as it changes the development of the total annual cost. Having a higher price of 62 EUR/MWh or 82 EUR/MWh results in the total annual cost developing much the same way, as can be seen in figure 8.8, but a high external price means lower total annual costs and thus more socioeconomic benefits. The trend is the same between *ref graph* and *high graph*, but the annual costs are lower at a high price. On the *low graph* the costs are simply increasing, but remain lower than the cost of the reference scenario up to a capacity of 9,630 MW. As indicated in subsection 8.1.1, the reference and high external price scenarios showed a generally higher level of export compared to import. Increasing offshore wind capacity means selling more marginally cheap produced electricity and exporting it at high prices, thereby profiting the system until the capacity reaches 8,630 MW in the reference price scenarios and 9,630 MW in the high-price scenarios. Furthermore, the total annual cost increase remains relatively low from the 8,630 MW reference price scenario to the 9630 MW scenario.
Therefore, a steady expansion of offshore wind turbines is highly dependent on high electricity price and export. Exporting at especially high prices pushes the point at which more wind turbines become a socioeconomic expense. The reference price has the same effect, although the socioeconomic expense increased earlier.

Another important socioeconomic factor is the bottleneck payment, where transmission lines are overloaded, which causes the transmission line operator to balance the load. Looking at the figure 8.9 it becomes clear that production will exceed demand to such a degree that even transmission lines cannot export all electricity.

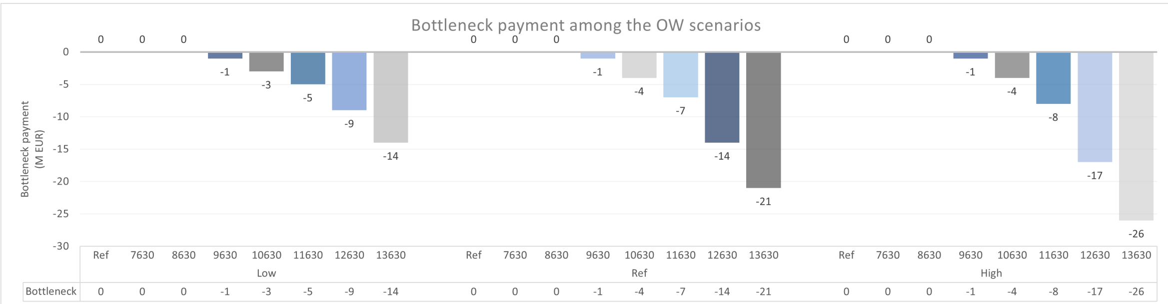


Figure 8.9. Visualisation of the bottleneck cost through all offshore wind increases and the three price levels.

In figure 8.9 the overload starts when the capacity reaches 9,630 MW for all price levels. The low external price scenario bottleneck payment has a less steep increase than with the other price levels. Again, it very likely traces back to the import/export balance; the import/export has a more balanced inflow and outflow of electricity, where with the reference price and high external price, there is a significantly higher amount of export than import. By evaluating the total annual costs and the bottleneck payments results shown in figures 8.8 and 8.9, the capacity at which the offshore wind sector becomes a technical liability is 10,630 MW.

The final socioeconomic parameter is the price of electricity. Crucial for suppliers, as it dictates the return on investment, and to consumers, as it is a fixed expense. Figure 8.10 shows that adding renewable electricity supply with very low marginal cost will decrease the electricity price. It should be noted that the system to which offshore is increasingly implemented is still relatively far from being fully renewable, and with the low external electricity price, the inmarket electricity price also becomes fairly low.

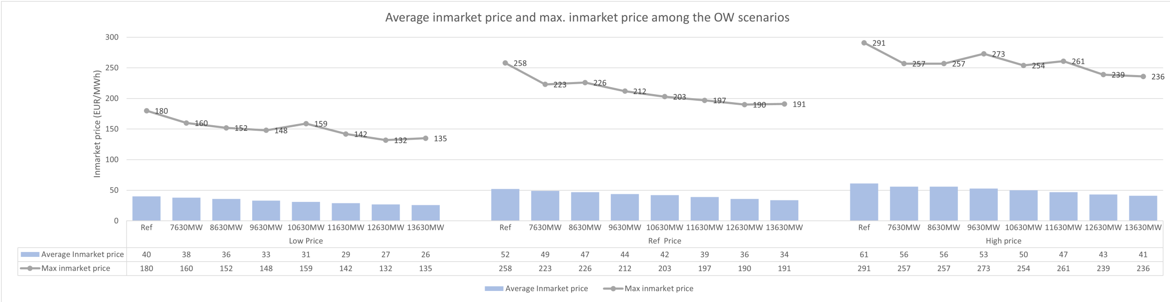


Figure 8.10. Electricity price in all offshore wind scenarios

From the analysis of figure 8.10 and the short- and long-term profits in subsection 8.1.2 the issues covered in Section 2.4.1.1 become apparent; too high penetration of RES can decrease the electricity price to an infeasible level for investors. The price decrease is the same across all external price levels; a higher external price will simply maintain the inmarket price at a relatively higher level through more capacity increase steps. Interestingly, the annual maximum electricity price is more volatile with a high external price; this is the price level of which import/export was less balanced and thus less dependent on import and containing a high amount of export. It is possible that with lower import dependence, there are more price spikes when there is a scarcity of wind-produced electricity in the system.

8.1.4 Decreasing carbon emissions when increasing offshore wind

The final parameter concerns the environmental aspect of increasing renewable electricity supply. Figure 8.11 shows a clear correlation between increasing offshore wind capacity and carbon emissions.

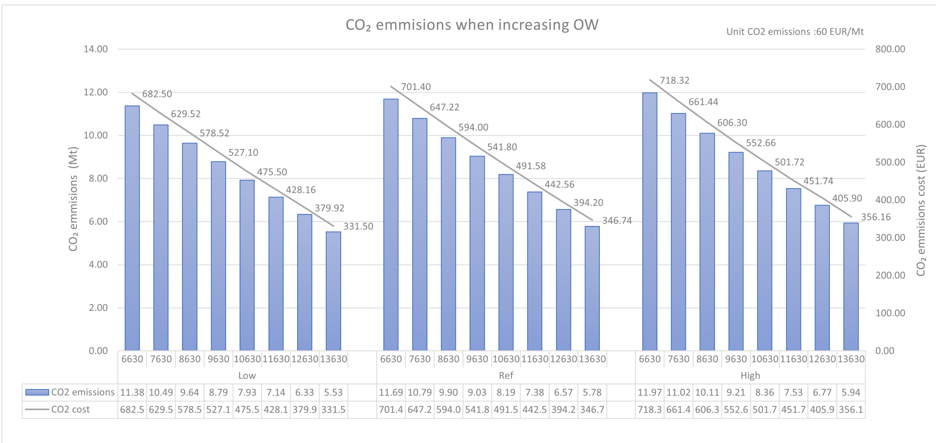


Figure 8.11. Development of carbon emissions in the system when increasing offshore wind.

Across all price ranges, see figure 8.11, carbon emissions decrease. The low price range has the lowest carbon emissions, the reference price the mid-level carbon emissions, and the high-price level the highest carbon emissions. Low-external-price scenarios also have the highest import, meaning that more CO_2 is emitted outside the borders and the energy system.

8.1.5 Summary of offshore wind increase

Some of these findings will eventually be compared with the PtX increase scenarios, and in such will be summarised now.
A higher external price means more export, with the lowest external price resulting in a more equal import/export. The more equal import/export put less pressure on the transmission lines than in the higher external price scenarios with the highest export. For the high- and reference-external-price scenarios, both reach the maximum short-term profit at 8,630 MW offshore wind, while for the low-external-price scenarios, the maximum profit occurs at 7,630 MW. Furthermore, the maximum profit differs from the reference to the high scenario, with the profit being around 30 pct. higher with high external electricity prices. In general, a high price in the external market meant a higher long-term profit. However, the increase in short-term profit could not cover the additional investment costs when the capacity became too high. Investigating the electricity price showed expected results compared to the findings in the problem analysis, section 2.4. The electricity price decreased as more offshore wind was implemented in the system. Environmentally, carbon emissions decreased with more offshore wind.

8.2 PtX scenarios; testing the system with additional electricity demand

From the findings in chapter 2, PtX should have the opposite effect of increasing offshore wind capacity. Adding consumption will mean more competition between electricity buyers. This section will jump into the same parameters as the previous one, analysing the system technically, economically, and environmentally, and establishing a consistent knowledge base for analysis two.

8.2.1 Increasing import as PtX demand increases

In this section, the transfer of electricity across borders will be analysed using different levels of external prices and PtX scales.

With a fixed OW supply capacity and an increase in the electricity consumption required from PtX, it is logical for the system to show an increase in import and a decrease in electricity export. In figure 8.12, with a reference external price level, only the reference scenario has more electricity export than import. By scaling up PtX the average inmarket price increases. As the PtX electricity demand scales up and reaches 75 pct. scenario the price increases by 21 EUR/MWh - this is due to a high inland electrofuel demand and electrofuel export.

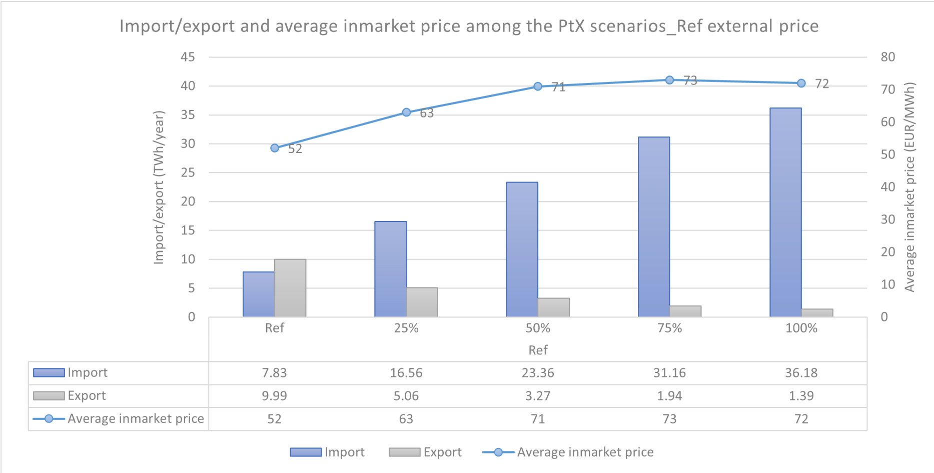


Figure 8.12. Import/export in the reference external price scenarios while scaling up PtX capacity

In the low external price scenarios, although import/export tend to be similar, the import amounts are greater than the corresponding scenarios with the reference external price, and the electricity export is lower in each scenario. That is, a low external price accelerates import, not export. Meanwhile, the inmarket price increases about 13 EUR/MWh while the PtX scales up, which is not as substantial as in the external reference price scenarios.

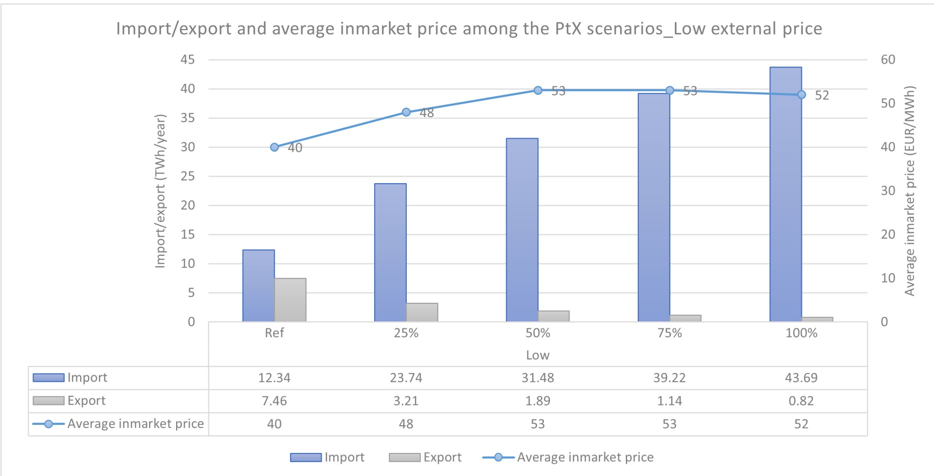


Figure 8.13. Import/export in the low external price scenarios while scaling up PtX capacity

Figure 8.14 shows a similar result as the reference external price shown in figure 8.12, only that the inmarket price increases significantly from 61 EUR/MWh to 92 EUR/MWh. Furthermore, the trend of increasing the average price in the market has a slight different among the three groups of external prices, especially in the 100 pct. scenario, which is caused by the overloaded transmission line and will be discussed later in subsection 8.27.

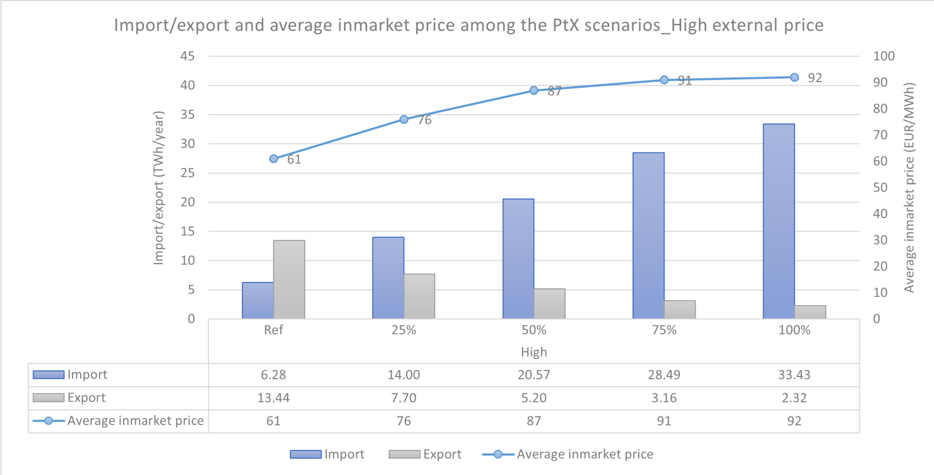


Figure 8.14. Import/export in the high external price scenarios while scaling up PtX capacity

The three figures 8.12, 8.13, and 8.14 show that the inmarket price has steeper changes from the start until the system increases to the 50 pct. PtX scenario, then the price changes become more gentle afterwards. Furthermore, as shown in figure 8.15, though different external price levels have an effect on the average inmarket price among the series of scenarios, the trend of the increasing demand of import/decrease in export is coherence while the PtX scale increase no matter under which external price level.

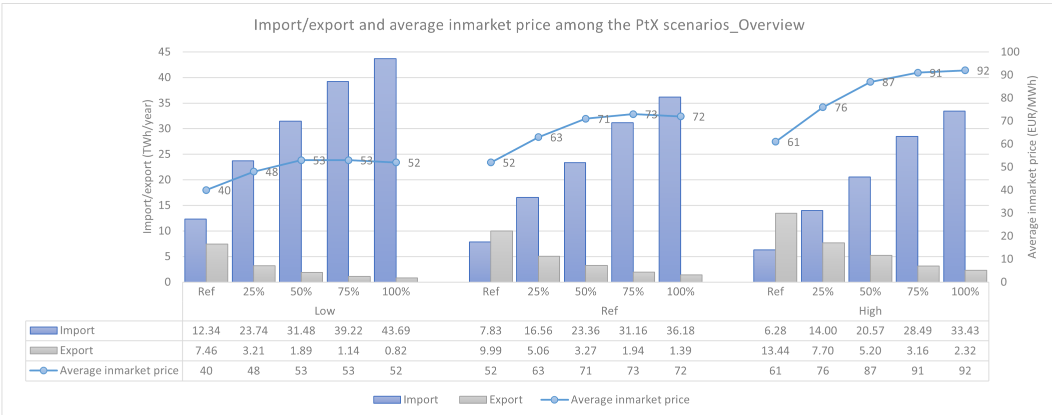


Figure 8.15. Overview of the import/export and average inmarket price among the PtX scenarios with three different external price levels

8.2.2 Higher profits for OW and higher production costs for PtX

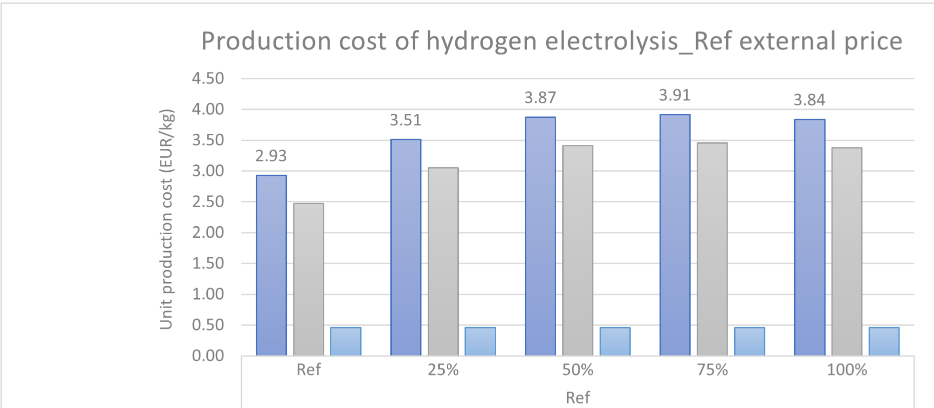
This section discusses the financial results of the private suppliers involved, including both PtX producers and offshore wind turbine suppliers. For OW, the indicator stays the same. As for PtX, the unit production cost of hydrogen is chosen instead as the indicator for the study because it reflects how the technology is affected as the energy system setup changes.

PtX producers:

Because hydrogen electrolysis constitutes the majority of the production cost of the liquid fuel, the production cost of hydrogen is chosen as a financial assessment indicator during the PtX development.

The following three figures 8.16, 8.17, and 8.18 show the production cost of hydrogen at different external price levels. These bar graphs demonstrate the values of annualised investment cost (dark blue bar), electrolysis power cost (light blue bar), and total unit production cost (grey bar), which is the total of the previous two values. As mentioned in the previous section, the average inmarket price in two latter PtX scenarios might not reflect the real price due to the bottleneck problem, caused by the relatively limited transmission line capacity in the system, when the system requires critical import. This has to be taken into account while analysing the following figures, which means that the values and growing trends in the first three scenarios (Ref, 25 pct., 50 pct.) are more accurate and will be used for further discussion in this case, whilst the two latter scenarios will be sorted out due to inaccuracy.

In figure 8.16, the annualised investment cost stays in almost the same price range at around 0.46 EUR/kg, while the electricity cost first rapidly increases from the reference scenario to 50 pct. increase scenario and then stabilises, with the total cost value going upward to 3.91 EUR/kg in the 75 pct. scenario. Subsequently, there is an unexpected decline in production cost, but this will be discussed later.



	Ref	25%	50%	75%	100%
Total cost of electrolysis	2.93	3.51	3.87	3.91	3.84
Cost of elec.	2.47	3.05	3.41	3.46	3.38
Cost of Inv.	0.46	0.46	0.46	0.46	0.46

Figure 8.16. Cost of hydrogen electrolysis in reference external price scenario

In figure 8.17, the overall trend is similar to the previous one, except that the total electricity cost has decreased due to the low external price. In addition, the production cost increase trend ends at the 50 pct. scenario. This occurrence will be discussed later.

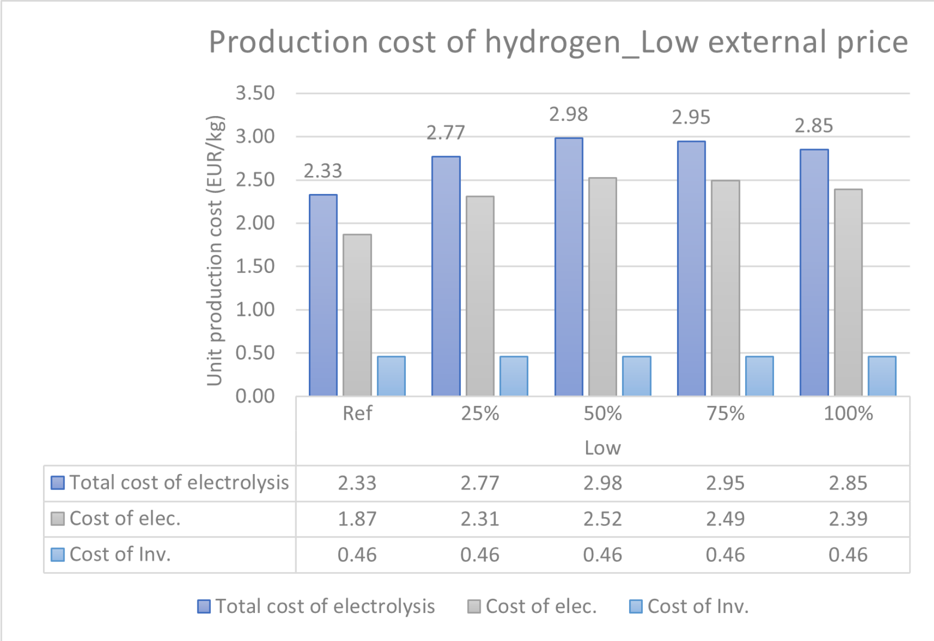


Figure 8.17. Cost of hydrogen electrolysis in low external price scenario

Vice versa, in the high external price scenario, the overall electricity cost increases compared to the reference and low external price scenarios. The highest total production cost has increased from 3.91 EUR/kg to 4.75 EUR/kg from the reference to the high external price scenarios.

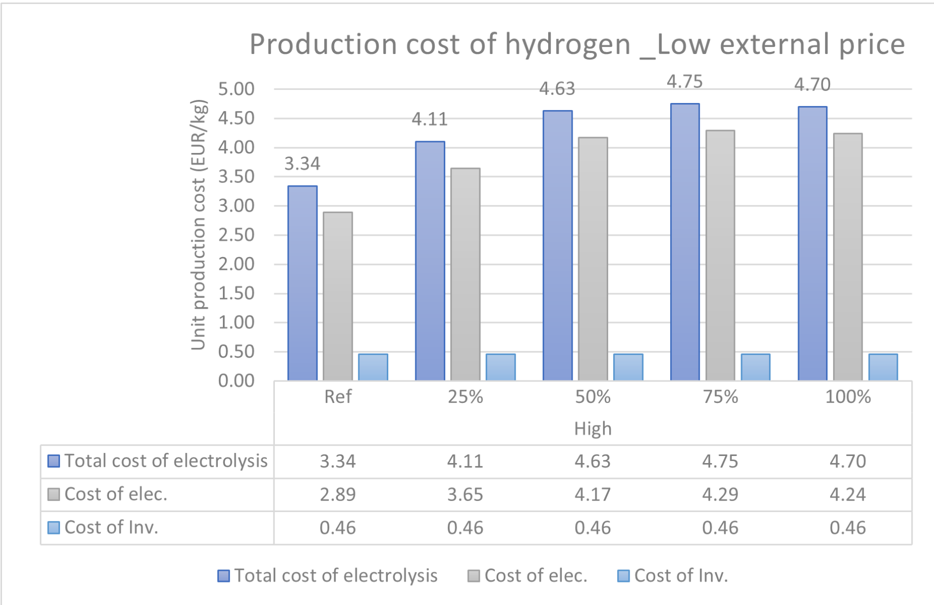


Figure 8.18. Cost of hydrogen electrolysis in high external price scenario

From the previous three figures, the data have shown that the electricity cost has constituted around 84 pct. to 88 pct. of the total production cost (with the reference external market price), meaning that the electricity price is a major impact compared to the investment cost. In the 50 pct. scenario among the three levels of external prices can differ from 2.98 EUR/kg, 3.87 EUR/kg, and 4.63 EUR/kg, which is about 55 pct. increase from the lowest to highest cost.

An overview in figure 8.19 shows on one hand a stable decrease of annual full load hours (FLH) rate through the increasing PtX scale; the value begins with around 60 pct. FLH but drops to about 30. On the other hand, the total production cost no longer increases in the 50 pct. scenario with a low external price and from the 75 pct. scenario for the reference and high price. The trend shows that the system requires more electricity to ensure the efficiency of the electrolysis plant; otherwise, the bottleneck issue hints at the need for expanded transmission line capacity when PtX scales up to the demand in the 75 pct. scenario.

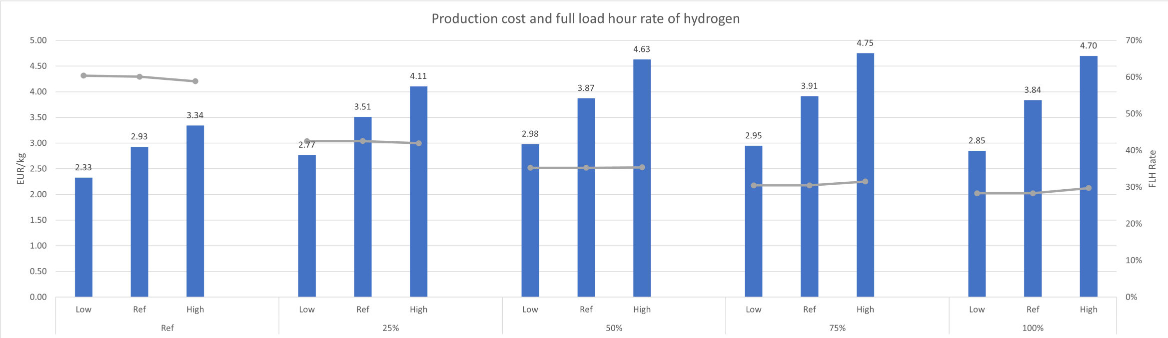


Figure 8.19. Cost of hydrogen electrolysis and annual full load hour rate

Before moving on to analysis two, additional testing is being carried out by scaling up hydrogen storage capacity. This test aims to verify whether storage has a potential impact on the development of PtX, in addition to the price and supply of electricity. When the hydrogen storage capacity is increased in the first two PtX scenarios, there are minor increases of 3 pct. and 6 pct. more full load hours, showing that increasing hydrogen storage does not benefit much in increasing PtX efficiency in this case. In the second analysis, a similar test and comparison will follow.

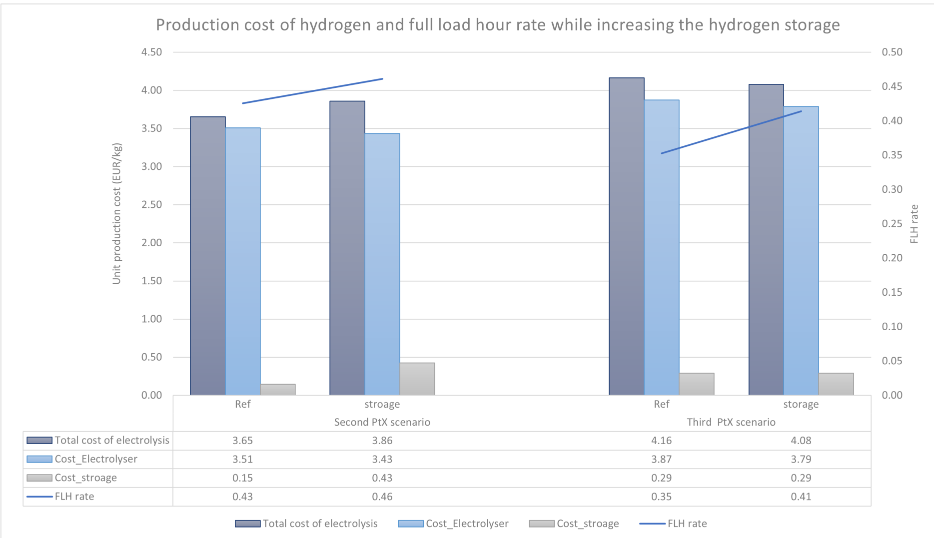
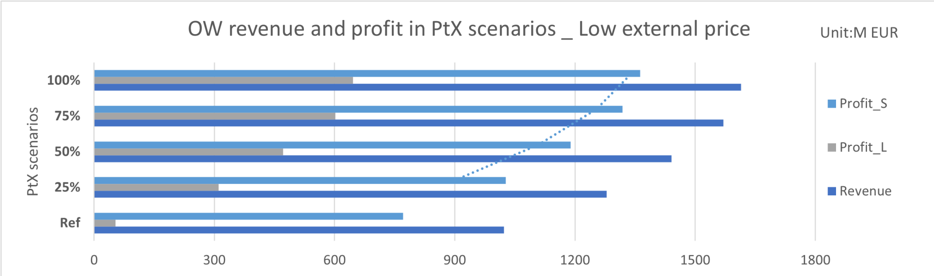


Figure 8.20. Impact on the storage capacity of hydrogen

Offshore wind suppliers:

Figures 8.21, 8.22, and 8.23 reveal a very positive consequence for offshore wind turbine owners when a significant demand is added for the production of green fuel.

In figure 8.21 the long-term profit of offshore wind is relatively low compared to just the first PtX increase scenario. The long-term profit increases from 54 M EUR to 310 M EUR by adding a PtX demand.

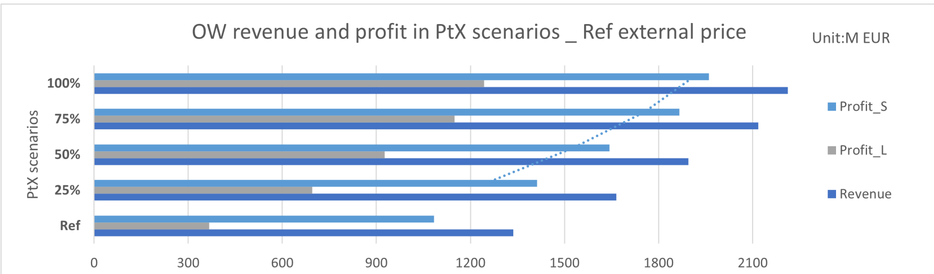


	Ref	25%	50%	75%	100%
Profit_S	771	1027	1189	1319	1363
Profit_L	54	310	472	602	646
Revenue	1023	1279	1441	1571	1615

Figure 8.21. Private economics of offshore wind turbines owners when increasing PtX in a low external electricity price market.

From the first PtX increase scenario, the long-term profit increases steadily until the final scenario, where the change in income is small compared to the earlier changes. The short-term profit instead has a major increase from the reference scenario to the first scenario, and from there it steadily increases until the final scenario, where, as with the long-term profit, it only increases relatively little, see figure 8.21. Revenue follows the same steady development.

As with the previous results, figure 8.22 shows the same steady increase in long- and short-term profit and revenue. However, there is a difference in the development between the reference scenario and the first PtX increase scenario.

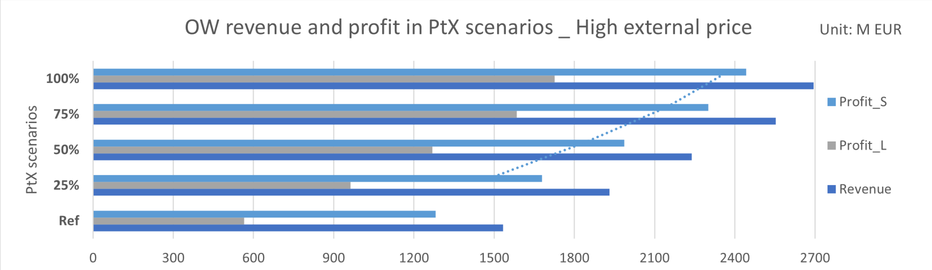


	Ref	25%	50%	75%	100%
Profit_S	1084	1413	1643	1866	1960
Profit_L	367	696	926	1149	1243
Revenue	1336	1665	1895	2118	2212

Figure 8.22. Private economics of offshore wind turbines owners when increasing PtX in a Ref external electricity price market.

In figure 8.22 the long-term profit increases from 367 M EUR to 696 M EUR from the reference step to the first increase. This is a relatively smaller increase compared to the previous low external price setting. From there all economic parameters; long- and short-term profits and revenues develop steadily, until a lower gain when the final demand for PtX is added, which will be elaborated in more detail in 8.27.

Figure 8.23 once again shows steady growth in income for offshore wind owners.



	Ref	25%	50%	75%	100%
Profit_S	1282	1680	1986	2302	2443
Profit_L	565	963	1269	1585	1726
Revenue	1534	1932	2238	2554	2695

Figure 8.23. Private economics of offshore wind turbines owners when increasing PtX in a high external electricity price market.

The results seen in the three figures 8.21, 8.22, and 8.23 verifies the findings from chapter 2; a production of green fuels will counteract the potential loss faced by wind turbine owners in the scenario without an increase in offshore wind.

8.2.3 Increasing total annual costs as PtX increases

Socioeconomically, there are negative consequences of increasing PtX without adequately securing this demand with renewable supply. Investors benefit greatly from more demanding consumers, but the overall system and households seem to suffer more than benefit.

Figure 8.24 paints a very clear picture; simply increasing the demand and production of renewable E-fuels causes a steep increase in the total annual costs of the Danish energy system.

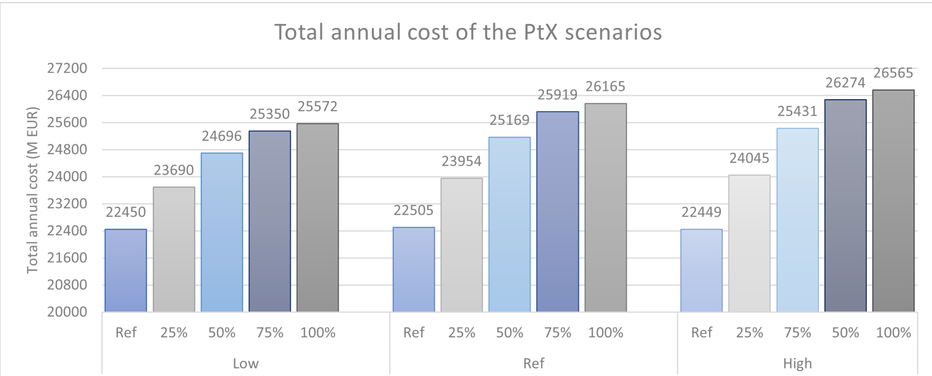


Figure 8.24. Total annual cost development when increasing PtX demand.

In the reference external price scenarios, the total annual cost jumps from 22,505 to 23,954 M EUR, a difference of 1,449 M EUR. Adding additional offshore wind turbines never caused an increase in annual total costs of this level; the final reference price offshore wind scenario reached a cost of 23,002 M EUR. Several extra expenses are tied into electrofuel production: Higher import, investment in electrolyser capacity, carbon capture storage, and E-fuel production. Therefore, the energy system investigated thus is not suitable for meeting the high demand for green fuels.

From 8.25 it can be deduced that having electrolysers and PtX producers will hit all consumers. The average price of electricity in the market increases in all scenarios, with all external electricity prices.

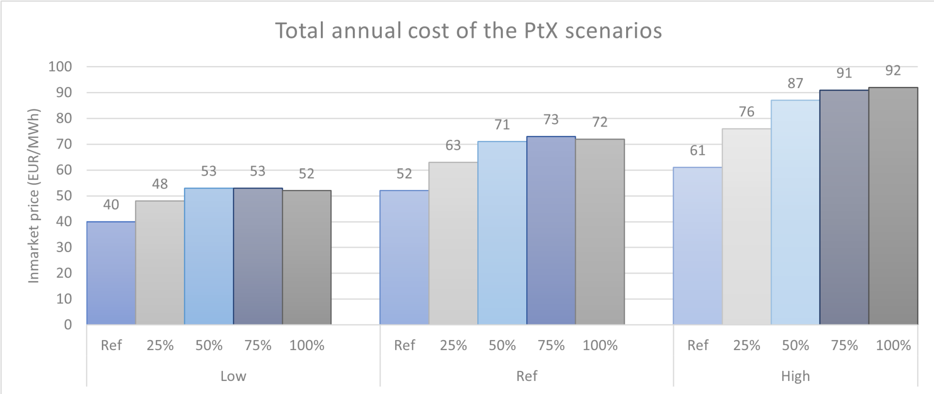


Figure 8.25. Overview of average inmarket prices in all scenarios

In figures 8.25 and 8.26 there is a clear increase from the reference scenario to the first scenario and from the first scenario to the second. Subsequently, the average price of electricity in the market stabilises and eventually falls in the last increase steps when using the low or reference electricity price. With a high price on the external electricity market, the price on the home market increases throughout.

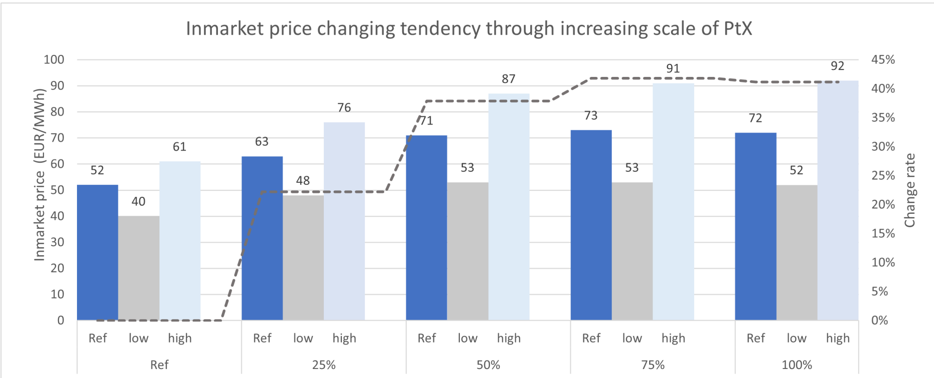


Figure 8.26. Inmarket price changing tendency through increasing scale of PtX.

In the scenarios, there is a heavy reliance on import, and thus the external market, which is a factor as to why the total annual cost increases. The external market also influences the home market by pushing the price of electricity higher as more demand penetrates the market. Household consumers and other private consumers are affected by high prices as PtX production enters the market.

Again, the final socioeconomic parameter is the bottleneck payment. Contrary to the offshore wind scenarios, adding a PtX demand results in immense bottleneck costs, especially in the two latter scenarios, see figure 8.27.

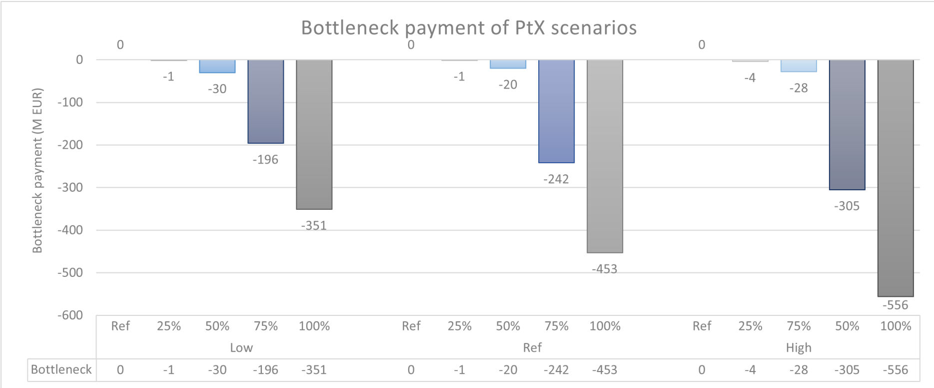


Figure 8.27. Bottleneck payment in PtX increase scenarios.

To put the results on 8.27 into perspective, 8.9 only reached a payment of 26 M EUR, whereas adding a high hydrogen and electrofuel production results in a payment of 351, 453 or 556 M EUR. Expenses that size make it clear that E-fuel production not only increases socioeconomic cost significantly, but will require an unrealistically critical amount of import without also having additional renewable electricity supply.

8.2.4 Carbon emissions increasing when producing green fuels

Contrary to the purpose of producing renewable fuels, figure 8.28 shows that carbon emissions, in fact, increase when no additional renewable electricity production is included.

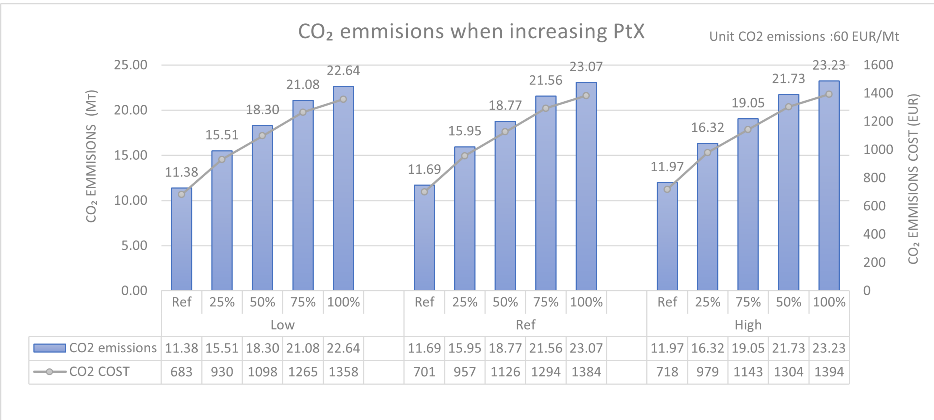


Figure 8.28. Carbon emissions across PtX scenarios.

The energy system in the PtX scenarios has: 6,630 MW offshore wind, 4,800 MW, and 5,000 MW PV, as seen in figure 7.1 in section 7.1.1.1. Given the significant growth of carbon emissions from the reference scenario to the first scenario in figure 8.28, that is, much too little renewable electricity supply. The increased demand for electricity pressures the system to increase fossil fuel production and import to cover the increased demand. The additional supply of electricity from fossil fuels will obviously increase emissions, but import can potentially have the same effect if the imported electricity also is from fossil fuel-generated electricity. In figure 8.28 the carbon emissions continuously increase.

8.2.5 Summary of PtX results

Producing E-fuels by electrolysis, carbon capture, and CO_2 hydrogenation added a significant demand for electricity in the system. Although the purpose of electrofuels is to be a green replacement for liquid fossil fuels in the transport sector, the production of E-fuels in a system that cannot sustain them had the opposite effect. The import/export balance revealed a high dependence on import. This indicates a great pressure on the energy system, supported by carbon emissions, the total annual cost, and the bottleneck payment. These parameters continued to rise from the first PtX scenario. The added demand for electricity was too high for renewable sources, so fossil-based power plants and import/export were needed. Unlike in the offshore wind scenarios, private offshore wind investors earned higher and continuously increasing revenue as a result of increasing electricity prices.

8.3 Comparative study of offshore wind scenarios and PtX scenarios

In this section, a few parameters will be shown again and directly compared between the offshore wind and Power-to-X scenarios. An explicit and clear comparison will help set up a balancing between the two sectors in the second analysis, and can tie the results to the overall purpose of the first analysis, being: using sectors to balance a transitioning market. Furthermore, the results will be connected to the game theory, specifically the consequences of two sectors behaving as two non-cooperating players.

Sections 2.4 and 2.5 showed two *potentially* important consequences of the green transition; **the electricity price can with enough RES go very low under the current electricity market design** and **the electricity price can increase, and the number of hours with a price of zero can be severely negated with PtX production**. These consequences are expressed in figure 8.29 in the form of duration curves.

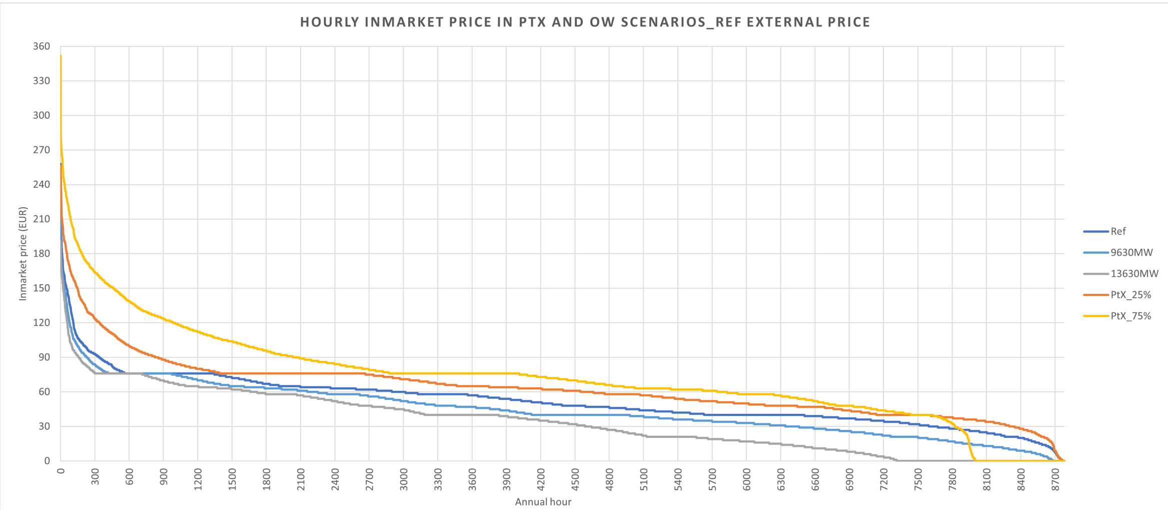


Figure 8.29. Electricity price duration curves in different scenarios.

The results in figure 8.29 to some extent verifies the findings from sections 2.4 and 2.5; implementing an abundance of offshore wind generally forces down the electricity prices, and especially with 13,630 MW (the grey curve in figure 8.29) will electricity prices of zero occur more often. In the simulated energy system, prices of zero only occur more frequently with the highest offshore wind capacity simulated. Given that the system is only a transition system, with fossil fuel plants and relatively lower use of electricity for heating,

the price setting is still highly influenced by conventional plants, but with very high amounts of wind, the low electricity price problem can occur. The light blue duration curve shows the 9,630 MW offshore wind scenario do not have the zero electricity price challenge.
On the orange duration curve (25 pct. PtX scenario), very low electricity prices essentially do not occur - there are around 360 hours with a price lower than 30 EUR - the PtX production will take advantage of the cheap electricity, generally raise the prices, and cause more price spike hours. The yellow duration curve (75 pct. PtX scenario) shows the same results in a more extreme manner. Something unexpected happens in the 75 pct. scenario (yellow duration curve), where electricity prices of zero occur, although the demand is significantly higher than in the 25 pct. PtX scenario. Due to the fact that the system depends on critical import, the system reaches a critical bottleneck, which means overload of transmission lines. Figure 8.30 shows the electricity prices and payment for the bottleneck. When the bottleneck becomes too critical, the electricity price is reduced to zero; this is a systemic response in EnergyPLAN [Lund and Thellufsen, 2021].

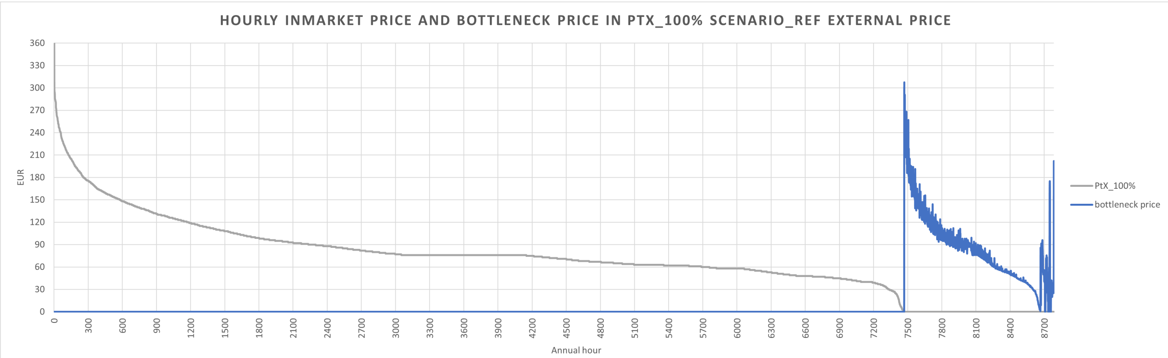


Figure 8.30. Visualisation of the electricity price and bottleneck cost.

The modelling software responding in such a way indicates that the energy system is unable to handle demand and supply in all hours, and, as such, a more major development of the electrofuel sector necessitates, according to these scenarios, a development of renewable electricity supply as well.

8.3.1 Game theoretical comparison

From the figures below it is clear that the PtX sector cannot develop as a separate player from the offshore wind sector without achieving the opposite environmental result than intended.

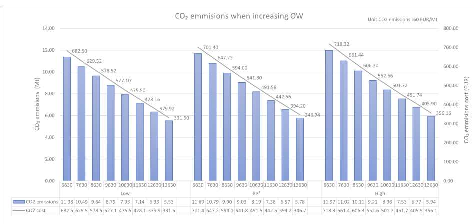


Figure 8.31. Carbon emissions when increasing offshore wind.

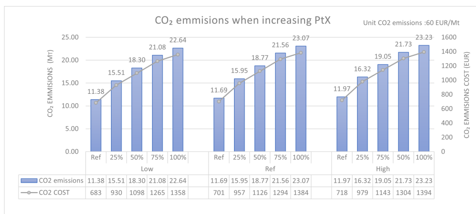


Figure 8.32. Carbon emissions when increasing PtX.

Carbon-free electricity supply greatly decreases carbon emissions but results in other negative consequences, as shown earlier. The following figures underline the importance of self-sufficiency in the system.

Overloaded transmission lines add to cross-border payment, and extreme overload of the cable pressures the system beyond a critical point.

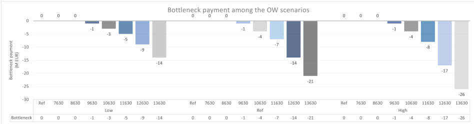


Figure 8.33. Bottleneck payment when increasing offshore wind.

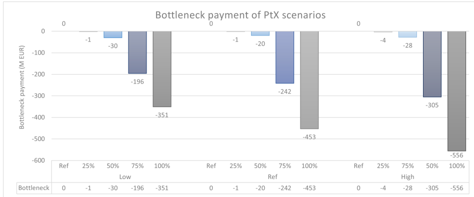


Figure 8.34. Bottleneck payment when increasing PtX.

Too large of a supply and too large of a demand can result in a negative outcome. However, PtX causes the greatest problem in the simulated scenarios, signalling the need for further supply. These results add to the fact that the two sectors cannot develop as separate players without causing systemic issues; demand and supply must be balanced. The figures below show that increasing offshore wind either reduces the total annual cost in the first few steps and then increases, or the total annual cost increases from the first step. As explained earlier, in scenarios where the total annual cost is lowered, wind turbine suppliers depend on exporting to a high-priced external market, with sales at a high price being a key factor. In the PtX scenarios, the total annual cost simply increases, with importing becoming more and more.

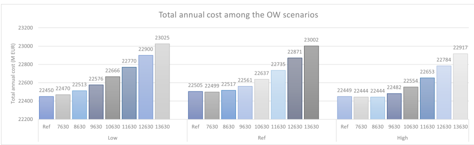


Figure 8.35. Total annual cost when increasing offshore wind.

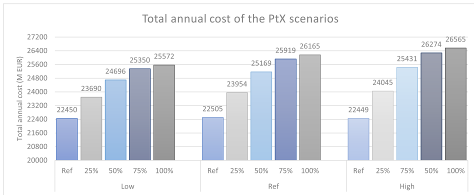


Figure 8.36. Total annual cost when increasing PtX.

On a socioeconomic level, the two players will eventually cause additional costs. However, there is a potential to negate the negative economics; offshore wind needs to sell electricity at higher prices, and PtX requires renewable electricity that is not imported. If better results will come of the two players following a more cooperative development rather than developing with complete disregard for the other sector will be explored in the second analysis.

As highlighted in subsections 8.1.2 and 8.2.2, offshore wind investors face a long-term profit issue if the offshore wind expands rapidly without PtX demand, making offshore wind unprofitable without subsidies. However, if the E-fuel production expands and adds an electricity demand, offshore wind farm owners will get an increasing revenue. Subsections 8.1.2 and 8.2.2 also showed that the production cost of electrofuels will increase as electricity prices increase. Developing as non-cooperative players hurts the players' own private economics whilst the other benefits. In a market situation, this is not sustainable, and a balanced increase will in the second analysis show if both achieve an economic gain.

8.4 Answer to first subquestion

How will individual development of offshore wind supply and Power-to-X production impact the energy system on self-sufficiency, private- and socioeconomics, and carbon emissions, under three possible external market prices?

Through simulations and scenarios, the potential issues of low electricity prices and investor loss or lack of electricity supply, found in the problem analysis sections 2.4 and 2.5, were tested and verified to some extent in this analysis.

If the two sectors, offshore wind owners and Power-to-X producers, develop completely separate from each other, there will be multiple systemic, private and external negative consequences. Departing from a 2027 - 2030 energy system, extensive offshore wind turbine expansion will result in private economic loss for wind turbine owners. A high price in the external market is crucial to preserve long-term profit and will result in additional long-term revenue, but continued growth will eventually result in long-term loss, where the total investment costs cannot be covered. Socioeconomically the gains of additional wind farm will similarly become negligible and instead the society will lose money. However, the addition of renewable electricity supply will increase self-sufficiency, as imports will far outweigh exports and CO_2 emissions will continue to decrease.

Electrofuel production has little positive effects on the energy system without increased green supply, and production of green fuels increased carbon emissions, socioeconomic cost, and self-sufficiency. Under all external market prices in all PtX scenarios, imports were hugely important, and the import only increased as the demand for green fuel increased. The increased demand for electricity in this form counteracted the falling price of electricity by raising it and taking advantage of the hours at a very low price. However, increasing the price resulted in an increase in the production costs of electrofuels.

In the scenarios conducted in this analysis, none of the two sectors benefit from developing non-cooperatively, it was instead the non-developing sector experiencing economic gains. However, the society lost regardless of whether each sector expanded beyond a certain point. These results show potential synergies in which the development of one sector can benefit the other.

Analysis two - Testing for optimality between OW and PtX 9

In this chapter all possible combinations between offshore wind and Power-to-X will be explored, and based on a holistic evaluation, a single combination will be chosen for each electrofuel scenario.

Finding the optimal combinations: To discover whether the theoretical synergistic effects between offshore wind and PtX will, in fact, counter the negative effects of the sectors developing individually, all the same parameters as in the previous analysis will be investigated. The parameters are as follows, and are based of the chosen expectations from the concept of a smart energy system:

- Import/export balance to determine self-suffiency and being integrable
- Offshore wind revenue to determine commercial viability and economic feasibility
- Electrofuel production cost to determine commercial viability and economic feasibility
- Electricity price to determine commercial viability and economic feasibility
- Total annual cost to determine commercial viability and economic feasibility
- Bottlenck payment to determine self-suffiency and being integrable
- Carbon emissions to determine being environmentally benign

As written in section 7.2, the primary parameters are centred on the private market and the total annual cost.

The following table 9.1 shows the simulation output of the parameters mentioned above among the 28 scenarios, covering seven OW capacities under four levels of the PtX scenario.

PtX scenario	OW Scale MW	Profit_S M EUR	Import/export balance TWh/yr	Bottleneck M EUR	Total annual cost M EUR	CO_2 emission Mt	H_2 prod. cost EUR/kg
First	7630	1518	8.81	-1.00	23866	15.00	3.39
First	8630	1589	5.92	0.00	23801	14.09	3.28
First	9630	1631	3.01	0.00	23763	13.17	3.16
First	10630	1633	-0.09	-1.00	23746	12.26	3.04
First	11630	1602	-3.26	-3.00	23759	11.37	2.92
First	12630	1544	-6.49	-5.00	23790	10.51	2.80
First	13630	1442	-9.88	-8.00	23851	9.67	2.67
Second	7630	1803	17.4	-13.00	25090	17.83	3.86
Second	8630	1908	14.63	-8.00	24986	16.92	3.75
Second	9630	1949	11.85	-11.00	24843	16.00	3.53
Second	10630	1995	9.05	-9.00	24780	15.07	3.42
Second	11630	2056	6.1	-4.00	24774	14.15	3.39
Second	12630	1981	3.12	-11.00	24716	13.22	3.18
Second	13630	1979	-0.12	-4.00	24749	12.36	3.14
Third	7630	2021	26.3	-209.00	25820	20.65	3.83
Third	8630	2143	23.45	-190.00	25707	19.73	3.72
Third	9630	2244	20.76	-171.00	25620	18.79	3.63
Third	10630	2321	17.98	-155.00	25543	17.87	3.54
Third	11630	2375	15.21	-143.00	25475	16.95	3.44
Third	12630	2387	12.32	-133.00	25432	16.02	3.34
Third	13630	2373	9.31	-124.00	25407	15.11	3.24
Final	7630	2137	31.83	-402.00	26082	22.16	3.77
Final	8630	2279	28.82	-356.00	26014	21.27	3.70
Final	9630	2390	25.9	-330.00	25911	20.36	3.61
Final	10630	2478	23.19	-308.00	25828	19.41	3.51
Final	11630	2545	20.37	-287.00	25761	18.49	3.43
Final	12630	2592	17.56	-263.00	25727	17.57	3.35
Final	13630	2593	14.59	-241.00	25710	16.67	3.27

Table 9.1. Overview of the 28 simulated scenarios with the accessed parameters.

9.1 Combinations in the first PtX scenario

The high electricity demand from the production of E-fuels drives the import much higher than the export; see figure 9.1, as the results of the first analysis also showed.

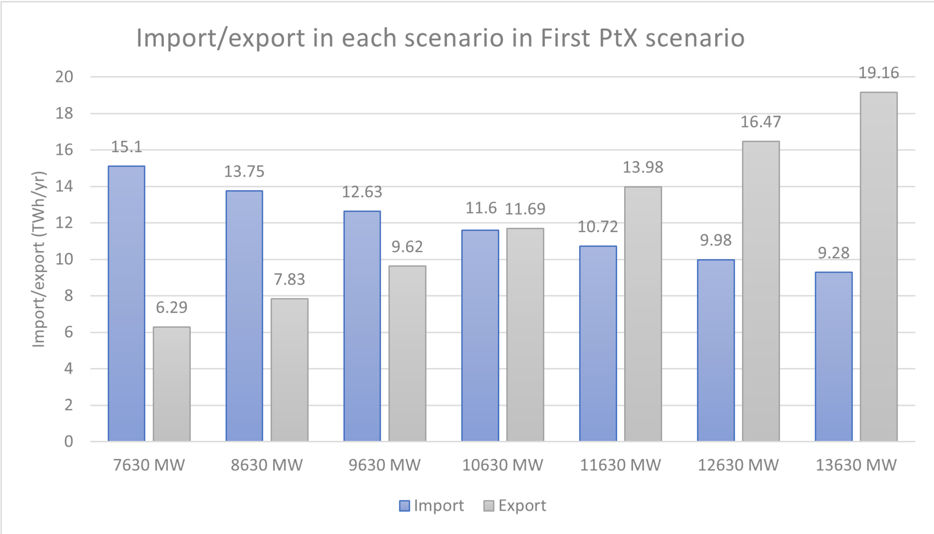
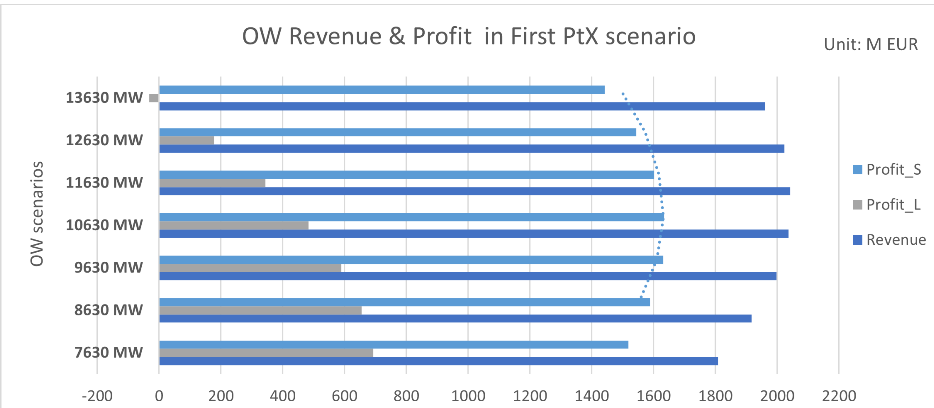


Figure 9.1. Import and export with the first electrofuel demand across all offshore wind capacities.

Figure 9.1 shows that increasing offshore wind capacity also increases self-sufficiency in the system. Import decreases and export increases as the OW capacity increases. The system reaches a balanced point at 10,630 MW offshore wind, but the tendency is a continuous increase in export and a decrease in import as more capacity enters the system.

From the financial perspective of OW owners, the figure 9.2 shows that long-term profits decrease as OW capacity increases. The maximum short-term profit occurs once the system scales up the OW capacity to 10,630 MW.

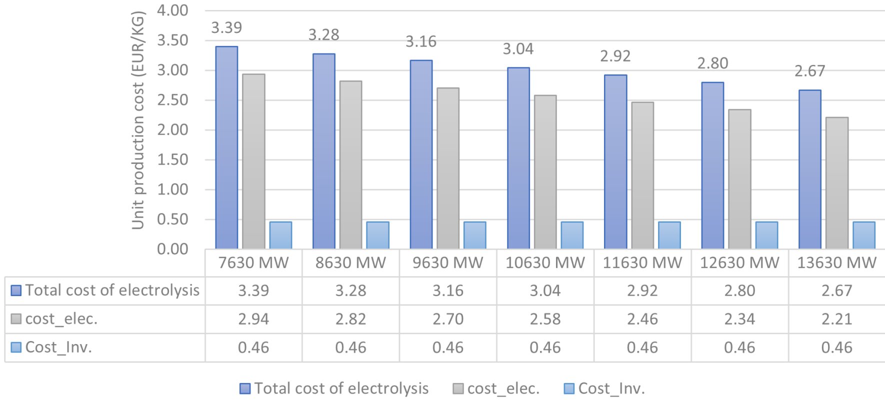


	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Profit_S	1518	1589	1631	1633	1602	1544	1442
Profit_L	693	655	589	483	344	178	-33
Revenue	1808	1917	1997	2037	2043	2023	1959

Figure 9.2. Offshore wind investors profit with the first electrofuel demand.

In terms of economic conditions of the PtX sector, the cost of hydrogen production is steadily declining as the OW expands, which is a result of the drop in the electricity price. From the column graph 9.3, a stable drop of 0.11 to 0.13 EUR/kg is observed in the production cost between each continuous scenario. Meaning, in this scenario, there is no step that obtains a more significant cost drop than another. Therefore, although

13,630 MW has the lowest production cost, the optimal combination will rely on a more thorough evaluation of other parameters.



	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Total cost of electrolysis	3.39	3.28	3.16	3.04	2.92	2.80	2.67
cost_elec.	2.94	2.82	2.70	2.58	2.46	2.34	2.21
Cost_Inv.	0.46	0.46	0.46	0.46	0.46	0.46	0.46

Figure 9.3. Electrofuel production cost across all offshore wind increase steps with the first PtX demand.

Figure 9.4 shows a smooth decline in the average inmarket price while the OW capacity increases, starting at 61 EUR and ending at 45 EUR. The low inmarket price would be beneficial both socioeconomically, for private consumers and PtX suppliers. However, the trend of a decrease in the average price results in a negative impact on short-term profit once the capacity reaches 11,630 MW, see figure 9.2.

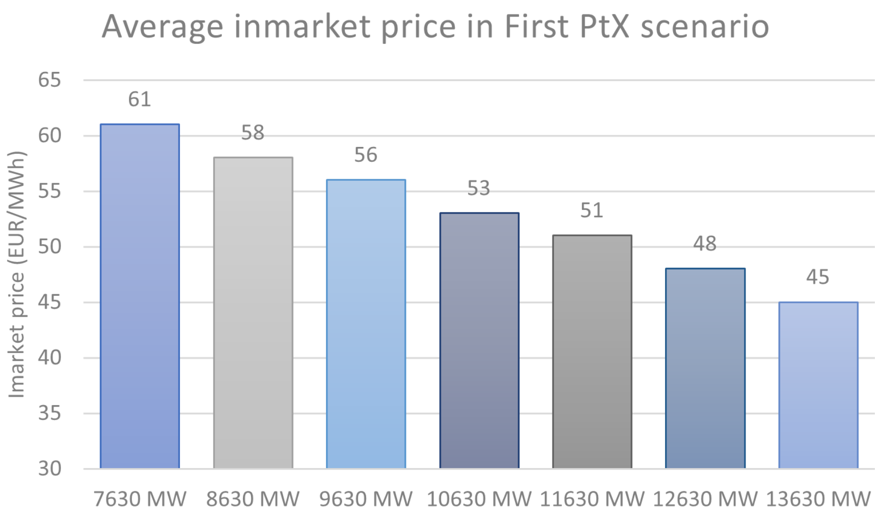


Figure 9.4. Average inmarket price across all offshore wind increase steps with the first PtX demand.

23,746 M EUR is the lowest total annual cost, and unlike any of the individual PtX scenarios or most offshore wind scenarios from the fist analysis, chapter 8, the results in figure 9.5 show the lowest cost occurring when the offshore wind capacity increases, until the OW capacity is 10,630 MW. In chapter 8 the total annual cost would generally simply increase from the first step.

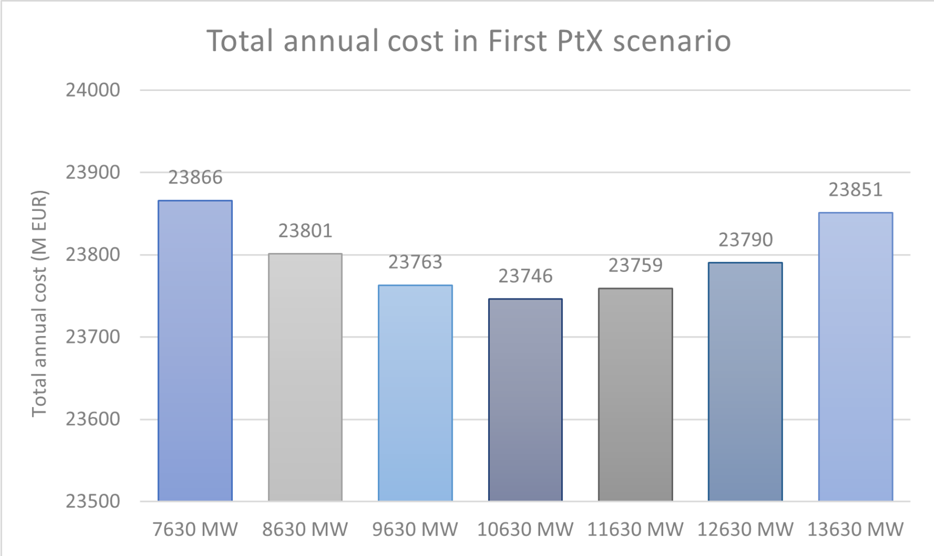
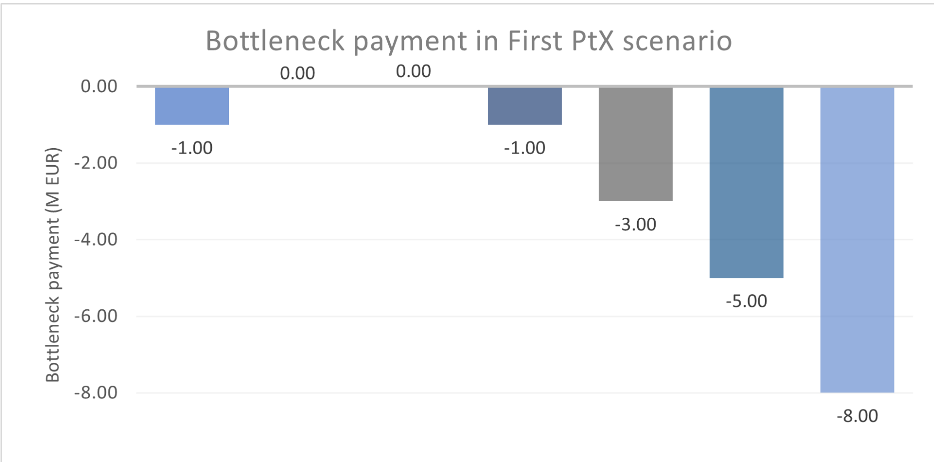


Figure 9.5. Total annual cost with the first electrofuel demand across all offshore wind increases.

From a socioeconomic perspective, the results from figure 9.5 means the most optimal strategy when producing green fuels is also investing in renewable electricity supply. In these particular energy system models, the optimal capacity is 10,630 MW.

The bottleneck payment varies between 1 and 8 M EUR for overloading the transmission lines, see figure 9.6. Without added offshore wind, there is a payment of 1 M EUR, but with 2,000 or 3,000 MW higher capacity, there is no payment.



	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Bottleneck	-1.00	0.00	0.00	-1.00	-3.00	-5.00	-8.00

Figure 9.6. Bottleneck payment with the first electrofuel demand across all offshore wind increases.

Based on the previous figure 9.5, the benefits of higher capacity outperform the bottleneck cost of 1 M EUR with an offshore capacity of 10,630 MW.

Figure 9.7 shows that CO_2 emissions decrease as the OW capacity increases. From 7,630 to 13,630 MW, there is a decrease in CO_2 emissions of 5.33 Mt, which converts into cost savings of CO_2 emissions of around 320 EUR. However, the annual system cost when the carbon emissions are the lowest, shown in 9.5, is 105 M

EUR higher than the 10,630 MW scenario, which is 328 thousand times the mentioned CO_2 emissions cost savings. Therefore, having OW expand no further than 10,630 MW, cutting off 2.74 Mt of CO_2 emissions with 264 EUR of emission cost savings and 103 M EUR savings in annual total cost is a relatively major progress and preferred alternative.

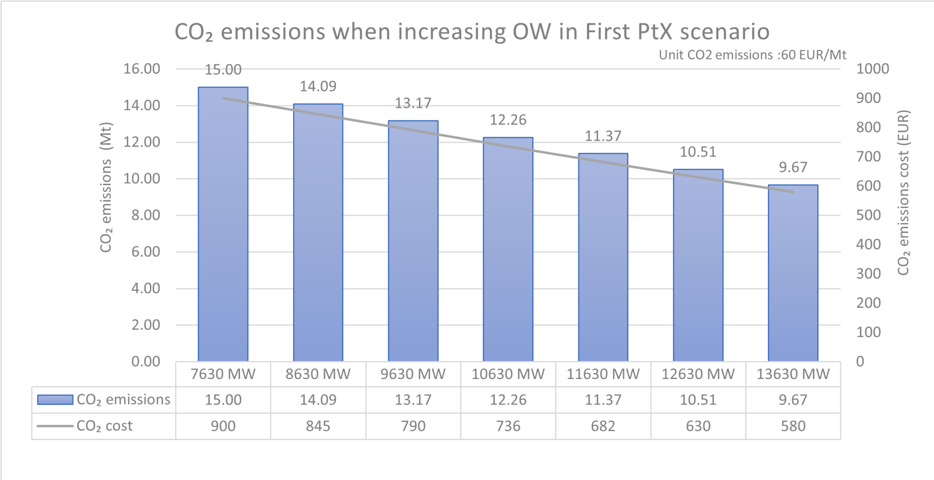


Figure 9.7. Carbon emissions with the first electrofuel demand across all offshore wind increases.

9.1.1 10,630 MW offshore wind best supplies the first PtX demand

From a socioeconomic perspective and from the perspective of offshore wind turbine owners, increasing the offshore wind capacity to 10,630 MW in the first electrofuel scenario proves to be the most optimal choice. With this capacity, the total annual cost reached the lowest point, and the OW investors make the highest short-term profit. The system exports a small amount, 0.09 TWh more electricity a year than import, meaning the in- and outflow is very equal, contrary to being highly dependent on import as when the OW capacity is lower. The production cost of E-fuels and carbon emissions simply decreases with more offshore wind, but the society ultimately loses from an economic perspective. The long term profit of OW is equally difficult to balance as it simply decreases with more capacity - therefore, 10,630 MW offshore wind turbines is under the tested conditions the ideal development.

9.2 Combinations in the second PtX scenario

As with the first electrofuel demand scenarios, the import and export balance increases from a high import to a decrease as more offshore wind turbines enter the energy model. With the second demand for PtX, the starting import is approximately six TWh/year higher than with the previous demand; see figures 9.1 and 9.8.

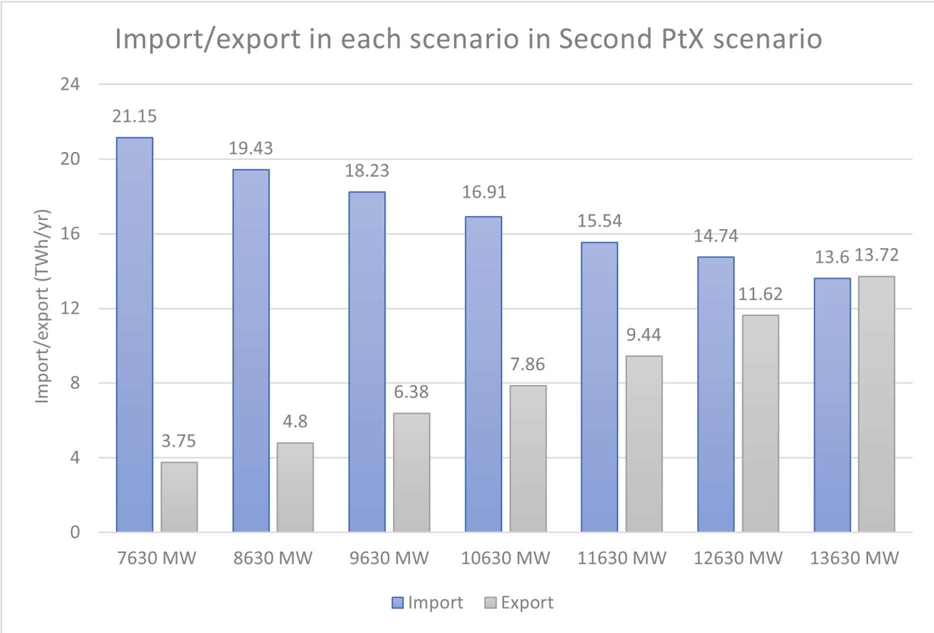
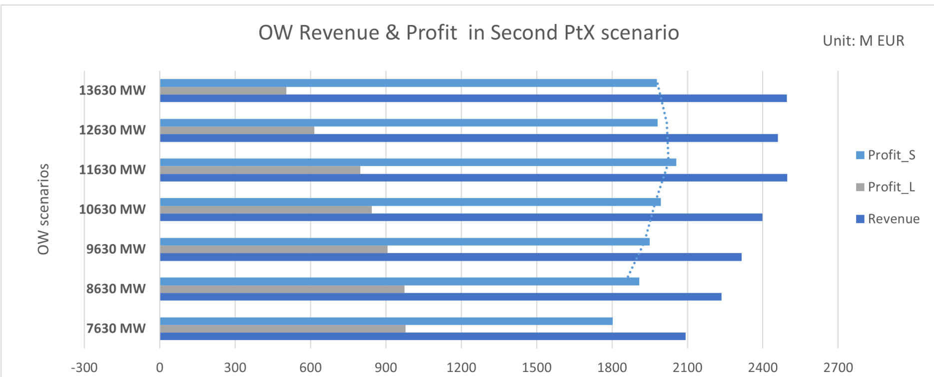


Figure 9.8. Import and export with the second electrofuel demand across all offshore wind capacities.

A significant difference that can be seen in figure 9.8 is that the export never significantly exceeds the import. There is equality between the two with the highest possible offshore wind supply tested. In the reference energy system with a reference price and in most offshore wind increase scenarios, the Danish energy system was a gross exporter, but already from the second demand for PtX, that is barely possible, as can be seen in figure 9.8. Denmark in these scenarios changes from being an exporter of *highly likely* green electricity to instead using green electricity within its borders and exporting green fuels.

In the second PtX scenario, the long-term OW profit stays positive on all scales of the OW capacity, while the short-term profit reached its maximum as the OW capacity is 11,630 MW, at a value of 2,056 M EUR. The figure 9.9 also shows a later growth in revenue from 12,630 to 13,630 MW, yet the long-term cost shows a relatively major decline compared to the previous scenarios.



	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Profit_S	1803	1908	1949	1995	2056	1981	1979
Profit_L	978	974	907	845	798	615	504
Revenue	2093	2236	2315	2399	2497	2460	2496

Figure 9.9. Offshore wind investors profit with the second electrofuel demand.

Compared to the first PtX scenario in figure 9.2, the second scenario shows an overall increase of around 300 M EUR among the corresponding OW steps. There is an extra 423 M EUR short-term profit compared to the maximum profiting steps in the first scenario.

From the perspective of the PtX suppliers, a continuously increasing OW capacity results in a steady cost drop in hydrogen production, from 10,630 to 11,630 MW, and from 12,630 to 13,630 MW are less significant developments. However, compared to the figure for the first PtX scenario 9.3, the unit production prices increase and are approximately 0.40 EUR/kg higher compared to the corresponding steps. At 11,630 to 12,630 MW, the last significant unit cost drop occurs, with a decrease of 0.11 EUR/kg.

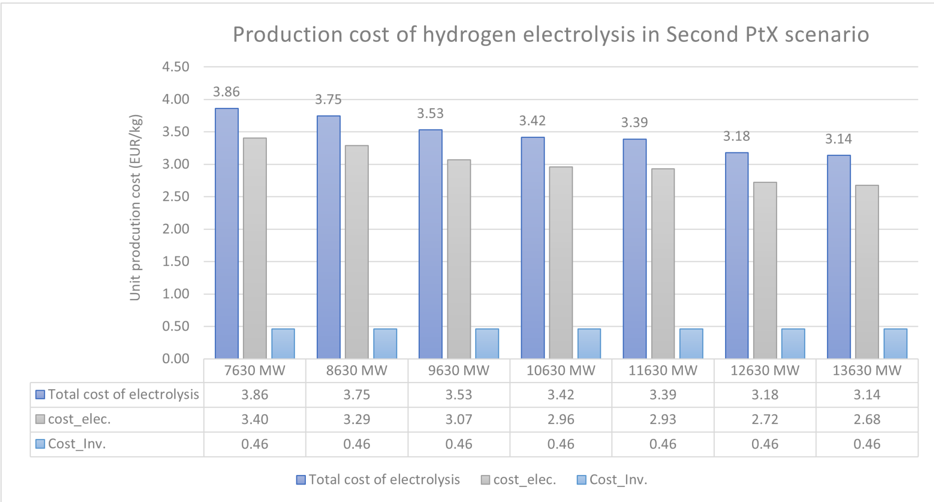


Figure 9.10. Electrofuel production cost across all offshore wind increase steps with the Second PtX demand.

The following figure 9.11 shows the total production cost in the second PtX scenario among different scales of OW capacity. The blue bar represents the total cost, while the grey area represents the cost drop for each step of OW compared to the 7,630 MW scenario. As mentioned above, the unit production cost has a significant decrease from 11,630 to 12,630 MW, and it also shows in figure 9.11 that the step to 12,630 MW has relatively high total cost savings and a sharp trend of cost reduction compared to step 11,630 MW. The gap is around 189 M EUR. Therefore, between 11,630 MW and 12,630 MW, step 12,630 MW is the preferred alternative from the PtX sector angle.

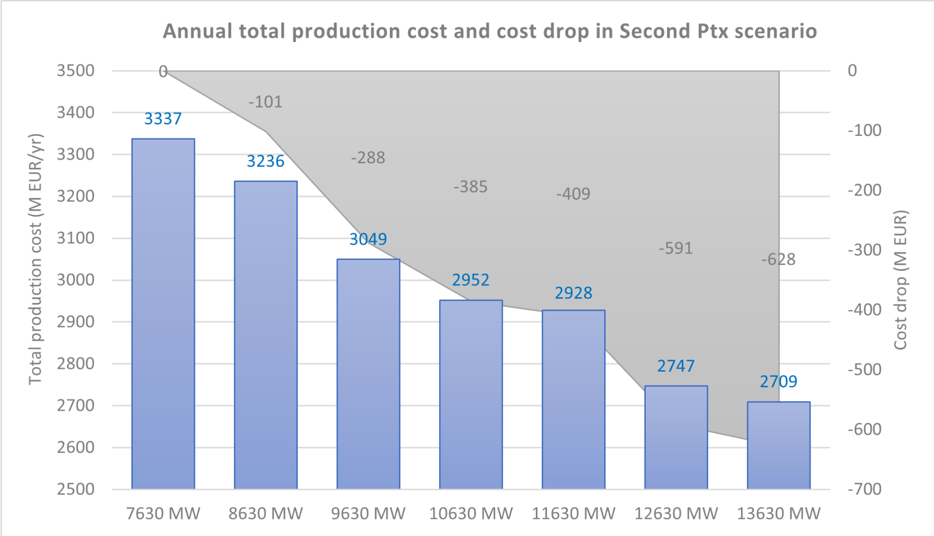


Figure 9.11. Electrofuel production total cost and dropping tendency across all OW increase steps with the Second PtX demand.

The average inmarket price much follows the expected trend of decreasing as the offshore wind capacity increases. As seen in figure 9.12 the price decrease however flattens between 9,630 and 11,630 MW.

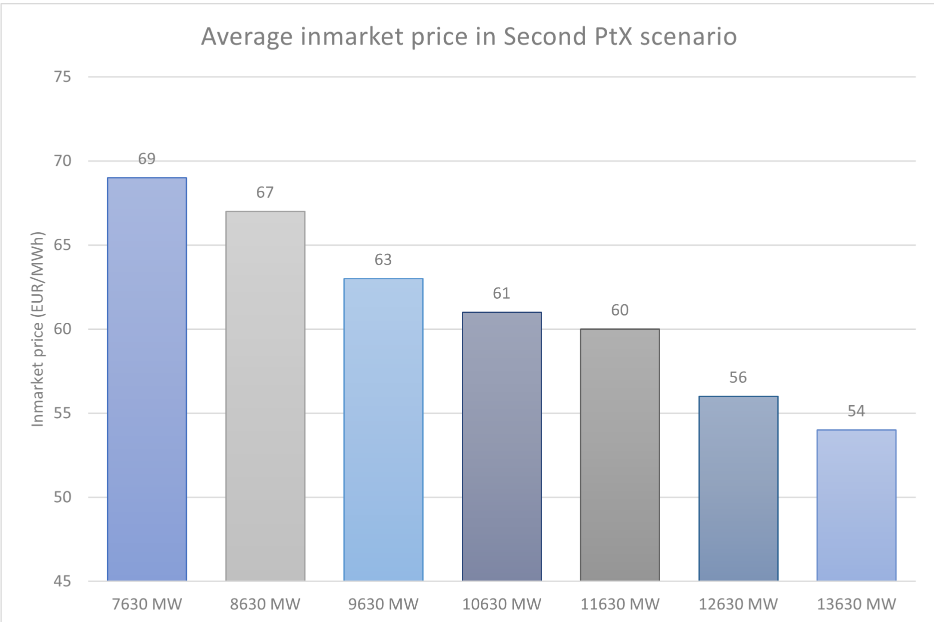


Figure 9.12. Average inmarket price across all offshore wind increase steps with the second PtX demand.

For offshore wind turbine suppliers, the price decrease becomes less ideal beyond 11,630 MW but benefits the consumer side, as there is a relatively more significant price drop when increasing to 12,630 MW.

Figure 9.13 shows a general decrease in the total annual cost, especially in the first three steps of increasing offshore wind. From 10,630 MW the total annual cost is more even, except for the 12,630 MW capacity scenario, which shows a major decrease from the previous step.

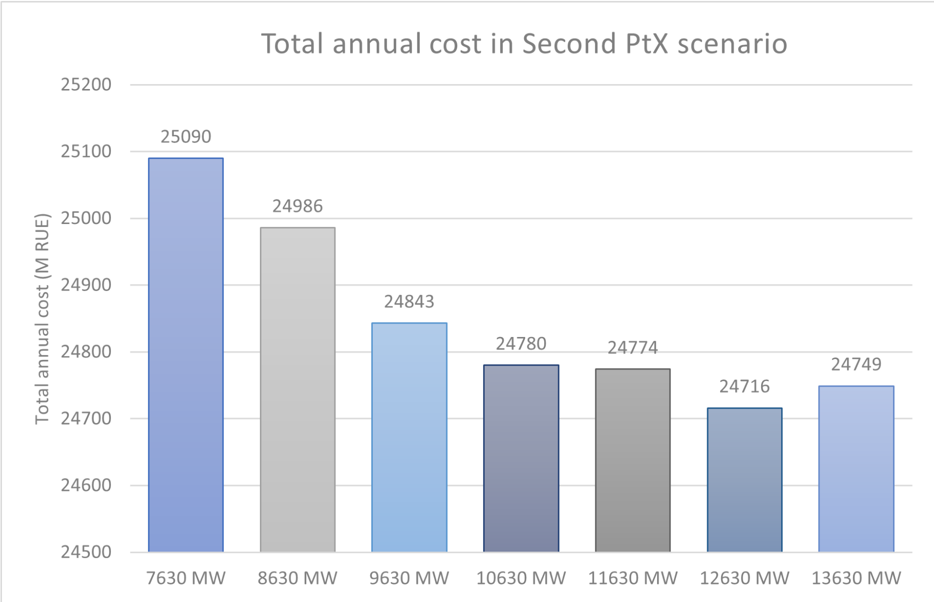


Figure 9.13. Total annual cost with the second electrofuel demand across all offshore wind increases in Second PtX scenario.

Unlike the previous PtX scenario, it takes more wind turbine suppliers to achieve the socioeconomically cheapest energy system when producing E-fuel. In the last step of increase of offshore wind, the total annual costs increase. As seen in figure 9.11 the PtX production cost decreases relatively little. So regardless of a payment fall in the production of electrofuels, a decrease in the price of electricity, lower import and more export, the investment costs of offshore wind supersedes the savings in the last increase step.

Rather than a general bottleneck trend occurring, trading across borders and thus utilising and pressing the transmission lines appear more random, as seen in figure 9.14. The lowest bottleneck payment occurs when the system has 11,630 MW offshore wind or 13,630.

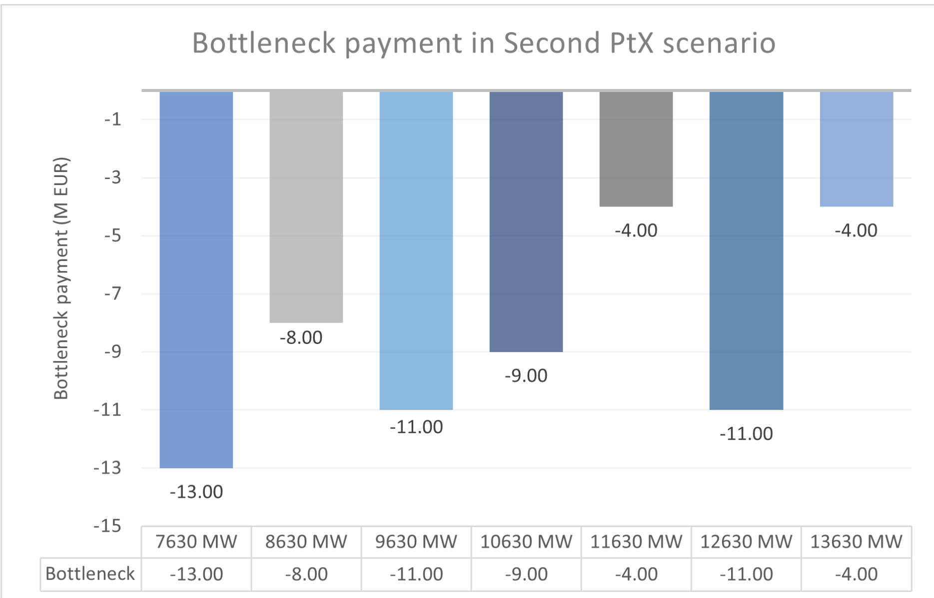


Figure 9.14. Bottleneck payment with the second electrofuel demand across all offshore wind increases.

Since the lowest total annual cost is when offshore reaches 12,630, see figure 9.13, the additional systemic savings when going from 11,630 to 12,630 MW outweigh the higher bottleneck payment. But, although the system socioeconomically improves, a higher bottleneck does indicate that there is at times critical excess or lack of electricity, pressuring the import/export infrastructure. Thus, there is a mismatch between technical and economic performance, but as described in subsection 7.2 a higher transmission line capacity will be simulated later.

Figure 9.15 shows the same trend as for all scenarios with increasing offshore wind capacity.

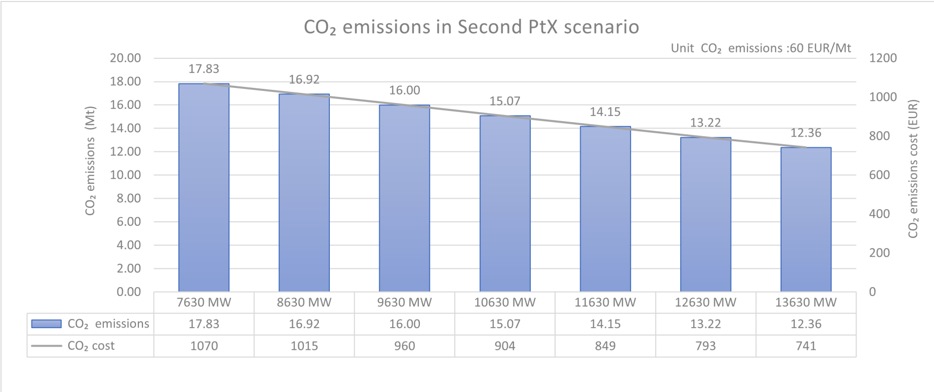


Figure 9.15. Carbon emissions with the second electrofuel demand across all offshore wind increases.

However, the implementation of higher production of green fuels does not mean lower carbon emissions. The difference between the lowest carbon emission scenarios in the figures 9.7 and 9.15 is about 2.5 Mt. The high demand generated by PtX pressures the supply further than what the offshore wind can deliver efficiently.

9.2.1 11,630 and 12,630 MW strikes out at the best alternatives

The analysis seeks to balance both private and socioeconomics, especially the problem of the low to zero electricity price. These combinations of PtX and offshore wind showed different optimalities with different combinations. Increasing offshore wind to 12,630 MW obtained the lowest possible total annual cost, and relative to previous OW capacities with this demand, had the highest export and lowest import, meaning higher self-sufficiency and lower PtX production cost and carbon emissions. Another considerable scenario is that with 11,630 MW. The total annual cost is about 60 M EUR higher and the carbon emissions are higher as well, but the system shows a higher efficiency in terms of a bottleneck cost of only four M EUR, and offshore wind turbine owners get the highest possible short-term revenue. In the 12,630 MW scenario, there is a major decrease in short- and long-term revenue. Both of these are striking out in different ways and will thus be tested in a sensitivity study.

9.3 Combinations in the third PtX scenario

As shown in figure 9.16 and figure 9.8, import demand again increased, this time around seven TWh/year, and the gap between import and export has increased from the beginning step. Unlike the previous two lower PtX demand scenarios, import and export do not meet a balance in this scenario, and still have around a 10 TWh/yr gap in the last step, 13,630 MW, scenario. It shows that the proposed increases in the OW capacity steps are no longer sufficient once the PtX developed to the third PtX scenario.

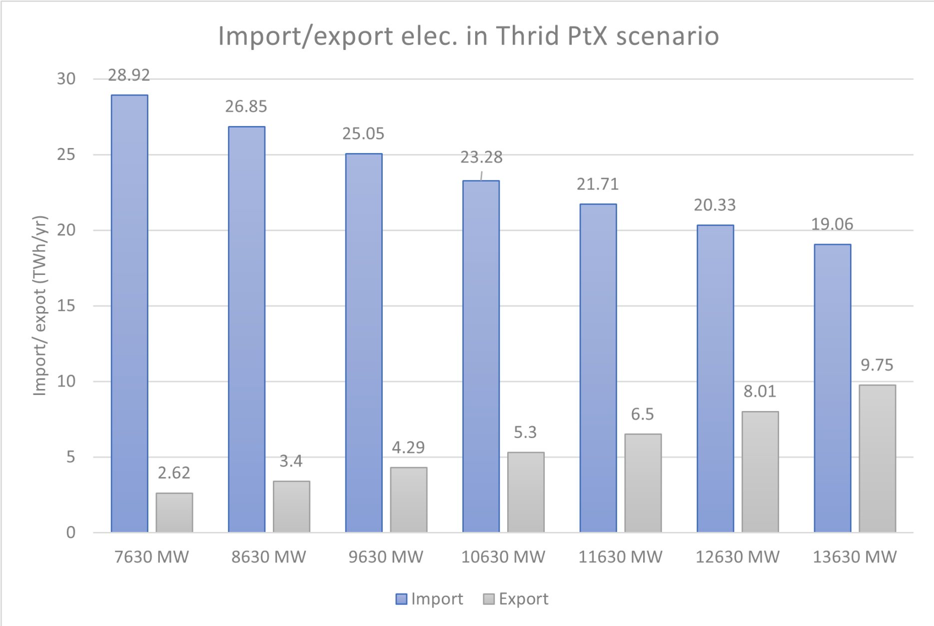
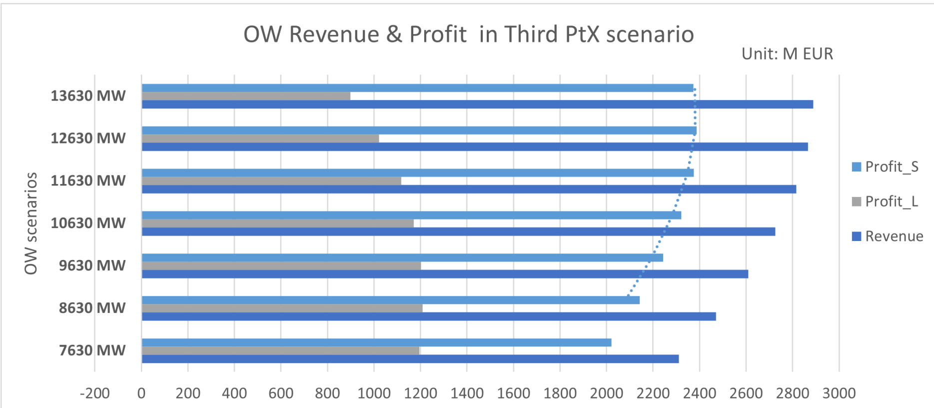


Figure 9.16. Import and export with the first electrofuel demand across all offshore wind capacities.

From figure 9.17, the maximum short-term profit is found in scenario 12,630 MW, with a value of 2,387 M EUR. Again, the overall profit has increased two to three hundred M EUR among the steps of increasing OW compared to the second PtX scenario.



	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Profit_S	2021	2143	2244	2321	2375	2387	2373
Profit_L	1196	1209	1202	1171	1117	1021	898
Revenue	2311	2471	2610	2725	2816	2866	2890

Figure 9.17. Offshore wind investors profit with the third electrofuel demand.

The electrofuel sector benefits immensely from having more offshore wind suppliers and more green electricity production in the system. Unlike the previous scenarios, in figure 9.18, each increase in offshore wind significantly reduces the cost of E-fuels.

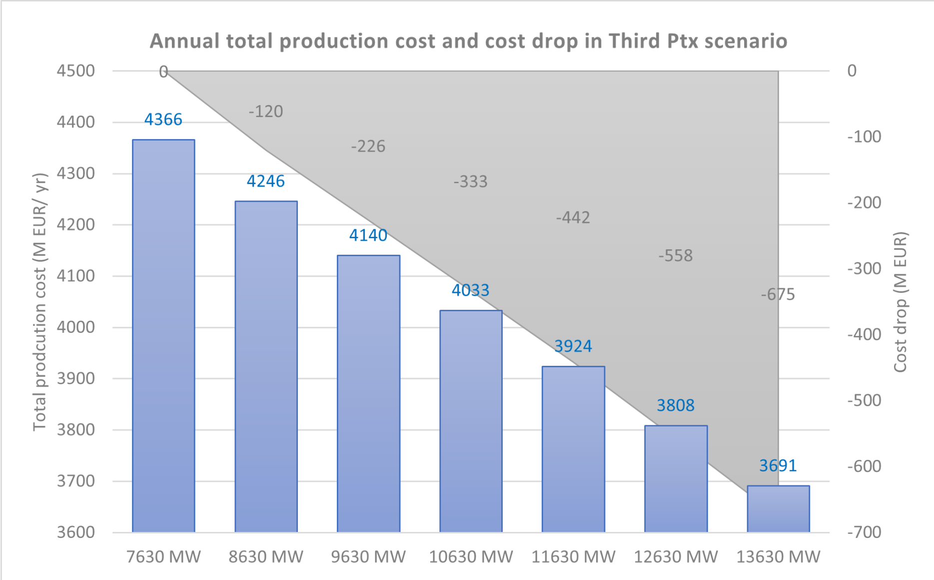


Figure 9.18. Electrofuel production total cost and dropping tendency across all OW increase steps with the Third PtX demand.

This figure, 9.18, underlines the need for a coherent development between offshore wind and PtX if the PtX sector expands rapidly. Unlike the results in figure 9.11, every increase in OW is economically important.

In the third PtX scenario, figure 9.19 shows a stable decrease in the unit production cost. For both 7,630 MW and 8,630 MW, the unit production cost is 0.03 EUR/kg lower than in the same two steps in the second Ptx scenario, which is illogical. With a higher electricity demand, the electricity prices and production cost should become higher, and these results will be discussed later.

The importance of scaling up renewable supply, figure 9.19, still shows an ongoing decrease in the unit cost of producing E-fuels.

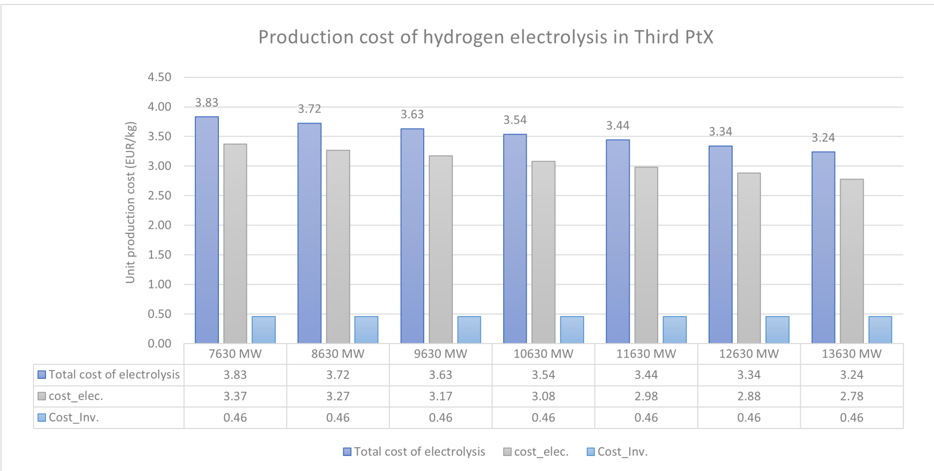


Figure 9.19. Electrofuel production cost across all offshore wind increase steps with the third PtX demand.

From the figure 9.20 it can be deduced why the cost of E-fuel production decreases; the average electricity price goes from 71 EUR/MWh to 58 EUR/MWh, thus decreasing majorly from the first to the last step.

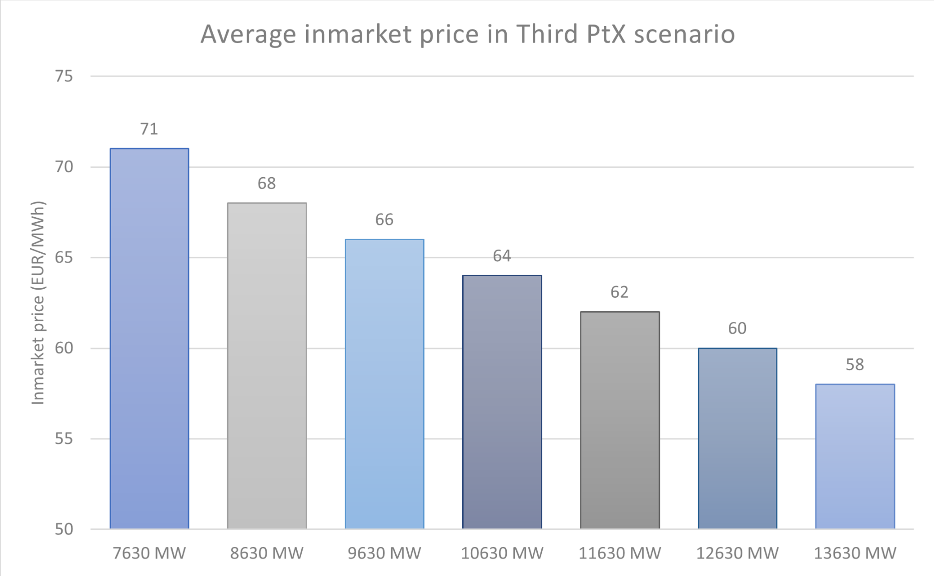


Figure 9.20. Average inmarket price across all offshore wind increase steps with the third PtX demand.

Because PtX production is closely related to the electricity price through the electrolyser, a lower electricity price is important to the production of electrofuels. Furthermore, household consumers and other private consumers benefit from lower prices, which means that a lower electricity price is better from a private perspective for the PtX sector and from a socioeconomic perspective, alas not from a supplier perspective.

The PtX production and electricity demand have now become so great that any additional offshore wind supply will decrease import and decrease the total annual cost; see figures 9.16 and 9.21.

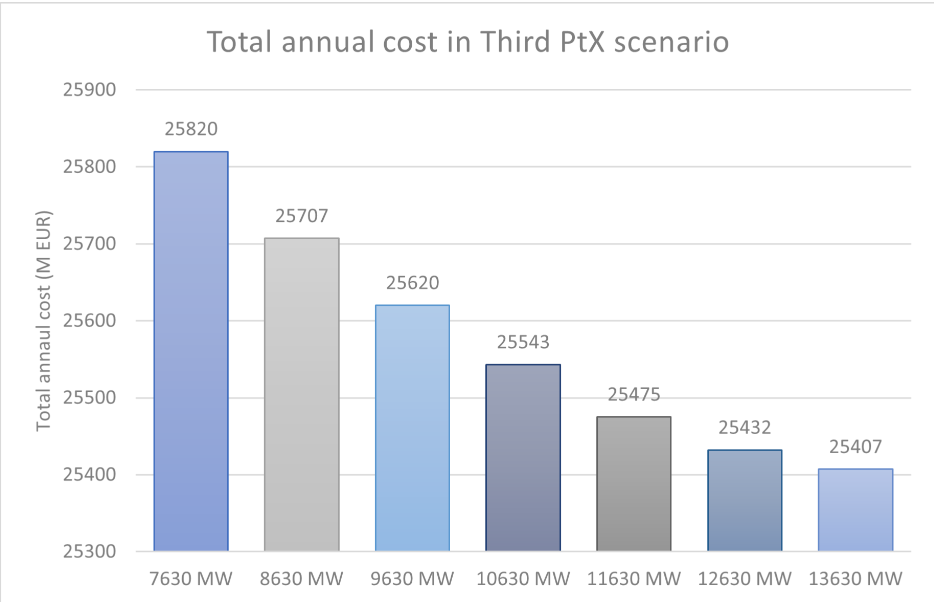


Figure 9.21. Total annual cost with the third electrofuel demand across all offshore wind increases.

The lowest total annual cost with this electrofuel demand is roughly 700 M EUR more expensive than the previous. From the increasing socioeconomic cost from the previous E-fuel demand scenarios to these, green fuels seem to burden the system more than benefit it, by sustaining the production at the expense of the society.

Another indicator of this is the bottleneck payment. The lowest payment in figure 9.22 is 124 M EUR, which is an increase of 120 M EUR compared to the previous scenarios.

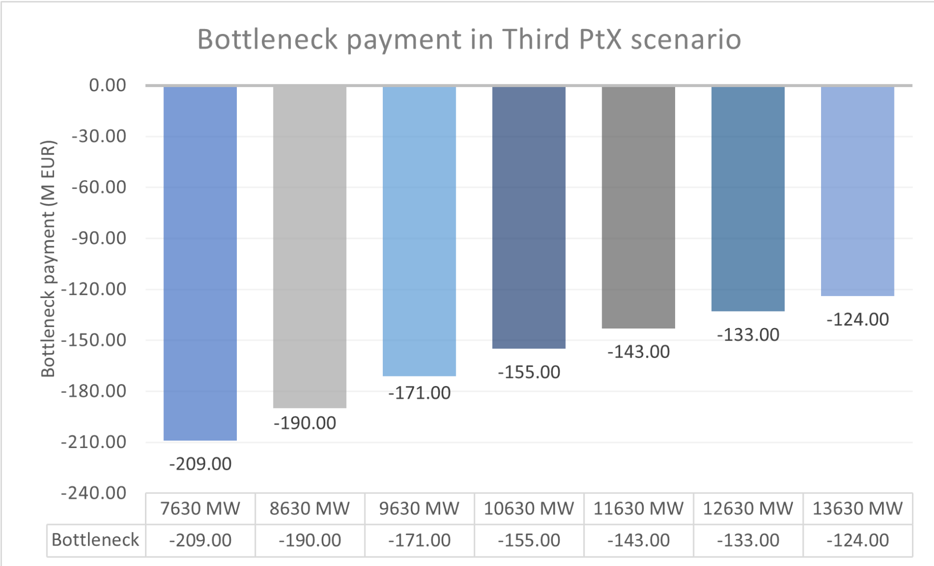


Figure 9.22. Bottleneck payment with the first electrofuel demand across all offshore wind increases.

From the figure 9.22 the energy system, with only an increasing offshore wind sector and no more flexibility and supply, is pressured to a point where it is not sustainable. Transmission lines are at times severely overloaded, based on the bottleneck cost results.

Regarding the development of carbon emissions as offshore wind increases, the same trend applies as for the previous scenarios. In figure 9.23 the carbon emissions are generally higher but decrease throughout.

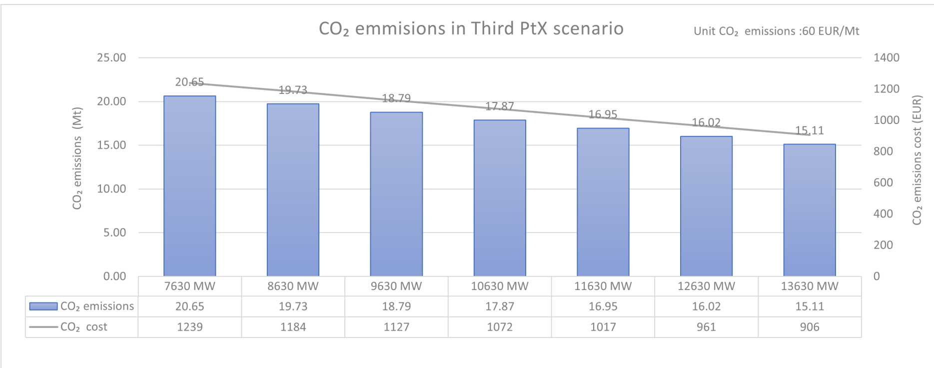


Figure 9.23. Carbon emissions with the third electrofuel demand across all offshore wind increases.

9.3.1 Maximising OW supply to 13,630 MW minimise pressure on infrastructure

Not the most profitable scenario for OW owners in the short and long term, but maximising offshore wind capacity is the most sensible approach and, based on the bottleneck payment, the most feasible scenario. Critical overload of transmission lines jeopardises infrastructure and supply security, and maximising offshore wind reduces this to a minimum. All parameters, but offshore wind revenue, point to maximising OW capacity; lower total annual cost, E-fuel production cost, and carbon emissions.

9.4 Combinations in the final PtX scenario

The import/export development repeats, but this time the imbalance between the two is more immense. In figure 9.24, instead of achieving a difference of 10 TWh more import, the lowest difference amounts to approximately 15 TWh import at the maximum OW capacity.

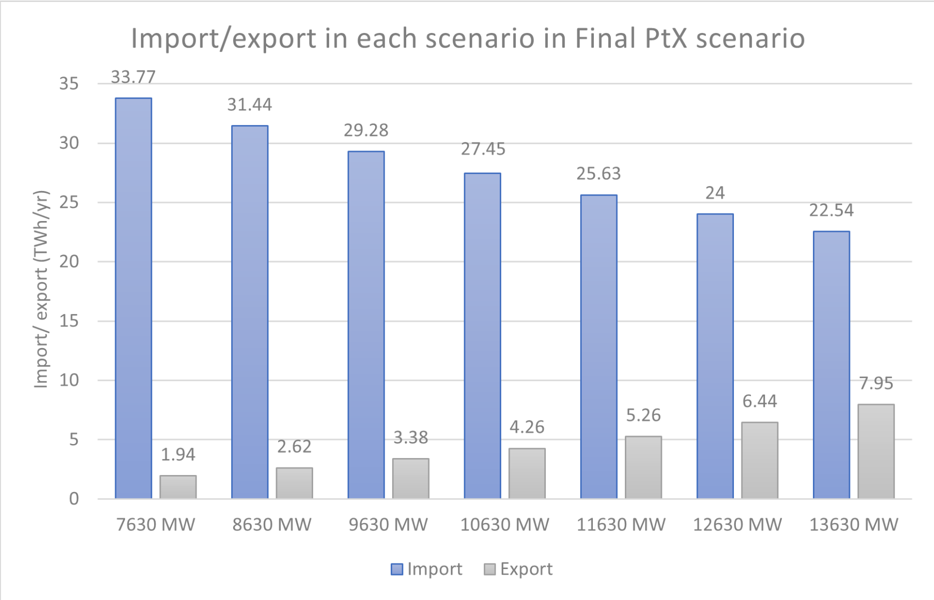
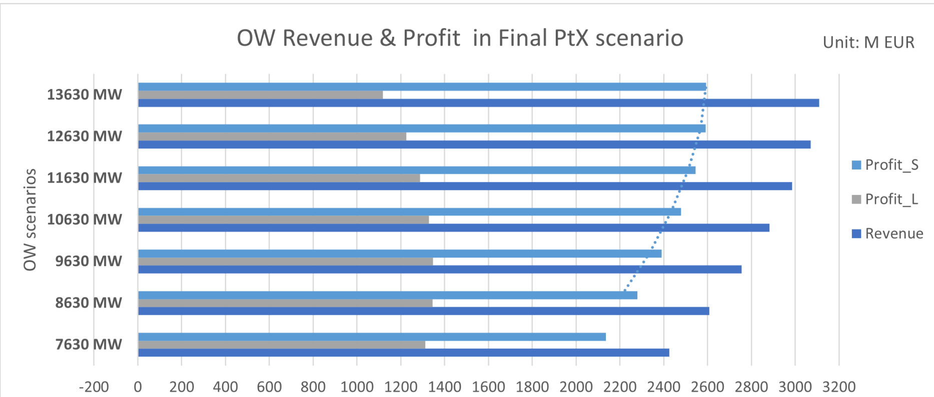


Figure 9.24. Import and export with the first electrofuel demand across all offshore wind capacities.

In figure 9.25, 13,630 MW is the step that obtains the maximum short-term profit. However, there is only one M EUR difference between 12,630 MW and 13,630 MW in the short-term profit, while there is a relatively major decrease in long-term profit of around 108 M EUR.



	7630 MW	8630 MW	9630 MW	10630 MW	11630 MW	12630 MW	13630 MW
Profit_S	2137	2279	2390	2478	2545	2592	2593
Profit_L	1312	1346	1348	1328	1287	1226	1118
Revenue	2427	2607	2756	2882	2986	3071	3110

Figure 9.25. Offshore wind investors profit with the final electrofuel demand.

Furthermore, compared to the changes between the second to third, and third to final PtX scenario, the amount of general increased profit turn less. The maximum profit is 2,593 M EUR for 13,630 MW in the final PtX scenario and 2,387 M EUR for 12,630 MW in the third scenario.

A similar trend of hydrogen cost has occurred in the final scenario. But there is an issue in the results; through 7,630 to 11,630 MW, the unit production costs are lower than in the third PtX scenario, although the PtX and electricity demand is higher. Only the last two steps obtain a higher unit cost than in the previous scenario. The reason why this occurs will be explained further in the sensitivity study.

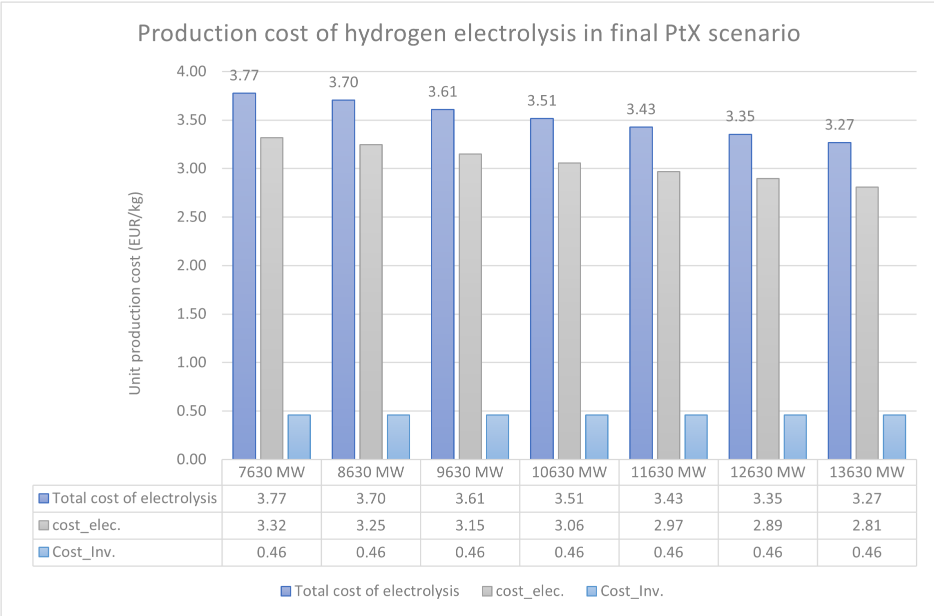


Figure 9.26. Electrofuel production cost across all offshore wind increase steps with the final PtX demand.

The average inmarket price of the final PtX scenario as shown in figure 9.27, have a similar price as in the third scenario with one EUR more in most of the increasing steps.

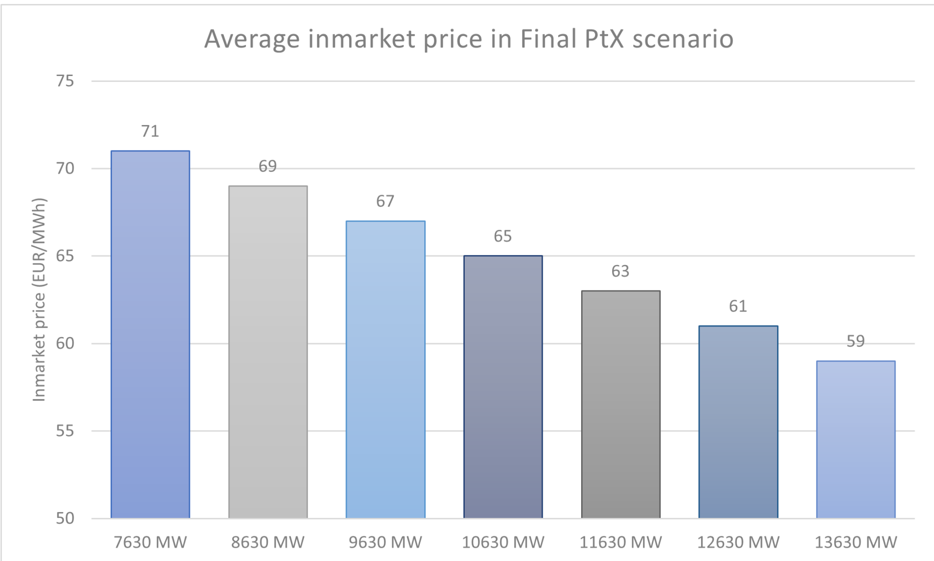


Figure 9.27. Average inmarket price across all offshore wind increase steps with the final PtX demand.

The results and trends repeat from the previous findings; the total annual cost decreases with more offshore wind entering the energy system, but is generally significantly higher than in the former scenarios.

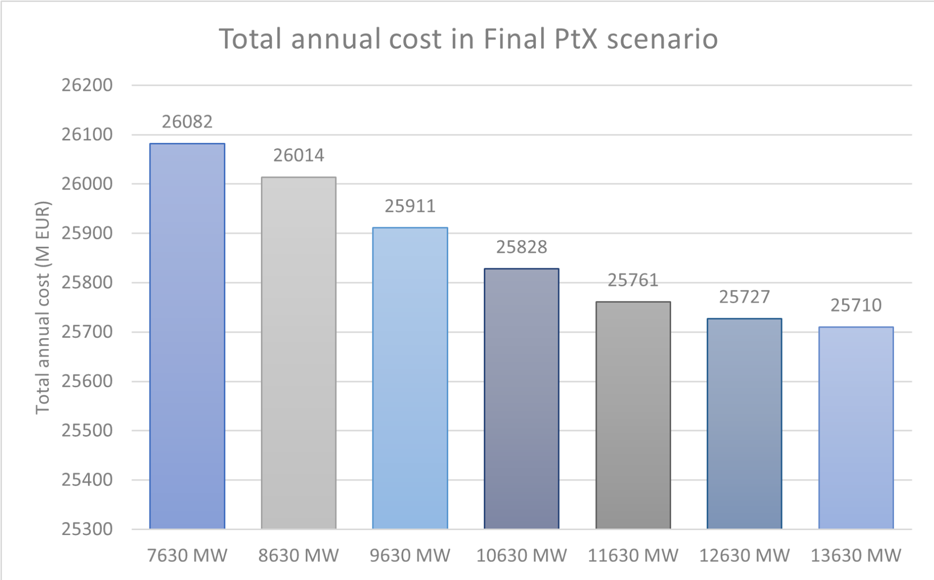


Figure 9.28. Total annual cost with the first electrofuel demand across all offshore wind increases.

25,710 M EUR is the lowest total annual cost achieved in the figure 9.28, approximately 300 M EUR more than the lowest total annual cost with the previous demand for PtX.

A similar conclusion to the last PtX scenarios follows regarding the bottleneck payment and carbon emissions.

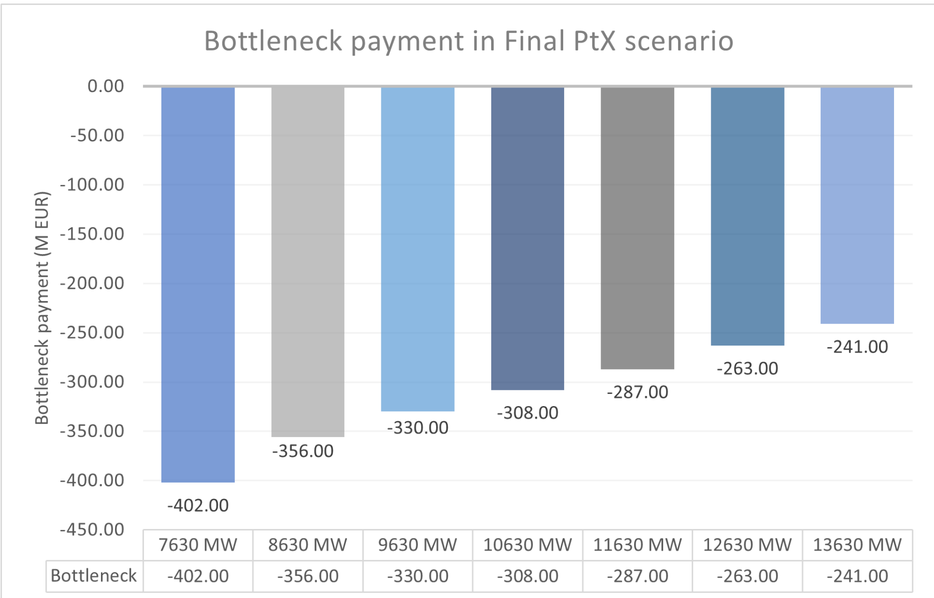


Figure 9.29. Bottleneck payment with the first electrofuel demand across all offshore wind increases.

The bottleneck payment in figure 9.29 is extreme at the beginning, with expenses reaching 402 M EUR, and never becomes very low. There is a lack of both supply and flexibility. This again negatively influences carbon emissions, as emissions increase to supply the production of green fuels, thus counteracting the purpose; see figure 9.30.

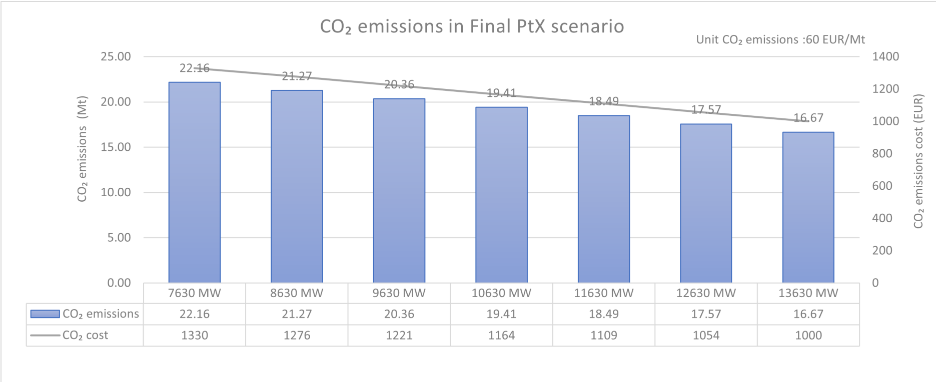


Figure 9.30. Carbon emissions with the first electrofuel demand across all offshore wind increases.

9.4.1 Maximising OW to 13,630 MW achieves the lowest curtailment, but the system is still infeasible

A more pressured repetition of the third PtX demand scenario, the final demand requires systems very different from those explored. The very high import bottleneck payment indicates a critical dependence on cross-border trade, but transmission simply needs development as well. Maximising offshore wind capacity still yields the best overall results in a general and economic perspective, except for offshore wind owners, who will generate fewer profits as the capacity increases.

9.5 The final combinations for a sensitivity study

Table 9.2 shows the five combinations between the increase in offshore wind and the production of PtX that excels in the chosen parameters. As mentioned, a PtX demand resulted in a less clear choice, and therefore there are two *optimal* offshore wind capacities to supply electrofuel production.

Scenarios	25% & no export	50% & low export	75% & mid export	100% & high export
7,630 MW OW				
8,630 MW OW				
9,630 MW OW				
10,630 MW OW	X			
11,630 MW OW		X		
12,630 MW OW		X		
13,630 MW OW			X	X

Table 9.2. The final five combinations between increase in offshore wind capacity and PtX production.

9.5.1 Increasing transmission to 10,400 MW and 13,000 MW

Transmission capacity has been a major systemic limitation; figure 9.31 shows that an increase in capacity in the size of the first planned transmission line is sufficient to solve most bottleneck issues.

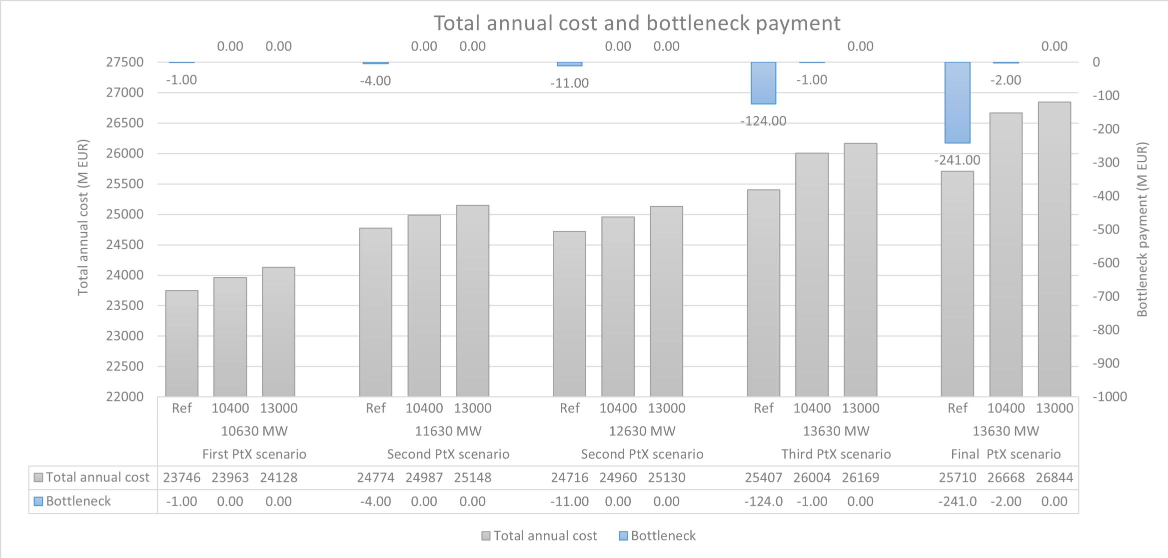


Figure 9.31. Showing annual cost and bottleneck payment as cross border transmission is increased.

As seen in figure 9.31 bottleneck expenses reach no more than one to two million euros with a transmission line capacity of 10,400 MW, and none with a capacity of 13,000 MW. However, by enabling the energy system to function properly, rather than having a critical overload or lack of electricity, more import is allowed to supply the high demand, causing the total annual cost to increase. Transmission lines allow for flexibility, but there is still a major dependence on trading, which is also shown in 9.32.

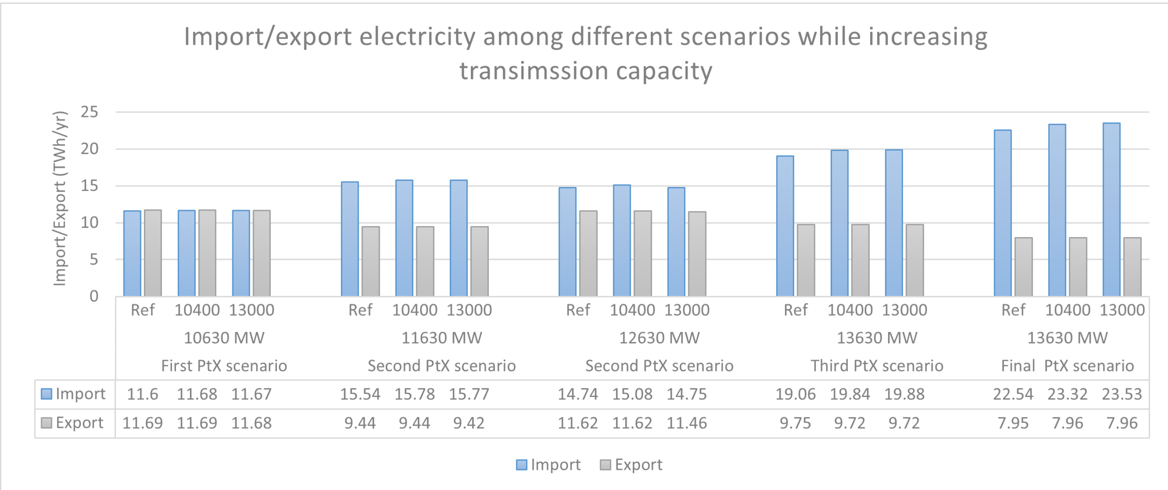


Figure 9.32. Import and export electricity as cross transmission is increased.

An unexpected coherence between transmission capacity and hydrogen unit cost occurs in figure 9.33. As mentioned in section 8.3 and covered by Lund and Thellufsen [2021], the critical import/export force EnergyPLAN to decrease the inmarket electricity price to zero.

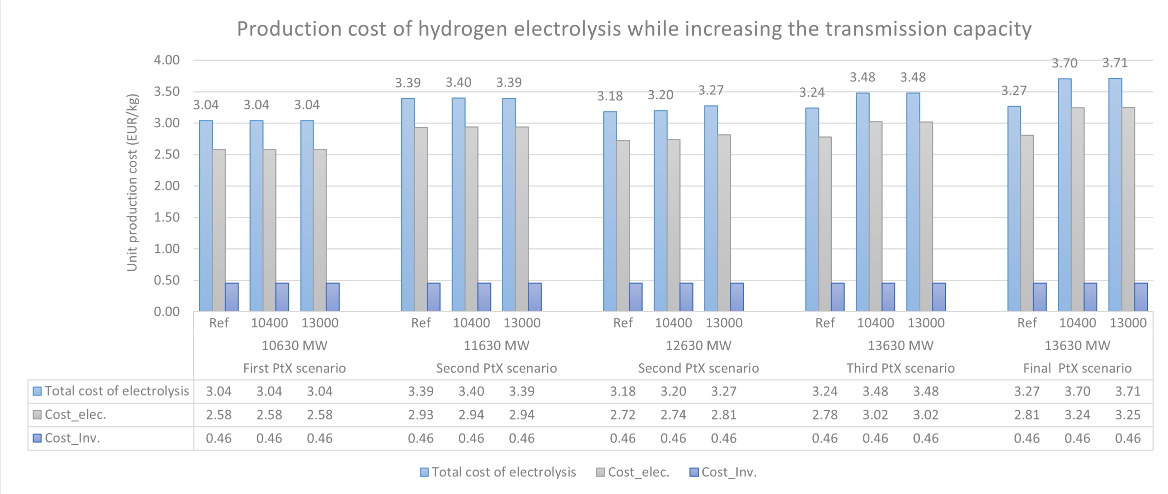


Figure 9.33. Showing the unit production cost of hydrogen.

Therefore, what happens in figure 9.33 more accurately illustrates how the very high electricity demand from PtX affects E-fuel production. With the actual possibility of importing very large amounts of electricity from the external market without overloading the transmission lines, electricity prices increase and, therefore, hydrogen production costs increase. Figure 9.34 demonstrates the correlation between electricity price and bottleneck payment.

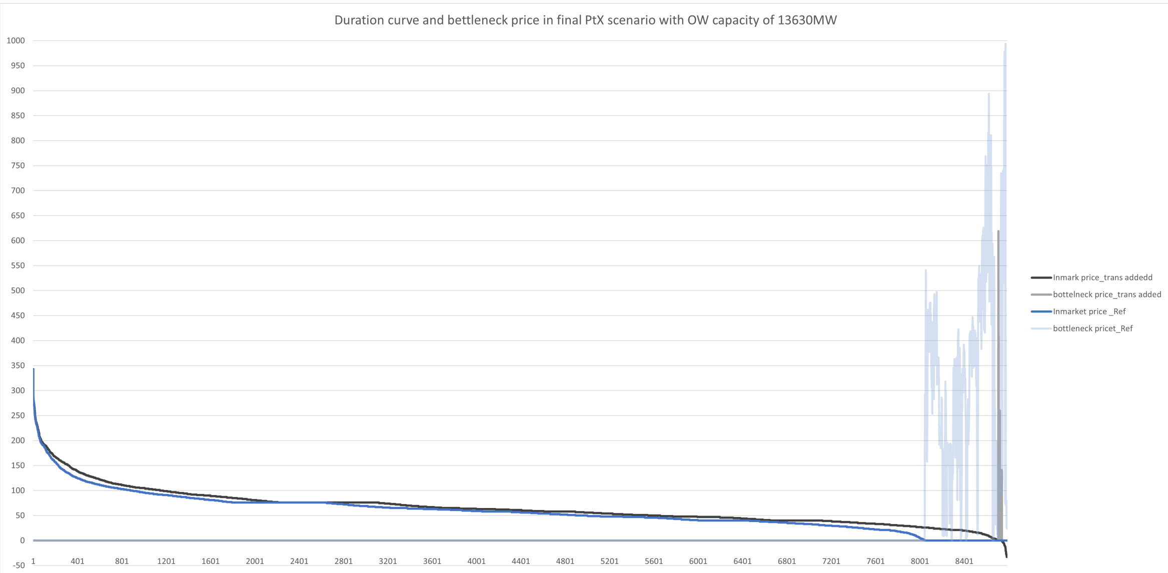


Figure 9.34. Showing duration curve showing electricity price and bottleneck correlation.

The light blue curve in figure 9.34 jumps up when the electricity price reaches zero. Meaning, with high bottleneck costs from the import/export reaching a critical level, the electricity price and hydrogen production costs become obscured.

The offshore wind sector is barely affected by increases flexibility through increased transmission. Figure 9.35 visualises the short term profit and revenue of OW owners, which show no real change.

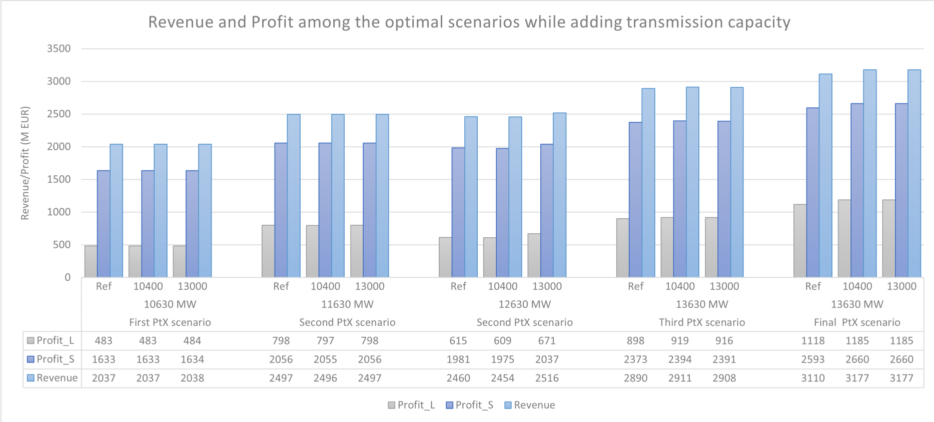


Figure 9.35. Showing offshore wind turbine owners revenue and short term profit.

9.5.2 Impact of having a 10 times bigger hydrogen storage

Increasing hydrogen storage is used to explore whether the system could benefit from more flexible storage capacity while having a relatively low electricity price. Through the output obtained from 9.36, it shows that there are no major changes in production cost other than the additional upgrade of the storage system. However, the electricity cost fluctuates slightly in an opposite tendency compared to the bottleneck payment. That means that while the electricity demand for PtX increased, the problem of the overloaded transmission line needs to be upgraded simultaneously to be ready for expansion in both OW and PtX.

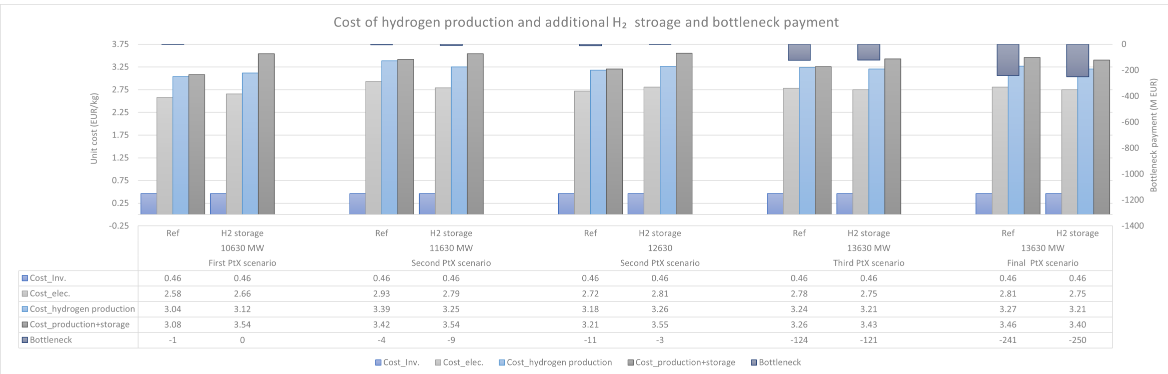


Figure 9.36. Showing.

In the less-pressured system with the first PtX demand increase, a more flexible hydrogen storage yields higher earnings for offshore wind owners. The other scenarios will require transmission line upgrade as mentioned earlier.

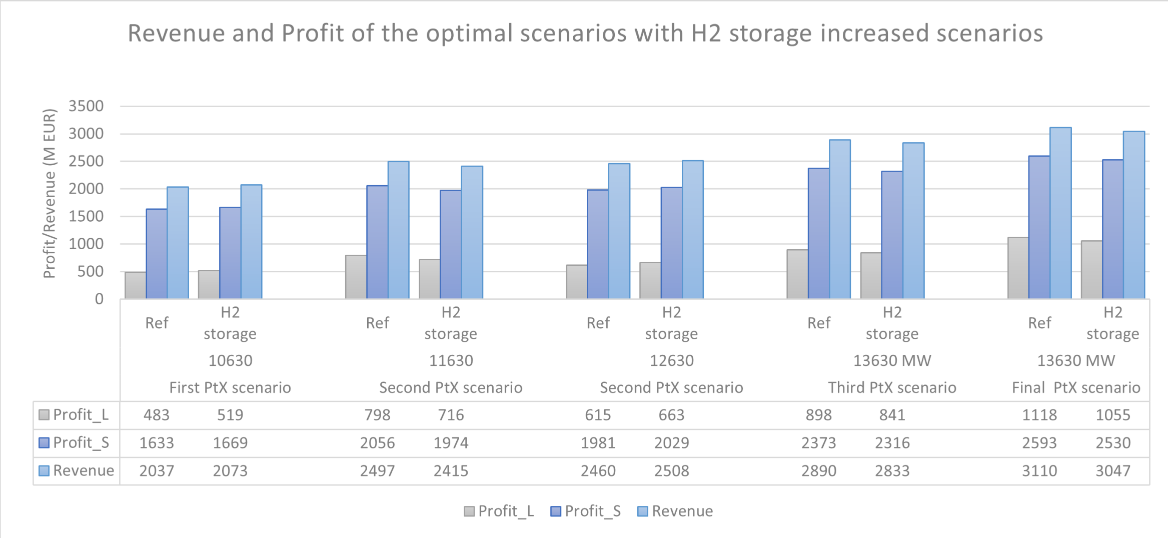


Figure 9.37. Showing offshore wind turbine owners revenue and short term profit.

In figure 9.37 the only system with a major difference is, as mentioned, the 10,630 MW scenario.

9.5.3 Impact of no flexibility in the carbon storage under different transmission capacity

To further illustrate the problematic electricity price and import problem, the following three tests have been carried out. Figures 9.38, 9.39 and 9.40 visualise electricity price duration curves with a different form of flexibility; there is no carbon storage, but very high hydrogen storage. Figure 9.38 shows generally higher electricity prices in the third and fourth PtX scenarios, where the demand for electrofuels is very high. In figure 9.38 the offshore wind capacity is only as high as the reference capacity, 6,630 MW and the transmission line capacity 7,000 MW. The problem with many zero electricity price hours still occurs in figure 9.38, especially in the latter two scenarios.

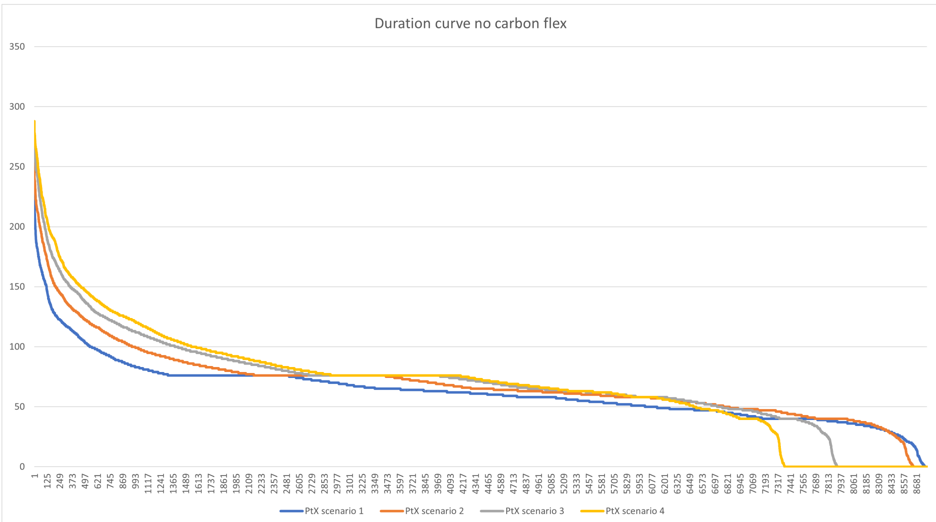


Figure 9.38. Showing electricity price duration curves when there is no carbon storage flexibility but very high hydrogen storage flexibility, and the offshore wind capacity is only 6,630 MW.

The same kind of flexibility is kept in figure 9.39, but with a transmission of 1,3000 MW, an increase of 6,000 MW. The results are now more logical, and higher demand follows higher electricity prices. There is no longer a high number of zero-price hours in the two high-demand scenarios.

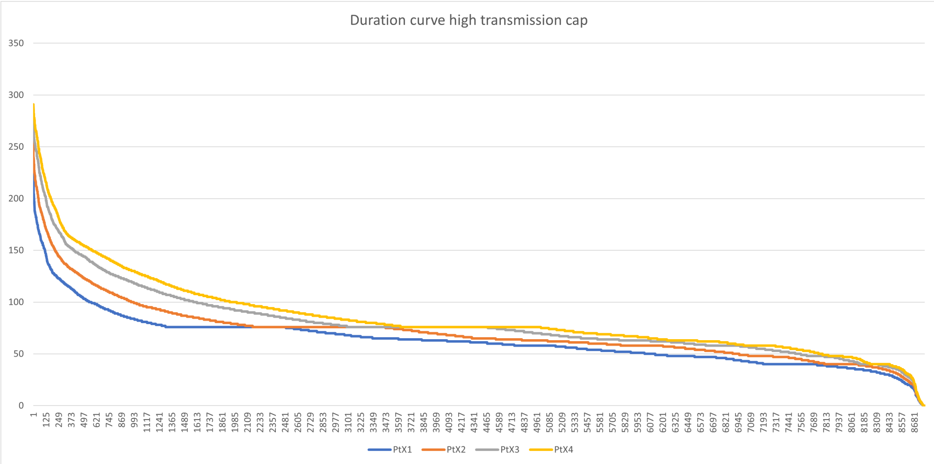


Figure 9.39. Showing electricity price duration curves when there is no carbon storage flexibility but very high hydrogen storage flexibility. The offshore wind capacity is only 6,630 MW but transmission line capacity is 13000 MW instead of 7000 MW.

Lastly, in figure 9.40 the electricity prices of the fourth PtX demand scenario are sorted from highest to lowest, and matched with the corresponding import plus export in that hour in MW when the transmission capacity is only 7,000 MW. When export becomes very high and exceeds transmission capacity, the price is zero.

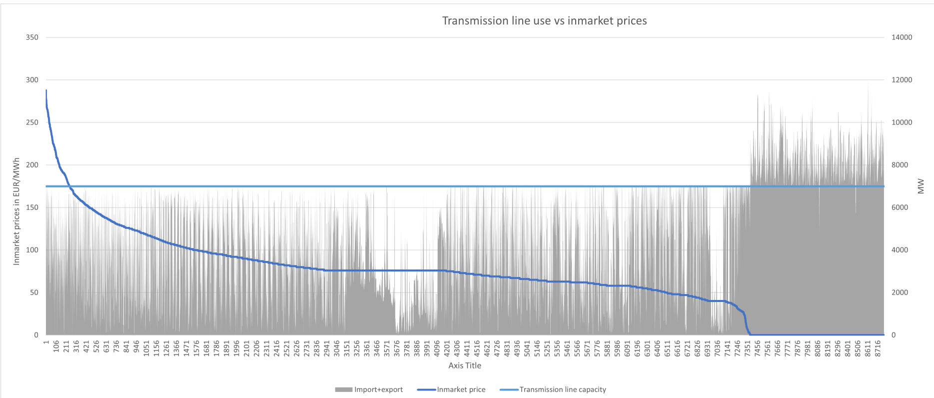


Figure 9.40. Showing the final PtX scenario inmarket price duration curve vs the import in the corresponding hour, with a 7,000 MW transmission and 6,630 MW OW capacity.

The grey columns on the right side generally exceed 7,000 MW, so the electricity prices are zero.

9.5.4 Impact of having a low or high external market

The following figures and results show very similar results when increasing the external electricity price - everything becomes more expensive.

In figure 9.41 the annual total cost increases as the price of the external market increases in all scenarios. The home market is affected by cross-border trading and price balances around both the internal and external markets.

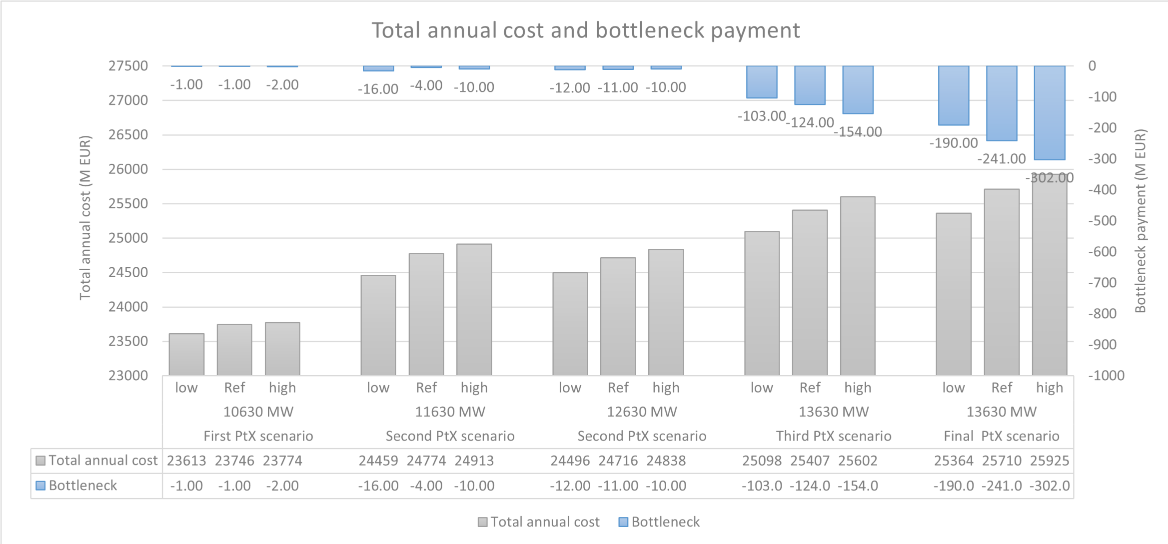


Figure 9.41. Showing the bottleneck and total annual cost when decreasing or increasing the external market price.

Factors that can influence carbon emissions when increasing the price of the external market. From a business and socioeconomic perspective, a higher price on the external market can make fossil-based power plants a cheaper and more viable option compared to the import of expensive electricity from the external market. Also, the business case of fossil fuel power plants is improved. Therefore, the carbon emissions can develop as seen in figure 9.42.

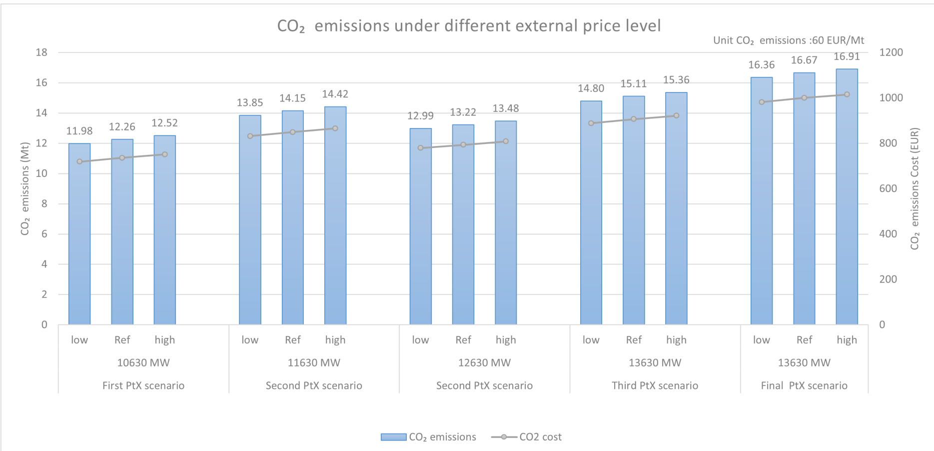


Figure 9.42. Showing carbon emissions when decreasing or increasing the external market price.

An external market price increases the inmarket price as well, thereby increasing a very large amount of the production cost of hydrogen, the electricity price. As seen in figure 9.43 the production cost of H_2 increases with higher external prices.

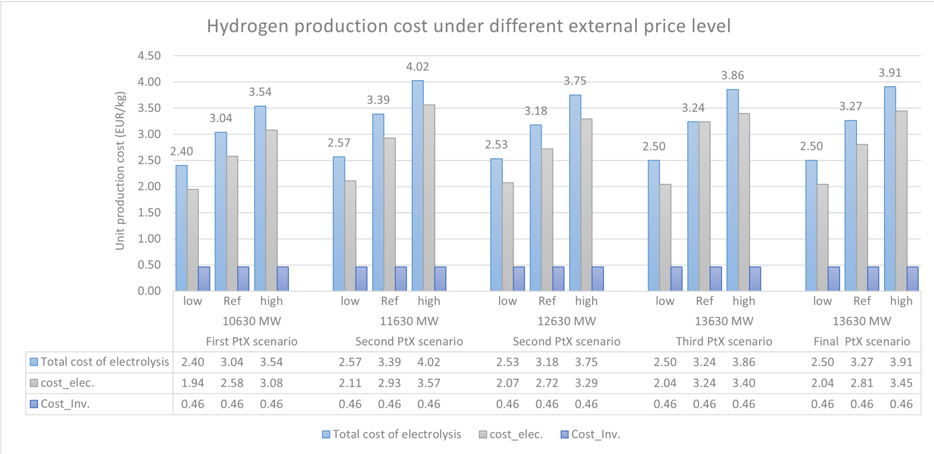


Figure 9.43. Showing the hydrogen production cost when decreasing or increasing the external market price.

On the other hand, this occurrence benefits the offshore wind turbine owners; a higher electricity price means more profit.

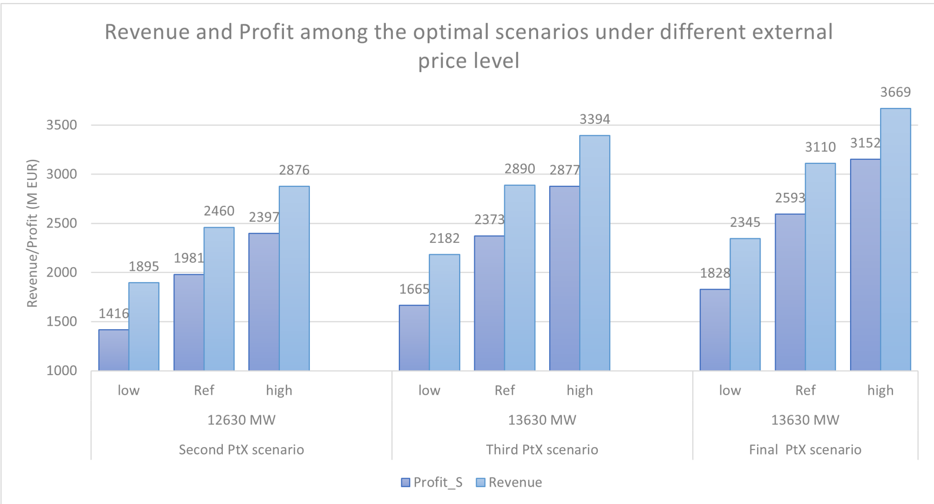


Figure 9.44. Showing OW revenue when decreasing or increasing the external market price excluding the long term revenue.

9.5.5 Impact of defining the maximum and minimum price after Nord Pool

Including a maximum and minimum price of 4,000 and -500 EUR/MWh generally does not affect the overall trends in electricity price development, but underline the penalty of lacking flexibility through energy conversion, storage, and transmission line capacity. In figure 9.45 the price jumps to the maximum price of 4,000 EUR/MWh relatively often, especially in the latter two scenarios.

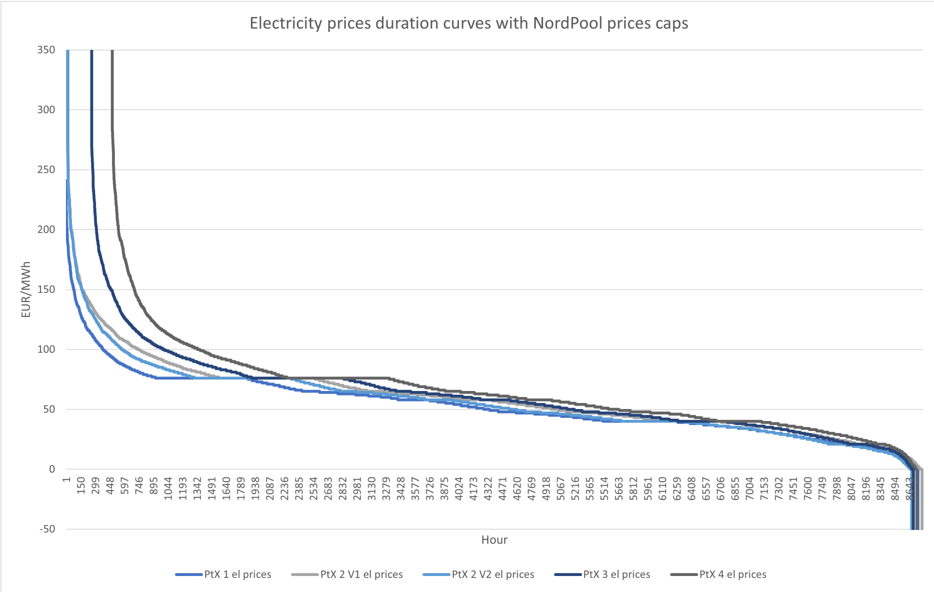


Figure 9.45. Showing duration curves of how the electricity prices develops across the final five combination scenarios. PtX1 = first PtX demand and 10,630 MW OW, PtX2 = second PtX demand and 11,630 MW OW, PtX2 V2 = second PtX demand and 12,630 MW OW, PtX3 = third PtX demand and 13,630 MW OW, and PtX4 = fourth PtX demand and 13,630 MW OW.

Given that Nord Pool [2022b] has changed the maximum price cap to 4,000 EUR/MWh in 2022, it severely penalises technically non-functioning systems with high overload of the transmission lines, which are the systems with the third and fourth PtX demands. In figure 9.46 the economic severity of lack of flexibility and transmission becomes evident; the two last combinations, which often overload transmission lines, are significantly more expensive. The maximum price of 4,000 EUR/MWh results in the bottleneck cost reaching 5,000 to 7,000 M EUR, and the total annual costs becoming 30,000 to 35,000 M EUR. A major increase. The price caps also change the choice of the best combination in the second PtX demand scenarios. In figure 9.46 it shows that having 12,630 MW to meet the PtX demand becomes socioecomocially more expensive than having 11,630 MW.

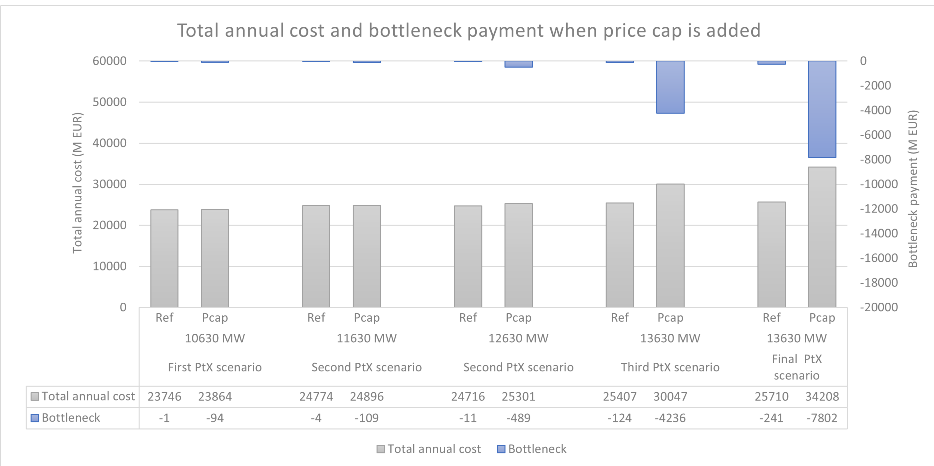


Figure 9.46. Showing the bottleneck cost and total annual cost with defined maximum and minimum prices.

These increases in costs underline the need for supply, flexibility, and transmission when hydrogen and PtX production is implemented in the system. Offshore wind power cannot always be used for electrolysis or transported across borders. This is also reflected from a business perspective. In figure 9.47 the OW revenue skyrockets in the last scenario and increases in the third, but in fact loses revenue in the first three scenarios.

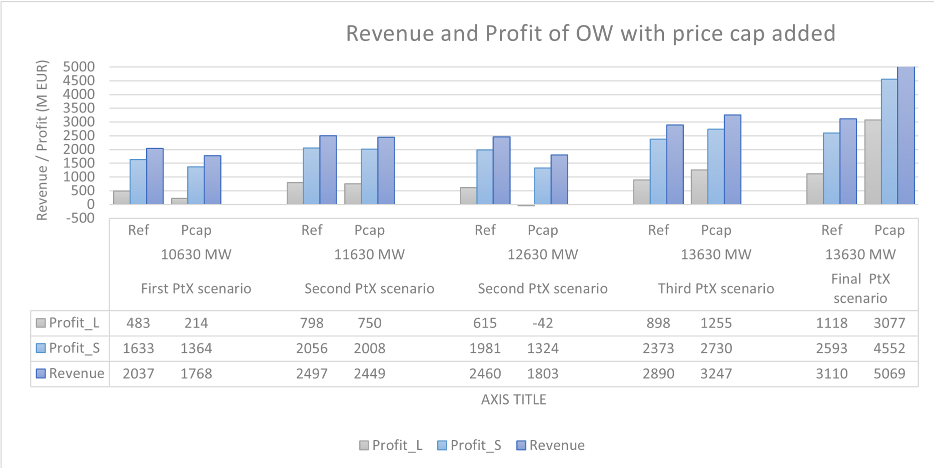


Figure 9.47. Showing offshore wind owners revenue and profit when adding a maximum and minimum electricity price.

In figure 9.47 the -500 EUR/MWh turns offshore wind supply into a non-profitable business case in the second PtX scenario with 12,630 MW OW capacity, as long-term profit is negative. Overloading the system and suffering the penalty of price cap prices seem to turn offshore wind investment into a volatile business, as 1,000 MW capacity can cause investment to result in losses. The unit production cost of hydrogen when price caps are defined signifies a strong need to avoid curtailment through flexibility of different kinds. In the first three scenarios in figure 9.48 the cost of hydrogen production changes very slightly.

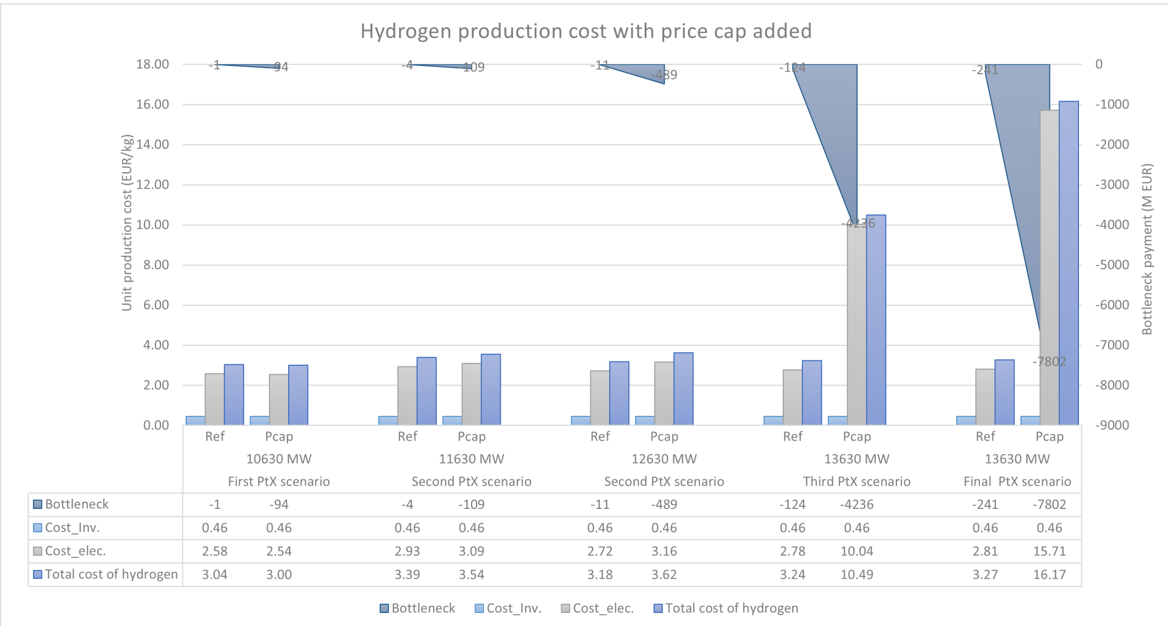


Figure 9.48. Showing hydrogen unit production cost when adding a maximum pand minimum electricity price.

The cost of hydrogen production ranges from 3.04 to 3.00 EUR/kg in the first scenario, from 3.39 to 3.54

EUR/kg in the second scenario, and from 3.18 to 3.62 EUR/kg in the third scenario. 12,630 MW OW supply capacity *should* yield a lower hydrogen unit production cost, but as can be seen in table 9.3 there are very few full load hours, but very high minimum capacity use. The reason why the system with this particular combination between PtX production and 12,630 MW OW supply refuses to efficiently use the electrolyser but instead has a very high minimum capacity use is unknown.

Scenario	Full load hours	Minimum capacity used
First PtX scenario	3741	0
Second PtX scenario 11,630 MW	53	3329 MW
Second PtX scenario 12,630 MW	3113	0
Third PtX scenario	2689	0
Fourth PtX scenario	2491	0

Table 9.3. Full load hours and annual minimum electrolysis capacity

Therefore, the results are inconclusive as to which capacity is best for the electrofuel sector with the second demand for PtX. But in the latter two scenarios, the hydrogen production industry suffers greatly from the system often overloading the transmission lines, and the price reaches 4,000 EUR/MWh, according to the figure 9.45. In figure 9.48 this results in the unit cost amount going upwards to more than 10 and 16 EUR/kg, which is a massive increase. Therefore, it is clear that lack of flexibility is not sustainable when electrofuel production and use are implemented.

9.6 Connection to theory

A key part of this project is to explore the interaction between the offshore wind sector and the PtX sector. In section 6.1 these two sectors essentially take the form of players in a non-cooperative game, where no agreements, contract or other strategies occurs between the players. In subsection 8.3.1, the theory connection, it was concluded from the analyses in the whole of chapter 8, that one sector developing without the other had damaging effects on the developing sector; lower revenue or higher production costs. In the second analysis, the results indeed back up the co-dependency between the players. Higher electricity demand logically produces higher electricity prices and, therefore, higher revenue for the offshore wind sector. Unlike in chapter 8, the OW player can expand to 10,630 MW and higher and achieve high profits even with a reference external market price, rather than a high external market price. In the first analysis, a high external market was the only factor that kept the offshore wind sector profiting at that capacity. Higher PtX demand generally meant higher profits. Another key benefit for the offshore wind player in having the PtX industry is the utilisation of very low electricity price hours. The PtX player not only increases the general prices, but also takes advantage of the lowest price hours, increasing the minimum price level. This interaction is especially crucial if the infrastructure is suboptimal, with price caps the OW player suffered lower profits from the added minimum price of -500 EUR/MWh.
Vice versa the PtX player benefit greatly by having more offshore wind supply in the energy system. The results showed a strong coherence between increased supply, falling electricity prices, and lower H_2 production costs. Electricity constitutes a major part of the unit production cost. Adding the maximum price of 4,000 EUR/MWh significantly financially hurt the electrofuel industry in the third and fourth PtX demand scenarios. Too little offshore wind supply relative to the electricity demand from PtX increased

the unit production cost by three to five times, making the sector much less able to compete with fossil fuels. Therefore, the two players, offshore wind owners and PtX producers, have a synergistic relationship in which they benefit from the development of the other sector.

An imbalanced development of the two sectors; offshore wind and the PtX industry, will result in the energy system never achieving the expectations of a smart energy system. In chapter 5 it was found that for an energy system to be smart, it would need to be at least; commercially viable, economically feasible, integrable and environmentally benign. By over-developing the PtX industry without sufficient green supply, the results showed that the energy system would fail the expectations. PtX would simply have a very high unit production cost, the total cost of the system would be expensive, the infrastructure would not be able to handle the implemented supply and production, and the carbon emissions would increase, bringing the system further away from the climate goals. Therefore, both sectors are required.

9.7 Answer to second subquestion

What are the relative optimal market economic, socioeconomic and environmental benign balance strategies when using the interactive development of offshore wind and PtX?

Four PtX demands were simulated with seven increases in offshore wind capacity, each 1,000 MW at a time. PtX demand went from low to high inland electrofuel demand, and in the latter scenarios, exports were added. For each PtX demand, a relative optimal offshore wind capacity was selected based on market economic and socioeconomic performance.

- Low PtX demand and no export –> 10,630 MW OW
- Mid PtX demand and some export –> 11,630 MW OW
- Mid PtX demand and some export –> 12,630 MW OW
- High PtX demand and high export –> 13,630 MW OW
- Full PtX demand and full export –> 13,630 MW OW

Two mid-PtX demand and some export scenarios were selected because the energy system showed more optimal technical performance through less curtailment and higher offshore wind revenue in one of them, whereas the other had lower total annual costs. Between all the selected combinations, a very high dependence on import began beyond the mid-PtX demand scenarios. When maximising offshore wind capacity to 13,630 MW, import and export were about the same with the two lower PtX demands, but it became impossible to have a balanced import/export with the two latter PtX demands. This means that too rapid an expansion of PtX without a higher supply compromises systemic self-sufficiency. Regarding the electricity price; the more offshore wind pushes out other power plants, the lower the price. But with more PtX demand, the higher the prices. For the total annual cost, in this project representing socioeconomic cost, capacities of 10,630 and 12,630 MW meant the lowest costs for the two first PtX demands; higher capacity and investment cost would eventually supersede the savings. However, this could be different with price caps added. With the last two demands, maximising the OW resulted in the lowest annual total costs. At that point, there was a very high import and high bottleneck cost, meaning that investment in supply made the systems cheaper. As just mentioned in sector 9.6, the two sectors have more optimal economic results for each sector developing, compared to developing a single sector. The long-term revenue of offshore wind continuously decreased with increasing capacity, but short-term profits would increase and decrease depending on the PtX demand and OW capacity. For OW owners, optimal short-term profits were with capacities of 10,630 MW, 11,630 MW, 12,630 MW, and 13,630 MW. However, ultimately, the optimal combinations were chosen considering other factors, the total annual cost, and the PtX industry. H_2 unit production cost simply decreased with more supply, which meant that the lowest hydrogen production cost *and* and the highest OW revenue could not be met. Total annual cost was a key consideration in choosing the optimal combinations.

The duration curves when adding the Nord Pool price caps of 4,000 EUR/MWh and -500 EUR/MWh revealed that all chosen combinations had hours with either the maximum or minimum price, and reaching these prices meant hours with overloaded transmission lines with either too much or too little electricity in the system. The added transmission capacity solved this problem. The fact that all combinations had a critical excess or lack of electricity suggests suboptimality in the chosen scenarios. Flexibility through increased transmission capacity is a measure to overcome the bottleneck issue. Of the chosen combined scenarios, the first two PtX demands could be covered within the system design; only by adding offshore wind, the two highest PtX demand scenarios had immense curtailment. The results show clear evidence that the optimal development of the two industries, offshore wind and PtX, requires the development of both sectors, to secure higher profits and lower hydrogen production costs. In the specific simulations in this project, the base system and 10,630 MW or 11,630 MW can cover;

- 2.5 to 5.1 TWh E jet fuel
- 2.9 to 3.0 TWh E diesel
- 1.9 to 2.7 TWh methanol
- 6.1 to 8.1 TWh H_2
- 1.0 to 2.7 TWh ammonia

Discussion 10

10.1 Synergy between OW and PtX makes it crucial to have an precise energy system development plan

A fair understanding of the effect of having OW and PtX in the system separately was discovered through the first analysis. Added to that, in analysis two, by performing 28 scenarios with seven scales of OW capacity and four levels of PtX, five optimal alternatives were identified as optimal through the evaluation of different parameters, including private and social economics, environmental conditions (carbon emissions) and technical limitations. These five optimal alternatives show a trend of a better overall result occurring when the system has both OW and PtX scaling up. But further upgrade of the system and infrastructure will be necessary as the energy system reaches the third level of PtX demand, which will be discussed in the following section.

EU member nations are seeking cooperation in expanding OW, a recent agreement among the Netherlands, Belgium, Denmark, and Germany is to expand up to 150 GW of OW in the North Sea. Industrial OW developers such as Ørsted and Copenhagen Infrastructure Partners are also dedicated to developing PtX, cooperating with aviation and marine companies in the production of E-fuel, and are proposing to build a hydrogen island to support the PtX development. In addition to the green transition, international economic sanctions toward Russia have added the urgency to accelerate cutting off the reliance of Russia's natural gas.

Therefore, it is crucial to know that simultaneous development of the two technologies is essential but not exactly enough. In the early stage of PtX development, the offshore wind sector can expand to a point that satisfies systemic demand, since more wind turbines in the results simply showed a positive effect on carbon emissions, and the first PtX demands already required a well-established offshore wind sector, with 10,630 MW capacity. Once the PtX industry develops to a relatively mature stage, to achieve the goal of fully green power, more flexible technologies will be needed not only to balance the offset production of offshore wind power but also to efficiently harness the surplus power generated in the system. From the results, with an inelastic electricity demand and a consuming industry in the PtX sector, wind turbines cannot meet the demand efficiently and constantly. At times there will be very high amounts of wind, potentially overloading the transmission through export, whilst at other times the import reaches critical levels instead, due to no or little wind. Diversity in the renewable energy supply through photovoltaic, on- and offshore wind and stable sources such as biogas can better handle the stress of the inelastic energy demand. Flexibility also entails application of heat pumps and electric or biomass boilers, more hydrogen storage and carbon capture ready for use at times with high renewable electricity production, and having backup supply when there is low renewable production. Upgrade of transmission lines to prevent system load can also function as a crucial backup mechanism when supply is severely high or low.

Hydrogen production can provide flexibility in the system, but also add demand, as the industry will rely heavily on cheap green electricity. CIP's strategy of establishing a hydrogen production island to take advantage of the hugely pledged offshore wind capacity of 150 GW in the North Sea ties well with the results of this project; secure high OW supply and keep the industries develop coherent. By having a massive supply connected to an island and the H_2 kept on an island as well, issues of hydrogen production that pressures the national supply and infrastructure can even be avoided.

10.2 Validity of results

With the massive lack of electricity supply in the energy system, the sensitivity study proved important to verify the results. Especially simulating using higher transmission capacity and defining a minimum and maximum price. With a relatively limited transmission line capacity, immense curtailment, and no defined price caps, the economic results eventually became obscured with the later PtX demands. The earlier results showed clear evidence that more PtX demand would indirectly raise electricity prices through higher electricity demand, and also put pressure on the infrastructure and compromise self-sufficiency. A sensitivity study with more transmission line capacity or added price caps, served to verify the trends discovered by eliminating the many zero price hours that followed from system overload. Higher transmission capacity underlined the trends found; offshore wind can supply hydrogen production and get the electricity price down, PtX can counter offshore wind pushing out suppliers that will decide a higher electricity price and avoid long-term loss for OW, and import will become crucial in supplying green fuel production, if the energy system is not improved in other areas than OW. Price caps proved that infrastructure overload was strongly penalised and so the systems with high lack of supply resulted in high total annual costs, bottleneck costs, and H_2 production costs. The trends found in this project were verified, but the choice of combinations is less certain. When price caps were added, the system started to behave differently around electrolyser usage, and very unusually in the second PtX demand scenarios, an OW capacity of 11,630 MW had a very high minimum capacity usage, but very few full load hours. On the contrary, an OW capacity of 12,630 MW had many higher full load hours and a minimum capacity of zero. The price cap seems to have the potential to alter the system behaviour, potentially changing the choice of optimal combinations between offshore wind turbines and hydrogen production. Given the very high curtailment cost in the latter two scenarios with price caps, maximising OW to 13,630 MW would almost certainly still be the optimal choice. But for the first PtX demand scenarios, the minimum price of -500 EUR/MWh could become a factor as the PtX was lower and easier supplied, and for the second PtX demand scenarios, both the maximum and minimum Nord Pool price definitions seemed impactful on the model behaviour and outcome. The discovered trends were proved through various sensitivity parameters, and most of the chosen combinations apart from the second PtX demand scenarios, seem to be valid. Therefore, the results proved that the two industries benefit from a coherent development.

Recommendations 11

The following recommendations are the product of the findings explored in the analyses and discussion. The figure 11.1 visually shows the recommendations to wrap up the concepts in search of better understanding for the readers.

- From the already relatively high required offshore wind supply of 10,630 MW in the chosen first PtX scenario, it is recommended to establish high functioning a renewable electricity with excess supply before majorly increasing the PtX sector.
- Given that PtX utilise very low electricity price hours, but raises electricity demand and therefore prices, it is recommended to keep the development of the two sectors coherent, for balanced OW revenue and H_2 production costs.
- Rather than any excess green power or lack of supply resulting in high export or import, it is recommended to implement flexibility through different storage, such as; heat storage, hydrogen storage or electricity storage, for higher flexibility, system efficiency, and closer sector coupling.
- To avoid the energy system depending too majorly on wind, and risking very high or low prices depending on the wind conditions, it is recommended to establish a more diverse electricity supply sector.
- As transmission lines offer flexibility in pairing price settlement with the external electricity market and a way to utilise high renewable supply in Denmark or the surrounding countries, it is recommended to upgrade the transmission lines, for the option of always utilising green power for PtX, through import or export, and avoid overload of the infrastructure leading to price cap prices.

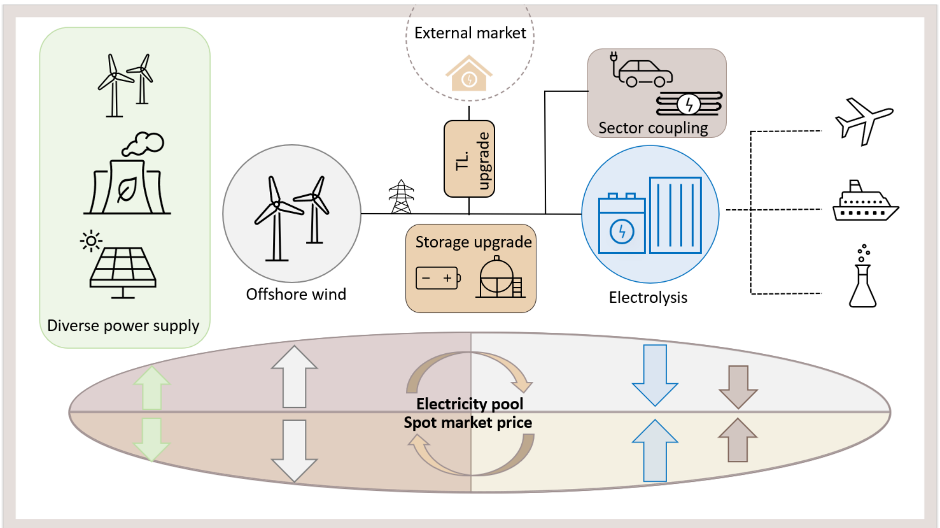


Figure 11.1. Visualised recommendations for improving the energy system

Conclusion - answer to main research question 12

- *How can a strategic development of renewable electricity supply and Power-to-X contribute to a steady commercial and technical green transition in a multi actor situation, with a goal of finding an equilibrium around individual profits and social welfare?*

A single sector and coherent development of the offshore wind sector and the Power-to-X industry have been analysed using EnergyPLAN software to simulate more than 28 scenarios. The hypothesis of problem analysis, chapter 2, that expanding offshore wind will lower the electricity prices was verified. Implementing more offshore wind turbines reduces the average price and causes more frequent hours with a price of zero. To counteract this, the implementation of PtX was also analysed. PtX increases the average price of electricity and, more importantly, the electrolyser exploits cheap electricity, thereby annulling the hours with a price of zero. It is important with a coherent and balanced development of the two sectors, as over-increasing one will have damaging effects on the developing sector and potentially system as a whole. An overincrease in wind would at times pressure the transmission infrastructure, and an overincreasing PtX would cause this to the point where the system could not realistically function. Theoretically, a strict non-cooperative development will not maximise individual profit and will cause the energy system to not fulfil the three Smart Energy System expectations. With the designs of the explored systems, offshore wind is a major factor in reducing carbon emissions. PtX demand adds to the electricity demand and indirectly to the emissions. Five combinations with different levels of development of the two sectors were selected as optimal:

- Low PtX demand and no export –> 10,630 MW OW
- Mid PtX demand and some export –> 11,630 MW OW
- Mid PtX demand and some export –> 12,630 MW OW
- High PtX demand and high export –> 13,630 MW OW
- Full PtX demand and full export –> 13,630 MW OW

The selection of these depended on the performance of the short-term profit of the wind sector, the unit production cost of PtX, and the total annual cost (socioeconomic cost). By evaluating the results, balances were found with; higher short-term profit, lower unit production cost, and the lowest socioeconomic cost. The short-term profit of the wind sector could be kept high while H_2 production cost pushed lower. From the results, it is recommended to balance the development between the two sectors. Each sector benefits the other, the energy system, and the green transition. Additionally, development of the two sectors also takes implementation of numerous more technologies; other supply technologies, different storage options, and upgraded transmission infrastructure. These can provide the needed flexibility.

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