Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

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Assessing potential effects of electrolysis and batteries on variable renewable energy in the European power market

Master's thesis in Energy and Environment
Supervisor: Magnus Korpås
Co-supervisor: Martin Kristiansen
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Summary

The European Green Deal was presented by the European Commission in 2019 and delivered a growth strategy on how to reach zero net emissions of greenhouse gases by 2050. The goal is to reduce global warming to a maximum of 2 degrees compared to pre-industrial times. To reach this goal, fossil fuel needs to be phased out and the transition to RES is essential.

When increasing the share of RES, and especially VRE, in the power system the generation will not be as elastic as before. This might result in a high share of curtailment and low prices in times of generation from VRE. If this is the case, investing in VRE might become less financially beneficial which again can slow down the development of VRE. The EU 2050 target is already ambitious, hence it is important to facilitate the technological transition according to VRE so that the power system enables an economically sustainable transition to a zero-emission society.

Batteries and electrolysers are examples of technology that might help the transition. Thus, the focus of the thesis is to assess potential effects of electrolysis and batteries on VRE economics. Firstly, important future trends in the power system that will affect the revenue for RES is located. Secondly, a power system representing 2040 is implemented with an objective to simulate the power prices and the generation dispatch. The simulation tool used for this thesis is PowerGAMA, which uses DC power flow equations to determine the optimal generation dispatch. The author found that when batteries were not the best option for increasing VRE economics. Adding electrolysers, on the other hand, improved the total revenue and decreased curtailment. It even had a significant positive impact on the total CO_2 emissions.

Further the thesis also contributes with valuable insight in how to easily model batteries and green hydrogen in PowerGAMA so that other master students or stakeholders can benefit from this and build on the work.

Sammendrag

"The European Green Deal" ble presentert av EU-kommisjonen i 2019 og leverte en strategi for hvordan man skal oppnå null netto utslipp av klimagasser innen 2050. Målet er å redusere global oppvarming til maksimalt 2 grader sammenlignet med førindustriell tid. For å nå dette målet, må fossilt brensel avvikles og overgangen til fornybare energikilder er viktig. Når man øker andelen fornybar, og spesielt variabel fornybar energi, i kraftsystemet vil ikke generasjonen være like elastisk som før. Dette kan resultere i at en høy andel av produksjonen fra fornybar blir begrenset noe som gir lave priser når fornybar energi produserer. Hvis dette er tilfelle, kan fornybare investeringer bli mindre økonomisk gunstig, noe som igjen kan bremse utviklingen av fornybar energi. EU sitt mål for 2050 er allerede ambisiøst, og det er derfor viktig å tilrettelegge den teknologiske utviklingen av kraftsystemet for en økonomisk bærekraftig overgang til et nullutslippssamfunn. Batterier og elektrolysører er eksempler på teknologi som kan hjelpe denne overgangen. Derfor er oppgavens fokus å vurdere hvordan elektrolyse og batterier påvirker den økonomiske gunstigheten i å investere i fornybar energi. For å gjøre dette vil flere aspekter ved kraftsystemet bli vurdert.

Først vil viktige fremtidige trender i kraftsystemet bli lokalisert. Oppgaven vil også lage en modell av et kraftsystem som representerer 2040 med et formål å simulere kraftprisene og produksjonsmiksen. Simuleringsverktøyet som brukes til denne oppgaven heter PowerGAMA, som bruker kraftflytligninger for å bestemme den optimale produksjonsmiksen. Forfatteren fant at batterier ikke var det beste alternativet for å øke investeringsviljen i fornybar energi. Når eletrolysører ble lagt til modellen økte derimot den totale inntekten til fornybar energi. Det hadde til og med en betydelig positiv innvirkning på de totale CO2-utslippene.

Videre bidrar oppgaven også med verdifull innsikt i hvordan man enkelt kan modellere batterier og grønn hydrogen i PowerGAMA, slik at andre masterstudenter eller andre interesserte kan dra nytte av dette og bygge videre på arbeidet.

Preface

This thesis is written by a master student at NTNU in close cooperation with NBIM. The author of the thesis has chosen to specialize in energy systems and optimization throughout her thesis at Energy and Environment. She believes a shift towards greener energy technology is a key factor to reduce CO_2 emissions and fight the climate crisis. This was the main motivation for the author to choose this master thesis about the economical incentives for investing in renewable energy generation sources. It is highly relevant to understand the power system today and get more knowledge about the future power system.

The author wants to thank her supervisors Magnus Korpås from NTNU and Martin Kristiansen from NBIM for their impressive support during the semester. Regular discussions and critical perspectives made the learning process especially interesting. They always contributed with valuable insight and thorough feedback has been much appreciated. In addition they have been patient and considerate, especially during a year where the circumstances was not optimal due to Covid-19. The author wants to show extra gratitude towards Kristiansen as he has showed a remarkable commitment and engagement for the thesis. She also wants to show gratitude towards Harald Svendsen who was helpful answering questions regarding PowerGAMA.

The author will look back at the time when writing this thesis as interesting, challenging, enlightening, meaningful and in some moments even fun.

Abbreviations

CAGR Compound Annual Growth Rate

CAPEX Capital expenditures

CCS Carbon Capture Storage

CCUS Carbon Capture Storage Utilization

CCU Carbon Capture Utilization

DE Decentralized Energy

DOD Depth of Discharge

DSR Demand Side Response

EV Electric Vehicle

GA Global Ambition

GHG Greenhouse Gases

LCOE Levelized Cost of Energy/Electricity

LCOH Levelized Cost of Hydrogen

NT National Trends

OPEX Operating expense

P2G Power to Gas

RES Renewable Energy Sources

TYNDP Ten-Year Network Development Plan

VRE Variable Renewable Sources

WV Water Value

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1 Introduction

This section will give the reader a quick insight in the topicality for this thesis as well as the objectives and the work progress to achieve these. In the end of the section a brief summary of each section is given to give the reader a quick overview of the thesis. Parts of this section is based on the specialization project report [34].

1.1 Background

The world is in the middle of a climate crisis. The year 2019 was the end of the warmest decade ever recorded [72] an the nineteenth year where the CO_2 level in the atmosphere was higher than ever measured [53]. Weather patterns are changing, sea levels are rising, and weather events are becoming more extreme. This will have fatal consequences for the life on earth. The threat towards bio diversity as climate disruption is a major cause of species endangerment and one of the reasons why the sixth mass species extinction is already ongoing [9].

Luckily the world is starting to take action and a lot has happened the past few years. An overview of the most important political incidents for turning this around is illustrated in Figure 1 and briefly elaborated on below.

Figure 1: The most important political incident for reaching a net zero-emission energy sector. Created by the author.

When the Paris Agreement was adopted in 2015 the world took action. Its goal was to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 °C above pre-industrial levels [72]. The temperature in the world is already at 1°C above the pre-industrial time. Thus, a reduction in greenhouse emissions is necessary, which is why the EU Commission made the European Green Deal. The Green Deal was presented by the European Commission at 11. December 2019 [62]. It is a growth strategy to make EU's economy sustainable by reaching zero net emissions of greenhouse gases by 2050 (EU 2050 target) [11]. To ensure that all countries involved reach this goal the European Climate Law was proposed in March 2020 by the European Commission, incorporating a legally binding target of net-zero greenhouse gas emissions by 2050 and raising the EU emissions reduction target for 2030 from 40% compared to 1990 to 55% [38]. The Commission's proposal aims to write into law the goal set out in the European Green Deal – for Europe's economy and society to become climate-neutral by 2050. This means achieving net zero greenhouse gas emissions for EU countries as a whole, mainly by cutting emissions and investing in green technologies. The law aims to ensure that all EU policies contribute to this goal and that all sectors of the economy and society play their part [12].

To become a climate-neutral society the energy sector will be a key sector to decarbonize. Decarbonizing the energy sector will need yearly investments of 350 billion euros. To get there the Commission has highlighted offshore wind integration, green hydrogen, electrified infrastructure and smart sector integration as key factors [65].

To reduce CO_2 emissions caused by the energy sector renewable generation, especially VRE, will play an important role in reaching the 2050 target, but to enable this transition, more investments in VRE is needed. This will decrease the costs related to the technology, maintenance and installation and will play a crucial role to increase the investment rate. Over the past years the LCOE has decreased drastically for renewable generation, resulting in solar PV and wind being the most cost beneficial generation source today. The LCOE forecasts for offshore wind also looks bright [43].

Low LCOE is not enough to secure investments in VRE. If the electricity price in times of production from VRE is extremely low, the investments might not be as economical beneficial after all. Because there is a risk of having a very high production of VRE in Europe at the same time, the electricity prices may decrease in times of high production causing a low revenue in the wholesale electricity market for VRE. Capture price express this issue and gives a good indication of what wholesale electricity prices VRE producers can expect when selling their power in the future.

If capture prices are expected to decrease in the future, the economic incentives to invest in VRE will follow. This could make it harder to reach the expected share of renewable generation in the system, which would make the already ambitious EU 2050 targets even more ambitious. Hence, it is important to not only look into how the capture price for VRE is expected to develop towards 2050, but also locate and initiate measures to stabilize the capture price.

1.2 Objective and scope

This thesis use a flow based simulation tool called PowerGAMA to simulate the European power system. The model for the power system for 2014 created by the master students Rye and Lie is used as basis [61]. The first objective is to expand this base system so that it fits a 2040 power system emphasizing the missing model areas, installed capacity, transmission constraints and the demand. The author has also located the most important drivers to support integration of VRE. Hence, electrolysers and batteries will be included in the model. A essential part of this thesis is to find out how to model electrolysers and batteries in PowerGAMA as there is not yet located a specific way to model its behaviour.

The modelled area is the European power system, with most details for the North Sea region. We go in detail on how the model is developed to enable other master students to build on this work. Unfortunately the optimization algorithm has a long running time restricting the work of the thesis. Thus, the focus is to find easy but yet suitable approaches and elaborate on future improvements to ensure that the knowledge from this thesis generates as much value as possible.

In addition to creating the model the author will analyze how the economical incentive for investing in VRE will evolve towards 2040 emphasising on how batteries and electrolysis will affect the capture prices for VRE. The focus will be on finding the future revenue from the wholesale market for VRE. This thesis will use the following to assess the VRE economics:

- Capture prices
- Curtailment
- Number of hours with nodal price equal to zero
- Average prices and price profiles
- Total revenue for VRE

where the focus will be on the capture prices and further comparing them to the expected future LCOE for VRE.

1.3 The work progress

The author found it valuable to visualize the work progress reaching the objectives described above so that the reader can get a better understanding of how the results were obtained. Figure 2 visualize the different objectives for the work process. The different objectives were kept relatively separated, meaning that the author would not go further without feeling comfortable with the previous objective. Still, in some of the cases it turned out to be valuable to work on several objectives simultaneously. As seen from the visualization, each objective needed to be validated before going on to the next. Because of the size and scope of the modeled system, many aspects needed to be considered, hence, in some cases it took several simulations to end up with a sufficient result. The run time made it harder to adjust the input files, thus the number of simulations and adjustments were limited by the time budget.

The first objective was to add the missing parts of the power system surrounding the North Sea region. When this was accomplished the next objective was to scale parameters in the input files for the existing model for 2014 so that they fit the three scenarios for 2040 in TYNDP 2020. When the author was satisfied with the result, the next step was to look into how batteries and hydrogen could be included in the model. These three steps are all explained thoroughly in section 5 and together they form the basis of the cases being analysed in section 6. The last objective is therefore to use the knowledge and input files created from step one, two and three to assess the impact of electrolysis and batteries on VRE economics, emphasising the capture prices for VRE in the North Sea region.

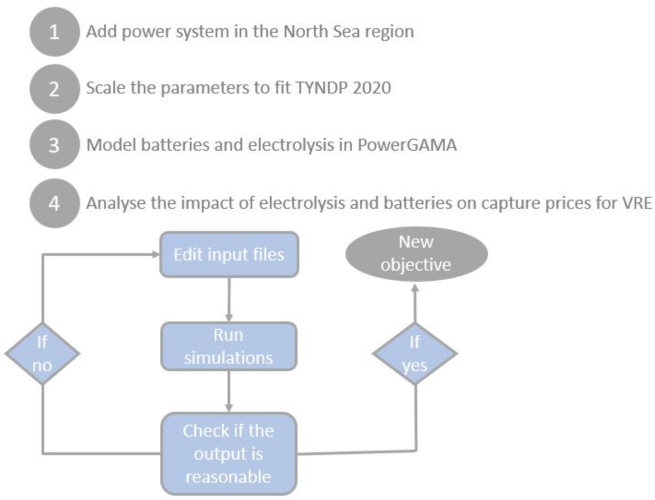


Figure 2: Illustration of the work method for this project. The objectives are stated in the top and for each objective the illustrated progress is executed. Created by the author.

1.4 Structure

This project is separated into seven sections where the first section introduces the background, objective, scope, and work progress of the thesis. The purpose of the section is to give a brief introduction on the focus and topicality of this master thesis.

The second section describes the important trends in the future power system focusing on the predicted demand, installed capacities, transmission capacity, batteries and electrolysis. It also highlights the drivers for these changes. In addition, the section gives a brief overview of the main references used to gather the information about the power system 2040.

The third section focuses on the economical consequences of the future power system with a focus on how this affects VRE economics. Capture prices and LCOE are keywords.

The fourth section looks into the methodology for this thesis. This includes going into details on how the simulation tool PowerGAMA works and a description of the code created by the author of this project.

The fifth section describes how the model of the power system in 2040 is built. This is a very important part of the thesis and will be emphasized so that other master students can continue the work done for this thesis.

The sixth section describes the results from the simulations in PowerGAMA with the created model in section five. The economical motivation for investing in VRE is evaluated by comparing capture prices and LCOE. Analyzes on the effect of adding batteries and electrolysis in the model as well as sensitivity analysis on the CO_2 prices are also performed.

The seventh and last section conclude with the most important results and put them in perspective according to the simplifications made.

Lastly, in Appendix some of the code developed for this thesis is included as well as some other illustrations that the author found valuable to include.

2 The European power system towards 2040

When building a model for 2040 it is important to understand the trends in the power system going forward. The year 2040 is twenty years from now and a lot can happen by then. Thus, it is necessary to understand what motivates and drive those trends and how they affect each other so that it is possible to get a better understanding of the range of possible outcomes. In this section we will investigate important trends and technologies that are relevant for the European power system development towards 2040. This analysis will be based on existing forecasts and scenarios and we will present a synthesis of the existing material on relevant topics. This will be used as background for the numerical modeling that is reported later in the thesis.

2.1 Report foundation

Many companies try to analyze how the future power system will look like, hence there are many reports on prediction on the future. Before the author goes into details on the predictions, the most frequently used reports for this thesis is clarified. These are used to build the foundation for the data processing and model validation. The author has chosen to use mainly the Ten-Year Network Development Plan 2020 (TYNDP 2020) conducted by ENTSO-E and ENTSOG. This report is created every second year in collaboration with TSOs all around Europe. For the TYNDP 2020 almost 90 TSOs, covering more than 35 countries, contributed to the process [20]. This report is therefore highly respected and used for multiple purposes all around Europe. The report includes an extensive data set with specified parameters that is highly relevant for this thesis. Hence, using the TYNDP 2020 is not only a valid basis for this thesis, but also convenient and accurate as specific numbers that is relevant for the model are available.

TYNDP 2020 consists of four main documents and several Annexes, data sets and a visualization platform, which are listed below.

- Main Report [20]
- Scenario Storylines [27]
- Scenario Building Guidelines [17]
- System Needs Study [22]
- Annexes for Scenario Building Guidelines [16]
- Data sets [18]
- Visualization platform [24]

The Annexes gives an overview of values used in TYNDP 2020 like values on installation cost for different technologies. The Annex of most interest for this thesis is the Annex including CAPEX for generation technologies cited above. The Main Report refers to the most important results and conclusions from TYNDP 2020. It also gives a brief introduction to the scenarios and an overview of the creation process of TYNDP 2020. Scenarios Storylines includes more details on the trends, like the share of EVs, while the Scenario Building Guildelines gives an insight on how the scenarios were created and which assumptions were made. The System Needs Study locate the needs in the transmission grid regarding transmission capacity and grid structure.

Even though TYNDP 2020 is published in 2020, it is important to keep in mind that this process takes time. Already 29th May 2018 the working group had their first interaction with stakeholders to exchange information and ideas [27]. Since costs related to technology and politics regarding the EU climate targets change rapid, reports only a few years old can already be outdated. Hence it is important to see TYNDP 2020 in light of other reports.

2.2 Scenarios

To give a better perception of the possible outcomes for the power system in 2040, TYNDP 2020 created three scenarios. They are illustrated in Figure 3.

Figure 3: The three scenarios for 2040 in TYNDP 2020, GA, NT and DE. GA is more centralized, DE has higher share of distributed energy and NT is in between those two. Created by the author.

ENTSOG and ENTSO-E identified two main characteristics to develop their scenario storylines: Decarbonization and centralisation/decentralisation. Decarbonization refers to the expected decline in the Green House Gas (GHG) emissions, while decentralisation refers to the share of power generation that is decentralised. The scores regrading these two characteristics for the different scenarios for 2040 are illustrated in Figure 4.

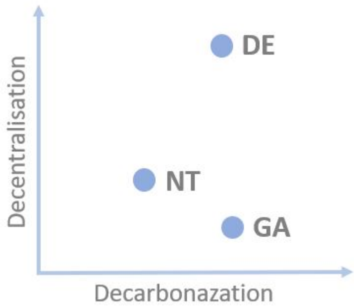


Figure 4: GA is the least decentralized TYNDP scenario. DE has approximately the same level of decarbonization, but has centralized energy generation. Created by the author and inspired by [20].

As seen from Figure 4, GA has the most centralized generation, while DE has the least. They score approximately the same on the level of decarbonization. National Trends (NT) is more similar to Global Ambition (GA) regarding centralization, while it scores lower than both Decentralised Energy (DE) and GA regarding decarbonization. In addition, NT stands out regarding the creation process. This scenario is a bottom up scenario, in relation to the DE and GA that are top down scenarios. The main difference between top down and bottom up is that the starting point for bottom up is the situation as it is today. Further, the scenario is built by assuming certain trends based on the situation today. Thus, if no countries had invested or were planning to invest in renewable energy, a bottom up scenario would have very low shares of renewable energy even though EU climate targets implies the opposite. The information creating the basis of the NT scenario is future national climate policies and official data sets from TSOs. In comparison, the starting point for a top down scenario is a reasonable future situation. For instance, a top down scenario would be based on EU reaching its 2050 climate targets. Further, the top down scenarios go backwards, focusing on what need to be done to reach the final goal. For the EU 2050 target, this can be achieved by investing in centralized renewable energy, like in the GA scenario. Hence, the top down scenarios are able to aim for more ambitious climate targets, as seen in Figure 5. A brief summary of the most important characteristics for each scenario is found in Figure 5.

Even though both DE and GA are top down scenarios, they are very different regarding generation and demand. This was in fact some of the reason why they were chose;, to show the range of possible directions for the future power system [20]. These differences will be highlighted in the following sections especially regarding installed generation capacity, demand and transmission capacity.

	GA	NT	DE
Main generation type			
Location	Centralized	Centralized	Decentralized
Building process	Top down	Bottom up	Top down
EU 2030 target?	✓	✓	✓
EU 2050 target?	✓	✗	✓

Figure 5: Summary of the most important features in the TYNDP 2020 scenarios for 2040. GA has centralized generation and the highest share of offshore wind generation. DE has dezentralized generation and the highest share of solar PV generation. Note that NT does not reach the EU 2050 target. Created by the author, information from [20].

2.2.1 Both average and peak demand will increase

According to TYNDP the overall total demand in Europe will increase towards 2040. For comparison, the total annual electricity demand for 2015 in EU28 was $3086TWh$. This is expected to increase to 3554, 3426 or $4029TWh$ for respectively NT, GA and DE. This increase can be seen in Figure 6.

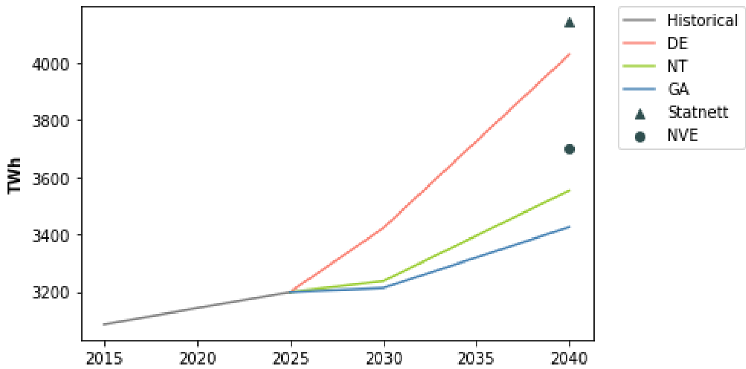


Figure 6: The predicted demand towards 2040 spreads depending on trends and how they are weighted. The lines are the three TYNDP 2020 scenarios [20] while the black dots are predicted by Statnett and NVE [65] [57]. The figure is inspired by [20].

The main reason for the increase is the electrification of several sectors like transportation, new industry and heating. As seen from Figure 6 the two top down scenarios has a very different total demand for 2040. The main reason for the difference is that GA has the strongest level of energy efficiency. DE also has a high level of energy efficiency, but in addition it has the highest uptake of electric vehicles and heat pumps resulting in a much higher total demand for 2040. This illustrates how trends like electric vehicles, heat pumps and energy efficiency pulls the total consumption in different directions, resulting either in an increase or decrease in total electricity demand. To which extent these trends will evolve is hard to tell for 2040. To capture this gape, the DE and GA scenarios are modeled with different trends regarding the electricity demand.

The annual demand is an important factor to locate the future challenges in the power system, but it is also important to examine when the demand is high. One way to describe this is through peak demand. Peak demand is defined as the highest single hourly power demand within a given year [20]. According to TYNDP peak demand will increase in the future, which is illustrated in Figure 7. Just how big this increase will be depends on the scenarios. The report points out some drivers that will impact the peak demand;

- Electric vehicles
- Heat pumps
- Smart metering
- Demand response
- Additional new baseload like datacenters

The electrification of electric vehicles and heat demand are according to TYNDP significant drivers in growth of electricity peak demand. Smart metering, on the other hand, may provide more opportunities for intelligent or efficient energy demand patterns by consumers. For instance, the scenarios assume that there is an inherent level of smart charging that shifts consumer behaviour away from peak periods. This is one example of demand response which will be important going towards 2040 to flatten the demand curve and reduce peak demand. Another example is having combined heat pumps that can shift their production to gas in times of extremely low temperatures [20].

Since some of the drivers mentioned above will increase the peak demand, while others will balance the demand curve, it is reasonable to raise the question of whether the peak electricity demand will in fact increase by 2040, even though the total average demand increases. As seen from Figure 7 all scenarios has a significant increase in peak demand, where GA is the scenario with the lowest levels of peak demand. This is caused mainly by its low share of heat pumps and its high energy efficiency. In DE the main driver for higher peak demand is the higher rate of electrification across all sectors. Although it is important to note that having a high share of electrification can at the same time provide additional opportunities for demand side response, such as vehicle to grid or demand flexibility [20].

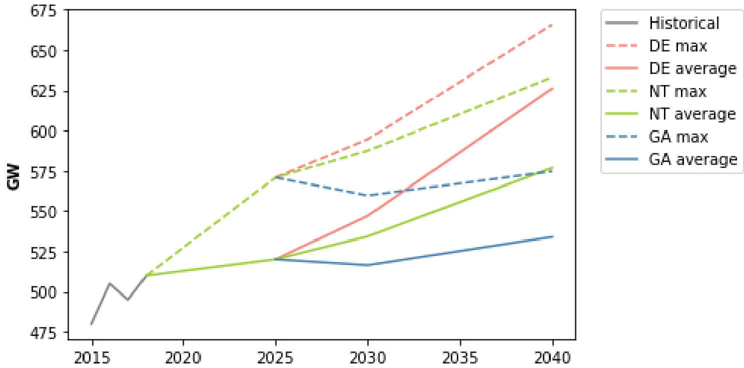


Figure 7: The predicted peak demand towards 2040 will increase even though measures to flat out the demand curve is taken. Figure inspired by [20].

Figure 7 only illustrates that the peak demand will increase. Whether it increases in line with the average demand or not is unclear from Figure 7. From Table 1 it is easier to compare the increase of peak demand to the average demand because it looks into the Compound Annual Growth Rate (CAGR). There is no clear trends, but it is still interesting to see the CAGR for peak compared to average demand from 2015 - 2030 for DE. The average demand has a significant increase of $0,7\%$ while the peak demand decreases with $0,14\%$. This illustrated the affect of electrification and which opportunities this brings for demand response.

		average	peak
2015 - 2030	NT	0,3	0,54
	GA	0,3	1,01
	DE	0,7	-0,14
2030 - 2040	NT	0,6	0,77
	GA	0,6	0,33
	DE	1,5	1,36

Table 1: CAGR - Compound Annual Growth Rate in [%] for average demand and peak demand for each scenario [20]. There is no clear trends, but it illustrated the affect of increasing balancing measures when the average demand increases significantly. It also shows that peak demand might increase or decrease going forward, depending on these measures.

With an increased peak and average annual electricity demand it is necessary to adjust the power system to this change, including transmission capacities, installed generation capacity and balancing services. This will be addressed in the following sections.

2.2.2 Installed generation capacity will more than double compared to 2014

When demand increases so will the need for installed generation capacity. In addition, the ambitious EU 2050 target to become climate neutral in 2050 pushes the shift from fossil fuel based generation to renewable. Solar PV, offshore and onshore wind will together form over half of the generation in 2040 according to TYNDP. Thus, VRE will become dominating in the generation mix. Since it is hard to control the generation dispatch for VRE because it is dependent on the weather the installed generation capacity needs to be higher than if the system was fossil fuel based. All together this correspond to an increase of more than 200% in total installed generation capacity from 2014 to 2040. In addition the fossil fuel based installed generation is almost halved. Note that the TYNDP scenarios are being compared to the 2014 data set which is not solely based on ENTSO-E data. See Figure 8.

The three scenarios have different takes on the installed generation capacity. DE is the most decentralized scenario and it also requires the highest investment in generation capacity. This is mostly because it also has the highest level of electricity demand. As seen from Figure 8, DE has the greatest focus on the development of solar PV. It also has a significantly higher share of onshore wind compared to the other two scenarios. In the DE scenario the renewable generation focuses on decentralized small scale generation, meaning that it is not necessarily installed in the best geographical locations, which gives a lower capacity factor. This also results in it needing more installed capacity to compensate for a lower capacity factor.

GA, on the other hand, has a lower electricity demand and focus more on centralized renewable generation. The renewable generation is installed at the sites that gives the highest capture factor. It is the scenario with the highest share of offshore wind. Consequently, the capacity required for this scenario is the lowest as more energy is produced per MW of installed capacity in offshore wind. National Trends is the national policy-based scenario. The renewable generation is a mix between the two top down scenarios. As seen in Figure 4 the NT scenario is more similar to the GA scenario regarding decentralization which is also reflected in Figure 8.

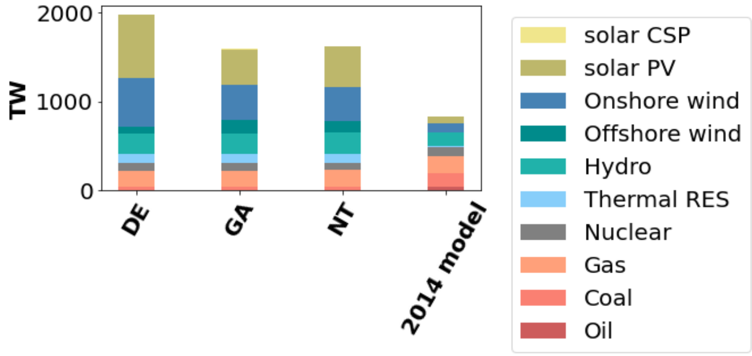


Figure 8: Installed generation capacity in the 2014 model in PowerGAMA [67] compared to the three TYNDP scenarios [18]. DE stands out as it has the highest demand and the lowest capacity factors caused by the decentralization. From 2014 (data set) to 2040 (TYNDP) the installed generation capacity more than doubles. The share of fossil fuel based generation is almost halved. Illustrated by the author.

2.2.3 Increasing transmission capacity is important to facilitate RES integration

The TYNDP 2020 identifies the necessary improvements in the power grid to facilitate the transmission to renewable generation. The improvements concern several aspects such as transmission capacity, grid structure, frequency stability, voltage control or congestion management control. The report concludes that making the suggested changes, the curtailed energy from renewable generation in 2040 will go from $244TWh/year$ to $134TWh/year$. This will decrease the need for thermal generation, which again will save $55Mton/year$ of CO_2 emissions. Not only will this be beneficial for the environment, but it will save $10bn€/year$ in generation costs [22]. Further the report claims market integration would progress, with price convergence increasing between bidding zones. This is thanks to an additional $467TWh/year$ cross-border exchanges by 2040.

Because of the parameters in the input data for this thesis, the focus of this thesis will be on the suggested improvements regarding cross-border transmission capacities and grid structure. Still, it is important to keep in mind that increasing the transmission capacities are not the only improvements in the transmission grid necessary to meet the ambitious political target in the European Green Deal, aiming at making Europe climate neutral in 2050 [22].

All scenarios have the same grid structure in the System Needs Report [22], but because of different demand profiles and installed generation mix there are individual system needs per scenario regarding transmission capacity. These are visualized in the TYNDP 2020 visualization platform [24]. They include both the planned and the existing transmission capacity. In addition, the capacities from TYNDP 2020 was given as NTC - Net Transfer Capacity. A country's NTC are frequently updated and shared with market participants to, amoung other things, enable them to use the updated notions for transmission network planning. NTC is a way of representing the maximum power that can be transmitted from system A to system B if there are several cross-system transmission lines. The calculation of NTC will normally be performed in three steps [21]:

- Calculation of the Total Transfer Capacity (TTC)
- Calculation of the Transmission Reliability Margin (TRM)
- Calculation of the Net Transfer Capacity (NTC)

TTC includes the physical realities that may impede operation of the system according to security rules. This includes thermal, voltage and stability limits. TMR covers the forecast uncertainties of tie-line power flows due to imperfect information from market players and unexpected real time events [21]. Finally, the NTC is calculated as $NTC = TTC - TRM$. When these calculations are made the generation in system A increases and the generation in system B decreases. The result will be NTC from A to B. When the generations in the two systems are shifted the NTC from B to A is found. Thus NTC from A to B might not be equal to NTC from B to A. In some cases the NTC from located in the TYNDP 2020 System Need report [22] reflect thisn. For instance, the NTC or the transmission line from SE03 to SE04 is $3,6GW$ while the NTC for the opposite direction is $7,2GW$. Hence, this difference can be significantly high, but for most of the lines it is not.

Finally, the report concludes that addressing the identified needs by 2040 would represent $45bn$€ of investment. These investments in infrastructure will generate jobs and growth, thus support the European industry which will be key to support the economy in the post COVID era [22]. Hence, increasing transmission capacities is not only convenient for VRE producers but also an essential socio-economical measure to reach the EU 2050 target.

2.2.4 CO_2 price is a key enabler for RES economics

Fuel prices are key enablers for decarbonizing the energy sector as they determine the merit order of the electricity generation units, hence the electricity dispatch and resulting electricity prices [17]. The CO_2 price has not been a significant part of the fossil fuel prices until recently. For instance, in 2014 the CO_2 price was $5/tCO_2$ which is less than 10% of the total fuel cost. In 2040 the CO_2 price necessary to reach the EU targets will lie in between $80 - 100/tCO_2$ [20]. These were obtained for each scenario from the calculation of the carbon budget. The carbon budget is compared to the emission target defined in each scenario and if the emissions are too high, the CO_2 price is increased. These CO_2 prices are set so that the EU 2030 and 2050 target are reached. Hence, the CO_2 price could be much lower or higher. For instance, in 'business as usual' scenarios the price is around $30/tCO2$ in 2030. In more ambitious scenarios the price reaches around $80/tCO2$ in 2030 [20]. Thus, it is not inconceivable that the CO_2 price for 2040 could reach close to $200/tCO2$ in 2040.

The change in the CO_2 price will have a significant impact on the fossil fuel costs. For coal an CO_2 price of $100/tCO_2$ imply approximately tripling the fuel costs from 2014 to 2040. When the fossil fuel costs increase so will the economical motivation for investing in VRE as the sources become more competitive. The increased electricity price will also contribute to increased revenue for VRE generation. This will be curtail for the transmission to a power system mainly based on generation from VRE. Thus, increasing CO_2 prices will be one of the most significant political measures to reach a zero emission energy sector within 2050.

2.3 Batteries becoming an essential part of the power system

In the long-term, Power-to-Gas and batteries are the main technologies balancing VRE [27]. Battery energy storage deployment is projected to grow rapidly and recent large-scale storage projects indicate that battery energy storage could play a greater role in electricity markets [49]. The TYNDP 2020 scenarios show that there is potential for batteries to smoothen demand peaks and level prices. The impact of these technologies in terms of energy may be low, but they show a vast potential to reduce generation from carbon based peaking units, supporting decarbonisation and help to integrate increasingly variable generation [20]. Thus, batteries is highly relevant when simulating capture prices and revenue for VRE.

2.3.1 Quantify battery capacity

The decision to build a particular technology is driven by the achieved electricity price for a particular market area [20]. Thus, the battery capacity installed in each area is highly motivated by the electricity prices. This makes the predicted installed battery capacity for an area dependent on the share of VRE generation, balancing factors like electrolysis and demand response and the cross-area transmission capacity. Based on this, the TYNDP 2020 scenarios has different predicted battery capacity. DE has the highest installed capacity followed by NT and GA. The installed battery capacity is illustrated in Figure 9. The battery capacity in Figure 9 include both batteries used for residential storage and large-scale battery plants located near power plants.

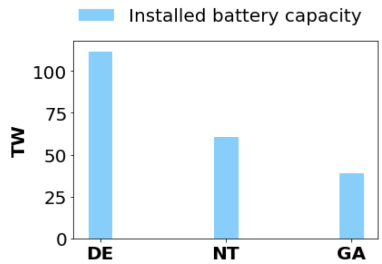


Figure 9: The installed battery capacity for an area is affected by the power system characteristics and its electricity prices. Thus, the TYNDP 2020 scenarios has different installed generation capacities for EU. Illustrated by the author, values gathered from [20].

2.3.2 Uses of battery and battery limitations

Batteries are mostly used to take part in the market and help to smoothen demand peaks and level volatile prices [20]. They are not applicable for balancing the power system at days or longer perspective [8]. Thus, when modeling the batteries in section 5.5 their charging and discharging profile should be fluctuating often and not on a day to day basis.

Just how often the battery should fluctuate is a complex issue. It depends on the battery technology and what the desired ancillary service is. For instance, if a battery is installed in the power system solely to smoothen demand peaks it should mostly charge during peak hours which is normally a few times a day [20]. If the purpose of the battery is to keep the frequency stable it should be used more frequently. In addition, batteries are often limited by specifications from the manufacturer on for instance charging and discharging rates or depth of discharge (DOD). DOD represent how much the battery can be emptied based on its full storage capacity. DOD is normally around 80% of the total storage capacity [6] and is important for battery operation as fully discharging the battery may dramatically reduce battery lifetime [10]. These limitations affect the battery behaviour but because of the scope of this thesis and the limitations in PowerGAMA this is not as relevant and will therefore not be addressed.

2.4 Green hydrogen emerges

There are many reasons why electrolysis is a key priority to achieve the European Green Deal and Europe's clean energy transition. Renewable electricity is expected to decarbonize a large share of the EU energy consumption by 2050, but not all of it. Electrolysis has a strong potential to decrease the need for generation from fossil fuels by generating power from hydrogen. To make this a better solution than fossil fuel based generation the hydrogen should be produced from electrolysis.

The green deal describes a vision where the share of hydrogen in Europe's energy mix will grow from the current less than 2% to $13-14\%$ by 2050 [28]. IRENA estimates that to achieve the Paris agreement around 8% of global energy consumption will be provided by hydrogen in 2050 [44].

According to Bloomberg, analysts estimate that clean hydrogen could meet 24% of energy world demand by 2050 [7]. Because of the uncertainties regarding policies, technology and electricity prices analysts do not necessarily agree when quantifying how big role hydrogen will play in the future power system, although it is clear that it can be a key player when decarbonizing the energy sector.

Thus, including electrolysers in the model for this thesis is necessary to understand how the power prices will evolve towards 2040. It is especially important when assessing the future economics of VRE since an increased load due to electrolysers is likely to decrease the share of curtailed energy and increase the electricity prices. Still, it is important to keep in mind that when increasing the load significantly the need for more generation from VRE increases as well. To fully understand the net effect this will have on the power prices is hard without running simulations on the system. Thus, modeling electrolysis is an essential part of this thesis and this section founds the basis of the electrolysis modeling part in section 5.6.

2.4.1 Electrolyser technology - PEM and Alkaline

An electrolyser use electricity to split water into oxygen and hydrogen

$$2H_2O(l) \rightarrow 2H_2(g) + O_2(g) \tag{1}$$

In reality this process is separated into chemical reactions in the anode and cathode. How this happens depend on the technology. There are mainly two types of electrolysers

- Alkaline electrolyser
- PEM - Proton Exchange Membrane electrolyser

Alkaline electrolysers use two electrodes in a liquid electrolyte. When voltage is supplied the product gases, H_2 and O_2 are released. PEM, on the contrary, separates hydrogen from the water by a solid electrolyte.

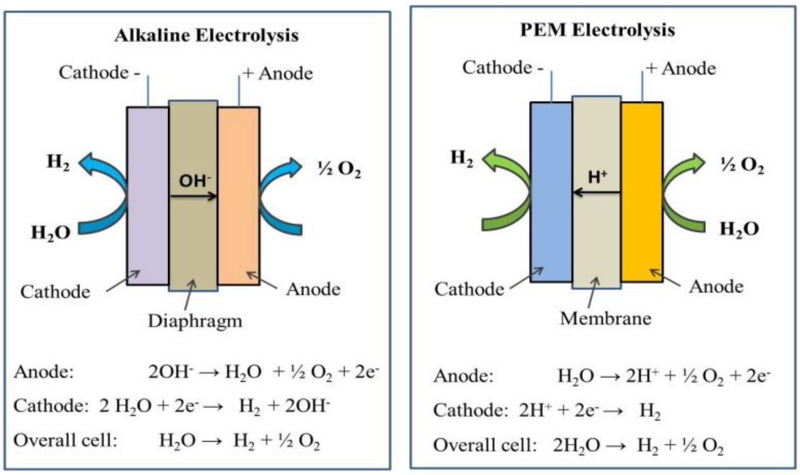


Figure 10: The two main types of electrolysis has different methods of separating H_2O into H_2 and O_2 [63].

The different technology in Alkaline and PEM electrolysers lead to different traits. The most important characteristic for this thesis is the ability to quickly adjust their production. PEM electrolysers are much better at this, which makes this method more suitable in combination with VRE. The rest of the pros and cons are listed in Table 2.

Alkaline	PEM
- Low manufacturing cost - Lifetime = 10 years - Mature technology - Slow start up - Corrosion - Complicated maintenance	- High manufacturing cost - Lifetime = 3 to 4 years - Fast start up - No Corrosion - Simple maintenance

Table 2: Pros and cons for different electrolysis technologies. The most important trait for this thesis is the start up speed because a fast start up makes it easier to adjust its production to VRE. Created by the author based on [32].

Alkaline electrolysers are considered mature technology, currently used to produce chlorine. PEM electrolysers are going through a steep learning curve. They are built similarly to solar cells, only with electrolyser cells that are combined to build an electrolyser stack. To build a GW scale electrolyser, a number of electrolyser stacks are placed in parallel. These electrolyser technologies are expected to achieve remarkable technology improvements in the next decade. To reduce electrolyser plant costs technology improvements like higher efficiencies and larger cell sizes is important. A substantial electrolyser market volume together with realizing GW scale electrolysers are also essential drivers for significant cost reductions. Reducing the electrolysis costs is important, but the dominant factor in the hydrogen production cost is the electricity price, determining 60-80% of the hydrogen cost. [39]

2.4.2 Black, grey, brown, blue and green hydrogen

When analyzing hydrogen it is important to know how it is categorized based on the production process. Black, grey or brown hydrogen refer to the production of hydrogen from coal, natural gas and lignite respectively. In 2018, over 99% of hydrogen was made using fossil fuels [7]. Blue hydrogen is normally used when hydrogen is produced from fossil fuels with CCUS [43]. CCUS refers to both the terms CCU (Carbon Capture Utilization) and CCS (Carbon Capture Storage). CCU is similar to CCS, only that the carbon being captured is not preserved, but utilized to create new products like concrete [46]. Because of the use of CCUS blue hydrogen has lower CO_2 footprint than black, grey or brown. Lastly, the most CO_2 emission friendly alternative is green hydrogen. It is a term applied to production of hydrogen from renewable electricity by electrolysis [46] and is therefore the only type of hydrogen production that directly affects the power system by increasing the demand, hence it is of the most interest for this thesis.

2.4.3 Discussion of the effect of green hydrogen on the power system

Categorizing green hydrogen might sound like a walk in the park, but in reality it is more complex. According to what is stated above, production of hydrogen can only be "green" if it is produced by electricity from RES. In a power system with solely RES this would not be a problem, but the power system in 2040 includes a significant share of fossil fuel based generation. Thus, according to the statement above, hydrogen can not be called 100% green as long as it is not solely based on renewable electricity. The author finds this statement inadequate as this issue is more complex. First of all, if there is production from fossil fuel based generation in times of load from electrolysis it is hard to tell exactly where the electricity from fossil fuel based generation ends up. This depends on the power system state. Thus, a better question to raise would be what would happen to the production from fossil based generation if the electrolysers are added? In a complex power system with balancing measures like batteries and demand response it will not necessarily result in a higher share of production from fossil fuel based generation. Still, it is possible to quantify this problem by simulating the power system.

It is also important to remember that even if adding the electrolyser increased the net production from fossil based generation over a year it has likely contributed to increase the electricity prices and lowering the share of curtailed energy. This would increase the economical motivation to invest in VRE. A simplified illustration of this is found in Figure 11. Hence, when analyzing over a longer period of time the increased installation of electrolysers might help reduce the production from fossil based generation and make the EU 2050 target within reach. Thus, for this thesis the author will investigate whether hydrogen produced from electrolysis is in fact green hydrogen. For simplicity's, hydrogen produced from electrolysers are called green hydrogen for this thesis.

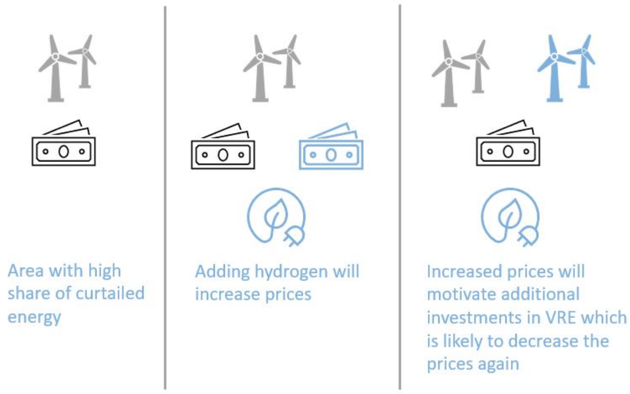


Figure 11: An illustration created by the author that shows a simplified example of how green hydrogen may contribute to increased integration of VRE.

2.4.4 Green hydrogen becoming competitive with grey and blue hydrogen

Even though there is a significant uncertainty regarding the future of green hydrogen several reports has looked into how the costs of green hydrogen will develop towards 2050. There is an agreement that it is probable for green hydrogen to be competitive with grey and blue hydrogen somewhere in between 2030 and 2040 [74][54]. A report by Credit Sussie [13] points out the difficulties when predicting this by pointing out two critical drivers for the hydrogen price for grey and green hydrogen. For grey hydrogen the CO_2 price and the gas price is the most important factors to determine the hydrogen price. Green hydrogen, on the other hand, is highly dependent on the electricity price and the reduction of CAPEX costs. Thus, green hydrogen's competitiveness depends on the political commitment to reduce the CAPEX of electrolysers.

Further the the report has looked into the relation between the electrolyser CAPEX and electricity prices both for ALK and PEM. The goal is to compare when green hydrogen (both PEM and ALK) will outrun grey hydrogen regarding the LCOH. The grey hydrogen is sensitive to the CO_2 price and the gas price, while the green hydrogen is sensitive to the electrolyser CAPEX and the electricity price. Since future grey LCOH has uncertainties regarding its sensitivities, the necessary conditions for green LCOH to outrun the grey LCOH is also uncertain. For instance, it states that an CO_2 price of $30\$/tCO_2$ and a gas price of $4.0\$/mmbtu$ results in a grey hydrogen cost of $2.1\$/kgH_2$. For green hydrogen to be competitive with this it needs to have a electrolyzer CAPEX cost lower than $400\$/kW$ and solely operate at an electricity price lower than $20\$/MWh$. If the gas CO_2 price were to decrease, the required electricity price would decrease making it more difficult for electrolysers to become economically competitive. Nevertheless, they conclude that given a CO_2 price of approximately $80€/tCO_2$ the following will lead to a lower green LCOH than for grey hydrogen.

The requeirement regarding the electrolyser CAPEX is in general much lower for ALK than for PEM. PEM has a higher CAPEX, but compensates with having lower maintenance cost and a fast start up. Thus, despite the high electrolyser CAPEX, it is competitive against the ALK electrolyser. To illustrate this an example from [13] is pointed out; If the electrolyser CAPEX was $500\$/kW$ for both the ALK and PEM technology, the electricity price of $20\$/MWh$ would lead to a LCOH of $2.3\$/tH_2$ and $2.1\$/tH_2$ respectively.

Type	Electrolyser CAPEX $/kW	Electricity price $/MWh	
		Will outrun	Could outrun
ALK	300 - 800	10 - 25	25 - 50
PEM	250 - 1500	10 - 25	25 - 50

Table 3: A price range of 10 - 50 $/MWh could outrun grey hydrogen. Inspired by [13].

To conclude, the CO_2 price is expected to increase significantly going forward and the same goes for the CAPEX costs for electrolysis. Still, it is hard to know which electricity prices is required for the green hydrogen to be preferred over grey and blue hydrogen. This also depends on the utilization of the electrolyser. For instance, if the electricity prices are blow $20\$/MWh$ just 10% of the hours during a year the utilization is too low making the electrolyser unprofitable [43]. This points out the importance of analysing specific incidents to learn how the electrolysers are affected by different behavioural patterns.

2.4.5 Uses of hydrogen and hydrogen value chain

Firstly it is important to understand how hydrogen is used today and how that will change going forward. Today, hydrogen is most commonly used in industrial sector where it is included in the process of making ammonia and methanol [71]. The need for hydrogen in the industrial sector is expected to stay approximately stable towards 2040 [1]. Still, the total need for hydrogen is expected to increase. This is because of the potential use of hydrogen for transportation or heating which are emerging markets. Hydrogen can also be an important energy carrier that can balance the power system over longer periods of time [71]. The increased use of hydrogen in new markets and the coupling with the electricity market is illustrated in Figure 12. Figure 12 also shows how the existing gas infrastructure and the new hydrogen value chain can cooperate to help decarbinization in both fields. For instance, it is possible for the hydrogen to use existing gas infrastructure to be transported and used for several purposes like heating or power generation.

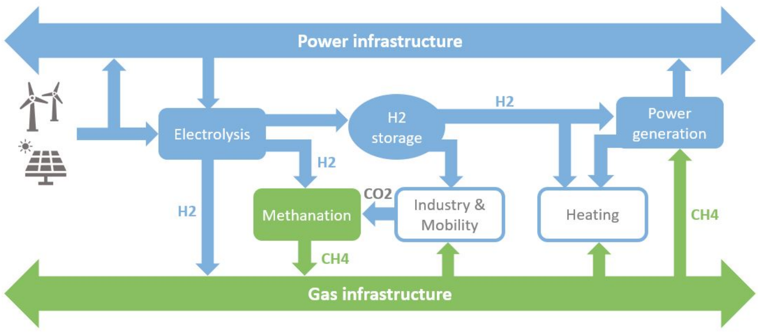


Figure 12: Hydrogen value chain that illustrate the symbiosis of green hydrogen, RES, power grid and existing gas infrastructure. Inspired by [17].

Hydrogen storage is an essential part of the power to gas process chain in Figure 12. Hydrogen has the highest energy per mass of any fuel; however, its low ambient temperature density results in a low energy per unit volume, thus it requires the development of advanced storage methods that have potential for higher energy density [73]. Today hydrogen is most commonly stored as a gas or liquid in tanks for small-scale mobile and stationary applications. However, the operation of large-scale and intercontinental hydrogen value chains in the future will require a much broader variety of storage options [39]. For instance, hydrogen storage may be required for a short period prior to shipping or at vehicle fuel stations. There is also the need to store hydrogen over days or weeks to balance hydrogen supply and demand. Much longer storage options would be required if hydrogen were used to balance seasonal changes in electricity supply or demand. The most appropriate storage medium depends on the volume, duration of storage, required speed of discharge, and the geographic availability of different options. However, geological storage is in general the best option for large-scale and long-term storage, while tanks are more suitable for short-term and small-scale storage [39]. Thus, when modeling hydrogen in section 5.6 it is important considering including hydrogen storage in the model.

Another important aspect of Figure 12 is the generation from VRE. This could represent existing VRE or VRE that is installed mainly to meet the increased demand from electrolysis. The European Commission target for electrolysis capacity is $40GW$. In turn, this would generate a need for $80 - 120GW$ of new installed renewable capacity, depending on the mix of solar and wind assets [13]. Agora assume $400-450GW$ of installed offshore wind capacity in Europe by 2050 given that the EU 2050 target is met. In addition, up to $500GW$ offshore capacity may be implemented by dedicating offshore farms to electrolysis for green hydrogen production [69]. Hence there is no doubt that investments in electrolysis will have a ripple effect on the total installed capacity of VRE. How this will affect the power prices is interesting and will be a focus in the result section 6.

2.4.6 Uncertainties regarding the future of electrolysis

One of the objectives of this thesis is to model the effect of electrolysis on the power system. Thus it is important to quantifying the future of electrolysis. Unfortunately this is very challenging. Apart from the fact that there always will be uncertainties when modelling the future, there are two main reasons why this is difficult:

- Uncertainties regarding the overall hydrogen demand
- Uncertainties regarding the share of green hydrogen

Hydrogen demand is the total demand for hydrogen, including the industrial demand and the demand for P2G, heating and transportation. The industrial demand is easier to quantify since it is not expected to increase or decrease substantially [1]. The use of hydrogen in transportation, heating and balancing of the power system is harder to predict since the demand is highly dependent on policies, technological progress and the trends in the power system.

In addition, there is uncertainty regarding the share of green hydrogen. If the technology, policies and trends in the power system is not headed in the right direction, green hydrogen might not become economical beneficial. As green hydrogen is especially dependent on the electricity prices the power system design is essential to support integration of electrolysis [74] for green hydrogen to be a make up a significant share of the total hydrogen production.

2.4.7 Quantifing electrolyser capacity

With this in mind it is hard to quantify exact values of electrolyser capacities for 2040. Nevertheless, through the Green Deal, EU set a target to install at least 6 GW of renewable hydrogen electrolysers in the EU by 2024 and 40 GW of renewable hydrogen electrolysers by 2030 [28]. Motivated by this, countries has announced specific targets to meet the this ambitious target production. The targets are listed below in Table 4 and found the basis of the hydrogen modeling in section 5.6.

As mentioned earlier, electrolyser costs are expected to decrease to a point where it will become superior to other technologies for hydrogen production. This results in ambitious predictions on installed electrolysis capacity in EU for 2040 by TYNDP 2020, see Table 5.

Country	Target 2030 GW
France	7
Germany	5
Spain	4
the Netherlands	3
Portugal	2
United Kingdom	5
Italy	5
Poland	2

Table 4: National electrolysis targets for 2030 [54]

Scenario	TYNDP electrolysis prediction GW
DE	280
GA	70
NT	40

Table 5: Ambitious predictions on the installed electrolyser capacities identified in TYNDP 2020 [20] for the year 2040.

2.5 Uncertainties and key takeaways

This section is inspired by the specialization project report [34]. In 2019, Europe witnessed two significant incidents in energy policy making. In June, the UK Parliament passed an amendment of The Climate Change Act 2008, becoming the first major economy to adopt a legally binding target of net zero emissions by 2050. Later in December, the European Commission presented the EU Green Deal, also targeting carbon neutrality by 2050 which was followed by the proposal of a European Climate Law in March 2020. The European Climate Law incorporates a legally binding target of net-zero greenhouse gas emissions by 2050 and raise the EU emissions reduction target for 2030 from 40% compared to 1990 to 55%. In line with these developments, several countries in north-western Europe reinforced their national climate targets and published electrolyser strategies. [38]

In Figure 6 the demand for each TYNDP scenario [20] as well as the historical 2020 demand is illustrated. The grey bars represent the demand predictions in TYNDP 2018 while the blue bars represent the demand predictions in TYNDP 2020. The scenarios in the TYNDP 2018 and 2020 are named differently, but based on many of the same trends. The same procedure is used to build them, only weighting the outcome differently. It is interesting to see how much predictions can change in only two years. If TYNDP 2020 included the predicted electrolysis demand the difference would be even bigger. This points out that the future in unclear and, as the TYNDP 2020 claims itself, "Predicting the future with certainty is not possible" [23].

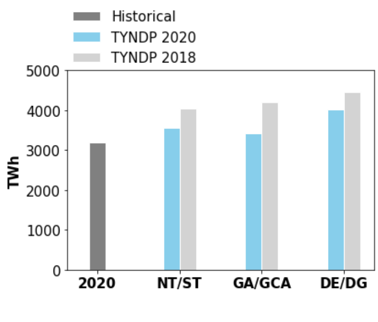


Figure 13: Total demand in EU according to TYNDP 2018 and 2020 show how fast predictions may change. Created by the author, values from [18] [19].

It is also worth remembering that creating reports like TYNDP is a process that takes time. For instance, the progress of developing the scenarios for TYNDP 2020 started already 29. May 2018 [20]. This means that even though the reports might in fact be published after important changes in policies and technological progress, it does not imply that these changes are taken into account. One example of this is how the production of hydrogen from electrolysis is modelled in TYNDP 2020. The scenarios was built with close to no electrolysers. After setting even more ambitious climate targets for 2030 and achieving technological progress, electrolysis is predicted to play an important part in the future power system. To avoid making massive changes to the scenarios that was already modelled for TYNDP 2020, the modeling of hydrogen was deeply simplified. Firstly it found the electrolysis demand. Secondly, instead of including electrolysis in the market simulations, the report assumes that all curtailed energy is dedicated to produce hydrogen by electrolysis. If the curtailed energy is not sufficient to cover the electrolyser demand, some P2G generators are added in the power system to cover the rest of the elesctrolyser load.

There are several problems with this approach. Firstly, the production of hydrogen will most likely be price sensitive, meaning that it will not only produce when there is curtailed energy because this will not be profitable [39]. Secondly, this simplification implies a system where there is no curtailment from renewable sources, which is not credible. TYNDP 2020 mentions that improving how production of hydrogen from electrolysers is an important improvement for TYNDP 2022 [20].

TYNDP is not the only projects that struggles to predict the future power system. The most important reason why this is so challenging is the uncertainty associated with [65]

- Policies
- Technological development

These two factors can change rapidly and are very hard to predict. A recent example of this is that the EU 2030 target has been adjusted over the past years from 40% to 55% emission reduction by 2030 compared with 1990 levels. In 2019 the EU 2030 target was set to 40% [65]. Just one year after the release of the target it was adjusted by the European Climate Law to 55% [28]. This forces the member states to set more ambitious climate actions. For instance, Norway announced 11. November 2020 a reinforcement of their climate targets towards 2030 from 50% to 55%[52]. This shows just how fast politics can change and the uncertainty that follows regarding the predictions. NVE also mentions this in their report [57] and claims that it is hard to tell which specific consequences the uncertainties regarding technology and politics will have on the climate and energy policy. They further state that changes in politics and technological development will be the most important factors for the future power system and power market.

Even though there are uncertainties regarding the future power system towards 2040 there is still a huge value in trying to predict what the future holds. It makes it easier to locate critical measures and make adjustments and plans that enables the shift towards a net zero emission power system.

All of the above results in different directions of the power systems towards 2040. Still, there are some key takeaways on the future power system for 2040:

- The annual electricity demand as well as peak demand will increase towards 2040. The degree of increase will depend on new technology, policies and economical development.
- The installed generation capacities for VRE generation will increase rapidly towards 2040, with the main focus on solar PV and wind (offshore and onshore).
- Gas and especially coal power plants will be slowly phased out towards 2050.
- The power grid must face new reinforcements to be ready for the future power system needs.
- Batteries, demand response and electrolysers will be important assets to phase out thermal power production and replace it with VRE.

3 Market perspective of VRE

The objective of this section is to give the reader an insight in what aspects are important when considering investments in VRE. Because of the objective of this thesis the focus will be on the capture prices and the LCOE. A sufficient explanation of the power market in Europe is also included. Some parts of this section is a modified version of what was earlier presented in the specialization project report [34].

3.1 The European power market

For this section the European power market will be elaborated on. Forecasts on the future power prices are also given.

3.1.1 Wholesale electricity pricing

To be able to understand the concept of capture prices it is important to understand the concept of wholesale electricity pricing in Europe today. The load and generation must be balanced every second to avoid failures or blackouts. This is ensured through several markets. These markets are separated into time sloths, which means that the response time of the producer or consumer determines which market you can participate in. For instance, the balancing market requires the participants to be able to activate their reserves only seconds before the operating second [66]. The simulations in this project will have a time step of one hour, which means that the costs related to the balancing markets are not included in the analysis.

The market that has the biggest impact on the revenue for VRE producers is the day-ahead market. Each day market participants issue forecasts of expected demand for the coming days or weeks. These are continuously updated as new information arises, like changes in weather or unexpected maintenance on power lines. Generators and electricity importers submit offers in the market, indicating the amount of energy they are willing to supply at what price. Large consumers and exporters submit bits into the market where they advice how much electricity they are willing to consume and at what price [36]. The price is set based on these bids and offers, at the market equilibrium also called the market-clearing price [50]. This is illustrated in Figure 14.

Some generators are more expensive to operate, like gas and coal generators. Hence, these will require a higher price for their electricity. Their lowest bidding price is called their marginal cost. If the market price is lower than their marginal cost, it will not be beneficial for the generator to produce energy. These bids will determine the electricity price where the lowest prices will be prioritized to minimize the power price. This means that the generators with the lowest marginal costs will be favored. This is illustrated in Figure 14.

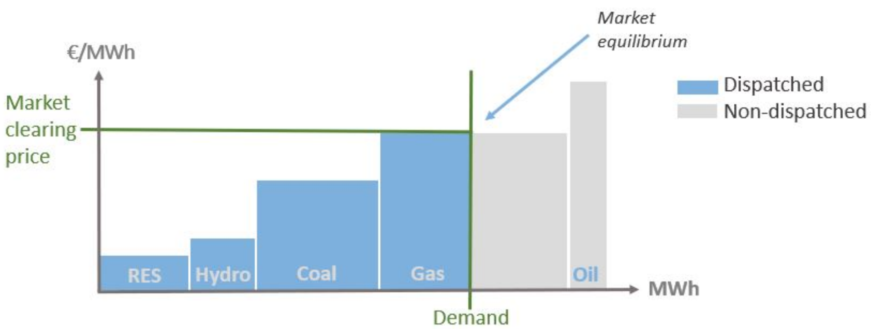


Figure 14: This example illustrate how the market-clearing price is determined based on the marginal costs of the generators. In this example gas determines the price. Inspired by [51] and [34].

Gas determines the market-clearing price in the example above. If the demand was lower or the production of RES was significantly higher, the price would decrease. Thermal generation is a large part of the generation mix in Europe today, hence it often determines the wholesale electricity price. In the future power system the share of generation from RES will be dominating, which will affect the power prices. The share of thermal generation compared to generation from RES is therefore highly relevant for the capture prices.

The marginal costs are not the only drivers for the wholesale electricity prices. They are also affected by congestions in the power grid caused by transmission constraints. These congestion problems may occur in both the transmission and distribution grid. Exceeding these limits can lead to failures or blackouts. Thus, the consumption and generation need to be adjusted in line with the limitations in the power grid [30]. One way to solve this is by adjusting the elastic demand and generation by introducing regional or national price differences in the power system. The prices can be unique for every node, also called nodal pricing, or it can be unique within one zone, called zonal pricing. A bidding zone is the largest geographical area in which market participants can exchange energy without capacity allocation [55], i.e., an area where grid congestion is assumed to be low. Europe has many bidding zones where one zone normally is limited by national borders. Some countries divide their power system into several zones [40], taking Norway as an example, which has five bidding zones [55]. Zonal pricing is the most usual pricing mechanism today, although some independent system operators use nodal pricing, for instance in the US [40]. Nodal pricing is similar to zonal pricing, only that transmission constraints are explicitly observed while determining the optimal dispatch of the system [42]. Based on this the market-clearing price is very much dependent on the restrictions in the transmission grid.

From the example in Figure 14, it is clear that by sufficiently increasing the amount of RES within one price area, the market-clearing price will decrease. This is called the cannibalization effect. Market cannibalization is defined as a sales loss caused by a company's introduction of a new product that displaces one of its own older products [45]. In terms of selling power, the company is the power producer and the new product is additional power from the same generation source. This often contributes to increase curtailment and/or decrease the electricity prices. When emerging towards a zero emission energy sector in 2050 this will become a major issue and might threaten the interests for investing in RES.

3.1.2 Future power prices will increase and become more volatile

To fully understand how the motivation for investing in VRE will evolve it is important to look into how the electricity prices are expected to develop in the future. Even though the share of VRE will increase significantly there is a broad agreement that the average electricity prices is likely to increase towards 2040 [65][2][57][20]. Statnett predicts an average electricity price during a year in continental Europe between 35-60 €$/MWh$. The uncertainty is liked to the CO_2 prices, the number of hours with prices around zero and the degree of subsidies for wind and solar [65]. The main reason for the increase in average electricity prices is the increased CO_2 price. On the contrary batteries and adjustable demand like electrolysers will contribute to a more dynamic power system where a higher share of the load is price elastic. This which will contribute to balance the prices and prevent extreme peaks in prices in times of low production from VRE. Even though these measures balance the prices, the electricity prices are predicted to be more volatile in the future, both on a daily, monthly and seasonal basis [65].

Statnett further claims that the electricity prices will decrease from 2040 to 2050. The reason for this is that the increased CO_2 prices will force a rapid change of the share of VRE while the demand and transmission expansions do not necessarily follow the same pace until 2040. According to Statnett, this could lead to congestions in the grid that forces new price zones with low prices in areas where the offshore grid in the North Sea is connected to continental Europe. These areas will have lower prices in times of high production from VRE, which again will decrease the capture price for VRE. This highlights how important it is to expand the transmission grid as an economical incentive for investments in VRE.

As mentioned above, the capture price for VRE is highly dependent on the drivers affecting the electricity prices. These drivers are deeply interconnected. For instance, if the share of RES increases within an area, the electricity prices will decrease, but only if the transmission constraints limit the problem. If the transmission contrants to limit the problem, but investments in batteries and electrolysis are made. Because they can adjust their power consumption to the variable power production, there might not be a significant need for transmission expansions. Because these drivers are intertwined, it is important to include them all when analyzing the capture prices and the revenue for VRE.

3.2 Capture price

Capture price for a generation source, for instance offshore wind, is the revenue from the wholesale electricity market that can be realized by offshore wind [2]. The wholesale electricity market consists of several markets (day-ahead market, the intraday market and balancing markets) where bids are submitted and where prices are determined [70]. In other words, average capture price, cp, is the revenue that the power producers will receive for the energy that they sell

$$cp = \frac{\sum_{t=1}^{n} i_t}{\sum_{t=1}^{n} E_t} \tag{2}$$

where E_t is the energy produced/sold every time step, t, over the whole period, n. The income is represented by i_t which is

$$i_t = E_t \cdot p_t \tag{3}$$

where p_t is the wholesale electricity price at time t. It is important to distinguish the electricity price and the capture price. The capture price is the electricity price when the generators produce energy. Averaging over a period of time, this becomes the weighted average capture price for the generator. The capture price is thus directly tied to the revenue for the power producer and will affect the economic incentives for investing in VRE. In the following sections its impact on the VRE economics will be discussed.

3.2.1 The capture price for offshore wind will be affected by the cannibalization effect

Even though wholesale electricity prices are expected to increase, capture prices are not necessarily expected to follow. This is because of the cannibalization effect [2]. As seen in Figure 15 the electricity price is expected to increase, while the capture price for offshore wind slowly increases towards 2040, before it decreases towards 2050. Even though the capture price increases towards 2040, it does not mean that the cannibalization effect does not affect the capture prices for offshore wind for this period. When looking at the graph to the right, we see that the capture rate decreases. The capture rate is the proportion of the baseload price realized by offshore wind. This illustrates the problem regarding the cannibalization effect for offshore wind in the future [2]. The New Economics of Offshore Wind (2018) by Aurora supports the tendency of a slow increase in capture price for offshore wind towards 2040 [5].

3.3 Levelized Cost of Energy - LCOE

When quantifying the importance of capture price for VRE economics, it is important to evaluate the Levelized Cost of Energy/Electricity (LCOE). LCOE represents the average revenue per unit of produced electricity that is required to cover the costs of building and operating a power plant during its lifetime [14]. Thus, this value represents the average minimal electricity price during the

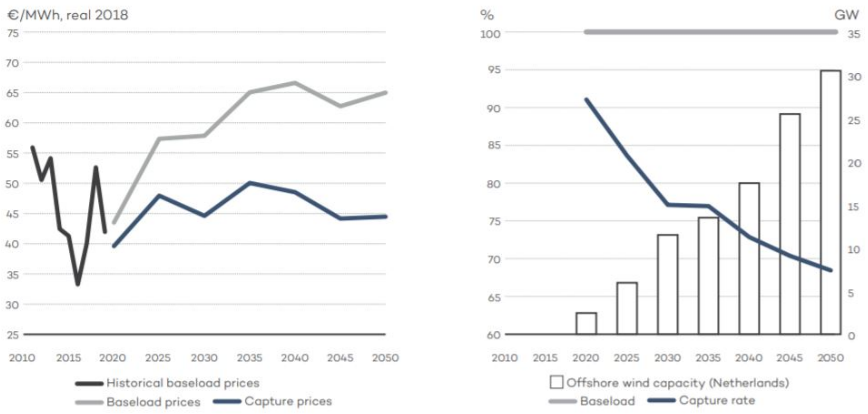


Figure 15: The capture price (real 2020) for offshore wind in the Netherlands are expected to increase towards 2040 and decrease towards 2050. The capture rate is expected to decrease evenly towards 2050. This illustrated the cannibalization effect [2].

lifetime of a power plant for the investment to be of interest. Normally LCOE is compared with the electricity price, but if the capture price strongly deviated from the average electricity price, this may lead to a false impression of the levelized returns. For instance, if the capture price is lower than the average electricity price, this may lead to a company investing in a project that is not beneficial. Hence, the capture price is influential when deciding whether to invest or not. Note that LCOE is not the single driver in the investment decision. When investing in power plants the investor considers the specific technological and geographical characteristics of a project, which involves many other factors not included in LCOE values [14].

3.3.1 Calculating LCOE

Before going into details on historical and future LCOE, the method for calculating LCOE is presented [14]. Firstly, the annual costs, c_t is calculated and discounted back to present value by a discount rate, r

$$c_t = \frac{I_t + M_t + F_t}{(1+r)^t} \tag{4}$$

I_t is the investment expenditure in year t, also called CAPEX. M_t is the operation and maintenance cost in year t, also called OPEX. F_t is the fuel cost, which is zero for VRE. Further, the annual electricity produced in year t, E_t must also be discounted back to present value with the same discount rate, r

$$e_t = \frac{E_t}{(1+r)^t} \tag{5}$$

E_t is often given in MWh. Both the present value of the annual costs, c_t, and the present value of the annual electricity produced, e_t, need to be summarized over the lifetime of the power plant. Then,

$$LCOE = \frac{\sum_{t=1}^{n} c_t}{\sum_{t=1}^{n} e_t} \tag{6}$$

Hence, LCOE is the sum of costs over the lifetime of the power plant divided by the electricity produced over the lifetime.

3.3.2 LCOE for VRE is expected to decrease

The LCOE for solar PV, offshore and onshore wind will be discussed, focusing on offshore wind because offshore wind will emerge becoming one of the key enablers for decarbonizing the energy sector [65]. Today the levelized costs for offshore wind is a lot higher compared to onshore wind and solar PV. This results in a higher LCOE for offshore wind [14]. Figure 16 illustrate this. Note that levelized variable operation and maintenance costs are estimated to be zero for the three generation sources in Figure 16.

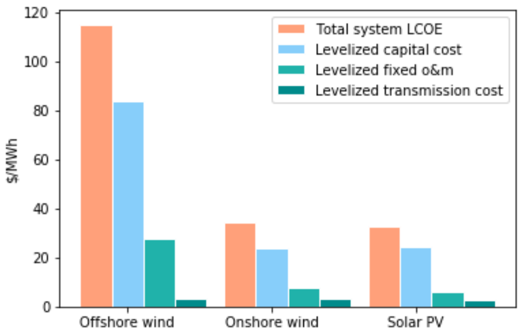


Figure 16: Today's LCOE for VRE. Offshore wind has a significantly higher LCOE than onshore wind and solar PV [14]. The Most of the difference is caused by the levelized capital cost, which is expected to decrease the next years [42].

Figure 16 shows that the main reason for the LCOE difference between offshore wind and onshore wind is the levelized capital cost. All the costs in Figure 16 are connected to the CAPEX cost. These are expected to decrease in the future which will affect the future LCOE for offshore wind. The TYNDP report made predictions on the LCOE for solar PV (commercial and residential), offshore and onshore wind. They are illustrated in Figure 17. The LCOE varies between the DE and the GA scenario. This is mostly motivated by the different VRE investments rates. For instance, DE has the highest installed capacity of solar PV and the lowest corresponding LCOE. Futher GA has the highest installed capacity of offshore wind and the lowest corresponding LCOE. The LCOE also vary within each scenario to capture the uncertainty regarding the LCOE predictions. The LCOE values are later in this thesis used to evaluate the calculated capture prices for the simulated power system of 2040.

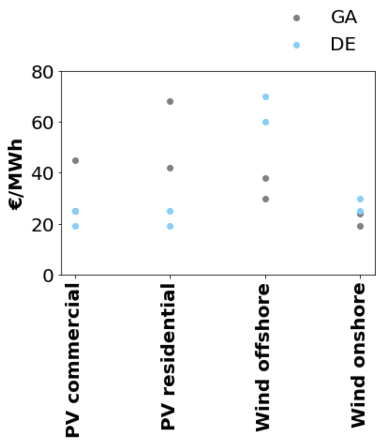


Figure 17: LCOE (real 2020) for the sources varies between and within each scenario. The LCOE for offshore wind varies the most. The reason for this is that the installed capacity for offshore wind in GA is much higher. The low LCOE is caused by the many investments in offshore wind. Created by the author and inspired by [20].

3.3.3 National differences

Statnett's report also clamis that the LCOE for offshore wind will decrease significantly towards 2050. Figure 18 clarifies this.

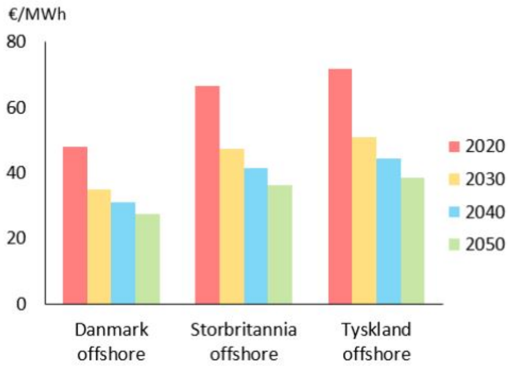


Figure 18: LCOE (real 2020) for offshore wind varies between the countries and is expected to decrease towards 2050 [65]

In addition, Figure 18 illustrates that there is a significant variation of the LCOE between the three countries. According to IRENA, Denmark had the lowest LCOE in 2019. This is because they were the first to pioneer offshore wind at a commercial scale in 1991. Hence, their low LCOE is driven by experience, installation in shallow waters and that the transmission assets farm-to-shore are not the responsibility of the project developer [41]. The national variations in LCOE is mostly relevant for offshore wind as the technology is emerging, even though LCOE can vary to some degree for all VRE.

3.3.4 LCOE for floating offshore wind

The development of the offshore wind sector has exceeded its expectations. With zero-subsidy projects in Germany and Netherlands, offshore wind has announced that it is here to stay as a competitive source of renewable electricity. However, these projects are in shallow water and there is still a large power potential that can be unlocked in waters deeper than 60 meters. The potential in Europe in water depths of 60 meters or more is $4TW$, which is almost twice the potential in shallow waters. Floating offshore wind could also significantly reduce the installation time as well as the operational and maintenance cost because the installation and maintenance can be carried out in port. Hence there is a vast potential for decreasing the CAPEX. Floating offshore wind is still at an early stage and most of the floating projects are pre-commercial, although they have proven to be technically feasible. The technical development is picking up the pace and by the end of 2020 up to five designs are expected to have been demonstrated at full-scale. They are expected commercialized between 2020 and 2025. [41]

To summarize, LCOE is expected to decrease going forward. This applies especially for offshore wind. This enables further investments in VRE, but at the same time, there is the possibility of a low capture price. Capture prices for all VRE are dependent on the electricity prices in hours of production. Hence, tThe important drivers for the electricity price are also essential for the capture prices. The most important drivers for the capture prices are listed below:

- The generation mix
- Marginal costs of thermal production which is highly affected by the CO_2 price
- The cannibalization effect
- Flexible demand and demand response

- Transmission expansions and congestions

It is hard to quantify the impact of these drivers since they are all intertwined. Thus it is valuable to use a simulation tool that can calculate how these drivers work together and further quantify their impact on the capture prices. In the following sections, this will be the focus.

4 Power market simulation model

This section is based on the specialization project report [34] and separated into two parts

- PowerGAMA
- New code created for this thesis

The simulation tool used in this thesis is called PowerGAMA. The functionality of the tool and the input files are described in this section. The aspect of PowerGAMA that is relevant this thesis will be the focus. The author will also give a brief introduction to the theory regarding DC power flow, which is relevant to understand the methodology of PowerGAMA. Note that not everything will be described in detail because there is already a very helpful user guide available at [67].

The second part of this section is about the additional code produced by the author. The most relevant code for the reader is briefly explained so that it will be easier for future master students to build on the knowledge gained during this thesis.

4.1 PowerGAMA

PowerGAMA is an open-source software in Python created by SINTEF Energy Research. It is short for *Power Grid And Market Analysis* and optimizes the generation dispatch based on marginal costs of generators meaning that for each time step PowerGAMA will find the optimal power produced at each generator in the system. PowerGAMA is a flow-based simulation tool, which means that the power flows in the grid is determined by power flow equations, which makes PowerGAMA a solver for optimal power flow (OPF) problems [67].

4.1.1 DC power flow

PowerGAMA uses DC power flow equations when describing the power system, but the actual European power grid consists mainly of AC power lines. AC power flow is described with the following non-linear equations [31]:

$$P_i = \sum_{j=1}^{n} (\mid V_i \mid\mid V_j \mid \cdot (G_{ij} cos(\theta_i - \theta_j) + B_{ij} sin(\theta_i - \theta_j)) \tag{7}$$

$$Q_i = \sum_{j=1}^{n} (\mid V_i \mid\mid V_j \mid \cdot (G_{ij} sin(\theta_i - \theta_j) - B_{ij} cos(\theta_i - \theta_j)) \tag{8}$$

where
P_i &: Net active power flow *into* node i [MW]
Q_i &: Net reactive power flow *into* node i [MVar]
i, j &: Node index
n &: Total number of nodes
V_i : Voltage magnitude for node i [V]
δ_i : Voltage angle at node i [rad]
G_{ij} : Conductance between node i and node j with negative sign [S]
G_{ii} : Sum of all conductances connected to node i [S]
B_{ij} : Susceptance between node i and j with negative sign [S]
B_{ii} : Sum of all susceptances connected to node i [S]

G_{ij} is the real part and B_{ij} is the imaginary part of the admittance, Y_{ij}. It is calculated by using the following formula

$$Y_{ij} = G_{ij} + jB_{ij} = \begin{cases} y_{ii} + \sum_{n \neq i} y_{ni} & i = j, \\ -y_{ij} & i \neq j, \end{cases} \tag{9}$$

where
Y_{ij} : Admittance in the admittance matrix Y_{bus} for row i column j [S]
y_{ij} : Admittance of branch between node i and j [S]

Further, y_{ij} is calculated from the impedance, z_{ij}, on the branch between node i and j

$$y_{ij} = \frac{1}{z_{ij}} \tag{10}$$

where z_{ij} is the impedance on the branch between node i and j

$$z_{ij} = r_{ij} + jx_{ij} \tag{11}$$

where r_{ij} is the resistance and x_{ij} is the reactance on the branch.

The main PowerGAMA application is to explore future scenarios for large-scale integration of renewable energy. To enable solving systems of this size in a reasonable amount of time and ensure that the system converges, it is necessary to do some simplifications [67]. Thus, PowerGAMA use the DC power flow method, which linearize equation (7) and (8). Thus, the power flows in PowerGAMA is modeled as DC where

- $sin(\theta_i - \theta_j) \approx \theta_i - \theta_j$ and $cos(\theta_i - \theta_j) \approx 1$ because phase angle differences are assumed to be significantly small
- $\mid V \mid \approx 1$ pu because voltage deviations are negligible
- $z_{ij} \approx jx_{ij}$ because resistance is negligible compared to reactance, which leads to the assumption that there are no reactive losses in the system
- $y_{ii} \approx 0$ because shunt reactances are so small, we ignore self-admittance

Based on the AC load flow equations (7) and (8) and the assumptions above, the simplified DC load flow equations can be expressed as

$$P_i = \sum_{j=1}^{n} B_{ij}(\theta_i - \theta_j) \tag{12}$$

Finally, P_i in PowerGAMA is used to describe the sum of generation, demand, load shedding and HVDC power inflow [67]

$$P_i = \sum_{j=1}^{n_{gen}} P_j^{gen} - \sum_{j=1}^{n_{pump}} P_j^{pump} + P^{shed} + \sum_{j=1}^{n_{hvdc}} P_j^{hvdc} - \sum_{j=1}^{n_{cons}} P_j^{cons} \tag{13}$$

where
P_j^{gen} : generator production
P_j^{pump} : pump demand
P_{shed} : amount of load shedding, also called unfulfilled demand
P_j^{hvdc} : inflow on DC branches

P_j^{cons} : consumer demand
n_{gen} : number of consumers at that node i
n_{pump} : number of pumpes at node i
n_{hvdc} : number of HVDC branches connected to node i
n_{cons} : number of consumers at node i

From equation (12) the optimization algorithm in PowerGAMA can find the optimal net active power flow, P_i into node i and from there locate the power produced at each generator.

4.1.2 Dynamic LP optimization problem

When modeling the power flows as DC, the problem includes only linear relations, which gives a linear programming (LP) problem formulation. In addition, PowerGAMA uses dynamic programming by optimizing each time step dependent on the previous, as the storage status in the system changes each time step [67]. To solve the LP problem, PowerGAMA uses an external solver. In this specialization project, the Gurobi solver was used, leading to a simulation duration of 5-6 hours for the European power system for this thesis. More information on the Gurobi solver is found on its web page [33]. The objective function and the description of the constraints included in the optimization algorithm is found at [67].

4.1.3 Nodal pricing

When the optimal solution of the objective function is found by the optimization algorithm the nodal price can be extracted. The nodal price at each node is calculated when doing sensitivity analysis where the nodal price is the shadow price of the constraint concerning energy balance at the specific node [67]. Shadow price represent the increase in the objective function for increasing the constraint by one unit [35]. Thus, the nodal price represents the increased cost in the system for increasing one unit of demand at the specific node. One possible interpretation of this is that the nodal price is the marginal price of the generator that is chosen to increase its generation to serve the increased demand. If there is not enough generator capacity to fill the increased demand due to for instance capacity constraints, the nodal price will be equal to the load shedding price at that node. If one node experience curtailment, the nodal price will be close to zero. The reason for this is that the cost of increasing the generation with one unit at that node is the marginal cost of the generator, which is $0,5€/MWh$ for solar PV and onshore wind, and $0,45€/MWh$ for offshore wind. It is also possible to extract sensitivity analysis on the branch capacities, which can be useful to identify bottlenecks [67].

4.1.4 Input files

The input files in PowerGAMA defines the scope of the power system. Hence, it requires, among other things, information about the generation, demand and power grid. The input file for generation includes information about all the generators in the system. One generator typically represents a power plant or several aggregated power plants. The generators in the input files describes the generator characteristics and gives details on the maximum capacity, the generator type (e.g. hydro, gas) or marginal cost. The input file for demand, on the other hand, only includes demand profiles and average capacity. It is also possible to model flexible load, but there are no consumers with such load in the model for this thesis. The consumers are also aggregated and assigned to their designated node.

In addition to the file describing the generation and demand, there are files describing the aggregated transmission grid where the reactance, capacity and connected nodes are described. In total there are seven input files in PowerGAMA. They are

- *generators.csv*
- *consumers.csv*
- *branches.csv*
- *hvdc.csv*
- *profiles.csv*
- *profiles_stor_val_filling.csv*
- *profiles_stor_val_time.csv*

Since there is no storage that depends on seasonal changes in the model used in this thesis, the *profiles_stor_val_time.csv* is unchanged from the 2014 model. All the other .csv input files are altered for this thesis. How these are modified are explained in section 5.

Figure 19 illustrates the three main input files. Note that this is only a simplification of the parameters, some of them are left out or grouped. The author still chose to include it so that the reader has a chance to understand the details in the process of modeling without having to open the input files.

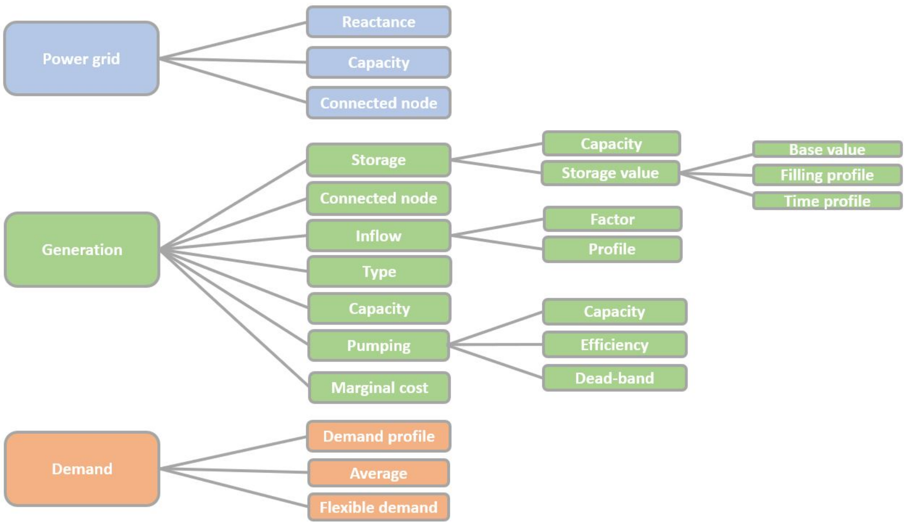


Figure 19: The input files in PowerGAMA contain information on the power grid, generation and demand. These have a number of parameters that can be adjusted by the user. Created by the author.

4.1.5 Storage and pumping is relevant for battery and electrolysis modeling

The power market in PowerGAMA is considered perfect so that generators with the lowest marginal cost is always favored. Hence, the optimization algorithm tries to minimize generator costs. For generators without storage the generator costs are defined as the generation times the marginal cost.

For generators with storage, like hydropower modeled with reservoirs, the marginal costs are modeled differently. In these cases the model also needs to take into account the value of the stored energy, also called storage value. Storage values are based on the principle that all power producers want to maximize their income, which means that they want to produce when the power prices are high. Thus, the ability to express the value of having a full reservoir versus an empty reservoir is essential. In PowerGAMA these are modeled similarly as water values.

In PowerGAMA there is also an option to model pumping which is typically used when modeling a pumped hydropower plant. Modeling hydropower is out of the scope of this thesis, but it still relevant when modeling batteries and electrolysis in PowerGAMA. This is explained thoroughly in section 5.5.

4.1.6 Previous analyzes

In this section, the author will briefly identify recent research using PowerGAMA to get an understanding of the research range and build on past experiences.

In 2016 Arne Øvrebø Lie and Eirik Andre Rye wrote their master thesis using PowerGAMA. It was entitled "Analysing the Integration of Renewable Energy Interconnected Power Systems Using a Flow-based Market Model"[61]. Firstly, an existing PowerGAMA model is expanded, updated and validated to include most of the 2014 ENTSO-E power system. This validation resulted in a paper called "Validation study of an approximated 2014 European power-flow model using PowerGAMA"[48]. The paper states that "The simulation shows acceptable correlation and the model is able to reproduce the main characteristics of the power system, meaning reservoir handling, hydro pump behavior and seasonal variations in cross-border flows" [48]. The 2014 system is used as a base for this project and is elaborated on in section 5.1.

Further they performed two case studies; a 2030 scenario for the Moroccan power system and the Spanish power system. In the Moroccan power system, they investigated which challenges the future power system face, emphasizing a cost-benefit analysis comparing investments in storage capabilities for concentrated solar power and grid reinforcements. The case study on the Spanish power system investigates how different renewable technologies affect the utilization of existing pumped hydro plants. The conclusion is that the approach is able to reproduce the actual hydro characteristics and ensures reasonable reservoir handling. Their overall conclusion was that PowerGAMA gives a reasonable picture of the reality and is well suited for analyzing large power systems with an hourly resolution [61].

An extension of Lie and Rye's work is the master thesis of Amaia Larrañaga Arregui [4]. She expanded the existing power system including also Nordic countries, UK and Ireland. This new system is also validated in her thesis by comparing, among other things, energy mix and cross-border power flows with actual data from ENTSO-E. The results show that the model can capture the seasonal as well as daily patterns of the power system in terms of energy generation, demand and power exchange. [4].

PowerGAMA is created by SINTEF Energy Research, highly inspired by SINTEF's PSST (Power System Simulation Tool) implemented in Matlab [58]. To increase the insight to PowerGAMA's area of use, a report conducted by H. Farahmand S. Jaehnert, T. Aigner and D. Huertas-Hernando[3] is highlighted. It is entitled "Nordic hydropower flexibility and transmission expansion to support integration of North European wind power." and use PSST to model the power grid of Europe. It assess the potential of increased Nordic hydropower production flexibility and necessary transmission capacity investments in order to reduce the challenges related to wind power production. The focus is on cost-benefit analyzes of different offshore grid typologies in the North Sea.

To summarize, their work illustrates that PowerGAMA has a wide area of use and can be implemented on large systems, still giving accurate results. In addition, PowerGAMA combines technical analyzes, like modeling reservoir levels or power flows, together with an economic perspective such as node prices and marginal costs of generators. This makes it possible to do economic analyses on a realistic future power system and shows that PowerGAMA is suitable for the topic and scope of this thesis.

4.1.7 Strength and weaknesses

As mentioned earlier, PowerGAMA operates with DC power flow assuming no active losses in the system. This is a simplification and according to NVE active losses in the power grid correspond to approximately 8% of the total consumption in Europe [57]. The DC power flow also assumes small voltage deviations, which means that voltage stability is not taken into account. When operating the power grid, it is important to keep the voltage at each node within certain limits [56]. Another simplification is that PowerGAMA does not take start-up costs or ramp rates into account. Due to this, PowerGAMA tends to overestimate the ability to accommodate large amounts of renewable energy [67].

Even though all these simplifications miss out on many important operational aspects of the power grid, PowerGAMA has proven to obtain accurate results regarding replicating the main characteristics of the power system. PowerGAMA also stands out from other methods such as the EMPS model that only considers energy balance, and not the physical power flows in the system [64]. Compared to this, PowerGAMA gives a more accurate representation of the power flows when using the DC power flow method.

Another strength is that PowerGAMA brings user flexibility into the analysis. For instance, the adjustable time step or the fact that the user can easily control or adjust all the input parameters. The fact that the user can decide the degree of details on the input data is especially positive regarding analyzes on the future since this data is uncertain. Another example of this is the generators and how the user can add storage and pumping if necessary or model it simple with simple parameters like inflow profiles, capacity factors, marginal costs and installed generation capacity.

4.2 Code developed for the thesis

?? As mentioned earlier, the output from PowerGAMA gives a wide horizon of research possibilities. The focus for this thesis is the outputs of relevance for the capture price. Hence, the most relevant outputs are the nodal price, the generation dispatch and the curtailment per generator. These are all extracted by using both existing code and new code that is created by the author of this thesis and for the specialisation project. Some of the code is listed in Appendix A. In addition to this, code has been developed to facilitate data extraction from PowerGAMA to analyze the power system.

The input files are extensive with many generators, consumers and transmission lines, which leads to a running time of approximately 5-6 hours. When calculating the capture price for the whole system, the author needed to extract generation and nodal prices for all generators and nodes. These calculations was time-consuming and took about another 5-6 hours, which restricted the number of simulations that was possible to perform during this project. With such an extensive system it was difficult to get an overview of the power system. Thus much time was used to create functions in Python to get an understanding of the important features such as generation mix, the installed capacity or the geographical location of the generation sources. Code was also written each time we needed to edit the input files for the same reason. This resulted in over 4000 lines of code in Python created by the author for this thesis and for the specialization project. Some of this code is found in Appendix A.

4.2.1 Calculation of capture price

Weighted average is used when calculating the capture price. The first step is to summarize the total power production for the generators

$$P_{total} = \sum_{i=1}^{N} \sum_{t=1}^{T} P_i t \tag{14}$$

where P_{it} is the power production of generator i in time t. N and T represent respectively the total number of generators and the length of the simulation time period. Secondly, the production per hour, t, per generator i and the corresponding nodal price, p_{it}, is multiplied to find the hourly income

$$I_{it} = P_{it} \cdot p_{it} \tag{15}$$

Finally, this income is summarized and divided by the total power production

$$CP_{avg} = \frac{\sum\limits_{i=1}^{N} \sum\limits_{t=1}^{T} I_{it}}{P_{total}} \tag{16}$$

This way, the average capture price, CP_{avg} is the weighted average of the sale price for the produced power. When calculating the capture price for an area or a specific type of generator, the same procedure is used, only that the generators included in the calculations is only the generators related to the specific area or type.

Capture prices are normally used to explain the average income per unit of produced power for generators. For this thesis we will also investigate the average profit for each unit discharged energy in batteries as well as the average price electrolysers must pay for their consumption. For this thesis these features are called captured profit and capture price for respectively batteries and electrolysers. The capture price for electrolysers are found similarly as the capture price for RES, only P_{it} is now the consumption at time t for electrolyser i. The captured profit, cp_{profit} is found by

$$cp_{profit} = \frac{\sum\limits_{i=1}^{N} \sum\limits_{t=1}^{T} I_{batt_{it}} - \sum\limits_{i=1}^{N} \sum\limits_{t=1}^{T} Ex_{it}}{P_{i_{total}}} \tag{17}$$

where i represents the battery. $P_{i_{total}}$ is now the total energy charged at battery i. Further Ex_{it} is the expense for charged energy Ec_{it} multiplied by the price, p_{it}. $I_{batt_{it}}$ is now the income for the battery for the discharged energy Ed_{it} multiplied with the price.

$$Ex_{it} = Ec_{it} \cdot p_{it} \tag{18}$$

$$I_{batt_{it}} = Ed_{it} \cdot p_{it} \tag{19}$$

Using this method to find cp_{profit} makes it easy to keep track of the revenue for each battery. Note that by calculating the revenue this way the losses are also taken into account. The only problem with this approach is the battery filing status in the end compared to the beginning. The battery is modeled to start being half full in the simulation. If the simulation ends up with a fully charged battery this will make the cp_{profit} less. When simulating over many hours this is negligible, but when simulating over less hours it is something to be aware of.

4.2.2 Calculation of percentage curtailed energy

The percentage of curtailed energy, $E_{percentage}$, from VRE is defined as the total curtailed energy from VRE generators, $E_{curtailed}$ divided by the power potential for all VRE generators, $E_{potential}$. In PowerGAMA the potential is dependent on the installed capacity and the inflow for each the generator [59]. The curtailed energy and the produced energy is extracted from the results of the simulation in PowerGAMA.

$$E_{curtailed} = \sum_{g=1}^{G} \sum_{t=1}^{T} E_{gt} \tag{20}$$

$$P_{prod} = \sum_{g=1}^{G} \sum_{t=1}^{T} P_{gt} \tag{21}$$

where P_{prod} is the total production from all the G VRE generators. T it the total time, E_{gt} and P_{gt} is the curtailed and produced energy for a given time t and generator g. The production potential is

$$E_{potential} = E_{curtailed} + P_{prod} \tag{22}$$

Thus, the percentage curtailed energy is

$$E_{percentage} = \frac{E_{curtailed}}{E_{potential}} \tag{23}$$

5 Data processing and model validation

This section use the knowledge gained from section 2 to create and validate models for the power system of 2040. Each choice being made is justified so that it will be easy to build on this work for future master students.

Firstly this section will analyze the existing model for 2014 before creating one model for each TYNDP 2020 scenario for 2040. These are validated and based on this one scenario is chosen for the case studies. Lastly we will look into how batteries and electrolysis can be modeled in PowerGAMA. The most favourable approach will be used in the case studies to locate the impact of batteries and electrolysis on VRE economics.

5.1 Existing model for 2014

It is important to get an overview of the 2014 power system created by the master students Arne Ø. Lie and Eirik A. Rye [48] as it founds the basis of the power system for this thesis. Section 4.1.6 describes how it was validated to be a good fit for the 2014 power system. Nevertheless, the power system will go through many changes when adapting to the future trends elaborated on in section 2. The changed mad to the 2014 case is elaborated on, but firstly the system for 2014 is briefly explained.

5.1.1 Scope and system description

This section is based on the specialization project report [34]. The original 2014 data set of Europe includes 26 countries, 1539 nodes, 1123 consumers, 1158 generators and 2899 branches. The input data is given in a time step of one hour and a time range of a year which is consistent for this thesis. Figure 20 represents the branches and the nodes for the 2014 data set.

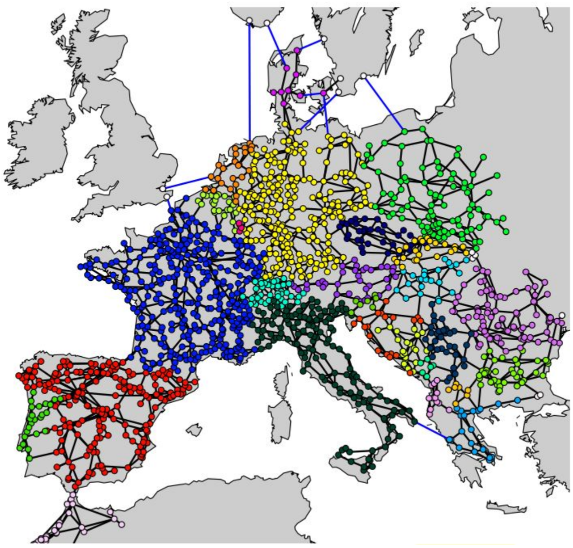


Figure 20: Location of the nodes and branches for the 2014 data set[48].

As seen from Figure 20, the West and North area surrounding the North Sea has fewer nodes and branches. These areas are located at the geographical endpoint of the power grid. In Norway and Sweden, these are modeled as generators of type exchange. This means that the net load flow from Norway and Sweden to Europe is positive. In Great Britain, it is modeled as consumption, as the net load flow from Great Britain to Europe is negative. Thus, none of the actual production in Norway, Sweden or Great Britain is taken into account in the optimization algorithm. Ireland and North Ireland is not included in the model at all. Of course, this results in an inaccurate description of the power system in the North Sea region. Thus it is necessary to expand the reference case, including Norway, Sweden, Great Britain, North Ireland and Ireland to enable greater analysis of the power grid for 2040. As mentioned earlier, Arregui has already expanded Lie and Rye's work also including Nordic countries, UK and Ireland. The author still chose to use input files created by Rye and Lie due to its comprehensive validity analysis [48] and because the data set created by Arregui was unavailable.

The constraints in the transmission system for the 2014 power system are simplified. Most of the branches within one price area have a capacity set to infinity. Only the branches connecting two price areas has a limited capacity. In this system, one area is typically a country. Germany is one exception as it is modeled with several internal branches with limited capacity tuned to fit actual data. It is also worth mentioning that even though PowerGAMA brings the opportunity to add flexible loads in the system, none of the consumers are modeled with flexible loads.

Since the focus of this thesis is the revenue for VRE the capture price for the 2014 case is illustrated in Figure 21. The capture prices lie in a range from 70€$/MWh$ for gas to 50€$/MWh$ for nuclear. Coal and nuclear is also responsible for most of the generation mix, which can be seen from the thickness of the bars in Figure 21.

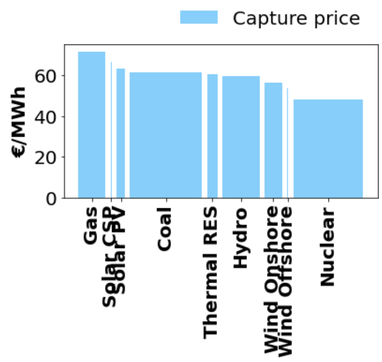


Figure 21: Capture prices (real 2014) after simulating the whole year for the 2014 power system in PowerGAMA. The thickness of the bars represent the generation mix.

5.2 Model for 2040 - base case

Because of the many changes in the power system towards 2040, the model created to fit the power system in 2014 is not in line with what to expect for a power system in 2040. Thus, several changes is necessary to meet the forecasts regarding the future. This applies especially for the region surrounding the North Sea since the model for 2014 hardly included this region. This section goes in detail on specific changes on the parameters in the input files in PowerGAMA. Thoughts and challenges that the author has dealt with during the work is also included so that the model can be easier to use as a basis in the future.

The sources creating the input data foundation is mostly data from

- TYNDP 2020 [18]
- TradeWind [47]

Most of the data is extracted from TYNDP 2020 while TradeWind is used to get a more detailed insight in the modelling of the generators in the North Sea region that is not covered by the 2014 model. When going through the changes made in this section, the author will focus on one input file at the time. All input files are changed except from the input files regarding time depedency of storage values, $profiles\_storval\_time.csv$. We will explain the changes so that it is not necessary to know PowerGAMA from before to understand the what is done. Still, if the reader notices that some knowledge is lacking and wants to understand the details of this section it is recommended to read the PowerGAMA userguide available at [67].

5.2.1 nodes.csv

The nodes.csv describes all the nodes included in the system together with their characteristics; latitude, longitude and corresponding area. Most of the nodes were unchanged from the 2014 case, some were added and some had their characteristics changed. The nodes that had their characteristics changed was the nodes located at the edge of the modeled power grid in the North Sea Region. These nodes were located in Sweden, Norway and Great Britain. In addition to this, some new nodes were added to the system. This applies for the countries Norway, Sweden, Finland, Great Britain, Ireland and North Ireland. Finland, Great Britain, Ireland and North Ireland were added as singular nodes while Norway and Sweden were separated into respectively three and four areas. The reason for this was that the TYNDP 2020 data set [18] had separated the countries into multiple areas.

The new nodes is illustrated in Figure 22. Note that even though the blue transmission lines and nodes represent existing infrastructure, the characteristics on some of them have been modified according to the data from TYNDP 2020.

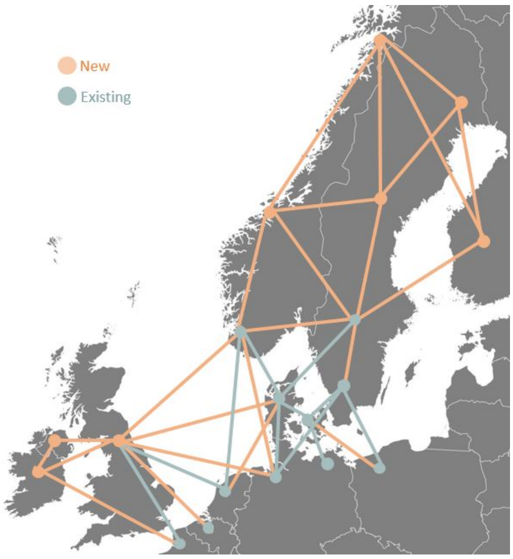


Figure 22: New lines and nodes (orange) was added in the input files to better fit the 2040 scenarios. All TYNDP 2020 scenarios had the same grid structure. The new lines and nodes are according to TYNDP 2020. The blue nodes and lines was already included in the 2014 data set. Created by the author.

A full overview of the new area names in the data set for this thesis and the corresponding area name in TYNDP data sets is found below in Table 6. As seen from Table 6 some areas in the data set for 2040 includes two or more areas from TYNDP 2020. The reason for this is that the two data sets has different degree of detail where the 2014 data set is much more detailed, containing over 1500 nodes, compared to almost 60 nodes in the TYNDP data set. The over 1500 nodes from the 2014 data set already has a specified area, which was not consistence with the areas in TYNDP 2020. Hence, the areas in TYNDP 2020 where this was the case were merged.

Data set 2040	TYNDP 2020 - generation
AL	AL00
AT	AT00
BA	BA00
BE	BE00
BG	BG00
CH	CH00
CZ	CZ00
DE	DE00, DEKF
DK	DKW1
DKE1	DKE1, DKKF
ES	ES00
FR	FR00,FR15
FI	FI00
GB	UK00
GR	GR00,GR03
HR	HR00
HU	HU00
IE	IE00
IT	ITCN,ITCS,ITN1,ITS1,ITSA,ITSI
LU	LUB1,LUF1,LUG1,LUV1
ME	ME00
MK	MK00
NI	UKNI
NL	NL00
NOm	NOM1
NOn	NON1
NOs	NOS0
PL	PL00
PT	PT00
RO	RO00
RS	RS00
SE01	SE01
SE02	SE02
SE03	SE03
SE04	SE04
SI	SI00
SK	SK00

Table 6: The overview of the areas show that each area in the data set for 2014 mostly correspond to one area in TYNDP 2020. Still, there are some exceptions like for Germany, Denmark, France, Greece, Luxemburg and Italy.

5.2.2 branches.csv and hvdc.csv

The input file *branches.csv* describes all AC branches in the system with information on node from, node to, reactance and capacity. Since PowerGAMA optimizes using DC power flow the resistance is considered to be zero. The input file *hvdc.csv* includes all HVDC lines in the system. Since they are DC lines they do not have a reactance, and thus are only modeled with node from, node to and capacity.

In the new system for 2040 only the transmission capacity is changed, and not the reactance since the structure of the grid is unchanged. In the branches.csv file for the 2014 system, the capacity for almost all domestic branches was set to infinity. In the 2040 models all domestic branches was set to infinity. New values for each scenario for the cross-border transmission capacities are extracted from TYNDP 2020 visualization platform and were given as NTC [25]. As mentioned in 2.2.3, the NTC from A to B can be different than from B to A. In PowerGAMA it is not possible to add different restrictions regarding maximum power flow according to the flow direction. For most of the lines the difference was not significant and in danger of limiting the system too much, the larges values were favoured.

Since the power system in TYNDP 2020 is much more simplified than for the data set for 2014, there is only one cross-boarder branch between two areas. Thus it was necessary to distribute the transfer capacities. To maintain the extensive work in the creation of the 2014 data set the decision was made to scale the cross-boarder transmission capacities in line with the 2040 power system so that the total transmission capacity in between two countries are in line with TYNDP 2020.

In addition to this, some new transmission lines were added. These are illustrated in Figure 22. They are all HVDC lines, which means that they are not included in the *branches.csv* input file, but in the *hvdc.csv* input file.

5.2.3 generation.csv

The *generation.csv* is the input file with the most modifications. It also includes many parameters, hence the process of editing this file is extensive. The modifications were made step by step, insuring that the changes were valid and acted as expected. The modifications were the following:

1. Added new generators in the North Sea region
2. Changed maximum installed capacity, *p_max*
3. Changed the inflow, $inflow\_ref$ and $inflow\_fac$
4. Changed the marginal cost, $fuelcost$

Since the scenarios have different values for what is mentioned above, this process is done for all three scenarios. The first step was to add the power system not included in the 2014 system in PowerGAMA. The input files for TradeWind project was used as a basis for the areas NOs, NOm, NOn, SE01, SE02, SE03, SE04, FI and GB. The information used was max capacity, min capacity, inflow profiles and information on storage. Since modeling hydropower is not a focus for this thesis, TradeWind and the existing 2014 data set founds the basis of how this is modeled in PowerGAMA for 2040.

Further their maximum installed capacity was increased to what the TYNDP 2020 data set claimed [18]. The maximum capacity is given for each country. When changing the capacities, the existing system for 2014 was used as a basis, meaning that the capacities was scaled according to the 2014 capacities. Thus, if the TYNDP 2020 data set claimed that a generation type is no longer in the given area in 2040, the generator is removed. If a generation type is not already in the data set for a given area, a new generator is added in the respective area. The generator is assigned a random node in the country. See the Table 22 in Appendix B to get an overview of the generator types that was added in each country for scenario NT.

The third step was to change the inflow, meaning both the parameter $inflow\_ref$ and the $inflow\_fac$. The $inflow\_ref$ refers to a specific hourly inflow profile while the $inflow\_fac$ for this thesis refers to the capacity factor for the generator. Thus, the generators' inflow can be modified either by changing the $inflow\_ref$, the $inflow\_fac$ or the hourly inflow profile itself in $profiles.csv$. For the old generators the inflow profiles used in 2014 is consistent, but the new generators got new inflow profiles. The new hourly inflow profiles was gathered from [60] and adjusted to PowerGAMA's criteria for inflow profiles [67]. The belonging $inflow\_fac$ was set as the average of the profile. All the inflow profiles are from the climate year 2014 to prevent the inflow profiles to be out of sync.

The capacity factor is highly dependent on the technology. For instance, a offshore wind turbine of type Vestas with a blade diameter of 164m, a hub height of 140m located at the cost of the Netherlands has a capacity factor of 55.8% if the rated capacity is 8000 kW and 51.0% if the rated capacity is 9500kW [60]. It does not necessarily mean that they produce less power, it simply means that the 800kW turbine has more operational hours with maximum generation. The same goes for the blade diameter.

Thus, technology is very important for the capacity factor. Still, we have not decided capacity factor based on the leading technology for 2040. For this thesis it was the other way around. Firstly predictions on capacity factors for VRE in 2040 was found. Further reasonable technology for VRE that fit these capacity factors was chosen in [60].

Predicted capacity factors for 2040 by TYNDP 2020 is listed in Table 7.

	Offshore wind	Onshore wind	Solar PV
Average	43%	28%	14%
Max	51%	40%	22%
Min	27%	19%	9%

Table 7: Capacity factor characteristics for 2040 from TYNDP 2020 claims that the capacity factor for offshore wind will lie between 27 - 51 %

IRENA, on the other hand, predict the global weighted average capacity factors for onshore wind plants would increase from an average of 34% in 2018 to $30\% - 55\%$ in 2030 and $32\% - 58\%$ in 2050. For offshore wind farms, even higher progress could be achieved, with capacity factors in between $36\% - 58\%$ in 2030 and $43\% - 60\%$ in 2050, compared to an average of 43% in 2018. This also includes wake effects [43]. For this thesis the capacity factor for offshore wind will lie between 30% (AL) and 58% (IE). The average is approximately 50%.

After simulating the power produced during a year and comparing it to TYNDP 2020 it was clear that the capacity factor for the existing generators were too low resulting in too little generation from VRE, especially the capacity factor for onshore wind. After scaling the capacity factor for the old generators with a factor of 1.3 and 1.1 for offshore wind and solar PV respectively, the generation was a better match. Nevertheless, when scaling the capacity factor it will affect the maximum possible production from the generators. This should never exceed the maximum installed generation capacity, but when only changing the $inflow\_factor$ in *generators.csv*, this could be an issue. The output of the generators in PowerGAMA is defined as [67]

$$P_{inflow(t)} = P_{max} \cdot inflow\_factor \cdot profile\_value(t)$$

Hence, the $profile\_value(t)$ is adjusted so that the $inflow\_factor \cdot profile\_value(t)$ is never greater than P_{max}.

The so called $fuelcost$ in *generators.csv* file in PowerGAMA is in fact the marginal cost of the generator. This means that it also includes operational costs and CO_2 price. The fuel cost in the *generators.csv* file from 2014 are normally the same for each country. Only for some countries Rye and Lie decided to tune the prices to make the model more accurate 2014 data. Hence, the marginal cost of gas ranges from $56 - 78€/MWh$ while coal varies from $55 - 78€/MWh$ [67]. The marginal cost from 2014 illustrated in Table 8 is the average cost of each generation source.

	2014				2040					
	Marginal cost $€/MWh$	CO_2 price $€/tCO2$	Emission factor $tCO2/MWh$	c_g	CO_2price $€/tCO2$			Marginal cost $€/MWh$		
					NT	GA	DE	NT	GA	DE
offshore wind	0,5	5	0	0,5	75	80	100	0,4	0,4	0,4
onshore wind	0,5	5	0	0,5	75	80	100	0,5	0,5	0,5
solar PV	0,5	5	0	0,5	75	80	100	0,5	0,5	0,5
solar CSP	0,5	5	0	0,5	75	80	100	0,5	0,5	0,5
nuclear	11	5	0	11	75	80	100	11	11	11
Thermal RES	50	5	0,2	49	75	80	100	64	65	69
Gas	67,8	5	0,4	65,7	75	80	100	95,7	97,7	105,7
Coal	58,6	5	0,86	54,3	75	80	100	118,8	123,1	140,3
Oil	162	5	0,675	158,6	75	80	100	212,6	216	229,5

Table 8: Marginal costs from 2014 data set [61] includes CO_2 price and fuel cost. The CO_2 price for 2040 is from TYNDP 2020 [20] and emission factors it taken from [37]. Together they form the basis of the marginal costs of the data set for 2040 which include both the new CO_2 price and old fuel costs. The CO_2 prices for 2040 is discounted to 2020 while the rest of the marginal cost of 2040 is not. Thus, the total marginal cost of 2040 is partly discounted to 2020.

It is assumed that the marginal costs from 2014 include a CO_2 price that is representable for 2014. According to [15], the historical CO_2 price in 2014 was approximately $5€/tCO_2$. It is necessary to relate the CO_2 price $[€/tCO_2]$ to energy output from each generation source $[MWh]$. To do this, the implied carbon emission factors from electricity generation by product are gathered from [37]. The values are represented in Table 8 and represent the average amount of CO_2 per MWh of electricity produced in OECD member countries between 2011 and 2015. Since the generation source called thermal RES in PowerGAMA is modelled as a combination of other-non RES (mostly CHP that use natural gas) and other RES (mostly geothermal, wave and tidal power and small bio plants that has close to no emissions) from TYNDP its emission factor was set to $0,2tCO_2/MWh$. Note that even though there are only one type for gas, coal, oil and thermal RES modeled in PowerGAMA there are in reality an extensive selection of fossil based generation sources. Thus, approximate numbers are chosen that describes the features well for a majority of the selection. Even though this approximations might seem like a major simplification, it do not affect the generation dispatch in the optimization algorithm in PowerGAMA. For instance, when looking into the marginal cost for different gas types it was clear that close to all types of gas still got a lower marginal cost than coal for 2040. Thus, this would not have a significant impact on the generation mix, but it might have a small impact on the prices for some countries.

To find how much of the marginal cost represent the CO_2 price for each generator

$$c_{CO2_{2014}} = f_{CO2_{2014}} \cdot p_{CO2_{2014}} \tag{24}$$

where $f_{CO2_{2014}}$ $[tCO_2/MWh]$ is the emission factor and $p_{CO2_{2014}}$ $[€/tCO_2]$is the CO_2 price in 2014. Further, the cost of CO_2, $c_{CO2_{2014}}$, is assumed to already be included in the marginal prices, $c_{m_{2014}}$, in the model of 2014. When $c_{CO2_{2014}}$ is extracted from the marginal cost in 2014, we get

$$c_g = c_{m2014} - c_{CO2_{2014}} \tag{25}$$

where c_g is the cost including operational costs and fuel cost and is included in Table 8. This c_g is expected to be approximately constant towards 2040. Thus, only the c_{co2} is expected to increase. The new marginal cost of 2040, $c_{m_{2040}}$, is calculated including the new CO_2 price for 2040, $p_{CO2_{2040}}$.

$$c_{m2040} = c_g + c_{CO2_{2040}} \tag{26}$$

where $c_{CO2_{2040}}$ is now

$$c_{CO2_{2040}} = f_{CO2_{2014}} \cdot p_{CO2_{2040}} \tag{27}$$

As seen from equation 27, the emission factors $f_{CO2_{2014}}$ are assumed to be kept constant towards 2040. This is a simplification and will likely lead to higher prices as more emission friendly gas power plants are on the rise [20]. Still, the difference is assumed to be so small that it is negligible for this thesis.

The fuel cost for RES is mostly unchanged, other than for offshore wind. The marginal cost of offshore wind is changed from $0.5€/MWh$ to $0.45€/MWh$. This change was made because the author found it was hard to see the impact of offshore wind on onshore wind in a system with a lot of curtailment. Since offshore and onshore wind often experienced curtailment at the same time and had the same marginal cost, there are multiple optimal solutions for the system at that hour. For instance, if offshore and onshore wind are located at the same node and the total curtailment from both needs to be $10MW$, it would not matter if the offshore wind experienced $20MW$ curtailment while onshore wind experienced $80MW$ or the other way around. This made the impact of onshore and offshore wind difficult to analyse. Hence, the marginal cost of offshore wind was reduced to $0.45€/MWh$. Because of this offshore wind is always favoured when the system experience curtailment. When discussing this with the stakeholders it was concluded that although this is a simplification, it is acceptable since offshore wind is often favoured in the wholesale electricity market. This is because it is more weather stable and reliable. In some countries it is also favoured to support offshore wind integration because of the high installation costs.

5.2.4 consumer.csv

No new loads were added except for the new nodes surrounding the North Sea region illustrated in Figure 22. The load profiles are taken from TYNDP 2020 and the average demand, $demand\_avg$, for each profile was found. The generation in TYNDP 2020 face three different climate years, but this does not apply for the demand which is different from TYNDP 2018 [26].

To enable control of hydrogen modeling, the load caused by electrolysis in each area need to be excluded from the load profiles referred to in the *consumer.csv* file as $demand\_ref$. In the TYNDP 2020 report it is in fact already excluded. Thus, the load profiles can be directly taken from the TYNDP 2020 data set. The same goes for batteries and DSR as these are modeled as generators and not demand in TYNDP 2020.

5.2.5 profiles.csv

This input file includes hourly, normalized values for the profiles. This includes both profiles for the inflow for the generators and profiles for the demand. Both new generation inflow and demand profiles were added to the profiles.csv file. The profiles was extracted from Renewables Ninja [60]. For offshore wind these were taken from approximately the places that the wind farms are planned according to [29]. All the profiles are taken from the climate year 2014 to match the existing profiles in the 2014 data set. As mentioned earlier, the demand ref profiles was extracted from the TYNDP 2020 data set [18].

5.3 Validating models for 2040

Since the data set from TYNDP 2020 creates the basis for this thesis this will also be the main focus in the validation process. Still, it is important to remember that the TYNDP 2020 data set does not necessarily show the future, it simply expose possible outcomes dependent on different trends. Thus, seeking the exactly same results as for the TYNDP 2020 data set it not the ambition for this section. The intention is rather to see whether it is proportionate to the results to validate the changes.

Since the TYNDP 2020 operates with three scenarios, all these will be compared. Results from the whole system will also be highlighted. The TYNDP 2020 data set building the foundation for the comparison is extracted from [18]. If the reader wants to easily get an overview of the data set it is illustrated at [25].

The focus for the validation is on comparing the

- Generation mix
- Cross border flows
- Power prices

5.3.1 Validation of generation mix

When analysing the generation mix it is important to both discuss the actual generation from each generator as well as their inflow forming their potential generation. The total installed generation capacity for each country is exactly the same for TYNDP 2020 and the model for this thesis. Their potential generation referring to their inflow profiles, on the other hand, is not necessarily the same. Inflow profiles can vary a lot from year to year, depending on the weather conditions. Thus, when comparing the generation it is important to not only look into the generation but also the curtailed energy. When combining these two it is possible to see if the inflow is modeled reasonable compared to TYNDP 2020.

Figure 23 illustrates the generation mix and the curtailed energy for scenario NT. The overall curtailment from RES is slightly higher for the model, which could be because the modeled NT scenario in PowerGAMA does not include balancing measures like batteries or DSR.

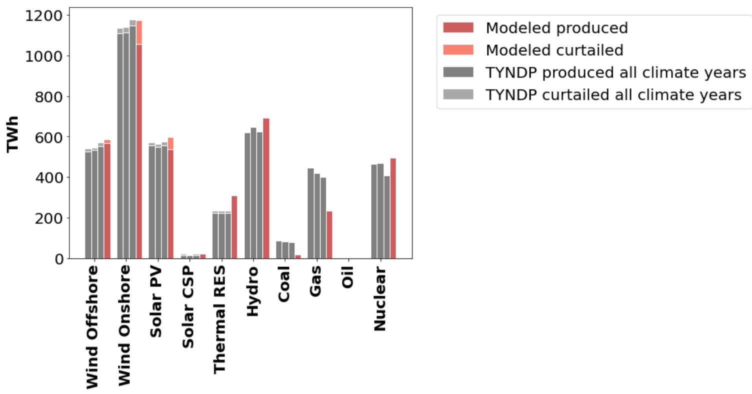


Figure 23: Generation mix including curtailed energy for EU 2040 for scenario NT fits the TYNDP 2020 well, which means that the input data for the generators is in line for the data set for this thesis and the TYNDP 2020 data set. The model for this thesis has a higher share of curtailed energy.

5.3.2 Validation of power flows

The net load flows does not fit the TYNDP 2020 as well as the generation dispatch. This could be because the model in PowerGAMA has more transmission lines. PowerGAMA also operates with DC power flow equations where the reactance affect the power flows. This is not included in TYNDP 2020 which could explain why there is a significant difference which is illustrated in Figure 62.

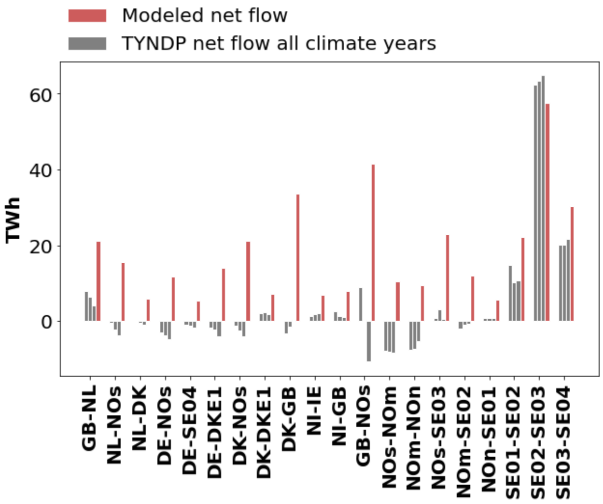
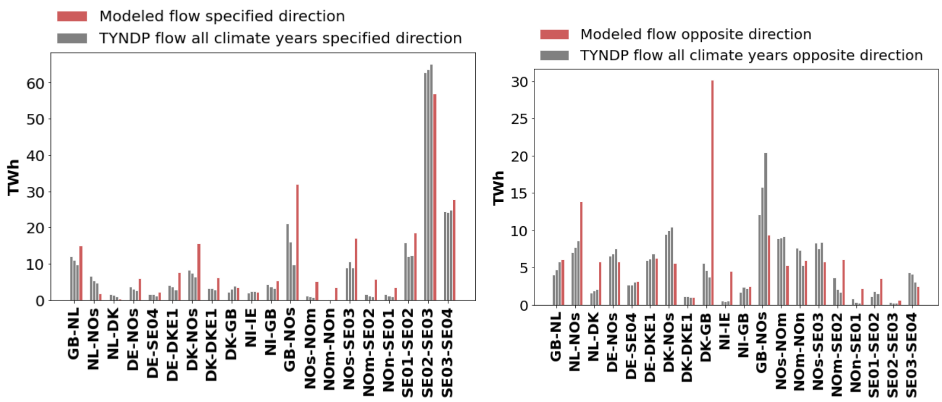


Figure 24: Net cross border flows in the North Sea region after simulating the NT scenario.

As seen from Figure 62 many of the net load flows are in the wrong direction. For instance, the load flow from the Netherlands to the south of Norway should, according to TYNDP, be negative, meaning that over a year there is a higher share of power going from the south of Norway to the Netherlands than the other way. Even though the net power flows differ from TYNDP 2020, it does not mean that they are not reasonable. As mentioned in section 2.2.3, the power system is getting more interconnected and cross-border flows is increasing. For instance, when looking at the absolute values of the power flows they are very small, indicating that a similar amount of energy flows between the countries during a year. Thus, it is important to not only to look into the net, but also the gross power flows. These are illustrated in Figure 25.



Cross-border power flows in specified direction

Cross-border power flows in opposite direction

Figure 25: Result from NT scenario. Most of the power flows surrounding the North Sea has a reasonable power flow in each direction compared to TYNDP 2020.

This give another impression when comparing the TYNDP load flows and the modeled load flows. This applies also for the other two scenarios. Their comparisons are illustrated in Appendix A. As seen from Figure 25 the only power flow that differs significantly from TYNDP 2020 is the power flowing from GB to DK which is approximately five times higher than in TYNDP. The power flow from DK to GB on the other hand is in line with TYNDP. It would be possible to modify some of the cross-border transmission capacities to get a better fit according to the TYNDP 2020 power flows. Still, when tuning the model we found that it often take several tries before achieving the wanted result as the model is so complex. For instance, decreasing the cross-border transmission capacity between DK and GB might be an efficient measure to decrease the power flow from GB to DK, but it could also affect other power flows or the generation mix. Because of the simulation time in PowerGAMA and the time limitations for this thesis making more adjustments to better fit the power flows it is not prioritized.

5.3.3 Validation of the power prices

When comparing the average power prices over a year, it is clear that they are similar to the prices in TYNDP 2020. This is illustrated in Figure 26. The modeled prices is in general higher than for TYNDP and in some countries the modeled prices are significantly higher than what TYNDP found. This is due to a significant amount of load shedding, which implies that there is either limited generation, too high load or too weak cross-boarder transmission capacities. TYNDP 2020 does not include load shedding. The countries with high share of load shedding is countries that is not as relevant for the North Sea region [1], hence no measures has been made to reduce the load shedding as it is out of scope for this thesis. In the countries surrounding the North sea there is no large deviation from TYNDP 2020. Norway and Sweden has in general higher prices in the model. This could be due to different approaches for modeling hydropower which is not the focus of this thesis. The average price for Ireland (IE), North Ireland (NI), Great Britain (GB), Denmark (DK and DKE1) and the Netherlands (NL) is close to what TYNDP expects for the NT scenario. The average price for Germany (DE) and Belgium (BE) is slightly higher [2] than for TYNDP 2020, but this is assumed to be a tolerable mismatch. Hence, the modeled prices in this thesis for the NT scenario are within a tolerable mismatch to the TYNDP prices.

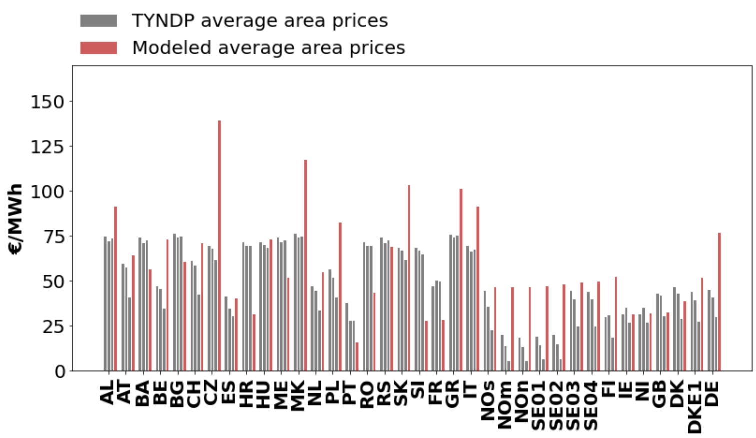


Figure 26: Power prices (real 2020) from the NT simulation. The simulated prices are slightly higher than for TYNDP 2020. The TYNDP 2020 prices are taken from [18]

The price comparison of the DE and GA scenarios are illustrated in Appendix B. The prices in these scenarios deviates more from the TYNDP 2020 where the modeled prices are significantly higher in many of the countries. Again, this could be due to the lack of balancing measures. As both DE and GA has a lower share of fossil fuel based generation this could lead to a higher share of load shedding in the De and GA scenarios, resulting in higher prices.

[1]For instance CZ - Czechia, MK - North Macedonia and SK - Slovakia
[2]approximately 25€/MWh higher

5.4 Nodes of interest in the North Sea region

In this section the weak nodes from the base case is located. These are the nodes of interest because they are best suited for implementation of batteries or hydrogen facilities. Firstly, it is necessary to understand what weak nodes really means for this thesis. Weak nodes are the nodes that has many hours of curtailment or high price volatility during the a simulation year. The nodes with a high share of curtailed energy has a potential of being suited for electrolysers, while the nodes with high price volatility has a potential of being suited for batteries.

Since the volatility is checked mostly to identify where to locate the batteries, the classification of volatility used for this thesis is in line with the price volatility that is favourable for batteries. Batteries for this thesis is modelled with a maximum charging/discharging capacity of 25% of their energy storage capacity. This means that they are able to charge/discharge completely within four hours. In addition, the modeled batteries are expected to not always charge/discharge. With this in mind, and the fact that batteries are not applicable for helping balancing the power system at days or longer [8], the author looks into an interval of six hours to find the max and min price in each time interval

$$p_{i_{max}} = max\{p_{6i}, p_{6i+1}, p_{6i+2}, p_{6i+3}, p_{6i+4}, p_{6i+5}, p_{6i+6}\} \tag{28}$$

$$p_{i_{min}} = min\{p_{6i}, p_{6i+1}, p_{6i+2}, p_{6i+3}, p_{6i+4}, p_{6i+5}, p_{6i+6}\} \tag{29}$$

where i refers to the time interval and is therefore all real numbers from 0 to $8760/6 = 1460$. This means that if there is a high price difference from p_6 to p_7 this will not be discovered by this method. Still, when simulating over many hours this source of error decreases.

Further the $p_{i_{max}}$ and $p_{i_{min}}$ is compared for each time interval

$$p_{i_{diff}} = p_{i_{max}} - p_{i_{min}} \tag{30}$$

If the price difference, $p_{i_{diff}}$, is higher than a specific value, a, time sloth i is characterized as price volatile

$$p_{i_{diff}} > a \Rightarrow i = volatile \tag{31}$$

The value, a was found by looking into the nodal prices during a year for the nodes. Even though the prices vary between the nodes, a does not. This is to enable comparison of the price volatility between the nodes. The value a was chosen to be $50€/MWh$ because this is the highest dead band in the modelling of the batteries.

This process is repeated for each node in the North Sea Region. After looking into the number of price volatile time intervals for each node, we made a decision on how many time intervals that need to be price volatile for the node to be categorized as price volatile. For the whole node to categorized as price volatile, it needed have a number of price volatile intervals that stood out from the rest of the nodes. Again, this means that even though some nodes are not categorized as price volatile, it does not mean that their price does no vary or that they are not suited for implementation of batteries. It simply implies that there are other nodes in the system with a higher number of price volatile intervals.

The author will also implement some electrolysis plants. Thus, nodes with a high number of hours with curtailment is of interest. When investigating relevant nodes the scepticism was high towards implementing electrolysers in nodes with an already high share of load shedding. Hence this was checked for the relevant nodes. None of them had more than eight hours of load shedding during a year and many of them had none. Thus, this was considered not to be a significant problem in the North Sea region. Table 9 shows the weak nodes in areas surrounding the North Sea. The nodes are given with indexes that matches the index in the *nodes.csv* input file. The

Area	Curtailment	Load shedding	Price volatility
DE	238, 388, 398 408, 409, 410	331, 380, 419	all nodes in area
IE	1539	none	1539
NI	1540	none	1540
NL	none	none	all nodes in area
BE	none	none	all nodes in area

Table 9: These are the nodes that are expected to have the highest potential for economical revenue for hydrogen production and batteries in the model.

nodes/areas GB, NOm, NOn, NOs, SE01, SE02, SE03 and SE04 was also checked, but did not give any weak nodes and are left out of Table 9.

This is also illustrated in Figure 27. Note that both Table 9 and Figure 27 only gives an indication of the most economically beneficial locations for adding batteries and electrolysers in the model for this thesis. Other areas might could give a higher profit because of other factors. For instance, if a node has no hours of curtailment, but the electricity price is never above 10€$/MWh$ it would very ideal to implement an electrolyser at that node. Nevertheless the weak nodes still gives a starting point for the analysis. Hence, the areas/nodes in Figure 27 form the base of where the batteries and electrolysers will be located in the case studies in section 6.

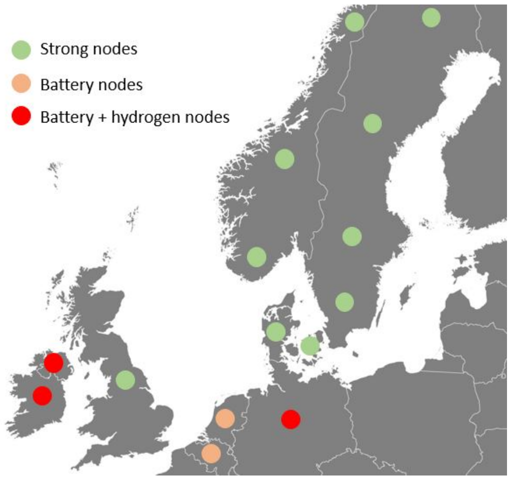


Figure 27: Germany, Ireland and North Ireland are the areas that are expected to have the grates economical potential for investing in batteries and hydrogen, while the Netherlands and Belgium are also expected to have a great potential for batteries. Created by the author.

5.5 Modeling batteries

Based on section 2.3 batteries will play an important role in the future power system, hence modeling batteries and analysing its impact on the power system is a significant part of this thesis. To do this it is also necessary to investigate how batteries can be modelled in PowerGAMA. Since battery technology for balancing the power system is emerging it is not yet thoroughly investigated how PowerGAMA can model them. This section focus on how the user can model batteries in the existing features in PowerGAMA. In section 6 the author will use this to look into how batteries will affect the power prices and the effect this has on VRE economics.

5.5.1 How to model storage and pumping in PowerGAMA

Firstly, it is necessary to look into how storage and pumping is modeled in PowerGAMA. As illustrated in Figure 19, storage is modeled with two main parameters,

- Storage capacity
- Storage value

The storage capacity is the amount of energy the storage facility is able to hold. The storage value is more complex. Storage values have three dependencies in PowerGAMA, one considering seasonal changes, p_{time}, one to include the storage filling status, $p_{filling}$ and one to facilitate for easy scaling of the storage value, b_{value}

$$S_{value} = b_{value} \cdot p_{filling} \cdot p_{time} \tag{32}$$

See [67] for more information on this.

The storage value is included to represent the economical potential of the stored energy to ensure full utilization of this potential. This is similar to water values in hydropower scheduling. For instance, when a hydropower reservoir is completely full, the next unit of water arriving the reservoir will be spilled water. Thus, it gives no value to the power producer. This water could have been sold, but instead it was spilled. When the reservoir is empty the next unit of water will have a vast value to the producer as it has the potential to create revenue and is not in danger of causing spillage. Thus, the storage values are typically high when the reservoir level is low to prevent the reservoir from being completely emptied. Similarly, the storage values are very low when the reservoir level is high to prevent spillage. Thus, storage value is related to the filling level of the energy storage, $p_{filling}$. The storage value is also related to the expected inflow in the future, p_{time}. For instance, if the reservoir level is low, but the weather forecast predicts a lot of rain the next days, the power producer knows that the reservoir levels will increase. Thus, the storage values are not as high, compared to a case with the same reservoir level and no rain. This is especially important regarding seasonal changes in inflow for hydropower since the reservoirs are normally filled in the spring when the snow melts. p_{time} is not as relevant for the thesis as it is not included in the input for the hydropower generators nor is it relevant for modeling batteries or electrolysers. $p_{filling}$, on the other hand, is highly relevant and will be discussed when modeling batteries.

As mentioned above, all generator has the opportunity to be modeled with storage. They can also be modeled with pumping. This is specified in the input file describing the generators in the system, as seen in Figure 19. From Figure 19 it is also clear that the pumping is described with three parameters

- Pumping capacity
- Pumping efficiency
- dead-band

The capacity describes the pumping capacity MW for one time step[3]. The efficiency, η, describes the energy losses when pumping and the dead-band is a way to economically compensate for the losses related to the pumping. For instance, if the pump efficiency in a hydro power plant is 0.9 and the storage value one hour is 40€$/MWh$, the power producer got the option to either sell one unit, pump one unit of water back into the reservoir or to do nothing. In PowerGAMA this decision is based on the nodal price that hour. This is illustrated with an example in Figure 28.

[3] which is one hour for this thesis.

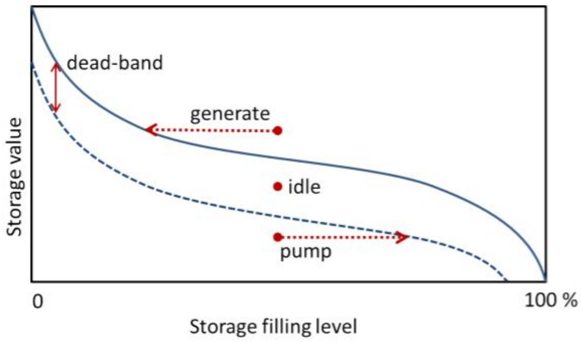


Figure 28: The decision whether to pump, produce or do nothing is based on the nodal price. The red dots represent the nodal price, the blue solid line represent the storage value and the dotted blue line represent the storage value minus the dead band. [67].

The read dots on Figure28 illustrates three examples of the nodal price for a generator with the ability to both do pumping and storage. The solid blue line describes the storage value profile in relation to the storage filling level. If the nodal price is above the solid line, the power producer will generate power. The dead-band is a fixed number that pushes the blue dotted line further down, creating a gap between the dotted and the solid line. This gap illustrates the area where the power producer is idle. Hence, the dead-band prevents the power producer to choose pumping even though the power price is just slightly below the storage value. This way, the dead-band represent the economical losses due to the inefficiency of the pumping. If the nodal price is low enough, the economical gain from pumping another unit into the reservoir is high enough to prioritize pumping. Thus, if the nodal price is below the dotted line, the power producer will choose to produce until it reaches the dotted line, as long as the pumping capacity allows it. [67]

Another important aspect with modelling storage and pumping in PowerGAMA is that the optimization algorithm is capable to look into the future and see whether the power price will go up or down the next hours. Thus, it will not find the optimal dispatch of pumping and storage that maximizes the profit of the producer over a whole year. Nevertheless it will aim to make the most profitable decision each time step.

5.5.2 Locating strategies to model batteries in PowerGAMA

Through the work of this thesis the author found several ways to implement batteries in PowerGAMA. Three approaches was found

1. Extra storage in VRE generators
2. Flexible load
3. Individual generator with zero inflow

The first approach was to model batteries as extra storage in VRE generators. This is valuable when modelling batteries that only charge from the surplus power from specific VRE plants. The down side with this method is that batteries are not able to charge from the grid. In addition to this it would be harder to tell exactly how much energy the batteries has charged and discharged because the inflow first goes through the storage before it can be registered as generator output. This is illustrated in Figure 29.

Another way to express the battery behaviour is by modeling them as flexible load. This implies that in times of low prices the flexible load would increase. The behaviour is could represent a battery that charges; When prices are high the load would decrease, acting like a battery that discharges. There are two problems with this approach. The first problem is that, in reality when a battery is discharging, the total power that flows in the lines increases which could lead to problems regarding congestion management. When a load decreases the opposite happens. Since the batteries have a relatively small impact on the rest of the system, this affect is not necessarily significant, but it could make the model incapable of capturing some congestion problems. The second problem with this approach is that we found this approach to be less user friendly and because it is less intuitive.

The third and final option is modeling the battery as an individual generator with pumping and storage. To do this, the inflow is set to be zero, which is illustrated in Figure 29.

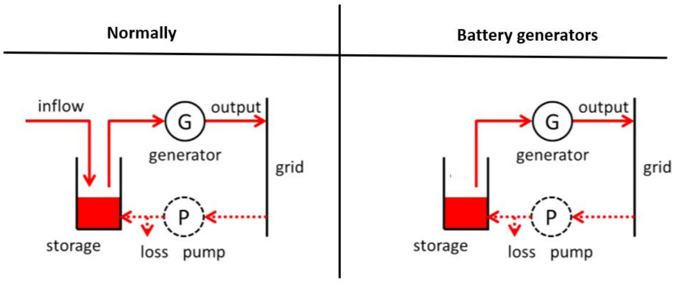


Figure 29: Batteries are modelled as a generator with an inflow = zero. The figure is inspired by [67].

This method makes it possible for the user to easily extract the charged and discharged energy by looking into the pumped energy and the generator output respectively. It is also possible to specify the maximum storage capacity, *storage_cap*, in the battery as well as the charging and discharging capacity, *pump_cap* and *pmax*. In addition, this method gives the user an opportunity to easily express the energy losses when charging the battery, $pump\_efficiency$. For this thesis the losses are both the losses related to the charging and discharging of the battery, also called the round-trip efficiency. Dependent on the battery technology the round trip efficiency varies from $60-97\%$ [68] thus the battery efficiency for this thesis is set to 85%.

Another feature that is highly important when exploring how to model batteries is how the decision whether to charge, discharge or be idle is made. In reality this is a complex problem and, similarly as for water values, it takes advanced algorithms to fully optimize the strategy. In PowerGAMA it is not possible to look ahead since it is a dynamic problem, solving each time step dependent on the previous. Thus it is hard to optimize the decision making accounting for the future. Nevertheless there is a way to capture some of the same behaviour in PowerGAMA. When modeling batteries as individual generators it is possible to model them with storage values, as for hydro power plants. This enables the optimization tool to value waiting to charge or discharge when the storage level is high or low.

The *pump_deadband* restricts the area where the battery is idle. Unlike for pumped hydro, the dead band does not represent the losses related to charging the battery. The role of the dead-band is to control the price range where the battery is idle, thus it controls much of the behaviour of the battery. We have chosen to experiment with this dead band to see its effect on both the behaviour of the battery and the rest of the power system. The steepness of the storage value curve is also looked into, resulting in three different versions to model batteries. This is more thoroughly explained later in this section.

5.5.3 Parameters in battery modeling

Before analysing the versions it is important to give the reader a thorough understanding of exactly what each parameter represent when modeling batteries and how they are different for each version. This will make it easier for future master students/stakeholders to understand and reproduce the results. For a more thorough explanation of the parameters the reader is recommended to read the userguide for PowerGAMA [67].

Parameter	Value/string	Explanation
desc	battery_name	random name for the battery
type	'battery'	Creates a new type of generators called batteries
node	node	The node it is connected to
pmax	1/4 of storage_cap	To avoid having a battery that discharge all its stored energy in one time step
pmin	0	Since it has no lower discharging limit
fuelcost	0	Because the storage value considers generation costs
inflow_fac	1	Does not matter since each time step in the inflow_ref profile = zero
inflow_ref	'battery'	'battery' is a specific inflow_ref profile added with every time step = zero
storage_cap	total installed capacity	Extracted from the TYNDP 2020 data set for each country
storage_price	10	Chosen in relation to the inflow_ref so that inflow_ref * storage_price = storage value
storage_ini	0.5	Start with half full battery
storval_filling_ref	'battery_vX'	X is either 1, 2 or 3, depending on which version the battery is. Each version has its own unique profile in profiles_storval_filling
storval_time_ref	'const'	Because batteries has no seasonal variations
pump_cap	1/4 of storage_cap	To avoid having a battery that charges the whole battery in one time step
pump_efficiency	0.85	Round-trip efficiency
pump_deadband	49, 6.75 or 50	Depending on whether it is a battery version 1, 2 or 3 respectively

Table 10: Specification on the parameters in the battery modeling

5.5.4 Three versions to describe battery behaviour

When creating the three versions we focused only on the storage value curves. The charging/discharging capacity of the batteries could also be analyzed taking, for instance, DOD into account. To limit the problem and free time for analysis, this was set to not considered. After discussing with the Magnus Korpås and Martin Kristiansen the charging/discharging capacity was set to 1/4 of the total installed battery storage capacity. The values for charging/discharging capacities were taken directly from the TYNDP 2020 data set [18]. The storage capacity for each battery was thus found by multiplying the charging/discharging capacity by four.

When describing the storage value curve for the three versions two aspects are especially important;

1. The value of the dead band
2. The steepness of the storage value curve

After analyzing and trying different approaches, the following versions were used in further analysis:

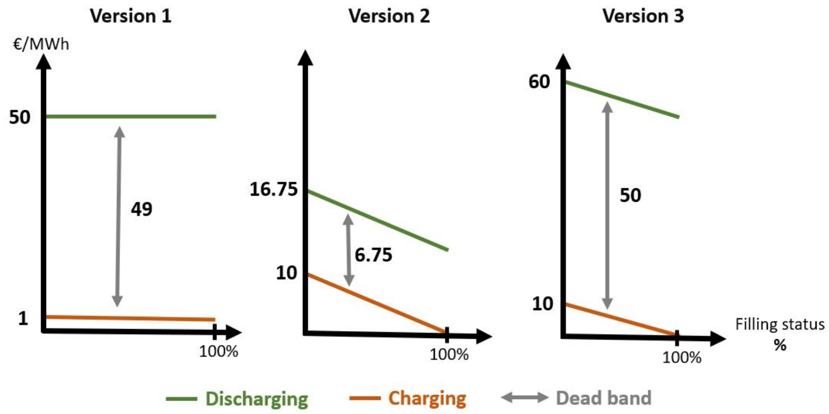


Figure 30: Three versions for modeling batteries for this thesis.

Version 1 is the most simple method, with a large dead band and no steepness in the storage value curve. This means that the storage value is not dependent on the filling level of the battery. This is not necessarily a weak approach, as it is reasonable to assume that some household solar batteries or vehicle to grid technology could solely react to a specific power price [68]. The discharging value, illustrated with a green line in Figure 30, is ment to be high, but still lower than the lowest marginal cost of fossil fuel based generation. This is important because a battery should not contribute to increasing the total CO_2 emissions. For instance, if the optimization tool would decide whether to discharge the battery or increase the production from fossil fuel based generation, the optimization algorithm should always choose the battery. This argumentation also implies for version 3.

Version 1 also has the lowest charging value, illustrated with the orange line in Figure 30. The purpose is for it to charge only when the node experience curtailment from RES, hence the value is set to 1. This leaves a dead band value of $49€/MWh$.

The purpose of version 2 is to represent a more market-based model that has a lower requirement regarding the discharging value. Thus, this battery will be used more intensive than version 1 and version 3. The highest charging value is set to be lower than the marginal cost of nuclear so that discharging the battery is favoured before increasing the power generation from nuclear or fossil fuel based generation. Further, the dead-band is chosen according to the battery losses. Since the round-trip efficiency is assumed to be 85%, the expense of these losses are $0.15€/MWh$. Yet, the dead band is set to $6.75€/MWh$. This is because there is a high potential of increasing the revenue when increasing the dead band. Thus, the dead band was set to the average loss of potential revenue, which is $(1 - \eta_{round-trip}) \cdot price_{avg} = 0.15 \cdot 45€/MWh = 6.75€/MWh$.

Version 3 is modeled as a combination of version 1 and 2. It has the highest dead band value and the same slope as for version 2. It was desirable for the charging curve to bee steeper, but this was limited by PowerGAMA. If the charging curve was steeper it would cross the x-axis before it reached 100%. In PowerGAMA, this would mean that the battery would never be fully charged. It would be possible to solve by increasing the total installed capacity with the corresponding gap, but this is not a user friendly solution as it would be confusing and misleading regarding the installed capacity for the battery. Thus, the decision was made to maintain the slope from version 2, but increase the dead band to $50€/MWh$.

5.5.5 Validating the battery modeling

To make sure the approach for modeling batteries worked like it should the storage filling status and nodal price was plotted in Figure 31. Version 1 is simulated, which is possible to see from the constant charging and discharging value. From Figure 31 it is clear that when the nodal price is in between the charging and discharging line the battery is idle. When the nodal price is above the discharging value the battery discharges and when the nodal price is below or the same as the charging value the battery charges. When the blue line, representing the storage filling status, flattens the battery has reached its maximum energy storage capacity. When looking closely, the storage filling status leads with one hour compared to the nodal price, but does not have a significant impact on the results.

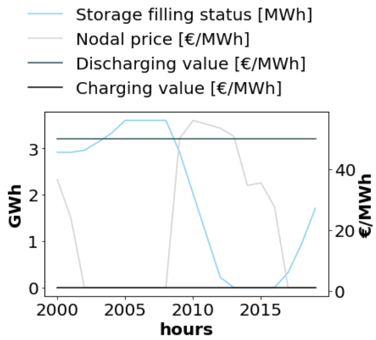
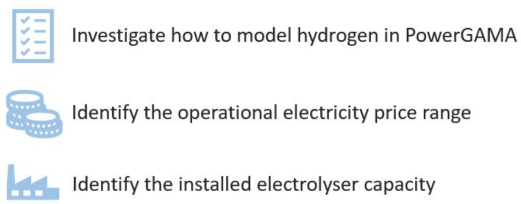


Figure 31: Battery version 3 acts like expected when it is implemented at node IE. Note that the filling profile leads with one hour.

5.6 Modeling electrolysers

Hydrogen will play an important part in decarbonizing the power system. Green hydrogen, or hydrogen produced from electrolysis, will be the focus of this section. When quantifying the impact of electrolysis it is important to explore how the future demand of electrolysers can be modeled. For this thesis the focus is to locate a simple and easy way to model electrolysis in PowerGAMA. It includes both finding a reasonable method and locating specific values for the belonging parameters. Thus, this section is separated into three parts



5.6.1 How to model hydrogen in PowerGAMA

When investigating how to model hydrogen in PowerGAMA it is important to keep in mind how business models for hydrogen might evolve. Because of the high uncertainty regarding the future of electrolysis it is hard to tell exactly how hydrogen will behave in a business model. It is not unlikely that electrolysers is subsided similarly as VRE to boost investments and decrease CAPEX. This would mean that electrolysers would not necessarily be as price sensitive to the wholesale electricity market. In PowerGAMA there are no options to model electrolysers - or any other loads - that is completely disconnected or partly disconnected to the wholesale electricity market. For instance if an electrolyser has a specific business arrangement where it sometimes gets its power directly from a power producer - or it somehow adjusts its consumption to a specific business agreement. Thus, this thesis will only look into how hydrogen can be modeled when it is solely connected to the power grid.

There are two main paths to model electrolysers in PowerGAMA. It can be modeled as

- generators
- consumers

There are pros and cons with both paths and we have chosen to highlight some of them before electing the favoured method.

If electrolysers were to be modeled as consumers, there is a range of possible approaches. For instance, it is possible to assume that it is modeled as fixed load, covering a fixed electrolyser need. If the power system towards the future has mainly Alkaline electrolysers this is a reasonable approach as the technology does not enable it to adjust its production as much. It would also be predictable for the hydrogen supply chain. Yet, it removes some of the most valuable asset of electrolysers; its ability to adjust the consumption to VRE generation. It would also be possible to model it as both flexible and constant demand. If the power system towards the future has a combination of Alkaline and PEM electrolysers, this could be a good option to represent their different production profiles. Since Alkaline electrolysers do not have the same ability to adjust their consumption, the fixed load could represent the Alkaline electrolyser while the flexible load would represent the PEM electrolyser. Of course, the two electrolyser technologies could be separated into two consumers, but when working in PowerGAMA we noticed that it is easier to analyse and present the results if the consumption/generators are aggregated. If the objective is to represent a power system that has a fair share of both PEM and Alkaline electrolysers the author recommends to model the Alkaline and the PEM consumption in the same consumer. Figure 32 illustrates how PowerGAMA models consumption. Flexible load could also have storage, which is an essential part of the hydrogen value chain according to Figure 12.

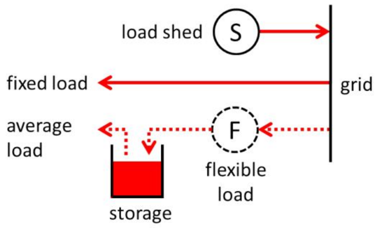


Figure 32: Hydrogen could be modeled as consumption where, for instance, fixed load could represent Alkaline electrolysers and flexible load could represent PEM electrolysers. [67]

The second path is to model electrolysers as generators. Then, the inflow and generator output would be zero. This is illustrated in Figure 33.

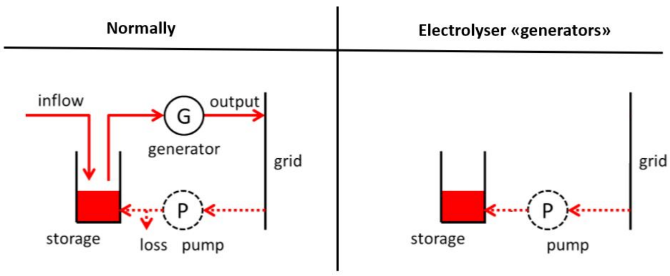


Figure 33: Electrolysers are modeled as generators with an inflow = zero, no losses and generation output = zero. Figure is inspired by [67].

This approach has just a few parameters that need to be adjusted, making it easy to use. Still it has some downsides. The storage now represent the total electrolyser consumption. The storage has a limit, hence it is important for the user to know how much electrolyser consumption is expected to produce during a year. On the other hand, this could be used to limit the production of hydrogen to a specific target. When this target is met there will be no hydrogen production for electrolysis for the rest of the year since PowerGAMA solves the system time step by time step. For this thesis the storage is set to a high capacity that is expected not to be exceeded. The down side of this method is that there is no option to model hydrogen storage. On the other hand it is easy to add functionality to produce electricity from hydrogen, which also is an important aspect of the hydrogen cycle in Figure 12.

Modeling electrolysers as generators or consumption offer different positives and brings different opportunities. The pros and cons discovered for this thesis is listed in Table 11.

	Hydrogen as a generator	Hydrogen as a consumer
Pros	- Easy to use - Possible to model electricity production - Easy to limit total hydrogen demand	- Possible to model constant load and price-sensitive consumption - Possible to model hydrogen storage
Cons	- Not possible to model constant load - Not possible to model other business deals - Not possible to model hydrogen storage	- Less intuitive for the user - Not possible to model other business deals

Table 11: Pros and cons when modeling hydrogen in PowerGAMA created by the author.

After considering the pros and cons of both methods the author decided to model hydrogen as generators as illustrated in Figure 33. The parameters set for this thesis are explained in Table 12.

To summarize, it is possible to model electrolysers in PowerGAMA, but as listed in Table 11 there is not one optimal option that takes all the wanted features for the rest of the hydrogen cycle into account. Modeling the electrolysers as generators or consumers is not sufficient if detailed models are desired. Thus, we have illustrated what we believe is the best approach for modeling hydrogen in PowerGAMA, which is a combination of how generators and consumers are modeled. It is not yet tested, but meant as a source of inspiration for future work.

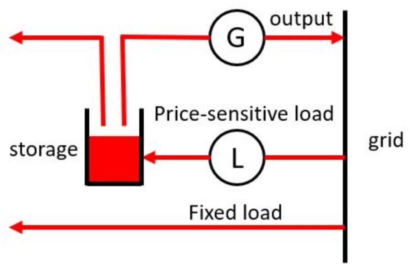


Figure 34: A suggested improvement for modeling hydrogen in PowerGAMA. Inspired by [67].

Parameter	Value/string	Explanation
desc	battery_name	random name for the electrolyser
type	'hydrogen'	Creates a new type of generators called hydrogen
node	node	The node it is connected to
pmax	0	Since it is only modeled as a load for this thesis
pmin	0	Since it is only modeled as a load for this thesis
fuelcost	0	Since it is only modeled as a load for this thesis
inflow_fac	1	Does not matter since each time step in the inflow_ref profile = zero
inflow_ref	'battery'	'battery' is a specific inflow_ref profile added with every time step = zero. The same inflow profile is used for batteries.
storage_cap	Total hydrogen load during the simulation period	How this is found is explained more thoroughly in the section.
storage_price	Electrolyser price	The initiating price for the hydrogen electrolyser. How this is found is explained more thoroughly in the section
storage_ini	0	Start counting electrolysis consumption at zero
storval_filling_ref	'const'	Profile that is equal to 1 each time step so that storage_price represent the actual initiating price for the hydrogen electrolyser
storval_time_ref	'const'	Because hydrogen is not modeled with seasonal variations
pump_cap	Electrolyser capacity	How much power the electrolyser can take each time step. How this is found is explained more thoroughly in the section
pump_efficiency	1	No losses included
pump_deadband	0	To ensure that the storage price is the initiation price.

Table 12: Specification on the parameters in the electrolyser modeling in PowerGAMA.

5.6.2 Deciding electricity price range for electrolysers

The second part of this section focus on finding the electricity prices for when the electrolysers should produce hydrogen. From now on these prices are called the operating prices. What these prices will be in the future is highly uncertain. Section 2.4.4 discuss how difficult this is and concludes that it is hard to give a price range that is applicable for all areas. Time limitations restrict the level of details for the modeling of electrolysis, thus it was decided to find one operating price profile for all countries with installed electrolysis. Table 3 give an indication of reasonable operating prices. In addition, we were inspired by Figure 13 in [43] where the impact of utilization on CAPEX and OPEX is compared to the electricity prices finding a competitive electricity price and utilization. There was not enough time to do this for all areas where the electrolysers will be added, thus Ireland founds the basis for the rest of the countries.

The nodal price in Ireland (IE) is analysed and plotted in Figure 35. The blue line symbolize the relative effect of CAPEX and OPEX for an LCOH for an electrolyser. It is dependent on the full load hours during a year. There is no values on the left axis because it is only meant to show that higher utilization helps to reduce the impact of CAPEX. The shape of the curve is taken from Figure 13 in [43].

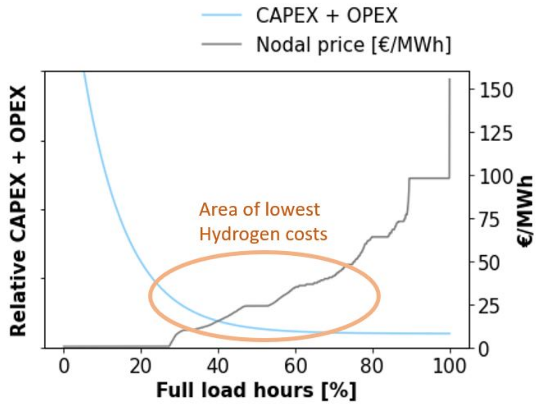


Figure 35: Electrolyser utilization of $30-80\%$ and an electricity price range from $0.5-50€/MWh$ could be beneficial for the hydrogen in IE. Blue line represent CAPEX + OPEX inspired by [43]. Grey line is the simulated nodal price without batteries nor electrolysers.

With this in mind, the optimal utilization of an electrolysers in IE is $30-80\%$, operating at a price range of $0.5-50€/MWh$. This correspond well to the prices found in section 2.4.4 for both ALK and PEM electrolysers with different electrolyser CAPEX. Keep in mind that Ireland is chosen to model hydrogen because of its many hours of curtailment. In fact, approximately 30% of the hours during the year experience a price of $0.5€/MWh$. Thus, an electrolyser utilization of 30% is possible to achieve with a operational price of $0.5€/MWh$. This would not be the case if the electrolyser was added in, for instance, the Netherlands. Thus, when adding electrolysers in the model for all areas, an operational price of $10-50€/MWh$ was chosen. When running simulations with these operational prices they turned out to be too low because adding electrolysers to the system significantly increased the power prices. Thus, the operational price was set between $20-50€/MWh$.

The steps for finding the operational price is listed below:

1. $0.5-50€/MWh$ based on nodal prices in IE and beneficial utilization according to 35
2. $10-50€/MWh$ because IE has a higher number of hours with curtailment [4] than for other countries
3. $20-50€/MWh$ final operational prices because the previous resulted in too low utilization of the electrolysers

The operational price make the basis of the price profiles. Next up was weighting the profiles where the objective was to get an approximately utilization of 60%. The value was chosen to be 60% based on Figure 35 and the fact that it was used for electrolyser utilization when calculating LCOH for green hydrogen in [13]. Based on this, the final weighting of the operational price profile is illustrated in 13. This profile is used in the case studies in section 6.

Operational price $€euro/MWh$	Percentage of price profile
20	30
30	30
40	20
50	20

Table 13: Price profile for the operational price for electrolysers for it to be economically competitive to grey hydrogen.

[4]Hours of curtailment means hours of nodal price = 0.5MWh

5.6.3 Installed electrolyser capacity

Now there is established a range of operational electricity prices for green hydrogen for it to be economically competitive to grey hydrogen. The new step was to identify the installed generation capacity of electrolysis. Since the exact capacity in each country is unclear in the TYNDP 2020 data set, other sources are used.

Some countries i EU has announced a specific electrolyser target by 2030, triggered by the EU 2030 target of 40 GW installed electorlyser capacity within EU [54]. Since the EU target is new, not all countries has announced their goal yet, which results in a gap of $6GW$. These are distributed over Ireland, Norway and Belgium based on predictions of total hydrogen demand from [1] and [38]. When finding the predictions on installed electrolyser capacity in 2040 these targets were multiplied with 2.5. This is based on the fact that between 2030 and 2040 green hydrogen is expected to approaching competitiveness with blue and grey hydrogen [74][54]. Green hydrogen is expected to be competitive to blue hydrogen between 2025 and 2035, depending on the effects of reduced electrolyser cost and cheaper renewable power [44]. Since electrolysis is likely to be the dominating procedure when producing hydrogen in the future, it is hard to tell exactly when this will happen. Multiplying with a factor of 2.5 most therefore be considered as a assumption with high uncertainty.

The capacities are used as a basis for *pump_cap* in the *generators.csv* input file when modeling green hydrogen. The *pump_cap* is separated according to the price profile described in Table 13. This means that the *pump_cap* for the electrolyser in IE with an operating price of $20€/MWh$ is set to $2.5 \cdot 0.3 = 0.75GW$, the electrolyser in IE with an operating price of $40€/MWh$ is set to $2.5 \cdot 0.2 = 0.5GW$ and so on.

Country	Target 2030 GW	Assumed 2030 GW	Factor	Predicted 2040 GW
FR	7	0	2.5	17.5
DE	5	0	2.5	12.5
ES	4	0	2.5	10
NL	4	0	2.5	10
PT	2	0	2.5	5
UK	5	0	2.5	12.5
IT	5	0	2.5	12.5
PL	2	0	2.5	5
IE	0	1	2.5	2.5
NO	0	2	2.5	5
BE	0	3	2.5	7.5
Total	40		2.5	100

Table 14: Electrolyser capacitiesin the future power system. The target values are taken from Table 4. The assumed capacity for 2030 is based on [1] and [38].

This leaves a total installed electrolysis capacity of $100GW$ in 2040. According to TYNDP 2020, this is slightly above what to expect for GA scenario and NT, but almost three times less than what to expect in the DE scenario, see Table 5. Note that these predictions were made before EU announced their ambitious target of 40GW. Is it likely that, accounting for this information, the total capacity in the scenarios can be even higher.

6 Results and discussion

Section 5 has created a foundation for analysing the impact of electrolysis and batteries on VRE in the European power market. For this section the results will be presented and discussed. The results that is highlighted are important for the power system in general and they are discussed with an economical perspective including, among other things, capture prices, revenue for VRE and LCOE. Note that the prices from TYNDP 2020 is real 2020 values, while the simulated prices are partly discounted for [5].

Firstly the three scenarios are analysed with an objective to see if batteries and electrolysers are needed to increase the financial motivation for investing in VRE. Secondly case studies in Ireland and Great Britain is studied where electrolysers and batteries are added. The objective is to get a better understanding of the battery and electrolyser behaviour and its impact on VRE economics. For the third section electrolysers and batteries are added in the relevant areas throughout Europe to see how it affects the whole European power system. Lastly, sensitivity analysis is performed to see how the capture prices are affected by the CO_2 price.

6.1 Base case

For this section a brief analysis will be made investigating the capture price and generation mix for the three scenarios. All the simulation for this section is done for a whole year, or 8760 hours. The objective is to determine which has the greatest potential to increase the capture price. Further this is used to choose one scenario as base case. The base case will be used for further analysis.

6.1.1 Generation mix and installed generation capacity

Figure 36 illustrated the installed generation capacity compared to the generation for each source. It is clear that the NT and GA scenario is the most similar regarding generation mix and installed generation capacity. They have an overall lower generation and a higher share of installed capacity for offshore wind. The NT scenario has a higher share of generation from gas, but apart from that they are very similar. The DE scenario on the other hand has a very high generation and installed capacity of onshore wind and solar PV.

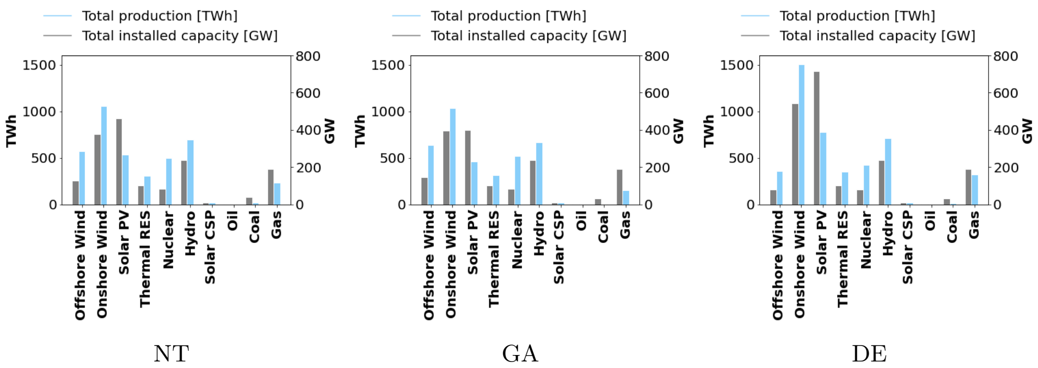


Figure 36: Simulation executed for a whole year. The generation mix (blue bars) and the installed capacity (grey bars) in Europe is visualized. The NT and GA scenario is the most similar, both regarding the installed capacity and the generation mix. The DE scenario has a significantly higher installed capacity and generation from RES especially regarding onshore wind and solar PV.

All the scenarios has the same input regarding their inflow profiles, meaning that the capture factors are the same. If the generation in each scenario is different it is either because of their different installed capacity or curtailment caused by diverse power system characteristics.

[5] Table 8 show that CO_2 prices are real 2020, while the rest of the marginal cost for 2040 is not discounted.

6.1.2 Capture prices

Solely based on the generation mix it would be reasonable to assume that the DE scenario would have the lowest capture prices since it has the highest share of RES generation. Figure 37 shows that this is not the case. In fact it has the highest capture price for offshore and onshore wind. It could be due to a higher load in the system in the DE scenario resulting in a lower share of curtailed energy. DE also has the highest CO_2 price which increases the marginal costs for fossil fuel based generation. Because the overall prices increase, so will the capture price for VRE. Table 15 quantify the most important differences between the scenarios. Note that these numbers does not alone give a good reason why the capture prices are different for each scenario, but they informs about possible explanations. For instance, DE scenario has a high total cross-border transmission capacity, the highest load and the highest CO_2 price which all work in favour of high capture prices.

	Total cross-border transmission capacity [TW]	CO2 price [euro/MWh]	Total average demand [GW]
NT	78.5	75	437
DE	78.1	100	498
GA	68.9	85	424

Table 15: NT scenario has the highest total cross-border transmission capacity in Europe while GA has the lowest. NT also has the lowest CO2 price. The DE scenario has significantly higher CO2 price and demand which may have affected the capture prices. Values are taken from [24].

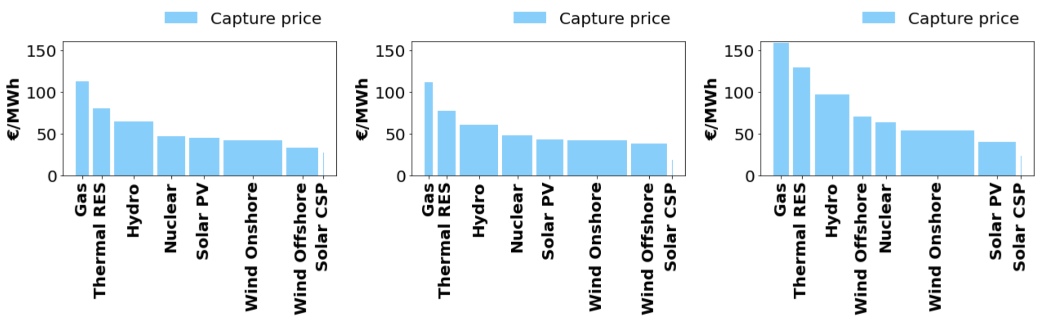


Figure 37: The NT scenario has the lowest capture prices for RES. The thickness of the bars represent the percentage generation for each source. For accurate numbers on the capture prices for VRE, see Table 16.

Coal is not included in Figure 37 because it had significantly higher capture price than the rest. It is because its marginal cost is the generation source that is the most affected by the increased CO_2 price due to the high emission factor. The capture price for coal was 156, 164 and 290€$/MWh$ for respectively NT, GA and DE scenario. This reveal the increased volatility of the power prices compared to the 2014 case, where the capture price for coal was 62€$/MWh$. In every scenario it makes up a very small share of the generation mix.

Figure 37 also gives an indication of the generation mix as the thickness of the bars represent the percentage generation for each source. As seen from the figure, the DE scenario has the highest overall capture prices. Even though the NT and the GA scenario has different capture prices, the order of the generation sources from highest to lowest capture price is the same. DE stands out from this. For instance, solar PV has the second lowest capture price in the DE scenario. This could be caused by a significantly higher solar PV generation than for the other two scenarios. An increased generation from solar PV would force the prices down in times of generation which is called the cannibalization effect. The capture price for offshore wind in the DE scenario climbs higher in the order than for the other two scenarios. This could be because of the low generation from offshore wind in the DE scenario. Again, this illustrate the cannibalization effect for offshore wind in the NT and GA scenario. The values for the capture prices for VRE in each scenario is listed in Table 16.

	Offshore wind	Onshore wind	PV
NT	33	42	44
DE	70	53	39
GA	38	39	42

Table 16: The capture prices [€/MWh] for RES in the three TYNDP 2020 scenarios. The NT scenario has the overall lowest capture prices. This is one of the reasons why it is chosen as base case for further analysis.

One of the biggest motivations for implementing batteries and electrolysers in the power system is to improve VRE economics so that it is more profitable to invest in VRE. Investments in VRE is essential for reaching the EU 2050 target. Thus it is interesting to see how the situation looks like without batteries nor electrolysis. The LCOE predictions by TYNDP 2020 is listed in Figure 38 together with the capture prices for each source for each scenario. It is important that the predicted LCOE for one scenario is compared to the capture price for the same scenario. This is because the LCOE is highly affected by the installed generation capacity. For instance, an increased installed generation capacity for offshore wind will force technological progress and bring down CAPEX costs TYNDP 2020 which again will decrease LCOE for offshore wind. This is why LCOE is so high for DE, but low for NT and GA. Note that TYNDP 2020 does not have predictions on LCOE for the NT scenario, so the LCOE predictions for GA is plotted in the NT scenario as well. This is acceptable as they have approximately the same installed generation capacity, see Figure 36.

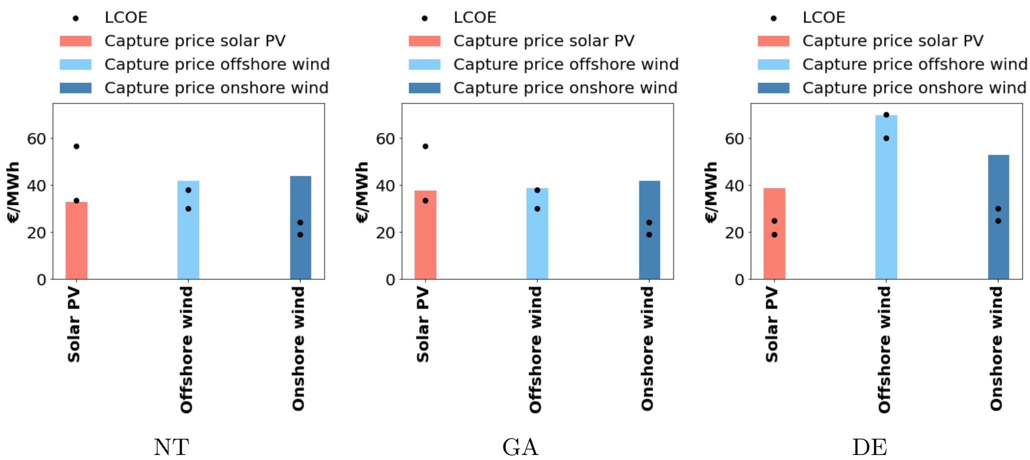


Figure 38: The LCOE predictions for GA is plotted in the NT and GA scenario. LCOE predictions for solar PV is the average of the commercial and the residential PV. The figure shows that the capture price is, for most of the time, higher than the LCOE. This implies that the installed generation capacity predicted by TYNDP is within reach without significant economical incentives or balancing measures like batteries or electrolysers.

Figure 38 shows that the capture prices is slightly higher than the predicted LCOE. It is especially interesting to see how the offshore wind capture price increased for DE along with the LCOE. In some way this is a validation of the prices in times of offshore wind production compared to TYNDP 2020. When decreasing the offshore wind capacity from the GA to the DE scenario, the capture price followed. If the capture prices for instance were severely higher than the LCOE for DE it would indicate that the prices in times of offshore wind production in the model was too high compared to the TYNDP 2020 predictions.

The most interesting part of this result is that the the capture prices for offshore and onshore wind is, for all scenarios above predicted LCOE. Thus, they are able to reach the predicted installation capacity without significant economical incentives or balancing measures like batteries or electrolysers. The DE scenario has the best capture prices as solar PV also is able to get a sufficient capture price. Solar PV for the NT and GA scenario, on the other hand, has too low capture prices compared to the LCOE predictions. Thus, according to this result, solar PV would need economical incentives to achieve the wanted installed generation capacity to reach the climate targets. Thus, there is a potential to decrease the capture prices to support integration of solar PV. Note that even though the capture prices for offshore an onshore wind are sufficient to reach the installed generation capacity without special measures, the capture price is not the only focus of this thesis. It is also of interest to learn more on how batteries and electrolysis in general affect the VRE in the European power market. For instance, will increased share of electrolysis increase or decrease the share of curtailed energy from VRE? Will batteries and electrolysis increase or decrease the overall electricity prices? And how will the total revenue for VRE be affected by this? These are all important in the financial analysis of the affect of batteries and electrolysis on VRE.

Because of the running time for the simulation in PowerGAMA we needed to go forward with only one scenario. Although it would be valuable to explore how the different scenarios responded to batteries and electrolysers, it is out of scope for this thesis. The NT scenario was chosen because of the following

1. It had the best fit regarding the electricity prices
2. It had a potential for increasing capture prices for solar PV
3. It is a mix of the two very different scenarios, GA and DE

Still, it is important to remember that the NT scenario in TYNDP 2020 does not reach the EU 2050 target because it has too high production of fossil fuel based generation, especially for gas. Nevertheless it is interesting to study whether implementing batteries and electrolysers will support generation from VRE and thus decrease fossil based generation.

6.2 Case studies

This section will take on specific case studies to evaluate and analyse the impact of electrolysers and batteries on VRE in the European power market emphasising on the following

- Capture prices for VRE
- Curtailment for VRE
- Total revenue for VRE
- Average nodal prices
- Number of hours with a nodal price of zero (referred to as zero hours)
- Price volatility

As mentioned earlier, the NT scenario is used for all of the simulations. Because of time limitations all the simulations are run for 2000 hours of the year. This includes a new simulation of the NT scenario, so that it comparable to the other simulations.

The first case studies takes on changed in node IE and GB. This is to isolate the incidents, making it easier to analyse what actually happens in the European power market when implementing batteries and electrolysers. Further this knowledge will be used to look into the consequences when adding batteries and electrolysers throughout EU.

6.2.1 Assessment of the three battery versions in node IE and GB

Node IE represents Ireland, while the node called GB in the model represents Great Britain. IE has been chosen for this section because it is characterized in section 5.4 as a weak node regarding both electrolyser and battery modeling which means that it is well suited for modeling both, based on the nodal prices during a year. GB is chosen because it has been characterized as a strong node, which means that it not as suited for modeling batteries nor electrolysers. Thus it is possible to compare the economical incentives for investing in batteries in two countries with different characteristics.

One simulation was run for each battery version for each area, in total six simulations for this case study. Note that there was just one battery in the total system at the time. The results in this section are extracted from result files that were solved for a time range of (1000,3000). This price time range is the basis for all simulation in the case studies. It correspond to simulating from the mid of February to the mid of May. Hence it does not directly represent a whole year. Still, it is able to capture the characteristics of the winter season, spring and towards the summer. It also has the most price volatility, which is of interest when looking into the battery modeling. The nodal prices in IE during a whole year is plotted in Figure 39 to give an impression of how the prices vary during a year. As illustrated, there is no clear seasonal differences.

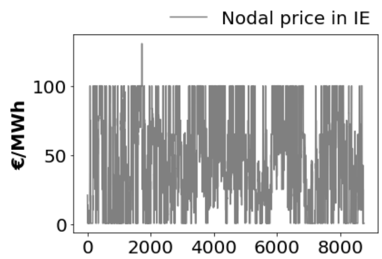


Figure 39: The nodal price profile in IE has few clear seasonal characteristics. This makes the time range of (1000,3000) representable for the whole year. This price time range is the basis for all simulation for the case studies.

The behavior of the different versions of battery modeling is revealed in Figure 40. Not surprisingly version 1 and 3 have a very similar behaviour, while version 2 stands out. From Figure 40 version 2 is more frequently used compared to the other to versions.

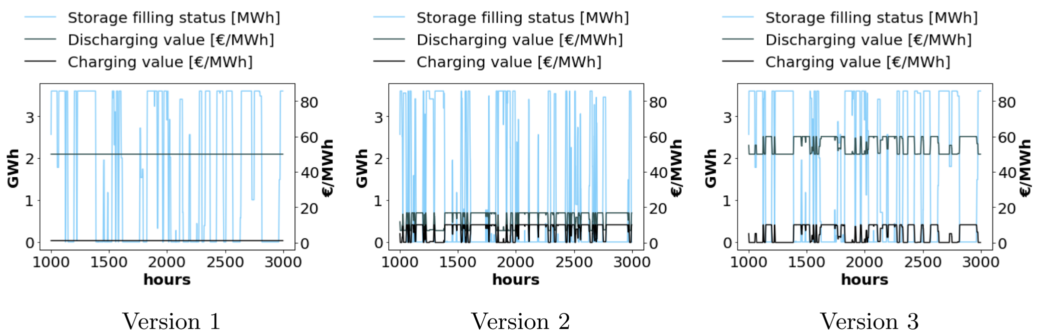
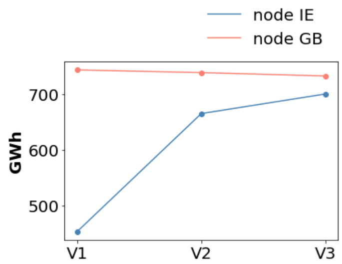


Figure 40: Storage filling status is the total energy stored at the specific time in the battery. Battery model version 1 and Version 3 behaves similar. Version 2 is more frequently used.

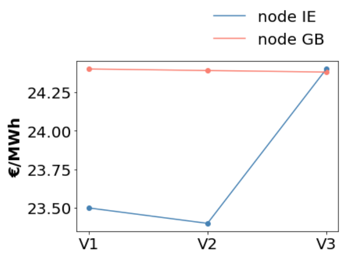
Further the different versions' impact on

- curtailed energy from VRE,
- capture price for VRE and
- average captured profit for the battery

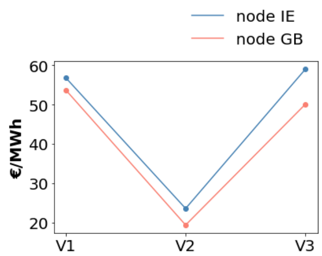
is evaluated. The average captured profit for the battery is evaluated so that it is possible to locate the most profitable version and analyse whether it shifts dependent on the geographical location of the battery. Figure 40 shows some results from from the case study.



Curtailed energy from VRE



Capture price for VRE



Average captured profit for the battery

Figure 41: Results when adding one battery in node IE and and one battery in node GB. V1 refer to battery of version 1 and so on. This shows that there is not necessarily a favourable version regarding curtailed energy from RES, capture prices for RES or average captured profit for the battery.

For the batteries in IE version 1 is better at decreasing the share of curtailed energy. It is interesting to see that for the curtailed energy from VRE there is such a difference between version 1 and version 3. These versions are very much alike and it was expected that these had similar results. The fact that version 1 is more favourable than version 3 to reduce curtailment was unexpected since valuing the filling level should enable the battery to increase the consumption when prices are low, like in times of curtailment. On the other hand, version 1 was modeled so that it only charged from curtailed energy. This is probably the reason why it gives such a low amount of curtailed energy compared to the other two versions. This also highlights a weakness in PowerGAMA; It would be valuable to enable modeling batteries with a straight line for the charging values and a steep line for the discharging values. This way it would be possible to only charge from curtailed VRE and still have a smarter and more profitable approach for discharging. In GB the opposite tendency is observed where version 3 is the most favourable regarding curtailment, although the difference between each version is almost insignificant compared to IE.

The three versions also affect the capture price for VRE differently in IE and GB. In IE version 3 gives the best capture price, while version 2 gives the worst. For GB there is close to no difference. Note that the batteries did not have a momentous effect the capture prices since the changes are very small. The reason why the capture price is lower for V1 and V2 than for V3 will be commented on later.

The profit for each battery version is also evaluated. The average captured profit portray the average profit that each battery gets when charging and discharing one unit of energy. This time the batteries in IE and GB were more in line. Version 2 definitely had the lowest captured profit for the battery. It is modeled with the lowest discharging values hence it is reasonable that it also gets the least captured profit. Version 1 and version 3 gets almost the same captured profit in both IE and GB. For GB version 1 had slightly higher captured profit, while for IE it was the other way around. This emphasise the complexity of the power system and how difficult it can be to find uniform ways to model batteries for multiple areas in Europe.

It is important to get back to why the capture price for V1 and V2 is lower than for V3 because this example illustrate how capture prices reflect the economical revenue for VRE. Since capture prices are defined as the total income divided by the generation, it would be reasonable to assume that when the capture price decreases the total revenue for VRE follows. This is not neccesarily true. This is because the capture price is affected by two factors;

1. the nodal price in times of generation
2. the total generation

If, for instance the nodal price in times of generation increased, so would the total revenue, thus also the capture prices. If, on the other hand, the nodal price in times of generation is unchanged, but the total generation increases the revenue would increase and the total generation would increase, The question is which one will increase the most. For instance, if the nodal prices did not change at all in a system where the curtailmend decreased, the VRE producer would get the same profit from the old generation and an additional revenue for the extra energy that is no longer curtailed. Thus, the revenue would slightly increase, but the capture price would decrease. This is because the capture price is weighted average values of the nodal price in times of production. Thus, the nodal price for the extra generation would need to be higher than the old capture price for curtailment to increase the capture prices. This is unlikely as the battery does not carry a big enough capacity to increase the nodal prices to that extent in times of curtailment. Based on this, curtailment will often decrease capture prices even though it will increase the total revenue for VRE. This illustrates a weakness of solely investigating the capture prices for VRE when evaluating the economical incentives for investing in VRE. Hence it also shows why it is important for this thesis to also look into how batteries and electrolysers affect other aspects of VRE economics.

It is interesting to increase knowledge about how the batteries affect the power prices in times of VRE production. One way to do this is the capture prices, but as explained above it does not always give a representative picture of it if there is a significant share change of curtailment from VRE. This problem can be solved if the curtailed energy also is added to the capture price. This way it represent the average nodal prices in times of potential generation from VRE and not only the actual generation. This is illustrated in Figure 42, called capture price VRE incl. cur. This value is lower than the actual capture price because it divides with a greater value, including both generation and curtailment.

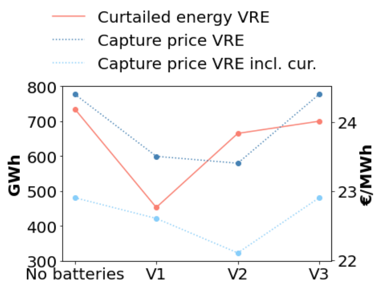


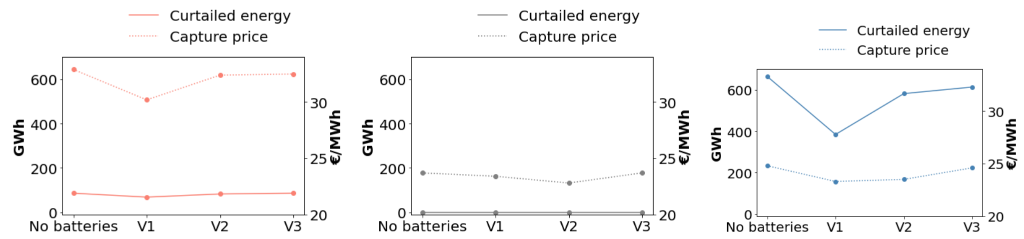
Figure 42: Curtailment drops in V1 simultaneously as the capture price drops. This implies that the prices drops in times of production from VRE.

The curtailment is also illustrated in Figure 42 in red. All batteries decreased the curtailed energy compared to the case with no batteries. It is interesting to see that the capture price including curtailment decreases significantly for V1 even though the curtailment decreases. The only reason why this happens is that the average prices in times of production from VRE decreases. From this it is clear that the batteries in fact have a small, but negative impact on the revenue for VRE. The total revenue is illustrated in Table 17. From the table it is clear that the revenue decreased for V1 and V2, while it increased for V3. Thus, V3 had the most positive affect on the revenue for VRE in IE.

	No batteries	V1	V2	V3
Income $m€$	264.25	261.18	255.06	264.68

Table 17

It is also of interest to see how the batteries affected each VRE source specifically. This is only done for the battery in IE. As Figure 43 illustrates, all versions had a negative impact on the capture price and a positive impact on the curtailment. Version 1 had the most negative impact on the capture prices and at the same time the best impact on the curtailment. This is reasonable as the results above concluded that decreasing the curtailment normally also decreases the capture price. Version 3 had the best impact on the capture prices while it had the worst impact on the curtailment. Using the same reasoning as before this means that version 3 is best capable to increase the prices in times of production from VRE although it is not as suited to prevent curtailment. Note that offshore wind experience no curtailment. This is because it is always favoured in the optimization since it has the lowest marginal cost.



Solar PV Offshore wind Onshore wind

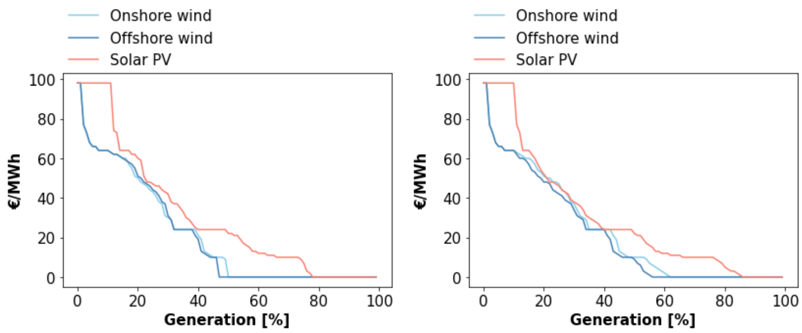
Figure 43: There is no clear favourable version regarding the reducing curtailed energy or increasing capture price for solar PV, offshore or onshore wind. V1 has the lowest curtailed energy for solar PV and onshore wind. V3 has the highest capture price and the highest share of curtailment.

Table 18 compares the revenue for each VRE for the system without a battery and with a battery of version 3 since it gave the highest revenue for VRE according to Table 17. The revenue for onshore and offshore wind increased, while the revenue for PV decreased. The overall revenue for RES increased.

	No batteries $m€$	version 3 $m€$
Onshore wind	128.65	128.95
Offshore wind	126.49	126.72
Solar PV	9.114	9.001
Total RES	264.25	264.68

Table 18: Implementing one battery at the IE node resulted in increased revenue for wind, but decreased for solar PV.

To understand why the total revenue for PV decreased when adding a battery it is important to look into how this affect the power prices in times of much generation from solar PV. From Figure 43 it was clear that the curtailed energy decreased, which means that the overall nodal price in times of generation from PV must also decrease for the revenue to decrease. This is illustrated in Figure 44 through duration curves for the nodal prices in relation to the generation. To the left there is no batteries in the system and to the right one battery of version 3 is added in IE. The first noticeable result is that, in both cases, onshore and offshore wind produce at approximately the same power prices. Also the solar PV has an overall higher electricity price when it is generating power. The reason for this is that solar PV has a daily generation pattern that matches the load better than it does for wind. This is also clear from Figure 45.



No batteries One battery version 3 in node IE

Figure 44: Adding one battery increased the linearity of the duration curve for generation from RES, especially for wind. In addition, it decreased the electricity prices in times of generation from solar PV which resulted in a lower revenue for solar PV than for the case without a battery.

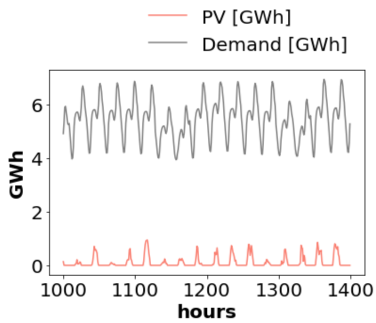


Figure 45: The generation from solar PV has a similar daily patterns as the total load in IE.

Figure 44 also points out that the duration curve shifts to a more linear form, especially for wind when adding a battery. The area underneath the graphs is the total revenue which has increased for wind and decreased for solar PV. It is also clear from Figure 44 that adding one battery decreased the number of hours with curtailment for all sources. This led to an increased production (from the battery) when the prices are between the discharging values of $50 - 60€/MWh$. This is especially where the graph has been straightened out. This is an important result as it shows how batteries contribute to decreasing curtailment but at the same time it decreases the number of hours with high prices. Over a period of time this will decrease the price volatility, especially when prices are high. For solar PV this affected not only the capture price, but it also decreased the total revenue from the wholesale electricity market.

6.2.2 Sensitivity analysis battery capacity in IE

For this thesis the TYNDP 2020 battery capacity is used when modeling batteries in PowerGAMA. To fully understand how batteries affect the power prices, the battery capacity is increased in IE. Because of time limitations simulations for a time range of 1000 to 3000 hours was used. The capacity was increased to ten times the installed charging and discharging capacity and ten times the storage capacity compared to the TYNDP 2020 value. The results are highlighted in Figure 46.

As Figure 46 points out, the average minimum price over a time period of six hours did not change significantly. The maximum price on the other hand, decreased slightly. This illustration is for a battery of version 2, but the same tendency was noticed when modeling the other version 1 and 3 as well. The average captured revenue for the battery is also presented in blue. The battery experience significant decrease from $23 - 8€/MWh$. This is likely to continue until it reached the dead band value of version 2 which is $6.75€/MWh$. Again, the same trend was observed for

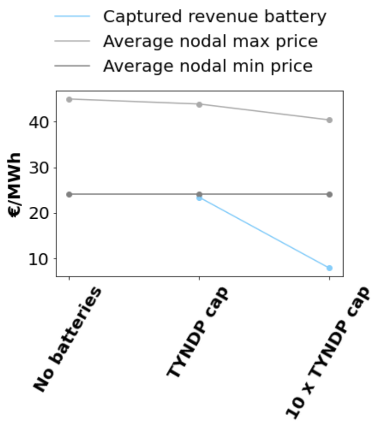
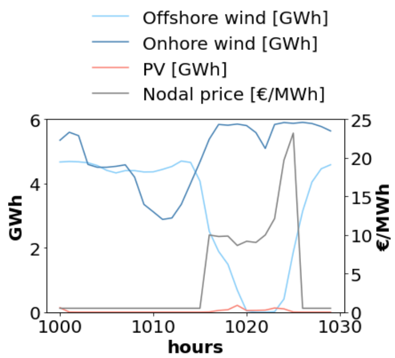


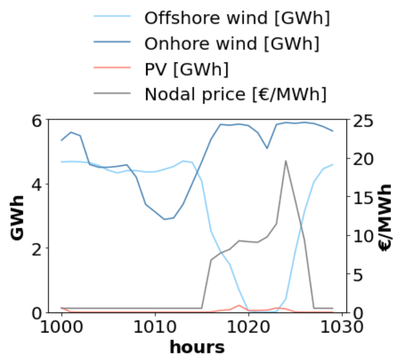
Figure 46: Simulations with one battery in IE of version 2. When increasing the battery capacity and storage capacity 10 times more than already expected in the NT scenario in IE, the maximum price during a time period of 6 hour decreased. The minimum price was not affected as much. The same tendency was observed for V1 and V3.

version 1 and 3, only that the decrease was limited to the dead band, which is 49€$/MWh$ and 50€$/MWh$.

Hence the battery decrease the overall price volatility by mainly decreasing the high nodal prices. The lowest power prices are not as affected by the batteries, although the battery in some cases slightly increase the nodal prices. In Figure 47 this affect is illustrated. At first it might seem like the highest nodal prices has decreased, but looking closely, the illustration to the right has a wider curve for the nodal price, meaning that the number of hours with a nodal price approximately at zero decreases.



No batteries IE



One battery version 2 in node IE

Figure 47: Generation and curtailment (the generation potential) for RES and the nodal price at node IE. It shows that adding a battery mostly decreases the higher nodal prices and slightly increase the lower nodal prices.

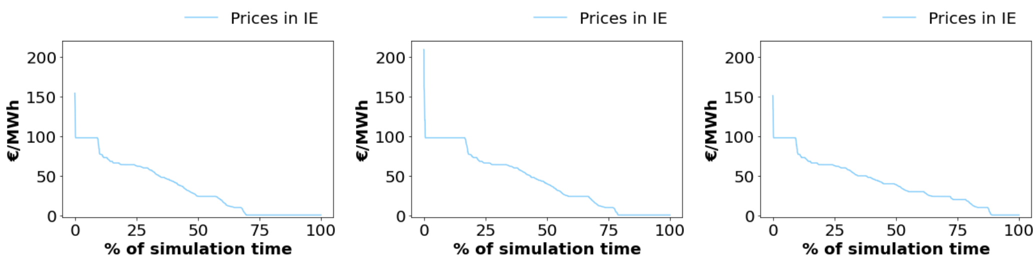
6.2.3 Electrolysers in IE

For these cases there are no batteries in the system. When modeling electrolysers the following simulations were run:

- Constant electrolyser demand - const H_2
- Flexible electrolyser demand - flex H_2
- Constant electrolyser demand and extra VRE generation - const H_2 + gen
- Flexible electrolyser demand and extra VRE generation - flex H_2 + gen

Firstly the simulations without extra generation was made. A total of $2.5GW$ electrolysis capacity was implemented in IE according to Table 14. This capacity refer to the installed capacity, which means that it is necessary to find the utilization for the electrolyser to find the $demand_avg$ in $consumers.csv$ when modeling the const H_2 case. The utilization factor for electrolysers are often set to 60% [13], but this will not be used when simulating the const H_2 case. To easily compare the two cases flex H_2 and const H_2 the total electrolyser demand after simulating the flex H_2 is used to set the average demand for const H_2. Hence, they will have the same total electrolyser demand, only not at the same time.

When adding electrolysis in IE the electricity prices increased for both const H_2 and flex H_2. A duration curve of the electricity prices is displayed in Figure 50. This was as expected as the only change to the system was an increased load. There did not appear any load shedding in IE when adding the electrolysis load. When adding the constant electrolysis demand the profile was lifted to a higher price. For the flexible electrolyser demand the upper part of the duration curve remained unchanged, while the lower part became less steep. To summarize, the both cases increased the nodal prices and decreased the number of hours with a nodal price of approximately zero, which implies that there is less curtailment in the system. Flexible electrolyser demand had the highest impact on curtailment as it had fewest hours of approximately zero nodal price.



No electrolysers | Constant electrolyser demand | Flexible electrolyser demand

Figure 48: Adding constant or flexible electrolyser demand in IE increased nodal price profile in IE.

Even though this did not lead to load shedding it would be unreasonable to assume that it is sustainable to increase the average load with 100GW in EU without increasing the generation from VRE. These generators are often referred to as Power to Gas generators, or P2G. Extra P2G capacity from VRE was added in IE in to the two cases. When determining how much installed capacity was added for each source the following approach was used

1. Determine the share of installed generation for each VRE
2. Find capture factor for each source in IE
3. Find curtailed energy for each source in IE
4. Find total electrolyser demand

5. Find installed capacity for each source without considering the capture factor
6. Find the extra installed generation capacity for each source, accounting for the capture factor and curtailed potential

The objective with this approach is to increase the energy produced by VRE in line with the total electrolyser demand. Both [13] and [20] have used similar approaches when quantifying the P2G capacity, hence these are used as a basis for this thesis. The capacity for each source is highly affected by the available resources at the specific location. For this thesis the values are chosen especially to fit the North Sea region. The share of P2G for each VRE source is listed in Table 19. Note that the values refer to the share of generation, and not installed capacity. The capture factor for IE is extracted from the input files and the curtailed potential is gathered from previous simulations without batteries nor electrolysers. The next step was to find the total installed generation capacity for each source without accounting for the capture factor, cf. The installed capacity without cf in Table 19 for solar PV, onshore and offshore wind is all together equal to 1076MW. Multiplying this with 2000 hours it correspond to the total electrolyser demand of $2.15TWh$. Thus, solar PV should provide $2150GWh \cdot 0.2 = 430GWh$ of this over a period of 2000 hours, which correspond to an installed generation capacity [6] of $215MW$. The last step was to find the final extra installed capacity for each source when considering the capture factor and curtailment. For solar PV this was $215MW/(0.3 \cdot (1 - 0.19)) = 885MW$. In other words, for solar PV to generate approximately $430GWh$ over 2000h the installed generation capacity must be $885MW$ assuming the curtailment is approximately the same as for the normal NT scenario.

	solar PV	onshore wind	offshore wind
Capture factor [%]	13	45	53
Curtailed potential [%]	19	13	0
Share of generation [%]	20	50	30
Installed cap without cf & curtailment [MW]	215	538	323
Final extra installed cap [MW]	885	1440	609

Table 19: Installed capacity represent the extra capacity that is added in IE when installing electrolyzers in IE. It correspond to the total electrolyser load (2.15 TWh for 2000 hours). The capture factor for IE, cf, and curtailed potential is considered.

The results form the simulations with extra P2G generation are discussed in the following section.

6.2.4 The synergy of hydrogen and batteries in IE

Finally, the synergy of hydrogen and batteries will be analyzed in IE. The cases included in the analysis is the same as the four cases listed in 6.2.3, only that one battery of version 3 is added in the last case with a flexible electrolyser and extra generation (Flex H2 + gen + battery). The focus is on how it affects the curtailed energy, the average nodal price and the percentage of zero price hours (below $0.5€/MWh$. First of all, Figure 49 shows that when adding a battery of version 3 the number of zero hours slightly decreased. The share of curtailed energy did not change much. The battery had close to no impact on the average nodal prices. This applied both for the case with and without an electrolyser. Based on this, the battery is not the most important solution to increase revenue for VRE in Ireland towards the future.

When removing the battery and adding constant and flexible electrolyser demand the curtailed energy and the percentage of zero hours reduced significantly. This affect was even higher when modeling the hydrogen as flexible instead of constant. The average nodal price increased for both cases, which is reasonable as there is only added more load to the system. The fact that the curtailed energy decreased significantly when modeling the electrolysers as flexible, shows how important flexible electrolysers is for the future profit of VRE.

[6] without accounting for capacity factor nor curtailment

Nevertheless, adding that much extra load without adding extra generation is not reasonable. Thus extra generation was added for the next two cases like described in Table 19. It is clear from Figure 49 that the curtailed energy and the percentage of zero hours increased significantly for these cases. It is reasonable that the total curtailed energy will increase when adding more generation. As there is a higher number of zero hours for the $constH2 + gen$ case it is reasonable to assume a higher share of curtailed potential. This is reasonable as the flexible electrolyser demand does not solely consume from generation from VRE.

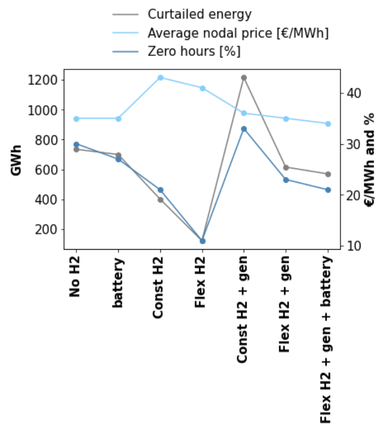
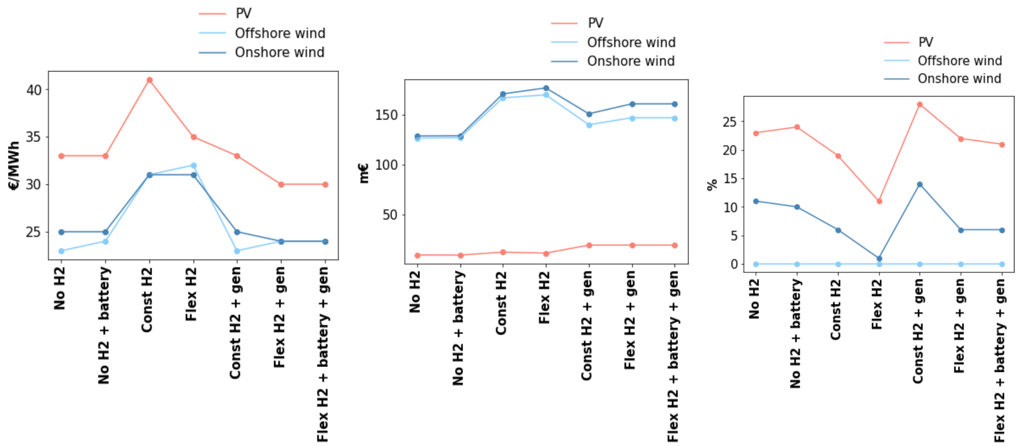


Figure 49: Flexible hydrogen reduced the curtailed energy from RES significantly. It also had the highest effect on reducing the number of hours with a nodal price below 0.6€$/MWh$, also called "zero hours".

As for batteries it is of interest to see how electrolysers and hydrogen affect each generation source. Figure 49 shows the capture price, total revenue and percentage curtailed energy for each generation source. As discussed earlier batteries did not have a significant impact on the capture prices. Adding constant hydrogen demand had the highest impact on the capture prices as it significantly increased the average prices, illustrated in Figure 50.

When comparing flexible hydrogen demand and constant hydrogen demand, the capture price for wind was not affected as much, but the capture price for solar PV had a noticeable change. The capture price for solar PV is higher than for the no H_2 case, but significantly lower compared to the const H_2 case. This is likely because the generation pattern for solar PV follows the demand better than other VRE. This is previously illustrated in Figure 45. Thus, when the high nodal prices increase, the solar PV is especially impacted. When the electrolyser load is flexible, on the other hand, the prices increased mainly for the lower prices, hence the capture price for solar PV experience an significant decrease. This highlights how differently the electrolyser demand can affect different VRE economics.

When adding the extra generation the graph to the left in Figure 50 show that the capture prices decreased. At first it looks like the const H_2 case gives the best profit, but when looking at the graph for the total revenue it is clear that flexible H_2 gives a slighlty higher revenue for all VRE. The capture prices does not give the same impression and the reason is the same as for the batteries; The decreased curtailment visualized in the graph to the right, results in decreased capture prices.



Capture price   Total revenue   Percentage curtailed energy

Figure 50: Adding batteries had close to no effect on the capture prices, total revenue or curtailed energy for VRE. Flexible hydrogen gives the highest increase in total revenue for VRE. When adding extra generation to the flexible hydrogen demand it still gave slightly higher revenue than the normal case (No H2).

It is also of interest to investigate how the different cases affected the capture price for the electrolyser, which we have defined as the weighted average price when electrolysers are consuming power. In addition it is important to see this in light of the total utilization of the electrolyser. For instance, the case const H_2 has a higher capture price than const H_2 + gen and the same average electrolyser utilization of 43%. Hence the const H_2 + gen is better than const H_2. This is reasonable as increasing the extra generation would help decrease the average power prices making it more profitable to invest in electrolysers.

The electrolyser performance in IE is illustrated in Table 20 The most profitable solution for electrolysers is the flex H_2 + gen as it has the lowest average capture price and the highest utilization. Also note that when increasing generation from VRE with flexible electrolyser demand (flex H2 + gen) the utilization for the lowest operational price increased from 24% to 35%. This implies that in IE for this simulation it is profitable to produce hydrogen at 20€$/MWh$ since the utilization decreased to a tolerable value according to Figure 35 and [13].

	Total H2 demand over 2000h TWh	Average capture price €$/MWh$	Average electrolyser utilization %	Electrolyser utilization range %
Flex H2	2.15	34	43	24-64
Flex H2 + gen	2.61	26	52	35-70
Const H2	2.15	43	43	43
Const H2 + gen	2.15	36	43	43
Flex H2 + gen + battery	2.61	27	52	35-71

Table 20: Results from modeling hydrogen flexible and adding extra generation had clearly the best results regarding the electrolyser utilization and the average capture price for the electrolyser in IE.

6.2.5 The impact of hydrogen and batteries on revenue for VRE in Europe

When adding batteries to the whole system version 3 because it gave the highest revenue for VRE in the case study. One battery was added in each area in a node that corresponded to an offshore wind generator. If there was no offshore wind generator in the area the battery was connected to an onshore wind generator [7]. The battery capacity was extracted from the TYNDP 2020 data set [18]. The electrolysers were added with the similar profiles as from the case study in IE. The electrolysers were added in offshore wind generators. If there was no offshore wind generators in the area the electrolyser was connected to an onshore wind generator[8].

Like for the case study in IE, when assessing how the total revenue for VRE is affected by batteries and electrolysers the capture prices and the percentage of curtailed energy is important. Thus these are plotted in Figure 51.

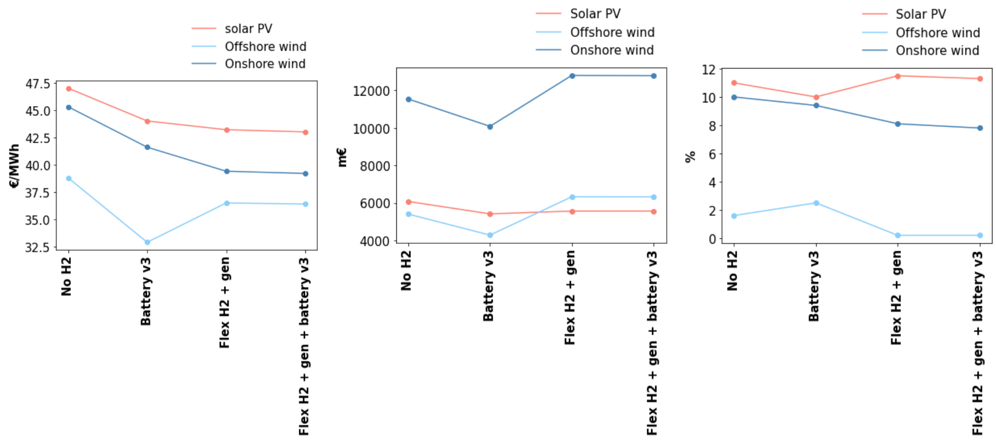


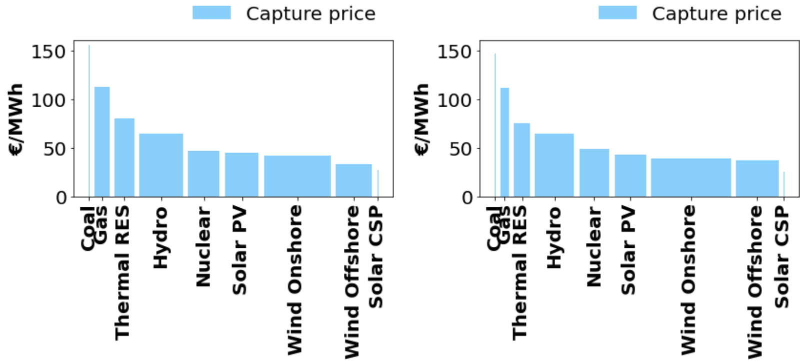
Figure 51: Result from adding batteries, electrolysers and extra generation in the whole European system. As for IE, batteries did not have an significant impact, in fact it decreased the total revenue for VRE. Flexible hydrogen with extra generation gave more favourable results for VRE.

Much of the same trends as for IE is seen. For instance, the revenue for VRE increases when adding flexible electrolyser demand with extra generation. Batteries does not have a significant affect on the revenue, the capture price nor the percentage of curtailed energy. In fact, when looking at the results in Figure 51 for the case with solely batteries, it had a negative effect on the capture price and the total revenue. Thus, from these results batteries are not the most efficient measure to increase the motivation for investing in VRE and in some cases it might even decrease the economical motivation for investing in VRE.

When assessing the effect of batteries and electrolysers on VRE in the European power market, the generation mix is also of interest. Figure 52 show the capture prices and the generation mix in the NT scenario with and without batteries and electrolysers in the European power system. The two illustrations look very much alike. The most significant difference is that the gas generation decreased when adding batteries and electrolysers. This decrease is especially interesting as the NT scenario is the only scenario that does not reach the EU 2050 target according to TYNDP 2020. Would this decrease in gas generation be sufficient to reach the 2050 target? This was investigated and the results are illustrated in Figure 53.

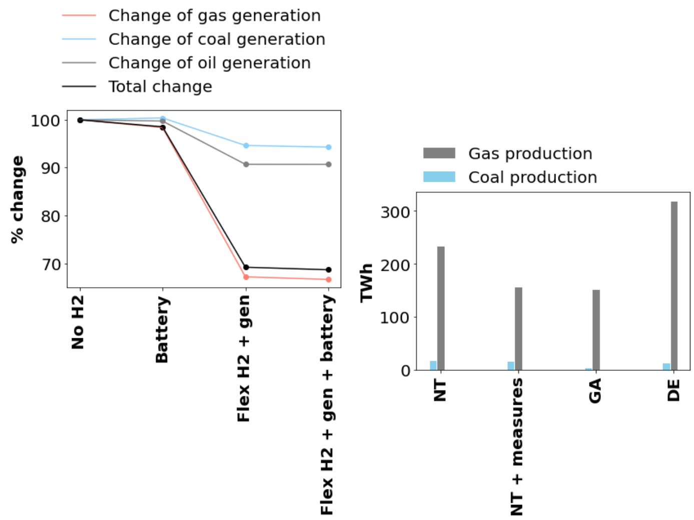
[7] This applied the following areas: AL, AT, BA, BG, CH, CZ, ES, HR, HU, ME, MK, RO, RS, SK, SI, LU, SE01 and SE02.

[8] This applied for ES and NOs.



NT NT with batteries and electrolysers

Figure 52: Capture prices (height of bars) and generation mix (width of bars). Generation from gas decreased and production from onshore wind increased when adding batteries and electrolysers.



Percentage change in generation for NT scenario

Generation gas and coal all scenarios

Figure 53: Decrease of generation from fossil fuel based generation for the NT scenario when adding flexible hydrogen and extra generation makes the emissions from energy generation in the NT scenario almost as low as in the GA scenario.

When TYNDP 2020 assessed whether the scenarios reached the EU targets or not the total emissions from fossil fuel based generation was one of the most important factors [20]. From Figure 52 it is clear that the NT scenario had high gas and coal production. Coal production is significantly lower, but still important to the total emissions because it releases approximately twice the emissions as gas [37]. When adding batteries and electrolysers to the NT scenario the production from gas decreases by 30% and is now in line with the gas production in the GA scenario. This is a significant reduction and which might be extensive enough for the NT scenario to reach the EU 2050 target.

Still, it is important to remember that when adding electrolysers to the system so was extra generation from VRE. For the IE case the extra generation did not exceed the simulated electrolyser demand, but because of the simulation time there was not enough time to do the same for all countries with electrolysers. Thus, the extra generation was found by assuming an utilization of 60% and fulfilling this extra load with extra generation from VRE. For some countries like Portugal, Great Britain, Ireland and Poland this was an good approximation, but for some countries the electrolyser utilization was simply too low. This applies especilly for the south of

Norway and Italy where the utilizaiton was 15% and 6% respectively. The average electrolyser utilization is listed in Table 21. For these areas it is likely that the extra generation added was too extensive accounting for the low demand increase caused by low utilization from electrolysers. If the power system experience a very high increase of generation from VRE it is only reasonable that the generation from fossil based production decreases. To single out this source of error, the total fossil based generation in the IE case was analyzed. As mentioned before, this case matches the extra generation from VRE and the extra load from electrolysers. The same trend was observed; gas production decreased by 28%. Coal production did increase by 33%, but since it is only makes up 0.2% of the total generation from fossil fuel based generation in IE, this reduction is has an insignificant effect on the total emissions in IE. Based on this, there is still a solid basis to believe that electrolysers has a significant effect on the reduction of gas production in throughout Europe. It would be interesting to analyse why electrolysers has this affect on the gas power production, but this is out of the scope of this thesis and will be valuable for future work.

Country	FR	BE	NL	ES	NOs	DE	IE	GB	IT	PT	PL
Utilization %	46	30	34	47	15	26	57	51	6	54	65

Table 21: Average electrolyser utilization for all countries with installed electrolysers. The same result for the case with flex H2 + extra gen and flex H2 + extra gen + batteries. IT and NOs stands out with too low utilization for the electrolysers to be economically beneficial with a price range as described in 13.

As mentioned earlier, the TYNDP 2020 does not model electrolysis, they simply add it after the power system simulations by assuming that the curtailed energy (and some P2G generators) supplies the electrolyser demand. In this way they are not able to capture its affect on the power prices and the generation mix. The results from this thesis shows that the environmental impact of scenario NT was significantly decreased by adding hydrogen. Thusthis thesis illustrates just how important it is to include modeling hydrogen in the power system simulations for the European power market.

6.2.6 The effect of CO_2 price on capture prices for VRE

Since the future of the CO_2 price is uncertain we found it valuable to see how the CO_2 price would affect the capture prices of VRE. Many more results could have been analysed, but because of time limitations only the capture price is highlighted in Figure 54. It would also be of interest to see how increasing the CO_2 prices would affect battery and electrolyser behaviour, but this is also out of scope for this thesis.

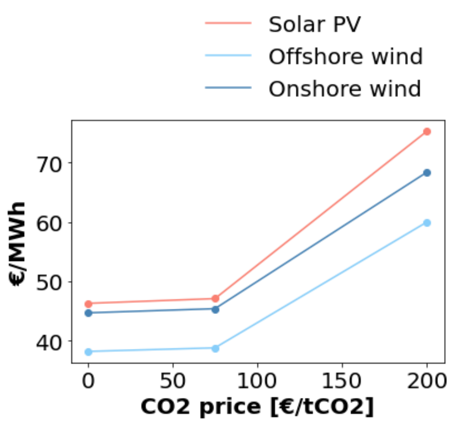
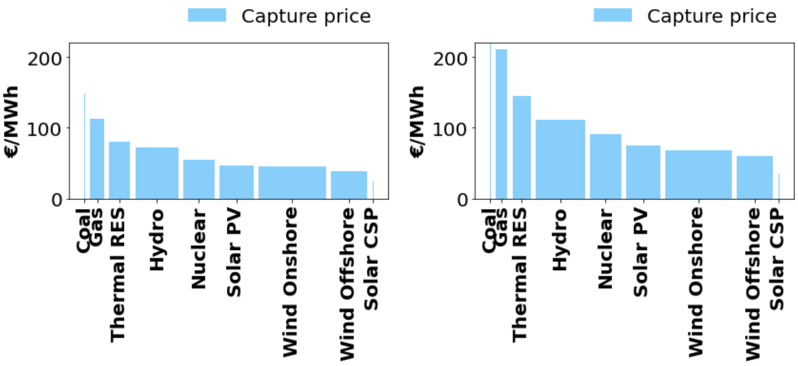


Figure 54: Capture prices for solar PV, offshore and onshore wind. They increase rapidly when the CO_2 prices are high.

As expected the capture price for VRE increase in line with the CO_2 prices. The reason for this is that the CO_2 price increase the overall electricity price, which also increase the capture prices. This is illustrated in Figure 55. From Figure 55 it is also seen that the generation from gas decreases as a result of increased marginal costs. This is mostly covered by an increase in generation from hydropower as the prices now are high enough for it to surpass the highest storage/pumping values.



NT CO_2 price = 75€$/tCO_2$ NT CO_2 price = 200€$/tCO_2$

Figure 55: The generation mix (width of bars) and capture prices (height of bars) for different CO_2 prices. When CO_2 price increases the capture prices follows as a result of increased nodal prices. Gas generation, on the other hand, decreases decreases while the production from hydrogen increases.

7 Conclusion and future work

This thesis assess the impact of adding batteries and electrolysers to the power system. The motivation for this topic is that going forward, the power system face many challenges that can be solved by investing in batteries and electrolysers. One of these challenges is the economical incentive for investing in VRE. To reach the EU 2050 target and become a net zero society the installed capacity of VRE must increase significantly. Hence, investments in VRE must be economically beneficial to enable decarbonization. When increasing the share of VRE in the generation mix the revenue from the wholesale electricity market could decrease, decreasing the financial profit for VRE. Thus, balancing measures like batteries and electrolysers can be important to reach the EU targets.

When analysing the future power system a DC power flow optimization tool called PowerGAMA is used and data from TYNDP 2020 founds the basis of the analysis. The input files forming the modeled power system were scaled, edited and tuned to fit TYNDP 2020 scenarios. Further simulations were run with an objective to analyse the impact of batteries and electrolysers on VRE economics in the European power market. This topic is vast and includes multiple aspects that are intertwined. Thus, the focus was to give broad analysis of the challenges in the power system towards a zero emission energy sector.

7.0.1 NT, DE and GA scenarios had high capture prices without balancing measures

When simulating the scenarios we found that most of the capture prices for each VRE source was above expected LCOE. Based on this, it is likely that investments will be made so that the installed generation capacity for each scenario is reached without balancing measures or financial support. On the other hand, investments are not made solely based on predicted capture prices. There are multiple other sides to VRE economics that is of interest when making an investment decision. These will be assessed in the following sections.

7.0.2 Valid approaches for modeling batteries and green hydrogen in PowerGAMA was found

One of the objectives for this thesis was to find simple ways to model batteries and green hydrogen in PowerGAMA. We located different approaches and found what was best suited for this thesis. Further the behaviour of the batteries and electrolysers were analysed. They turned out to be a good fit for the simulations for this thesis and can also be used for similar analysis in the future.

Three versions of batteries was modeled for this thesis to see if they would affect the power system differently. They were tested by adding one battery in IE and GB. The results regarding curtailed energy, capture price, average captured profit for the battery and total revenue were assessed and they were surprisingly inconsistent for all three versions. For instance, in IE version 1 gave the least curtailed energy while V3 gave the overall highest capture price. For GB the difference between the versions was smaller yet the tendency was not necessarily the same as for IE. For instance, V3 gave the highest share of curtailed energy in IE, but the lowest in GB. From this two conclusions can be drawn;

- There is no favourable battery version for all aspects of VRE economics.
- The batteries affect VRE economics differently based on geographical differences.

Although the results did not point out a superior battery version, version 3 was chosen to model further as it gave the best captured profit for the battery, the highest capture price and the highest revenue for VRE.

7.0.3 Batteries did not have a significant impact on VRE economics

This was a surprising result, but when looking closer we understood why. The batteries are modeled to charge from hours of low prices, preferably when there is curtailment. When the power system modeled for this thesis experience curtailment it is in large quantities. Thus, the batteries did not have the capacity to consume all this power. The batteries therefore had a positive impact on the share of curtailment from VRE, but they were not able to increase the prices in times of curtailment. Further, the battery discharged in times of high prices which lowered the higher prices in the power system. In other words, implementing a battery in IE decreased the price volatility, mostly by decreasing the higher power prices. A large quantity of the revenue for VRE comes from selling power in times of high prices, thus the total revenue for VRE just slightly increased when adding batteries. For solar PV the total revenue actually decreased because of this. The same tendency was observed when batteries were added throughout Europe.

7.0.4 Capture prices did not capture all aspects of VRE economics

When modeling batteries we also found a weakness when using capture prices to evaluate VRE economics. During the simulations it was clear that when a battery decreased the curtailed energy, so did the capture price. Decreasing the curtailed energy has a positive impact on the revenue for VRE, but this is not reflected in the capture prices. This is because the capture prices is a weighted average of the nodal price in times of generation. This highlights why it is important to not only focus on capture prices, but also other effects on the power market when assessing VRE economics.

7.0.5 Electrolysers had a significant impact on VRE economics

From the results it was clear that adding additional flexible load from electrolysers had a solely positive impact on VRE economics. The curtailment decreased, the capture prices increased (even with decreased curtailment) and the total revenue increased. This also applied for modeling with constant electrolyser load, but the impact was not as extensive. The reason why is because an increase in the load lifts the prices which has a positive impact on VRE economics. The most interesting result were found when also increasing the generation from VRE in line with the electrolyser demand in IE. This still had a positive impact on the revenue for VRE. When increasing the generation the utilization of the electrolyser also increased, making it profitable to operate even if is solely produce hydrogen when the electricity price is below 20€$/MWh$.

When adding electrolysers with additional generation throughout Europe the curtailed energy and the capture prices decreased, but the total revenue increased for all sources. The utilization of the modeled electrolysers in EU did not reach its wanted utilization. This points out which areas must take action to facilitate hydrogen utilization to reach their announced electrolyser goals.

Another significant conclusion that can be drawn from the results is that by adding electrolysers throughout Europe the total gas generation decreased significantly. The decrease is so extensive it might be enough for the NT scenario to reach the EU 2050 target regarding CO_2 emissions. In section 2.4.4 we discussed whether electrolysers could be categorized as green hydrogen or not. The results show that electrolysers contribute to decrease the total fossil based generation both directly through the generation mix and indirectly by increasing the VRE economics. Based on this we find that if electrolysers behave like they are modeled in this thesis, they can be classified as green hydrogen.

7.0.6 Increased CO_2 prices gives increased capture prices for VRE

Finally, a small sensitivity analysis was performed regarding the effect of CO_2 prices on the capture prices for VRE. As expected, when increasing the CO_2 the overall electricity prices increased, resulting in an increased capture price for all VRE. The results also points out that for the CO_2 price to have a significant effect on the capture prices, the CO_2 price needs to increase significantly. Analysing why is out of the scope of the thesis, and is listed as possible future work.

7.0.7 Comparison of future LCOE and capture prices for the European power system

Finally, the capture prices in each case study for the whole system is listed in Figure 56 and compared to the original simulated NT scenario and the predicted LCOE. They show that adding batteries and electrolysers to the system did not necessarily increase the capture prices. Still they have proven to give higher revenue and lower curtailment for VRE. These feature are also important for the investment decision and illustrate the importance of using a simulation tool that enables to look into other aspects of VRE economics when analysing the future economical motivation for investing in VRE.

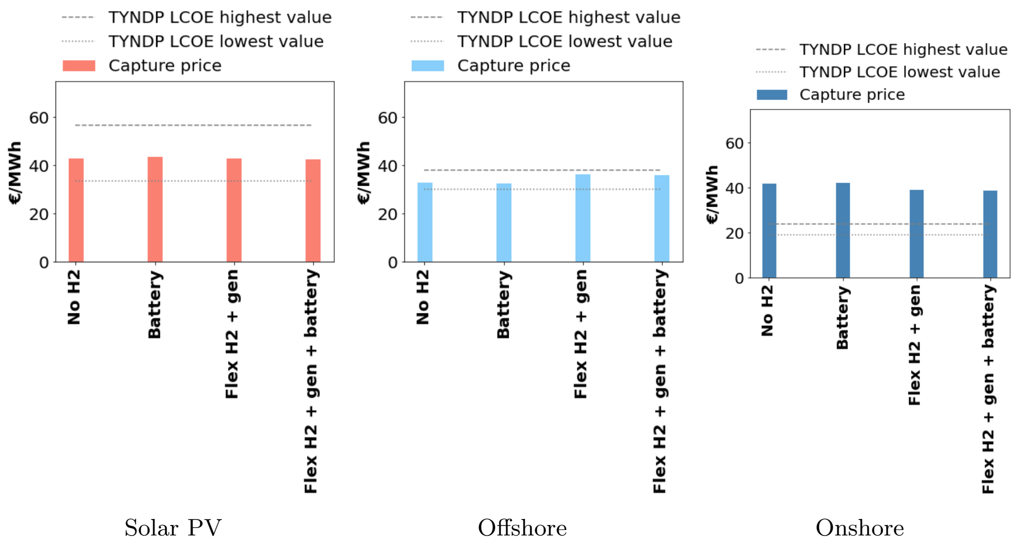


Figure 56: LCOE from TYNDP [20] and calculated capture prices for the case with flex H2 + extra gen + batteries throughout Europe. Because of decreased curtailment, the balancing measures does not always increase the capture prices, but as illustrated before batteries decrease the revenue for VRE while flexible hydrogen + extra gen increases the revenue.

7.1 Future work

This thesis has focused on many aspects of VRE economics, which gives a broad picture of how VRE is affected by future trends like batteries and electrolysers. Still, by focusing on how the system is interconnected like how curtailment, revenue and capture prices play together, difficult trade-offs has been made and interesting details is left out. Thus we have located some future work that either improves existing work or continues the work for this thesis.

- Find a way to model batteries like a constant, straight line for the charging values and a steep line for the discharging values. This way it can charge solely from curtailment and still enable smarter discharging.
- Find a way to model the whole hydrogen cycle including also hydrogen storage and generation from hydrogen to electricity. We made a suggestion for how this can be done in section 5.6.
- This thesis has focused on modeling electrolysers and batteries, but not on DSR. This is also pointed out an important trend for the future power system, hence it could be valuable to model it in PowerGAMA and further assess its impact on VRE.
- Other improvements to the existing model is to look more into how hydropower is scheduled or to tune specific parameters like transmission capacities to fit the TYNDP 2020 better.
- It could also be of interest to locate the most efficient measure to improve the electrolyser utilization in countries like Norway and Italy.
- Do further assessment on why the electrolysers had such a great impact on the gas generation
- There was only enough time to do a short analysis on the impact of CO_2 prices on the VRE economics. It would be interesting to look further into why the CO_2 price needs to be so high for it to increase the capture prices.
- Also, the impact of transmission constraints was not assessed for this thesis. This is likely to affect VRE significantly, thus this would be very valuable to look further into.

Finally, the master student that has worked on this thesis is highly motivated to help take this work further and hopes that future students will reach out if there are any questions regarding the work or results.

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Appendix

A Comparison of modeled results and TYNDP 2020 results

The NT, DE and GA scenarios were compared to TYNDP 2020. The generation mix, power flows and power prices are compared. Since the NT scenario is used further in the case studies it is illustrated in section 5.3.

A Generation mix

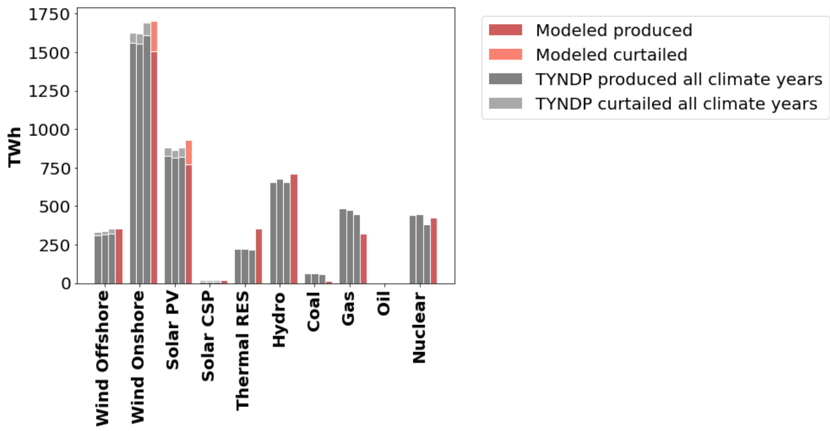

Figure 57: Generation mix with curtailment fit the DE scenario well. The curtailment is higher for the PowerGAMA model.

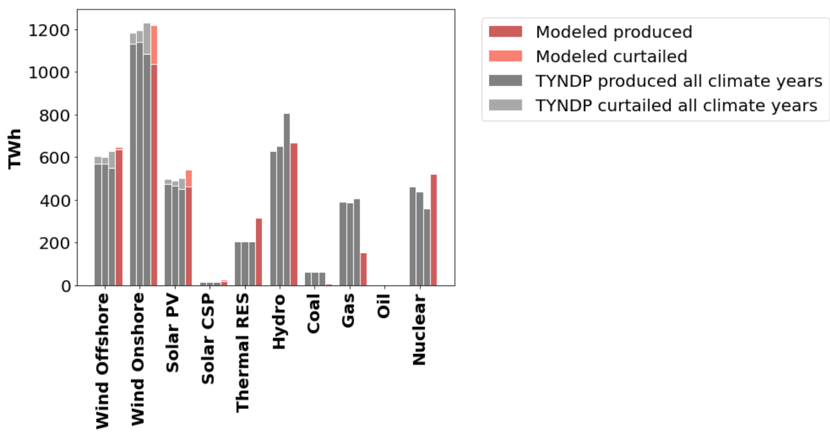

Figure 58: Generation mix with curtailment fit the GA scenario well. The curtailment is higher for the PowerGAMA model.

B Power flows

As for the power flows the same goes for DE and GA scenarios as for the NT scenario; The net power flow is not in line, but when looking into the power flows in each direction they are a batter fit.

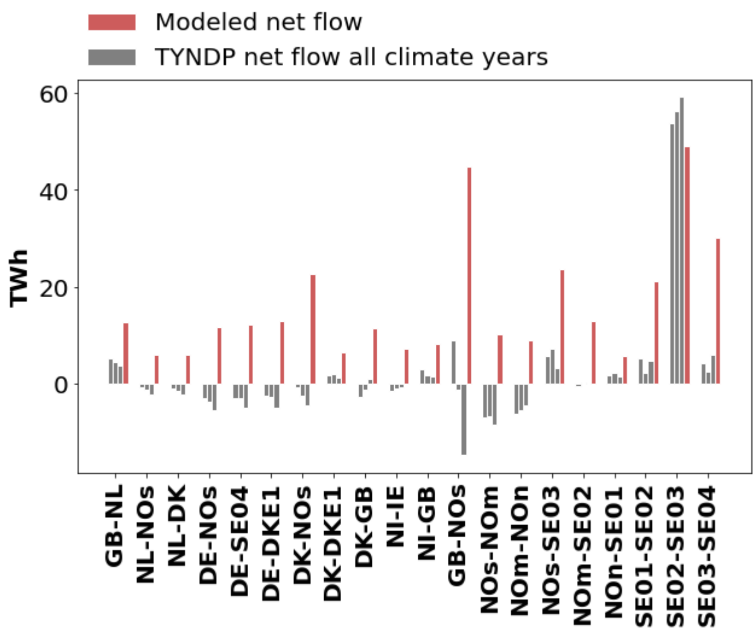

Figure 59: Net cross-border power flows in the DE scenario.

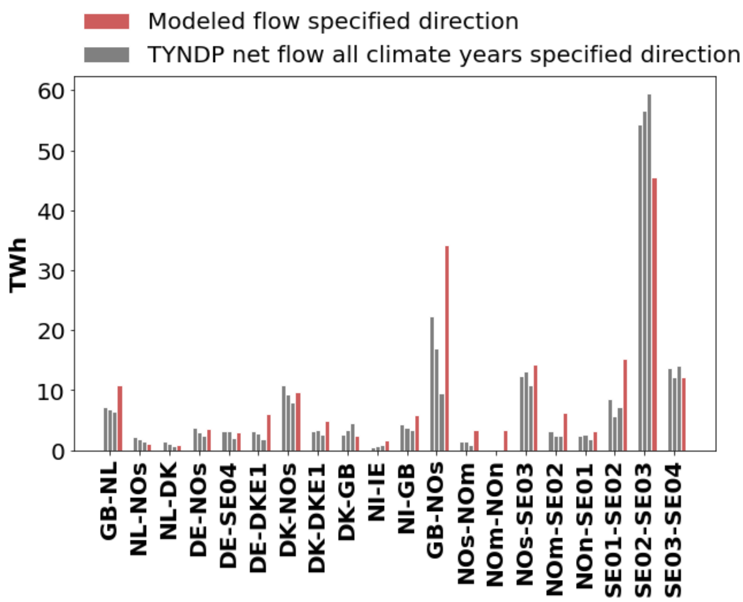

Figure 60: Gross cross-border power flows in the DE scenario for the specified direction.

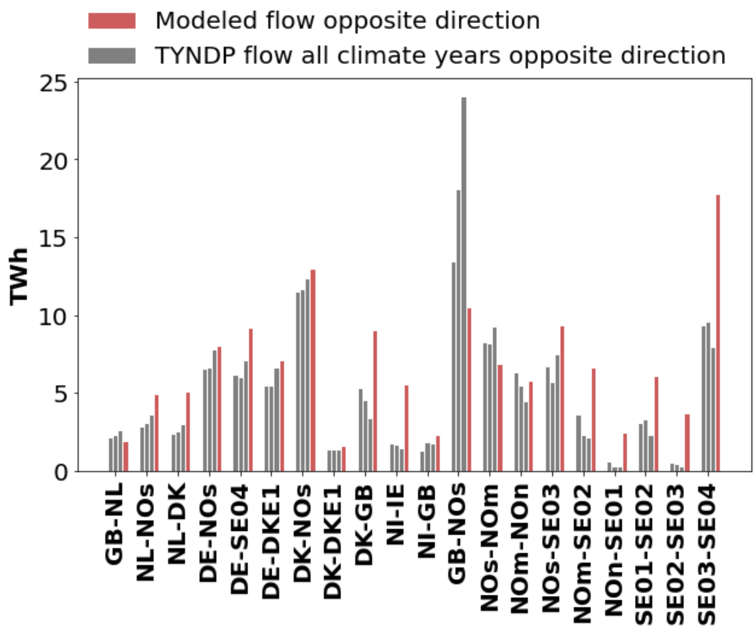

Figure 61: Gross cross-border power flows in the DE scenario for the opposite direction.

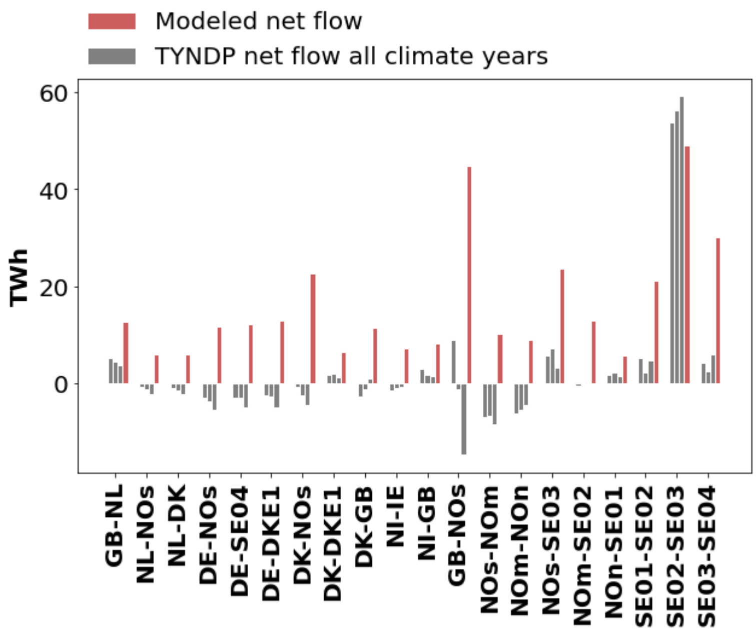

Figure 62: Net cross-border power flows in the GA scenario.

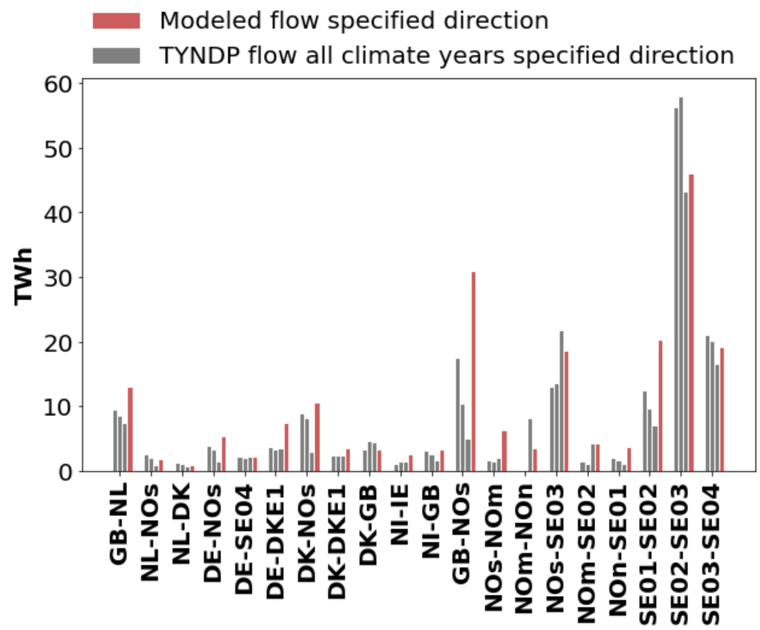

Figure 63: Gross cross-border power flows in the GA scenario for the specified direction.

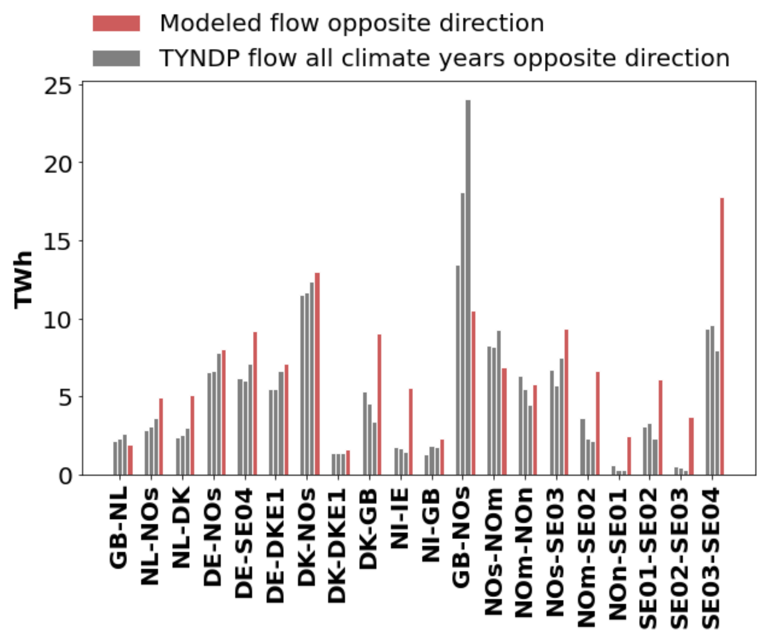

Figure 64: Gross cross-border power flows in the GA scenario for the opposite direction.

C Electricity prices

The simulated electricity prices are in general higher than the TYNDP prices for the GA and the DE scenario. The prices for the DE scenario is also much higher than for the GA scenario. Note that in these cases no balancing measures are included in the model, but they are in TYNDP.

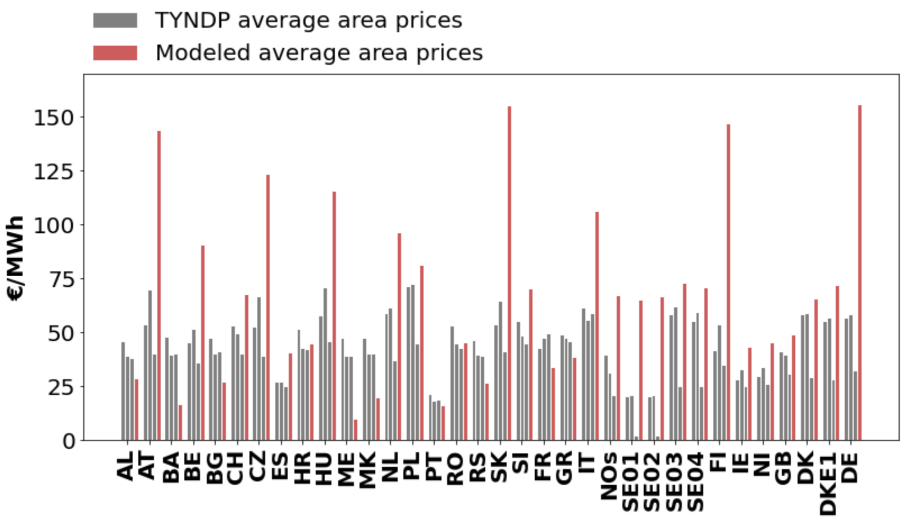

Figure 65: TYNDP prices [18] compared to the simulated pricen in the DE scenario.

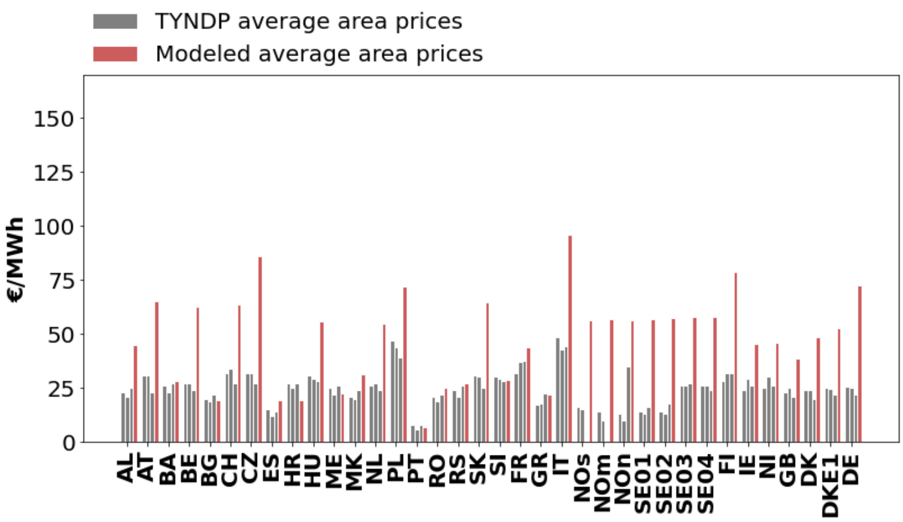

Figure 66: TYNDP prices [18] compared to the simulated pricen in the GA scenario.

B Modeling

When tuning the input files regarding the installed generation capacity some generator types was not already included in the 2014 data set for some areas. In these cases they were added. Below is the overview of the areas and generator types this applied to.

Type	Area
Gas	AL,SE02,IE,NI
Oil	IE,NI
coal	IE,NI
Other_res	ME,MK,RS,NOs,NOm,NOn,SE01,SE02,SE04,IE,NI
Solar_PV	AL,BA,ME,MK,PT,RS,NOs,SE02,SE03,SE04,FI,IE,NI,GB
Solar_CSP	HR,GR,IT
Nuclear	PL
Wind offshore	FI,PL,PT,FR,GR,IT,IE,NI,SE03,SE04,GB
hydro	IE
Wind onshore	AL,BA,ME,RS,NOs,IE,NI

Table 22: Overview of the new generators categorized in types that were added to the generator.csv input file because they were not included in the 2014 data set.

A Python code developed for the thesis

The code for this thesis builds on the work done in the specialization project report. Thus, this Appendix is taken from the report [34]. Note that the we have created more code in the master thesis, but we did not feel it was necessary to include it here.

For calculations of capture price, curtailment, also called spillage, and percentage generation the following functions are used. They are all created by the author, but some of them use existing code in PowerGAMA. The functions mentioned in blue are created by the author. In some cases it was necessary to calculate both capture price for the total system and for a specific area. More functions are therefore made, but the author did not find it necessary to include them. Table 23 gives a short description of each function.

⋮

Function name	Description
writeProductionIncomePerGen()	Is run in every new simulation after a res object is created. Creates two additional files called result_income and result_prod. Both are lists where result_income[i] correspond to the total income during one year for generator i. This is calculated by using; getNodeConnectedToGenerator() numGenerators() getGeneratorHourlyProduction() getNodalPrices()
getGeneratorHourlyProduction.. ..(genNumber)	Added in the Result class in PowerGAMA. Returns a list of the production of the production of generator genNumber.
getNodeConnectedToGenerators()	Returns a list of the node that is connected to all the generators. Node_connected[i] gives the index of the node connected to generator i. The function use; getListOfGenerators() numGenerators()
getListOfGeneratorsAtNode()	Returns a list of the index of the generators at each node. Gen_at_node is a list like this: [[0,1], [2], [3,4,5]] where generators 0 and 1 is connected to node 0 and so on. The function use; getGeneratorsAtNode() numGenerators()
getPercentageSpilledEnergy(type_gen)	Takes in a string that defines the type of generator. Returns the curtailed energy for a type of generators divided by the total energy potential. The energy potential is defined as the spilled/curtailed energy plus the production. The function use; getGeneratorsPerType() getGeneratorSpilled(i) the result_prod file
getPercentageGenerationPerTypeAnd.. ..Area(type_gen, area)	It returns the percentage of a type of generation in one area. It use; getGeneratorsPerType() getGeneratorsConnectedToArea() the result_prod file
getGeneratorsConnectedToArea(area)	Returns a list including the index number of the generators connected to the area. It use; getGeneratorAreas()
getAverageCapturePrice()	It calculated the average capture price for all sources for a give area. It use the methodology explained in section ??. There are also functions that calculate this for a specific type and a specific area. It use; the result_prod file the result_income file

Table 23: Descriptions of the most important functions created by the author.

```python
def writeProductionIncomePerGen():
    list_prod = []
    list_income = []
    node_connected = getNodeConnectedToGenerators()
    num_gen = data.numGenerators()
    for i in range(num_gen):
        hourly_prod = res.getGeneratorHourlyProduction(i, timeMaxMin=None)
        total_prod = sum(hourly_prod)
        total_income = sum(hourly_prod*res.getNodalPrices(node_connected[i],timeMaxMin=None))
        list_prod.append(total_prod)
        list_income.append(total_income)
    np.savetxt(datapath + name_res + 'result_income.csv', list_income, delimiter=',')
    np.savetxt(datapath + name_res + 'result_prod.csv', list_prod, delimiter=',')
```

⋮

```python
def getGeneratorHourlyProduction(genNumber, timeMaxMin=None):
        if timeMaxMin is None:
            timeMaxMin = [self.timerange[0],self.timerange[-1]+1]
        genProd = self.db.getResultGeneratorPower(genNumber, timeMaxMin)
        return genProd
```

⋮

```python
def getNodeConnectedToGenerators():
    node_connected = [None] * data.numGenerators()
    gen_at_node = getListOfGeneratorsAtNode()
    for i in range(data.numGenerators()):
        for j in range(len(gen_at_node)):
            for k in range(len(gen_at_node[j])):
                if i == gen_at_node[j][k]:
                    node_connected[i] = j
    return node_connected
```

⋮

```python
def getListOfGeneratorsAtNode():
    gen_at_node = []
    for i in range(data.numNodes()):
        gen_at_node.insert(i,data.getGeneratorsAtNode(i))
    return gen_at_node
```

⋮

```python
def getPercentageSpilledPotential(type_gen):
    list_spillage = []
    list_prod = []
    prod = np.loadtxt(datapath + name_res + 'result_prod.csv')
    generators = data.getGeneratorsPerType()[type_gen]
    for i in generators:
        list_spillage.append(sum(res.getGeneratorSpilled(i,timeMaxMin=None)))
        list_prod.append(prod[i])
    tot_prod = sum(list_prod)
    spilled = sum(list_spillage)
    return (spilled/(spilled+tot_prod))*100
```

⋮

```python
def getPercentageGenerationPerTypeAndArea(type_gen,area):
    generators_type = data.getGeneratorsPerType()[type_gen]
    generators_area = getGeneratorsConnectedToArea(area)
    generators = list(set(generators_type).intersection(generators_area))
    prod = []
    tot_prod = []
    production = np.loadtxt(datapath + name_res + 'result_prod.csv')
    for i in generators_area :
        tot_prod.append(production[i])
    for i in generators:
        prod.append(production[i])
    percentage = sum(prod)/sum(tot_prod)*100
    return percentage, sum(prod)
```

⋮

```python
def getGeneratorsConnectedToArea(area):
    list_gen = []
    generator_area = data.getGeneratorAreas()
    for i in range(len(generator_area)):
        if generator_area[i] == area:
            list_gen.append(i)
    return list_gen
```

⋮

```python
def getAverageCapturePrice():
    income = np.loadtxt(datapath + name_res + 'result_income.csv')
    prod = np.loadtxt(datapath + name_res + 'result_prod.csv')
    cp = sum(income)/sum(prod)
    return cp
```

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