Impacts of Green Hydrogen Uncertainties on the Future Dutch Integrated Energy System of 2030

MSc Complex Systems Engineering & Management
Technology, Policy, and Management

by

Elena Mastropietro

to obtain the degree of Master of Science
at the Delft University of Technology,
to be defended publicly on Friday June 23, 2023 at 03:00 PM.

Student number:	5620244	
Project duration:	February 6, 2023 – June 23, 2023	
Thesis committee:	Prof. dr. ir. L. de Vries,	TU Delft, Chair & First Supervisor
	Prof. dr. ir. A. Correljé,	TU Delft, Second Supervisor
	Dr. ir. D.G. Ribo-Perez,	TU Delft, Advisor

TU Delft

Aknowledgements

This report marks the fulfilment of a demanding but satisfying journey. Beyond the acquisition of academic knowledge, the entire process of graduation served as a profound test of perseverance and patience. I am deeply thankful to my family, boyfriend, and friends for their unwavering support throughout my entire academic journey at TU Delft. Their presence, understanding, and encouragement were fundamental in sustaining me during the long and challenging days.

Moreover, I would like to express my sincere gratitude to my first and second supervisors, Laurens de Vries and Aad Correljé, for their guidance throughout this work. Their expertise, insights, and constructive feedback greatly enhanced the quality of this research. Furthermore, I extend my sincere appreciation to my external advisor, David Ribo-Perez, for his exceptional interest and involvement in this research. His unwavering dedication, contagious positivity, and consistently on-point feedback during our weekly meetings were driving forces that drove me forward. His genuine enthusiasm and commitment to my work inspired me to push the boundaries of my knowledge and to strive for excellence in every aspect of this study.

Lastly, I would like to express my gratitude to each and every reader who invests their time and interest in engaging with my thesis. I hope that the content of this report proves to be as educational and thought-provoking for you as it was for me. It is my sincere wish that the insights and findings presented within these pages contribute to the advancement of knowledge in the field and inspire further exploration in related areas.

Executive Summary

The transition to renewable energy sources and green hydrogen is of paramount importance in the global effort to mitigate climate change and reduce carbon emissions. However, the lack of secure demand and infrastructure poses significant challenges to the widespread deployment of green hydrogen, creating a detrimental cycle. To overcome this energy challenge, policymakers require a comprehensive understanding of the potential impacts of hydrogen uncertainties on the penetration of green hydrogen infrastructure within the energy system, as well as effective policy interventions to mitigate these uncertainties and promote its deployment as a clean energy source.

The primary objective of this Master's thesis is to contribute to the existing body of knowledge on the challenges and opportunities associated with the deployment of renewables and green hydrogen. Specifically, the study aims to provide insights into the potential impacts of hydrogen uncertainties on the energy system and propose policy interventions that can address the coordination problem and foster the deployment of green hydrogen. To achieve this, an exploratory modelling research approach has been employed, focusing on the case of the Netherlands.

The study utilises the Calliope multi-scale energy systems modelling framework to gain insights into the potential future Dutch integrated energy system of 2030. The analysis concentrates on hydrogen uncertainties, which hinder the establishment of an energy system capable of effectively integrating flexible solutions.

Through scenario analysis, the study examines the effects of different hydrogen demands and capital costs of electrolysers on the Dutch integrated energy system of 2030. The scenarios investigated include a Base Case scenario representing the predicted parameters for 2030, a Demand-led scenario incorporating varying hydrogen demands, a Cost-led scenario considering different capital costs for electrolysers, and a No-Blue-Hydrogen scenario that implements a policy prohibiting blue hydrogen production.

By conducting this exploratory modelling research, the study aims to shed light on potential policy interventions that can promote the deployment of green hydrogen in the Netherlands and provide insights into the potential future Dutch integrated energy system of 2030. The findings of this study hold significant value for policymakers and stakeholders involved in the transition to renewable energy sources and green hydrogen.

The study's findings suggest that the energy goals set for the Netherlands in 2030, as well as the broader European energy goals, can only be achieved through the implementation of robust policies, including a ban on blue hydrogen production in the medium term. The results highlight that investment in blue hydrogen technologies does not stimulate investment in green hydrogen technologies but rather perpetuates dependence on fossil fuels within the energy system.

Furthermore, the study reveals that policies aimed at reducing electrolyser capital costs, rather than policies solely stimulating higher hydrogen demand, are more effective in achieving a rapid transition. This is because reducing capital costs makes Proton Exchange Membrane (PEM) electrolysers more attractive than Alkaline electrolysers. This preference for PEM electrolysers leads to increased green hydrogen production, given their superior technical characteristics, and promotes the establishment of a hydrogen value chain necessary for the transition to occur swiftly.

Contents

List of Tables

List of Figures

Acronyms

AEL	Alkaline Electrolyser
BC	Base Case
CAPEX	Capital Expenditure
CBS	Centraal Bureau voor de Statistiek
CCGT	Combine Cycle Gas Turbine
CCHT	Combined Cycle Hydrogen Turbine
CCS	Carbon Capture and Storage
COC	Cost-led Optimistic Case
CPC	Cost-led Pessimistic Case
DPC	Demand-led Pessimistic Case
DEA	Danish Energy Agency
DOC	Demand-led Optimistic Case
DPC	Demand-led Pessimistic Case
GHG	Greenhouse Gas
IC	Industrial Cluster
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquified Natural Gas
NBH	No-Blue-Hydrogen
NUTS	Nomenclature of Territorial Units for Statistics
OPEX	Operational Expenditure
PEM	Polymer Electrolyte Membrane
PEMEL	PEM Electrolyser
PV	Photovoltaic
RES	Renewable Energy Sources
RQ	Research Question
SMR	Steam Methane Reforming
SQ	Sub Question
vRES	Variable Renewable Energy Sources

Nomenclature

A_{NL}	Area in km^2 of the Netherlands
$A_{ON_{2020}}$	Area in km^2 occupied by onshore wind turbines in 2020
A_P	Area in km^2 of the selected province
$A_{PV_{MW}}$	Area in km^2 occupied by solar PVs to generate 1 MW of solar power
$CCGT\_cost_{2030}$	Total cost for CCGT power plants in 2030
$CO2_{CCGT}$	CO_2 emitted by the CCGT power plant
$CO2\_cost_{SMR+CCS_{2030}}$	CO_2 cost of the SMR combined with CCS in 2030
$CO2\_cost_{2030}$	CO_2 cost in 2030
$CO2_{SMR+CCS}$	CO_2 emitted by the SMR combined with CCS
ED_{NL}	Electricity demand of the Netherlands
$ED_{P_{IC_{2030}}}$	Electricity demand per province with an industrial cluster
$ED_{P_{no\_IC_{2030}}}$	Electricity demand per province without an industrial cluster
$HD_{NL_{2019}}$	Hydrogen demand in the Netherlands in 2019
$HD_{NL_{2030}}$	Hydrogen demand in the Netherlands in 2030
$HD_{NL_{2030\_best}}$	Bets predicted hydrogen demand in the Netherlands in 2030
$HD_{IC_{2019}}$	2019 industrial cluster hydrogen demand
$HD_{IC_{2030}}$	2030 industrial cluster hydrogen demand
$HD_{IC_{2030\_best}}$	Best forecast for 2030 industrial cluster hydrogen demand
IC_{share}	Share of industrial electricity demand from an industrial cluster
IS_{share}	Share of industrial electricity demand
NG_cost_{2030}	Cost of natural gas in 2030
no_IC_{share}	Share of industrial electricity demand from a province without an industrial cluster
$ON\_cap_{NL_{2020}}$	Onshore wind electricity generation capacity installed in the Netherlands in 2030
$ON\_cap_{P_{2030}}$	Onshore wind electricity generation capacity installed per province in 2030
OS_{share}	Share of other sectors electricity demand

P_{share}	Share of total population per province
$PV\_cap_{P_{2030}}$	Solar PV electricity generation capacity installed per province in 2030
RS_{share}	Share of residential electricity demand
$share_{A_{ON_{2030}}}$	Share of the area of the Netherlands that can be covered with new onshore wind turbines by 2030
$share_{A_{PV_{2030}}}$	Share of the area of the Netherlands that can be covered with new solar PVs by 2030
$\#T_{2020}$	Number of onshore wind turbines in the Netherlands in 2020
$\#T_{2030}$	Number of onshore wind turbines in the Netherlands in 2030

1

Introduction

This chapter introduces the research topic of this master thesis research project. It starts with background information in Section 1.1 to motivate the relevance of the problem analysed in this study. In Section 1.2 the knowledge gap is described and in Section 1.3 a close explanation of hydrogen uncertainties is given. Section 1.4 narrows the problem to the case of the Netherlands and presents the main research question and the sub-questions. Section 1.5 summarises the objective of this research. Section 1.6 reports the link between this study and the CoSEM master program. Finally, Section 1.7 summarises the outlines of this document.

1.1. Problem Introduction

The ongoing energy transition constitutes a critical challenge in today's world, due to the alarming rise in greenhouse gas concentrations in the atmosphere, which is leading to a corresponding increase in global temperatures and posing a threat to human life on Earth. The recent Intergovernmental Panel on Climate Change (IPCC) Special Report on Impacts of Global Warming of 1.5°C above Pre-industrial Levels highlighted the potential consequences of a 1.5°C rise in temperature, which is projected to occur between 2030 and 2052 [12]. The report suggests that maintaining the average temperature increase below 1.5°C, compared to a 2°C scenario, could help to preserve human services provided by terrestrial and coastal ecosystems, and that climate-related risks would escalate if the average temperature increase exceeds this limit [12].

Given the urgency of the situation, global action is imperative to address the impending climate catastrophe. In this regard, Europe has stated its intentions for the future decarbonisation process in several plans. For instance, the Paris Agreement, which seeks to limit the global temperature increase to below 2.0°C and significantly reduce greenhouse gas emissions [71] and the European Green Deal, which aims to make Europe carbon neutral by 2050 [11]. Other plans are the REPowerEU, which aims at rapidly decreasing the European Union's dependency on Russian fossil fuels [14], and the EU Hydrogen Strategy, which aims to create a project pipeline and an investment agenda to encourage the use and production of hydrogen [13].

To achieve the decarbonisation goals defined in these documents an energy transition towards low-carbon energy sources is required. To make this happen various changes need to be implemented, including a shift from fossil fuel-based energy generation to renewable technologies that leverage carbon-neutral energy sources, such as solar and wind power. Additionally, the transition entails a move away from end-user applications that rely on fossil fuels in favour of appliances powered by “green” energy carriers such as hydrogen or electricity [43].

Green hydrogen, in particular, is considered essential to support the EU’s commitment to reach carbon neutrality by 2050 by playing a significant role in decarbonising hard-to-abate sectors. However, technical challenges, such as the development of the hydrogen infrastructure and the interdependence of electricity from renewable sources and green hydrogen, exist and represent a crucial barrier to the effective penetration of green hydrogen [44].

1.2. Knowledge Gap

In an effort to decarbonise Europe, various scenarios have been proposed in the academic literature that considers utilising multiple combinations of existing energy technologies. The studies conducted reveal similar findings and predict that the reliance on fossil fuels will be significantly reduced in the coming years and will be replaced by variable renewable energy sources (vRES) [7, 76]. The transition to a zero-emission energy system will be achieved by the widespread adoption of solar photovoltaics (PV) and onshore and offshore wind power, enabling the direct electrification of several sectors and contributing to the overall decarbonisation effort [64, 65, 76].

The high dependence on vRES can give rise to imbalances between the supply and demand of electricity due to the inherent volatility of these sources. Such imbalances can result in grid instability when production rates exceed or fail to meet consumption rates [1, 64]. Therefore, it is crucial to have storage solutions that can store excess electricity when it cannot be fed into the grid due to low demand, and supply electricity to the grid when there is demand but insufficient energy production from wind or solar sources. In this context, green hydrogen can serve as a viable storage option to address the challenges posed by vRES. Green hydrogen production relies on renewable electricity and can store electricity in the form of hydrogen [1, 64, 74].

Regarding the widespread adoption of hydrogen, the “chicken-and-egg” threefold coordination problem has to be considered. This issue refers to the difficulty in establishing a comprehensive hydrogen value chain due to the uncertainty surrounding hydrogen supply, demand, and infrastructure development [57, 61]. Therefore, despite the large number of electrolysis projects that have been announced, as shown in Figure 1.1 taken from the article of Odenweller et al. [57], the aforementioned coordination problem keeps uncertainty regarding the number of projects that will effectively materialise by 2030.

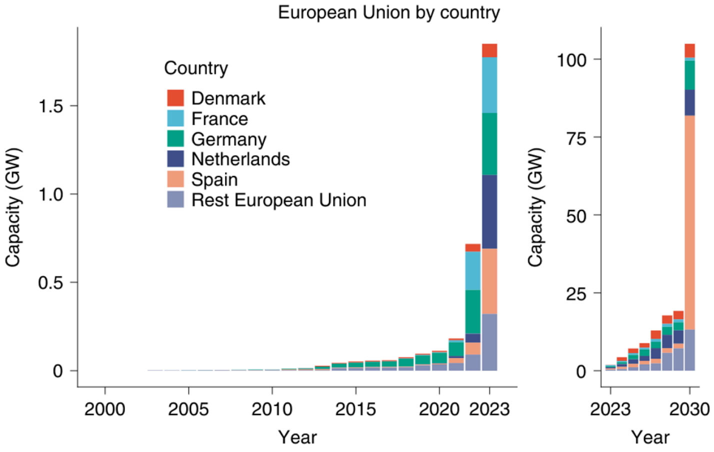

Figure 1.1: Historical development and future announcements of electrolysis projects

The article of Odenweller et al. [57] shows that, if electrolysis capacity growth is equal to that experienced by wind and solar power, green hydrogen supply will remain scarce in the short term and uncertain in the long term. Indeed, the 2030 European target of having 100 GW of electrolysis capacity will not be met, as reported in Figure 1.2 taken from the article of Odenweller et al. [57].

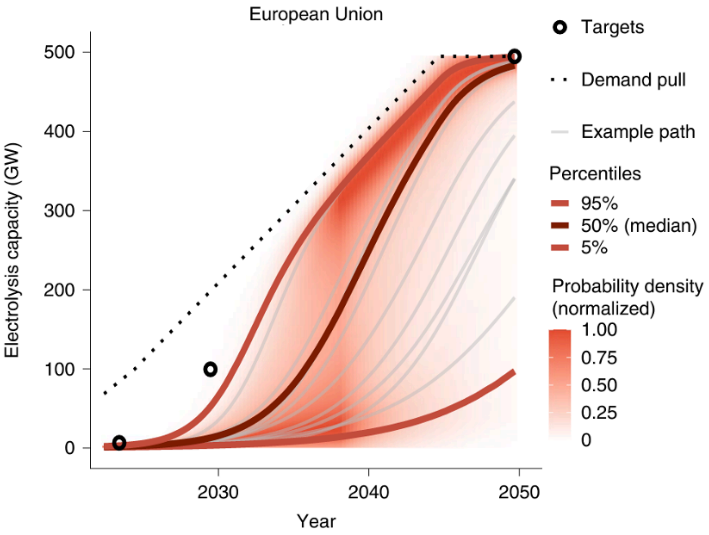

Figure 1.2: Electrolysis growth in the conventional growth case

On the other hand, Figure 1.3, taken from the article of Odenweller et al. [57], shows that if electrolysis capacity growth goes beyond that of wind and solar power the issues of short-term green hydrogen scarcity and mid- to long-term uncertainty will be mitigated. However, for green hydrogen to reach such unconventionally high growth rates requires specific conditions, which are still uncertain [57].

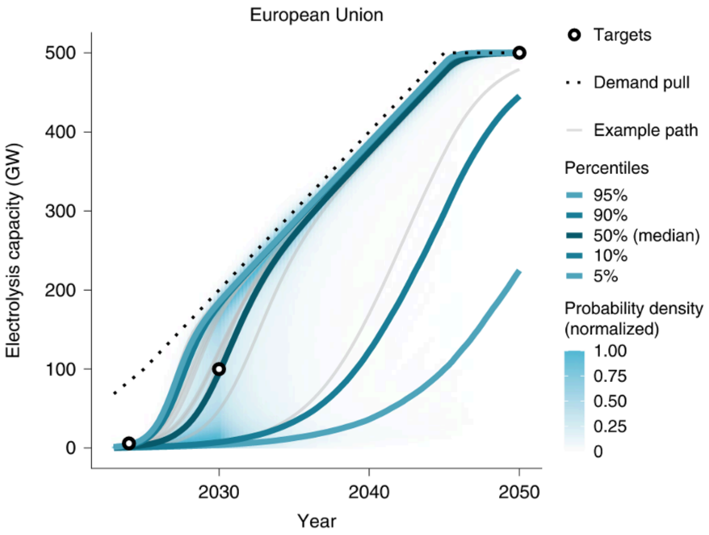

Figure 1.3: Electrolysis growth in the unconventional growth case

Therefore, although green hydrogen is projected to have a critical role in the upcoming energy transition, a knowledge gap exists with regard to the effective penetration of green hydrogen infrastructure in energy systems. This gap can be mainly attributed to the threefold coordination problem, which specifically manifests during the mid-term period.

1.3. Hydrogen Uncertainties

As mentioned above, to analyse the future role of green hydrogen in the decarbonisation process key challenges need to be taken into account. One of these is the "chicken-and-egg" problem, which stems from the pervasive uncertainty surrounding the establishment of a complete hydrogen value chain.

The effective expansion of hydrogen utilisation in the energy sector requires a substantial deployment of infrastructure to produce green hydrogen or convert the existing facilities into facilities with lower environmental impact, but also of infrastructure to link production and consumption sites, as well as for intermediate storage. However, the actual lack of hydrogen production and distribution infrastructure acts as a barrier to potential users investing in hydrogen-based technologies, while simultaneously, the absence of demand discourages investment in hydrogen production and distribution infrastructure [47].

These uncertainties surrounding the hydrogen market create a challenging environment for stakeholders, including industry players, policymakers, and investors. Without a clear and stable market signal, it becomes difficult for investors to make informed decisions regarding the allocation of resources for the development of hydrogen-related projects. The lack of confidence in the future prospects of hydrogen hampers the mobilisation of necessary capital and inhibits the scaling-up of hydrogen technologies.

Moreover, uncertainties regarding future hydrogen supply, demand, and infrastructure development not only impede the effective acceleration of hydrogen adoption and hinder its establishment as a pivotal solution in achieving climate mitigation targets but also impact the design of future energy systems. For instance, they can affect the deployment and penetration of renewable energy sources technologies as well as the dependence on carbon-based energy [61].

Hence, it is crucial to mitigate these uncertainties in order to achieve the targets established by Europe for both 2030 and 2050. This mitigation will facilitate a self-reinforcing loop encompassing hydrogen production, distribution, and utilisation. This, in turn, will align infrastructure investments with the anticipated increase in hydrogen demand, thereby guaranteeing a reliable and sustainable hydrogen supply.

1.4. Main Research Question and Sub-questions

With the objective of examining the implications of the aforementioned uncertainties surrounding hydrogen, we have chosen to focus our analysis on the future Dutch integrated energy system. This choice is motivated by the fact that the Netherlands is recognised as one of the largest producers of hydrogen [43]. Furthermore, the country has proposed a comprehensive plan, as summarised in its Hydrogen Strategy and Green Gas Roadmap [34], which outlines its intentions for the production and utilisation of low- and zero-carbon hydrogen. Additionally, the Netherlands has proactively launched its own energy transition journey in response to global initiatives, as reflected in the Dutch Climate Act. This Act sets ambitious targets aiming to reduce greenhouse gas emissions by 49% by 2030 and by 95% by 2050, relative to 1990 levels [50].

In accordance with these objectives, the Netherlands has identified the electrification of end-use sectors as a pivotal strategy in its pursuit of decarbonisation targets. Additionally, the country has set a goal to derive 70% of its total electricity from wind turbines and solar panels by 2030 [32, 63]. To achieve this transition, substantial investments in vRES are necessary, accompanied by the implementation of technological solutions capable of effectively managing the inherent variability associated with these sources. However, it is important to note that the electrification strategy alone may not suffice for decarbonising hard-to-abate sectors.

In this context, the Netherlands aims to address the challenges posed by vRES and hard-to-abate sectors through the utilisation of green hydrogen. By leveraging renewable electricity for the production of green hydrogen, it becomes possible to simultaneously meet the energy demands of the hard-to-abate sectors and introduce flexibility to the energy system through its role as a viable electricity storage option [42, 63].

Nevertheless, the uncertainties surrounding green hydrogen highlighted earlier create a gap concerning the effective penetration of green hydrogen and the consequent impacts on the future 2030 Dutch integrated energy system. To address this knowledge gap, we formulated the following main research question (RQ):

"How do hydrogen uncertainties impact the penetration of green hydrogen infrastructure in the 2030 Dutch integrated energy system?"

To be able to answer our main RQ, we decided to analyse the impacts on the 2030 Dutch integrated energy system coming from two factors among those which generate green hydrogen uncertainty. These are the demand for hydrogen and the capital costs of electrolysis technologies. Moreover, we also analysed the impacts on the 2030 Dutch integrated energy system if blue hydrogen production is not allowed.

We chose to analyse the uncertainty related to the demand for hydrogen and its impacts on the 2030 Dutch integrated energy system because of the "chicken-and-egg" dilemma above explained. The interdependency of hydrogen demand, hydrogen supply, and hydrogen infrastructure development presents a coordination challenge. Consequently, shedding light on the uncertainties surrounding the future demand for hydrogen in the Netherlands is crucial in overcoming the self-perpetuating cycle of hydrogen-related uncertainties and gaining insights into the future role of hydrogen within the integrated energy system of the Netherlands in 2030.

On the other hand, we chose to analyse the impacts of capital costs associated with electrolysis technologies on the future Dutch integrated energy system in 2030. We took this choice due to the pivotal role that capital costs play in determining the production cost of green hydrogen. Indeed, the production cost of green hydrogen is the sum of the price of renewable electricity and the investment cost of electrolysers. Renewables have already become a cheap source of power, while the investment costs associated with electrolysis facilities remain considerably high, resulting in green hydrogen being 2-3 times more expensive than blue hydrogen [37]. However, a reduction in the electrolysers' capital cost is expected in the near future due to learning curves. Therefore, we are interested in understanding the impacts that different electrolysis capital costs could have on green hydrogen competitiveness and on the future Dutch integrated energy system.

In conclusion, we decided to examine the potential effects on the future integrated energy system of the Netherlands in 2030 under a policy that restricts the production of blue hydrogen. This decision is driven by the understanding that the country's significant dependence on gas could hinder the extensive integration of green hydrogen infrastructure in the medium term if the production of blue hydrogen is allowed. Furthermore, the analysis is motivated by the previously mentioned uncertainties surrounding the hydrogen landscape, which cast doubt on the establishment of a robust green hydrogen value chain by 2030, potentially necessitating reliance on blue hydrogen within the future Dutch integrated energy system.

According to this, we broke down the main RQ into four sub-questions (SQs):

1. How will the Dutch integrated energy system look like in 2030?
2. How does hydrogen demand impact the 2030 Dutch integrated energy system?
3. How do electrolysis capital costs impact the 2030 Dutch integrated energy system?
4. How will the Dutch integrated energy system look like in 2030 if there is no blue hydrogen?

The first SQ helps us present the future Dutch integrated energy system of 2030. This will be our basis for comparing the results obtained in SQs 2, 3, and 4. The comparison in question will allow us in the first case to understand the impacts on the future Dutch integrated energy system due to changes in future hydrogen demand. In the second case, it will allow us to assess the impacts on the future Dutch integrated energy system generated by different costs of electrolysis. Finally, in the third case, the comparison will allow us to estimate the impacts of a policy prohibiting the production of blue hydrogen on the future Dutch integrated energy system.

1.5. Research Objective

The deployment of renewable energy sources and green hydrogen is crucial to achieving the global goal of reducing carbon emissions and mitigating climate change. However, despite the potential benefits of green hydrogen, its deployment is currently hindered by the “chicken-and-egg” threefold coordination problem, where the lack of infrastructure and supply is due to the absence of secure demand, while demand cannot reach a level that justifies infrastructure because there is no supply. This challenge creates a vicious cycle and it also raises the possibility that in the medium term, only blue hydrogen will be deployed.

To overcome this challenge, policymakers need a better understanding of the possible effects that the penetration of green hydrogen can have on the energy system. This understanding requires insights into the circumstances under which hydrogen can become cost-competitive and how policy interventions can promote the deployment of green hydrogen as a clean energy source. Therefore, the purpose of this Master’s thesis is to contribute to the existing body of knowledge on the challenges and opportunities associated with the deployment of renewables and green hydrogen.

Our research aims to reduce uncertainty regarding future hydrogen demand, impacts of electrolysis costs, and impacts of restriction on blue hydrogen by performing a scenario analysis. Moreover, the study will provide insights into possible policy interventions that can promote the deployment of green hydrogen and facilitate the transition towards a more sustainable energy system. The results of this research will be of significant interest to policymakers, researchers, and industry professionals working towards the decarbonisation of the energy sector.

1.6. Link to Study Program

The problem described has a clear connection with the MSc CoSEM. Indeed, the Dutch integrated energy system can be seen as a complex socio-technical system that includes numerous subsystems that occur simultaneously and feed off each other. To design in the complex technical environment just depicted, indeed, we have to consider several different elements, such as demand, supply, and policies, that impact the functioning and the interactions of the system’s components, such as production technologies, storage options, transmission links, etc. Moreover, since we are researching the Dutch integrated energy system the problem is even more complex because of uncertainty generated from unknown future developments of system components and external elements.

What we have just claimed creates a clear link between the study that will be conducted here and the teachings that the Master’s program in Complex Systems Engineering and Management aims to give to its students. In fact, the CoSEM Program equips students with the skills and knowledge needed to analyse and manage complex systems and these skills include system thinking, modelling and simulation, and optimisation techniques among others. By applying the principles and methods taught in the program, we therefore should be able to perform effective analysis of complex problems and provide interesting results.

1.7. Thesis Outline

We structured our master thesis report as follows. Chapter 2 presents the literature review we performed to understand what previous research claimed regarding the role of hydrogen in 2030, specifically by using energy system models to assess its role. Moreover, Chapter 2 summarises the literature review of the hydrogen value chain and our selected technologies for hydrogen production, storage, and transmission. Chapter 3 discusses the methodology of our research. In particular, it summarises the exploratory modelling research approach, the integrated energy system we wanted to model, the calliope framework, and the modelling process. Chapter 4 presents our case study on the Netherlands, the data needed to model the 2030 Dutch integrated energy system, the gathering process and the assumptions we made. Chapter 5 talks about the Scenario we created to answer our SQs. Chapter 6 summarises the scenario analysis results and the sensitivity analysis. Finally, Chapter 7 discusses sensitivity among the scenarios and provides recommendations for policymakers. Moreover, it also summarises the limitations of the model and future research. Chapter 8 is for the conclusion.

2

Literature Review

This Chapter presents the literature review performed in this study. It is divided into Section 2.1, which presents the role of hydrogen in 2030 asses specifically by energy system models, and Section 2.2, which summarises the hydrogen value chain and describes the main technologies involved in the various steps.

2.1. Role of Hydrogen in 2030

As previously mentioned, the availability of VRES is expected to increase in the next future, replacing fossil fuels. Hydrogen has been recognised as one of the most promising electricity storage options to cope with RES volatility since excess renewable electricity can produce green hydrogen through electrolysis, where electric energy is converted into chemical energy [44]. Acting as a large-scale and long-term energy storage for renewable sources, green hydrogen is able to add more flexibility to the electrical system, reducing RES curtailment [1, 48, 64]. Subsequent to its production, hydrogen can be stored, can be transported through pipelines and can be then employed when needed, contributing in this way to cope with peak load variations and assuring the stability of the entire energy system [1, 6, 45, 64, 76]. Basically, the role of hydrogen is akin to the role of fossil fuels with the difference that hydrogen produced through electrolysis supplied by renewable electricity offers the distinct advantage of generating solely water vapour as waste [44].

However, today 95% of the hydrogen produced is brown/grey, produced by steam reforming with fossil fuels as energy input. The rest is 1% blue hydrogen, produced like brown/grey hydrogen but with the addition of Carbon Capture and Storage (CCS) systems, and 4% green hydrogen [44, 54]. At present, green hydrogen has been limited to demonstration projects but is expected to be developed in the coming years [7]. In particular, it can contribute to further decarbonising the energy system since it has the potential to decarbonise hard-to-abate sectors, such as transport and industry, which cannot be fully electrified [44, 61, 64, 65]. For instance, heavy-duty transport vehicles, such as long-haul trucks and buses, require fast recharging energy options that battery-powered vehicles cannot yet offer. At the same time, hydrogen fuel cells are able to provide a longer driving range and quicker refuelling times [62].

Being aware of the crucial role of hydrogen in the decarbonisation process, Europe has set ambitious goals for hydrogen produced from electrolysers powered by renewable electricity. Specifically, Europe aims to install 100 GW of electrolysis capacity by 2030 and encourages investments in clean hydrogen production, targeting 10 Mt of renewable hydrogen production by 2030 [7, 44, 57]. Similarly, the Netherlands is committed to investing in green hydrogen technologies, with a target of having a cumulative electrolyser capacity of 3 GW and 9 GW of installed renewable energy system capacity for green hydrogen production by 2030 [41, 75].

To achieve these goals, it is essential to reduce the costs of the hydrogen production chain. Renewable hydrogen costs have decreased by 60% over the past decade and are expected to halve again in 2030. However, hydrogen production and related processes remain energy-intensive, making hydrogen more expensive than the natural gas or electricity used to produce it [44]. Consequently, the Dutch government recognises that natural gas will continue to play an important role in the energy system through at least 2030. As a result, the Netherlands intends to utilise the existing gas infrastructure to facilitate the transportation and utilisation of low-carbon gases while promoting carbon capture and storage processes to produce low-carbon gases, including blue hydrogen [34]. Utilising CCS technology to produce hydrogen from natural gas enables substantial hydrogen production in the near future and complements the production of hydrogen from renewable energy sources [61].

2.1.1. Energy System Models

In the literature, several Energy System Models investigated possible decarbonisation paths. Victoria et al. [76] modelled the transformation of the European energy system under different carbon budgets. The model shows that tight carbon budgets will allow substantial technological transformations and the use of RES to produce hydrogen via electrolysis rather than via SMR by 2030. Sgobbi et al. [66] also studied the European energy system by applying a linear cost-optimisation model approach. The model showed how hydrogen could become a viable option already in 2030, particularly playing a crucial role in the heavy industry and transport sectors. However, hydrogen investment costs represent a key obstacle and a tight CO2 cap is needed to sustain the transition.

Beccarello et al. [4] designed a 2030 scenario to forecast the role of decarbonisation drivers in future energy systems in the case of Italy. The results show that green hydrogen has the potential to become the main source of energy in the industrial and transportation sectors. However, it seems unlikely that it will be cheap enough to play already a significant role by 2030. Therefore, the 2030 scenario includes the possibility of using CCS technologies to produce blue hydrogen in the industrial and transport sectors.

Since hydrogen produced by electrolysis can also be used as storage, its cost competitiveness is compared to that of other, more mature, technologies, such as batteries. Schulthoff et al. [64] showed through their model that with current cost trends and projections, hydrogen storage is not competitive with alternative solutions. However, Mazza et al. [48] claimed as the comparison between hydrogen produced from electrolysis and batteries could not be based only on the total cost but rather green hydrogen's benefits, such as the environmental ones, should be considered as well.

Santos et al. [62] investigated the use of green hydrogen produced from surplus renewable electricity and stored in salt caverns as a means of ensuring energy supply security in Portugal in 2030. The findings demonstrated that seasonal hydrogen storage is feasible because, even in unfavourable years, hydrogen plants for power-to-power generation can always receive the necessary hydrogen from excess solar and wind energy if their round-trip efficiency is more than 33.3%.

Broadly speaking, the results of the analysed models indicate that hydrogen can contribute to lowering CO2 emissions and have a significant impact on challenging sectors while facilitating inter-sectoral integration. However, in order to maximise the benefits of incorporating hydrogen into the energy system, it will be necessary to provide financial backing and implement rigorous standards and regulations that promote technological development and economies of scale.

2.2. Hydrogen Value Chain

We divided the hydrogen value chain into three main steps, which are: production, storage, and transportation.

2.2.1. Production

The first step in the hydrogen value chain concerns the production of hydrogen. This can be produced starting from fossil fuels or renewable sources. Both cases include different technologies to perform the conversion to hydrogen. We reviewed only the most mature available methods/technologies used to produce green and blue hydrogen.

Green Hydrogen

The production of green hydrogen can be achieved through the electrolysis process, which involves the use of water and renewable electricity. Electrolysis represents the most mature technology currently available for green hydrogen production, although it is primarily used in small-scale industrial hydrogen plants [44]. In particular, the most promising electrolysers for large-scale hydrogen production are the polymer electrolyte membrane (PEM) electrolyser (PEMEL) and the Alkaline electrolyser (AEL). The former has an energy efficiency of 85% and provides high levels of hydrogen purity, but its capacity is considerably lower than that of the Alkaline electrolyser. The Alkaline electrolyser represents the most mature technology, albeit with an energy efficiency of 73% and a higher rate of ramping compared to PEM electrolysers [44, 54, 78]. The process involves the use of water and renewable electricity, allowing the production of the cleanest energy carrier. However, electrolysis is electricity-intensive, and therefore, even if green hydrogen is more sustainable and contributes to RES integration as an electricity storage option, its production cost is not competitive with other large-scale technologies [54]. Moreover, water electrolysis from renewables has to deal with VRES and high capital expenditure (CAPEX) [44, 54].

Blue Hydrogen

Steam Methane Reforming (SMR) is widely recognised as the leading and most mature method for producing hydrogen on a large scale. SMR entails a catalytic conversion process that transforms methane and steam into hydrogen and CO2. The conversion efficiency of SMR typically ranges from 74% to 85% [54]. It can be then coupled with CCS systems, showing a reduction rate of up to 95% in greenhouse gas emissions, but leading to a reduction in the process energy efficiency of 5%-14% [55]. Moreover, the integration of CCS into SMR production, also known as blue hydrogen, increases the total cost of hydrogen production by approximately 10% [54]. Nevertheless, research suggests that brown/grey hydrogen production coupled with CCS systems is currently the most cost-effective method of hydrogen production, including externalities [44]. Blue hydrogen production, however, may require additional infrastructure to transport CO2 from the hydrogen generation plant to the storage site, increasing the overall cost. Additionally, underground CO2 storage options, which are currently the most mature technologies to store carbon dioxide, have finite capacities. For this reason, blue hydrogen may not be a sustainable long-term solution [44].

2.2.2. Storage

Upon its production, hydrogen may be stored for later utilisation. There are various modes of hydrogen storage available, supported by a range of storage technologies. In this study, we have evaluated one of the most debated compressed hydrogen storage options for the future Dutch energy system, namely salt caverns [44].

Compressed Hydrogen Storage

Hydrogen can be compressed and stored in gaseous form. The best way to do so, as recognised by the International Energy Agency (IEA) in 2019 [33], is underground in geological formations, namely salt caverns. Indeed, these represent a cheap and efficient (up to 98%) solution to store large quantities of hydrogen and they have an infinite lifetime [44]. Also, since they are less likely to experience fires and are less exposed to possible threats from hostile military or terrorist forces, subsurface geological formations are extremely secure. [23]. Caverns are gas-tight and stable for a long period of time because of the beneficial physical characteristics of salt. They are also ideal for short-term peak shaving operations because of their great injection and withdrawal flexibility [23, 49]. However, salt caverns are geographically irregularly distributed and they do not necessarily occur in those regions that have the highest potential for cavern storage [44, 49]. Nevertheless, the northern part of the Netherlands shows several salt domes and therefore seems to be particularly promising for salt cavern storing options [60].

2.2.3. Transportation

Hydrogen can be transported and distributed through vessels and trucks. This method is the conventional method but due to its low capacity results in high delivery costs. Hydrogen can be also transported and distributed through pipelines, which allow a higher capacity and represent the future transportation method. However, infrastructure investments are required since dedicated hydrogen pipelines do not exist yet. For this reason, natural gas pipelines are used but the blending of hydrogen and natural gas increases transport losses up to 20% [54]. In the absence of pipelines, liquid hydrogen carriers allow high-density storage and high-volume transport over long distances, but they require a very energy-intensive process because hydrogen needs to be liquefied [44].

3

Methodology

In this Chapter, we presented the methodology of our study. In particular, Section 3.1 summarises the research approach, Section 3.2 the integrated energy system we analysed, and Section 3.3 the Calliope multi-scale energy systems modelling used to apply the exploratory modelling approach to the integrated energy system.

3.1. Exploratory Modelling Approach

A knowledge gap emerged from the literature review leading us to formulate the following main research question: *"How do hydrogen uncertainties impact the penetration of green hydrogen infrastructure in the 2030 Dutch integrated energy system?"*. To address this main RQ we selected the exploratory modelling approach, a research methodology that uses computational experiments to analyse complex and uncertain systems [3]. In particular, we applied this approach to the case of the Netherlands since we modelled uncertainty in technology development, the need for infrastructure, levels of demand, and maximum renewable and electrolyser capacity to be installed, with the aim of gaining insights into the possible future Dutch integrated energy system of 2030.

We selected this approach because even if relevant data to develop the energy system of the Netherlands in 2030 are available the uncertainty surrounding hydrogen, renewables, and their interactions does not allow us to specify a single model that effectively captures system behaviour [3]. Through the results obtained from the various model runs, we should be able to analyse potential and possible future Dutch integrated energy systems and assess if these are viable options.

The exploratory modelling approach has proven to give robust results, even if still contextual, thanks to the high number of model runs that characterised this methodology. However, while this characteristic creates an advantage for this approach, it also makes it computationally complex [3].

3.2. Integrated Energy System

In Figure 3.1, we have presented an overview of the components that constitute the integrated energy system of the Netherlands in 2030 and the manner in which they interact with each other to ensure the system's functionality.

The electricity generation landscape is characterised by a mix of non-renewable and renewable technologies. Specifically, it includes two non-renewable technologies, namely the combined cycle gas turbine (CCGT) and nuclear, and three renewable technologies, namely onshore wind, offshore wind, and solar PV. The generated electricity is transmitted through the electricity grid to satisfy the electricity demand of the residential, industrial, and service sectors. In cases where the electricity supply surpasses the demand, the excess electricity is stored in a lithium-ion battery and can be supplied to the grid when the electricity supply falls short of the demand.

Furthermore, the system harnesses renewable electricity to produce green hydrogen via the process of electrolysis, which can be executed through an Alkaline or a PEM electrolyser. The produced green hydrogen is transported through hydrogen pipelines to fulfil the hydrogen demand of industrial clusters. If the hydrogen supply exceeds the demand, the excess hydrogen can be stored in a salt cavern and utilised when the hydrogen supply falls short of the demand. Additionally, the produced hydrogen can be converted back into electricity via a combined cycle hydrogen turbine (CCHT) to meet electricity demand. Finally, the hydrogen demand can also be met through blue hydrogen, which is produced via steam methane reforming combined with carbon capture and storage (SMR+CCS) or via imports.

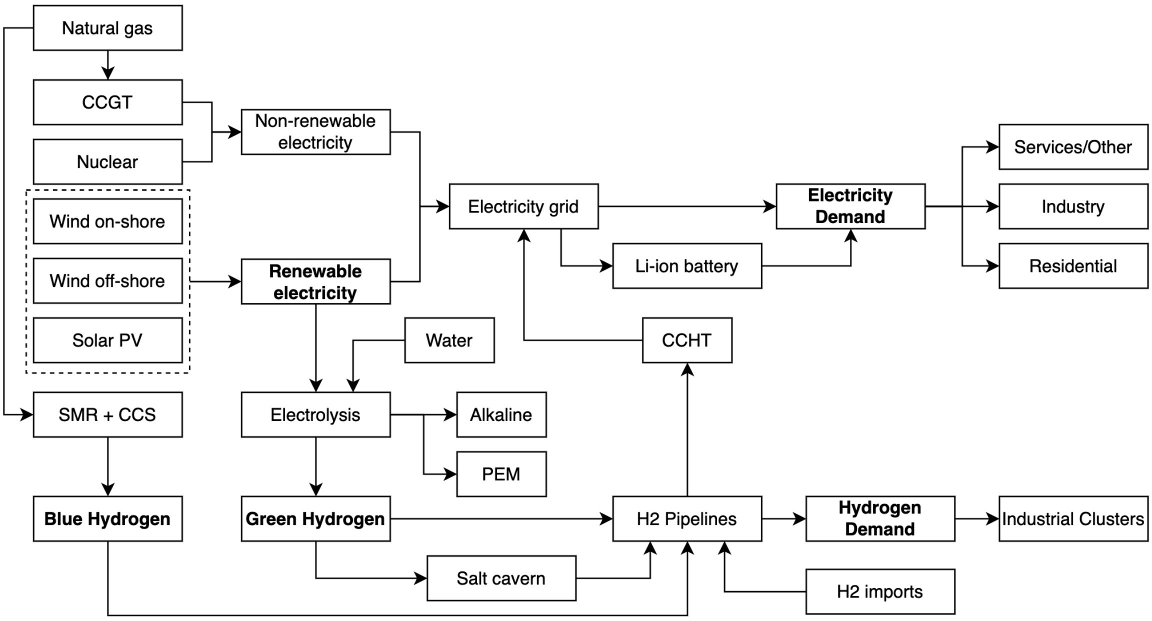

Figure 3.1: Overview of the 2030 Dutch integrated energy system

3.3. Calliope

The exploratory modelling approach applied to the integrated energy system of the Netherlands utilised the Calliope multi-scale energy systems modelling framework developed by Stefan Pfenninger and Bryn Pickering [58]. This framework enables the modelling of various energy sources, including renewable and conventional energy, hydrogen, energy storage options, and energy demand profiles. It allows for the analysis of energy system transitions, energy policy scenarios, and the impacts of different energy technologies and policies at a high spatial and temporal resolution.

The Calliope framework operates by taking input data, formulating an optimisation problem, solving it, and presenting the results. Input data required for running simulations include information on energy supply, energy demand, energy storage, energy conversion, energy costs, greenhouse gas emissions, and other pertinent parameters. Calliope provides a user-friendly interface for easy data input and manipulation, and it supports data import from various file formats, including CSV.

By utilising Calliope, detailed information on energy flows, energy costs, and greenhouse gas emissions can be obtained. This framework allows for the assessment of the economic, environmental, and social impacts of different energy systems. Therefore, it enables the construction and evaluation of the future 2030 Dutch energy system under different conditions, facilitating the analysis of changes in hydrogen infrastructure penetration and addressing the main research question.

The modular design and open-access nature of the Calliope framework are its key advantages. Its flexibility makes it suitable for projects requiring customisation, while its open-access nature allows for the verification and replication of findings. Furthermore, this research builds upon previous studies that employed the same modelling paradigm, providing a solid foundation for the current work.

However, the Calliope framework does have limitations. Its computational power is constrained, necessitating certain simplifications and assumptions to manage computational complexity. Additionally, like any complex energy system model, Calliope relies on extensive and up-to-date data inputs, which can be challenging and time-consuming to gather. Lastly, Calliope primarily focuses on the techno-economic aspects of energy systems and may not fully capture social, behavioural, and political dynamics. This limitation restricts its ability to assess factors such as social acceptance, behavioural change, and policy-related influences that significantly impact energy transitions.

In summary, Calliope serves as a powerful energy system modelling tool with several strengths that facilitate comprehensive analysis and decision-making. However, it is crucial to recognise its limitations and complement its outputs with other analytical approaches and considerations to obtain a more comprehensive understanding of energy systems and their transitions.

3.3.1. Calliope Framework

Figure 3.2 shows the internal workflow of the Calliope Framework. Starting from the left-hand side we can see that Calliope enables model data stored in YAML files and timeseries data stored in CSV files. The data from these files are taken as input from the model and then prepared in order to be optimised in a linear solver, such as Gurobi [29]. Finally, the results of the optimisation are analysed and saved.

The python packages ruamel.yaml and pandas are used to parse the YAML and CSV files, respectively. Xarray is then used to restructure the data into multidimensional arrays, ready for saving, plotting, or sending to the backend. The pyomo package is currently used in the backend to transform the xarray dataset into a pyomo ConcreteModel. All parameters, sets, constraints, and decision variables are defined as pyomo objects at this stage. Pyomo produces an LP file, which can be read by the modeller's chosen solver. Results are extracted from pyomo into a xarray dataset, again ready to be analysed or saved.

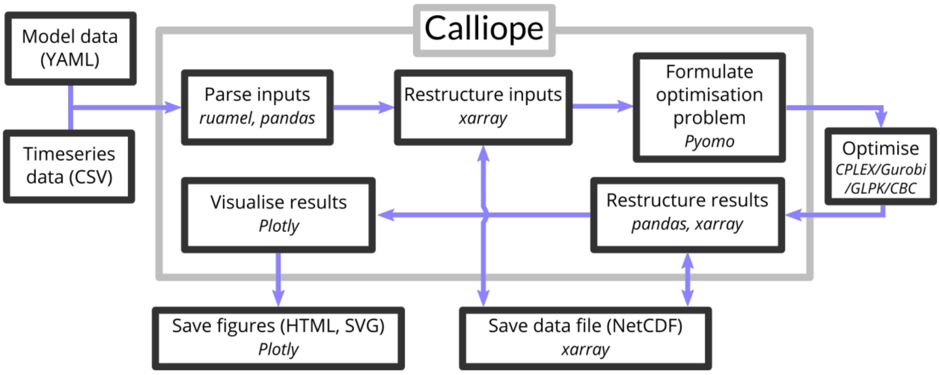

Figure 3.2: Calliope framework workflow [58]

3.3.2. Modelling Process

The modelling process can be broken down into three phases, which are Building the Model, Running the Model, and Analysing the Results.
In the first stage, we loaded into the model all the necessary files such as CVS files, YAML files, and override files. The YAML files are used to define technologies and locations throughout a set of variables and constraints. The constraints defined for the various technologies changed according to the class of the technology in question. We modelled six different classes of technologies and these are supply, supply_plus, conversion, transmission, storage and demand.

After the model is built, the model is then run. During this step, the solver solves the LP optimisation problem and finds time-optimal values for all the decision variables for the given objective function. During this same step, the dual variables and their values are also extracted. The model results and dual variables are then both stored.

The examination of the outcomes may be partitioned into two discrete phases. Firstly, we scrutinised the results at the system level to evaluate the physical flows within the model, assess the feasibility of the model, and determine its representativeness. Subsequently, we proceeded to enhance the resolution of our analysis by inspecting the node-level results to gain a more comprehensive understanding of the system's performance at each node. To facilitate the comprehension of the outcomes in both stages, we employed graphical visualisations such as charts and graphs.

Technology Definition

We defined six different technology classes, which are supply, supply_plus, conversion, transmission, storage and demand. Supply and supply_plus are both technologies that supply energy to a carrier. The difference is that the supply_plus technologies have also a storage for the resource. Indeed we used the supply class for the technologies that use non-renewable energy sources, such as natural gas, and the supply_plus class for the technologies that use RES, such as solar and wind.

Figure 3.3 shows the technology we modelled for each of the six classes in the model and their interactions to satisfy electricity and hydrogen demand.

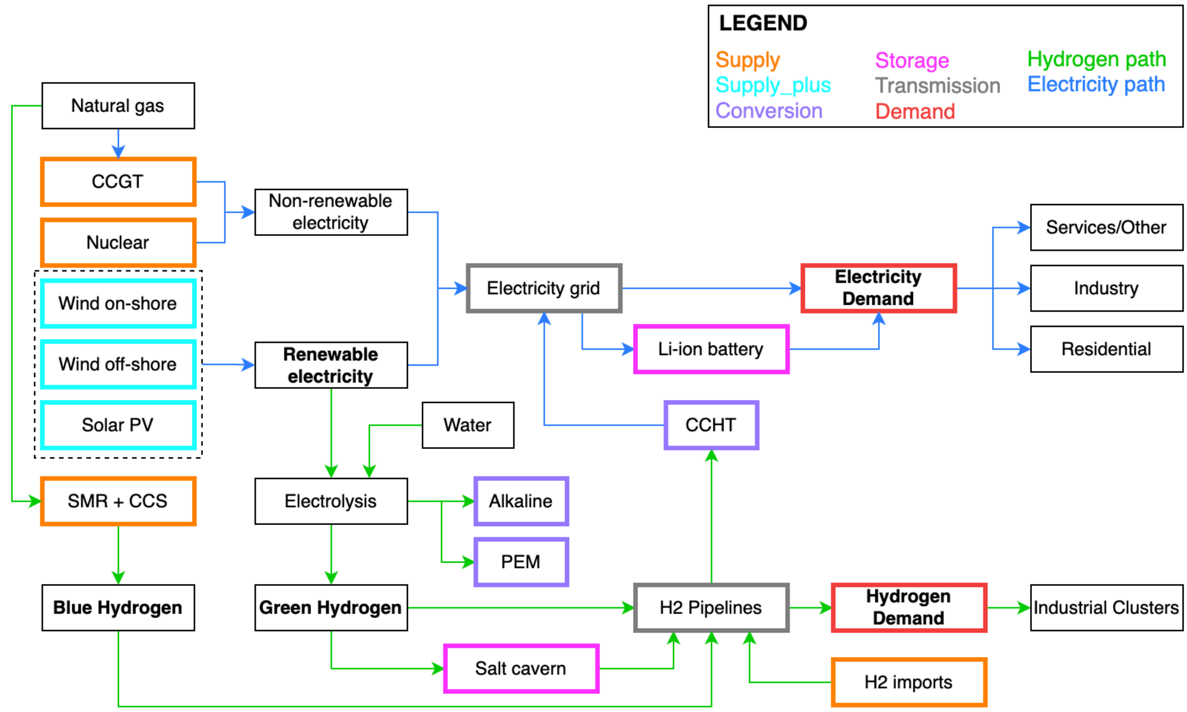

Figure 3.3: Overview of the technology classes defined in the 2030 Dutch integrated system

To specify the technology classes above mentioned we can use three different types of constraints, which are the default constraints, also called *essentials*, the allowed constraints, also called *constraints*, and the allowed costs, also called *costs*.
The default constraints we defined are the same for both supply and supply_plus technologies, namely:

- `name`: the name of the technology.
- `color`: the colour of the technology in the plots.
- `parent`: the class of the technology.
- `carrier_out`: the supplied carrier.

Conversion technologies need also the default constraint `carrier_in`, which is the input energy carrier, while demand, storage, and transmission technologies need the default constraint `carrier`, which defines the energy carrier demanded, stored, or transmitted.

The allowed constraints we modelled differ to some extent according to the technology class. They are:

- `resource`: the resource availability, which for supply technologies is infinite, while for supply_plus technologies corresponds to the capacity factor imported from timeseries files. We defined the resource for demand technologies as well, importing it from timeseries files.
- `resource_unit`: the unit of the resource, which is kWh for supply technologies and kWh/kW for supply_plus technologies.
- `lifetime`: the technology lifetime. We defined it for supply, supply_plus, conversion, storage, and transmission technologies.

- `energy_eff`: the conversion efficiency of the technology. We defined it for supply, conversion, and storage technologies.
- `energy_eff_per_distance`: the conversion efficiency of the technology per distance. We defined it for transmission technologies.
- `energy_ramping`: the ramping rate of the technology. We defined it for supply and conversion technologies.
- `energy_cap_equals`: the specific installed energy capacity, used for supply, supply_plus, conversion, and storage technologies already installed.
- `energy_cap_max`: the maximum installed energy capacity, used for supply, supply_plus, conversion, and storage technologies that could be installed by the model.
- `storage_loss`: the rate of storage loss per hour we defined for storage technologies.
- `storage_cap_max`: the maximum storage capacity of the storage technology.
- `energy_cap_per_storage_cap_max`: the ratio of maximum charge/discharge for a given storage capacity of a storage technology.

The allowed costs we defined for the various technologies are monetary costs and CO2 emissions costs. They are:

- `monetary`:
  - `interest_rate`: the interest rate used to compute levelised costs of supply, supply_plus, conversion, storage, and transmission technologies.
  - `energy_cap`: the capital costs of supply, supply_plus, conversion, and storage technologies. In our case, it is zero for the plants already installed.
  - `om_con`: cost of the energy source used by supply, supply_plus, and conversion technologies. In our case, it is zero for supply_plus power plants.
  - `om_annual`: the yearly operational and maintenance costs of supply, supply_plus, conversion, and storage technologies.
  - `om_annual_investment_fraction`: the fractional yearly operational and maintenance cost transmission technologies.
  - `storage_cap`: the storage capacity cost of storage technologies.
  - `energy_cap_per_distance`: the cost of energy capacity per unit distance of transmission link technologies.
- `CO2`:
  - `om_prod:`: operational and maintenance carrier production costs. We modelled it for supply technologies which generate carbon emissions.

4

Case Study

In the Case Study Chapter, the 2030 Dutch Integrated Energy System is presented in Section 4.1. This is followed by the data needed to model the system, in Section 4.2, and the data gathering process and the assumptions made, in Section 4.3.

4.1. 2030 Dutch Integrated Energy System

The Netherlands declared in the Climate Act the willingness of reducing GHG emissions by 49% by 2030 [50]. To reach this goal, the Country has to rethink its energy system in order to integrate into it RES and clean energy carriers, such as green hydrogen. To this end, the Netherlands has defined several targets, which should help in achieving a more sustainable energy system by 2030.

To what concerns renewables deployment, the Netherlands wants to reach 30.6 GW of installed wind electricity generation capacity, of which 21.5 GW is offshore and 9.1 GW onshore. The current target for installed solar electricity generation capacity, combining residential, industrial, and utility-scale solar PV, is 59.3 GW [52]. However, according to SolarPower Europe, the actual direction should lead to having 62 GW of solar capacity installed in the Netherlands by 2030 [26]. Moreover, the Netherlands claimed that 70% of the 2030 electricity demand would be satisfied by renewable electricity [34]. While, regarding hydrogen and electrolysis capacity, the goal is to have 6-8 GW of electrolysis capacity installed by 2030 [21].

To model the 2030 Dutch integrated energy system we started by defining the provinces of the Netherlands. We specified twelve onshore nodes through coordinates, corresponding to the twelve Dutch provinces, and names, corresponding to those determined by the Nomenclature of Territorial Units for Statistics (NUTS) [77] and summarised in Table A.1. Moreover, we defined 2 off-shore nodes, OFF1 and OFF2, to model the offshore wind parks in the North Sea. The division we performed is territorial, therefore OFF1 represent the western part of the Dutch North Sea area, while OFF2 is the northern part. For this reason, OFF1 includes the Borssele and the Hollandse Kust zuid, noord, and west, and the IJmuiden Ver wind farm zones, while OFF2 includes the Ten Noorden van de Waddeneilanden wind farm zone [53]. Finally, we modelled one node for hydrogen imports called IMP. We defined just one node because we considered only green hydrogen imported by vessel from Spain since it is projected to be the cheapest one in 2030 [36].

We connected the different nodes to each other through electrical lines and/or hydrogen pipelines. We assumed that the electricity grid will not change by 2030 and therefore we connected the nodes by simplifying the actual existing electricity grid [70]. On the other hand, we built the hydrogen grid by simplifying the hydrogen network designed by Gasunie for 2030 [28].

Regarding the electricity grid, Figure 4.1 shows the existing electricity transmission links in the Netherlands in 2022 and those in the planning or under-construction phase. Our model focuses exclusively on replicating the onshore 380 and 220 kV connections, as they are capable of linking the twelve provinces together. Additionally, we incorporated offshore electricity links to connect offshore wind parks with the mainland. To simplify the representation, we reduced the complexity of the connections documented in the TenneT grid by establishing a connection link between node NL11 and node OFF2, and another connecting link between node NL32 and node OFF1. This decision is based on the fact that, in Figure 4.1, the province of Groningen (NL11) is the sole province connected to the offshore wind parks situated on the north-west side of the North Sea (OFF1), while the province of North Holland (NL32) has the highest number of planned connections with the offshore wind parks located on the west side of the North Sea (OFF2).

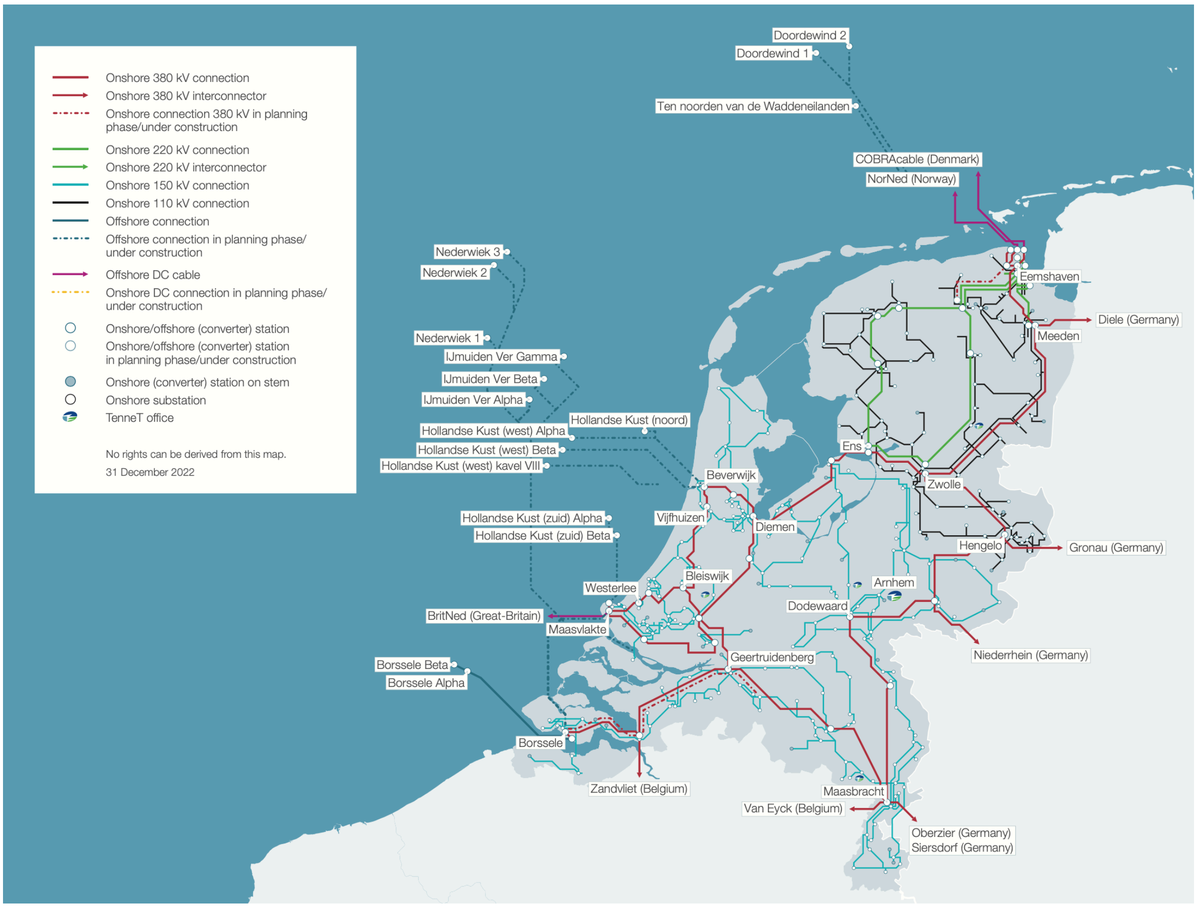

Figure 4.1: Electricity grid of the Netherlands in 2022 according to TenneT

Regarding the hydrogen grid, Figure 4.2 shows the industrial clusters and the hydrogen pipelines planned to be available in the Netherlands in 2030 according to Gasunie [28]. The hydrogen grid designed by Gasunie is quite similar to the actual gas grid existing today in the Netherlands. Indeed, the design aligns with the Netherlands' strategic plan of repurposing existing natural gas pipelines for hydrogen transportation in the foreseeable future, instead of constructing dedicated pipelines. Notably, the utilisation of repurposed natural gas hydrogen pipelines is expected to be considerably more cost-effective compared to the construction of new hydrogen-specific pipelines [69]. We simplified the hydrogen grid by modelling only domestic connections, and only one node for hydrogen imports. Moreover, we also included offshore hydrogen pipelines in our model with the aim of transporting hydrogen produced offshore on the mainland.

Figure 4.2: Hydrogen grid of the Netherlands in 2030 according to Gasunie

Accordingly to what we mentioned, Figure 4.3 shows nodes, connections, and industrial clusters' locations modelled in this study.

All the nodes included in our model have different technologies. Each onshore node has a demand for electricity generated by the industrial, residential or service sector, while only nodes with an industrial cluster (IC) have a demand for hydrogen. This is due to the fact that the hydrogen demand from the five ICs was almost equivalent to the total hydrogen demand in 2019 [34]. Therefore, to simplify the model, we assumed the same for 2030. On the other hand, both offshore nodes and the node designated for hydrogen imports do not have any type of demand. Moreover, the nodes have production, conversion, storage, and transmission technologies both for hydrogen and electricity. In particular, onshore nodes can have combined cycle gas turbines, nuclear reactors, onshore wind turbines, solar PVs, SMR+CCS, Alkaline electrolysers, PEM electrolysers, CCHTs, Li-ion batteries, and salt caverns. On the other hand, offshore nodes can have offshore wind turbines, Alkaline electrolysers, and PEM electrolysers. Finally, the import node has technologies for importing hydrogen.

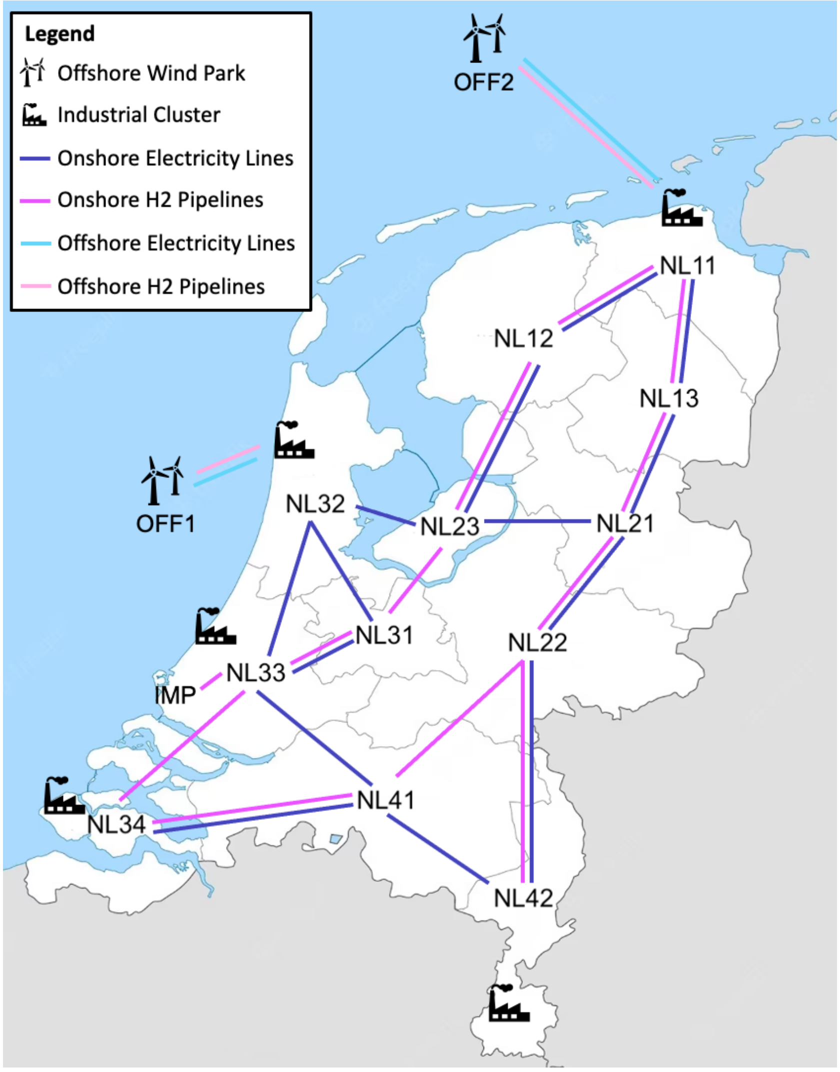

Figure 4.3: Map of the Netherlands with the nodes modelled

4.2. Data Needed

To translate in coding language what is presented above, we identified data points that would provide an approximation of the future 2030 Dutch integrated energy system. Table 4.1 summarises the data needed to model technologies, infrastructure, and demand profiles included in Figure 3.1.

Table 4.1: Data needed to model the 2030 Dutch energy system

Technologies	Data Needed
Electricity demand	Hourly demand profile per province
Hydrogen demand	Hourly demand profile per IC
CCGT, nuclear	Lifetime, efficiency, ramping rate, CAPEX, OPEX, fuel cost, CO_2 cost, capacity, location
Onshore wind, offshore wind, solar PV	Lifetime, capacity factor, CAPEX, OPEX, capacity, location
SMR+CCS	Lifetime, efficiency, CAPEX, OPEX, fuel cost, CO_2 cost, capacity, location
AEL, PEMEL	Lifetime, efficiency, ramping rate, CAPEX, OPEX, water cost, capacity, location
CCHT	Lifetime, efficiency, ramping rate, CAPEX, OPEX, capacity, location
Battery, salt cavern	Lifetime, efficiency, storage loss, charge/discharge rate, CAPEX, OPEX, capacity, location
Electricity lines, hydrogen pipelines	Lifetime, efficiency, CAPEX per distance, OPEX per distance

4.3. Data Gathered and Assumptions

We gathered data and made assumptions both for hydrogen and electricity, focusing primarily on the demand and then production, conversion, storage, and transmission technologies involved in our model.

4.3.1. Electricity Demand

To calculate the electricity demand for the Netherlands in 2030, we first gathered the yearly hourly electricity demand of the Netherlands for 2019 from the Entso-e Transparency Platform [25]. Then, we increased the 2019 electricity demand by 5%, assuming that the electricity demand for 2030 in the Netherlands would have the same percentage increase as in Europe for 2030 compared to 2019 [30].

In order to obtain the electricity demand per province, we analysed the breakdown of the total electricity demand for the 12 Dutch provinces. This involved examining the distribution of the Dutch electricity demand in 2019 across the industrial, residential, and service sectors, which accounted for 34%, 23%, and 43% of the total demand, respectively [34]. Finally, to allocate the electricity demand to each province, we took into account the industry clusters in each province for the industrial sector and the population of each province for the residential and service sectors.

To what concerns the industrial electricity demand, we divided it by six, of which five-sixths were equally divided among the provinces with an IC, namely 5 provinces, and the remaining one-sixth was divided among the provinces without an IC, namely 7 provinces. We chose to divide the industrial electricity demand by six so as to also take into account the industrial electricity demand not coming from the five ICs. The result was that the cumulative share of the provinces with an IC of industrial electricity demand was 83.3%, while that of the provinces without an IC was 16.7%. Table 4.2 summarises what we just mentioned.

Table 4.2: Shares per province of the industrial electricity demand

		Share per Province	Cumulative Share
Provinces with IC	Groningen, North Holland, South Holland, Zeeland, Limburg	16.67%	83.3%
Provinces without IC	Friesland, Drenthe, Overijssel, Gelderland, Flevoland, Utrecht, North Brabant	2.38%	16.7%

To what concerns the residential electricity demand and the electricity demand coming from the service sector, we broke them down according to the percentage of the population of each province in relation to the entire Dutch population. Regarding population, we gathered figures for 2019 from Centraal Bureau voor de Statistiek (CBS) [9] and assumed them to be the same for 2030. Table 4.3 shows the population share of each province.

Table 4.3: Total Dutch population broken down per province

Node	Province	Population	Share Population
NL11	Groningen	583,990	3%
NL12	Friesland	647,672	4%
NL13	Drenthe	492,167	3%
NL21	Overijssel	1,156,431	7%
NL22	Gelderland	2,071,972	12%
NL23	Flevoland	416,546	2%
NL31	Utrecht	1,342,158	8%
NL32	North Holland	2,853,359	17%
NL33	South Holland	3,673,893	21%
NL34	Zeeland	383,032	2%

NL41	North Brabant	2,544,806	15%
NL42	Limburg	1,116,137	6%
	The Netherlands	17,282,163	100%

The formulas we used to calculate the electricity demand coming from each province in 2030 are:

$$ED_{P_{IC_{2030}}} = ED_{NL_{2030}} \cdot (IS_{share} \cdot IC_{share} + RS_{share} \cdot P_{share} + OS_{share} \cdot P_{share}) \tag{4.1}$$

$$ED_{P_{no\_IC_{2030}}} = ED_{NL_{2030}} \cdot (IS_{share} \cdot no\_IC_{share} + RS_{share} \cdot P_{share} + OS_{share} \cdot P_{share}) \tag{4.2}$$

Table 4.4 shows the results obtained from the above-mentioned formulas.

Table 4.4: Total Dutch electricity demand in 2030 broken down per province

Node	**Province**	**Share Electricity Demand**	**Electricity Demand 2030 [TWh]**
NL11	Groningen	8%	9
NL12	Friesland	3%	4
NL13	Drenthe	3%	3
NL21	Overijssel	5%	6
NL22	Gelderland	9%	10
NL23	Flevoland	2%	3
NL31	Utrecht	6%	7
NL32	North Holland	17%	20
NL33	South Holland	20%	24
NL34	Zeeland	7%	9
NL41	North Brabant	11%	13
NL42	Limburg	10%	12
	The Netherlands	100%	120

4.3.2. Hydrogen Demand

We gathered data regarding hydrogen demand coming from the five Dutch ICs from the International Energy Agency (IEA) [34]. These are Maasdelta, located in the Port of Rotterdam, Zeeuws-Vlaanderen, located in the province of Zeeland, Limburg, located in the province of Limburg, Eemshaven, located in the province of Groningen, and IJmond, located in the province of North Holland [34].

The IEA Report claims that hydrogen demand in 2019 from the five ICs was 175 PJ and that it could reach up to 250 PJ in 2030 [34]. In our model, we assumed that the hydrogen demand in 2030 comes only from the five ICs and that the aggregate total is 215 PJ, which is the average between the 2019 demand and the estimated maximum demand in 2030. Consequently, to scale up the demand of each IC, we calculated their share of the total demand in 2019 and multiplied it by 215 PJ. Therefore, the formula we used to calculate the 2030 hydrogen demand of each IC is:

$$HD_{IC_{2030}} = \frac{HD_{IC_{2019}}}{HD_{NL_{2019}}} \cdot 100 \cdot HD_{NL_{2030}} \tag{4.3}$$

In accordance with data presented by the IEA [34], Table 4.5 displays a comprehensive breakdown of hydrogen demand for five distinct industry clusters in 2019, accompanied by their respective shares. Additionally, the table also presents the projected hydrogen demand for the year 2030, estimated to reach a total of 215 PJ.

Table 4.5: Hydrogen demand pe IC in 2019 and in 2030

Node	Industial Cluster	Demand 2019 [PJ]	Share Demand 2019	Demand 2030 [PJ]
NL33	Maasdelta	67.5	39%	83.0
NL34	Zeeuws-Vlaanderen	53.5	30%	65.8
NL42	Limburg	25.8	15%	31.7
NL11	Eemshaven	18.4	11%	22.6
NL32	IJmond	9.7	5%	11.9
	Total Demand	175	100%	215

Since we needed demand in an hourly form, we made the assumption that hydrogen demand would be constant throughout the year for each IC. We assumed this because even if the industry will use hydrogen rather than natural gas or coal, its processes will still be baseload. To deal with green hydrogen variability we considered hydrogen storage options. Through this assumption, we build our CSV file by dividing the total demand per 8760, which are the hours of one year. In this way, we created our CSV file for the 2030 ICs' hydrogen demand.

4.3.3. Production, Conversion, Storage, and Transmission

We gathered data on electricity and hydrogen technologies pertaining to their production, conversion, storage, and transmission. We distinguished between stranded technologies, which are technologies already installed today and, therefore, we assumed them to have no capital costs in 2030, and non-stranded technologies, which are technologies that could be installed by 2030 and, therefore, have capital costs to install. The technical specifications of the stranded technologies were defined based on data from 2020, whereas those of the non-stranded technologies were based on 2030 forecasts.

It is noteworthy that the first group of technologies we modelled is currently operational in the Netherlands, providing us with information about their geographical distribution and installed capacity. Conversely, the non-stranded technologies have not yet been implemented, and thus the model was employed to determine their optimal locations and associated capacity. Specifically, the model was used to define the location and respective installable capacity for compact technologies, such as electrolysers, reformers, hydrogen turbines, and Li-ion batteries. Moreover, we left the model to decide on new offshore wind turbines' capacity because space constraints are less strict thanks to the possibility of exploiting the North Sea part belonging to the Netherlands.

On the other hand, with what concerns new onshore wind turbines and new solar PVs we constrained their potential installable capacity in each node where they could be installed. We did this because we were expecting high onshore renewable capacity for 2030 which could not be installed all in one node due to space constraints. Finally, we restricted locations where salt caverns could be installed because this technology requires specific geological conditions and therefore it is not realistic to build it anywhere.

Non-renewable Electricity Production Technologies

In our model, non-renewable electricity comes from natural gas, processed through CCGTs, and uranium, processed through nuclear reactors. We only listed these technologies as stranded, because the Netherlands not only does not foresee any future investment in these technologies but also has plans to dismantle them [34]. Regarding data sources, we gathered data on lifetime, efficiency, ramping rate and OPEX of both nuclear and CCGT from the Technology Data for Generation of Electricity and District Heating of the Danish Energy Agency (DEA) [19]. To what concerns the nuclear fuel cost we took the data found in the Levelized Cost of Energy Calculator of the DEA [15], while for the CCGT fuel cost, we used the forecast of Energy Brainpool [5]. For CCGT CO_2 cost, we collected the emissions generated by the CCGT from ISPRA [39] and we multiplied them by the forecasted 2030 CO_2 price, namely 100 €/tonCO_2, gathered from Statista [68]. Therefore, the formula we used to calculate the cost for CCGT in 2030 is:

$$CCGT\_cost_{2030} = CO2_{CCGT} \cdot CO2\_cost_{2030} + NG\_cost_{2030} \tag{4.4}$$

In regard to location and capacity installed, we found information for CCGT plants on the Global Energy Monitor [51] and for nuclear reactors on the International Energy Agency (IEA) [34].

Renewable Electricity Production Technologies

In our model, renewable electricity can be produced from onshore and offshore wind turbines and solar PVs. We modelled these technologies both as stranded assets and non-stranded assets because, as mentioned in 4.1, the Netherlands has set targets for renewable capacity installation by 2030, which translates into investments in renewable electricity production technologies.

Onshore Wind Turbines

Regarding specifications and data sources for onshore wind turbines, we downloaded a CSV file with the hourly capacity factor per province from Renewables.ninja [59, 67] and assumed it to be the same in 2030. For CAPEX, OPEX, and lifetime we gathered data from the Technology Data for Generation of Electricity and District Heating of the DEA [19]. Finally, for the location and capacity installed, we used information from CBS [8] for stranded onshore wind turbines, while for non-stranded onshore wind turbines, we made some assumptions.

In the context of the installation of onshore wind turbines in the Netherlands, we assumed that the new turbines could be placed in the same locations as the turbines already installed. This allowed for the possibility of installing new turbines in all 12 provinces of the country. Regarding capacity installation, we modelled the maximum installed capacity of 6.3 GW of onshore wind power by 2030 by taking into account various factors. Firstly, we considered the number of wind turbines in use, the total area needed to install one windmill, and the total electrical capacity installed in 2020 [8]. Based on this information, we calculated the space required by one wind turbine and its electrical capacity.

Furthermore, we assumed that only 5% of the total area of the Netherlands could be utilised for installing new onshore wind turbines. In addition, we assumed that the nominal electric capacity of the turbines installed in 2030 would be twice that of those installed in 2020. Using these assumptions, we determined the maximum number of wind turbines that could be installed by 2030 by dividing the total area that could be covered by new turbines by the space required for one wind turbine and rounding it to zero decimal places. Additionally, we calculated the maximum onshore wind power that could be installed by 2030 by considering the expected increase in nominal electric capacity.

As the turbines cannot all be installed in one node due to space constraints, we divided the total capacity between the provinces according to their extensions, collected from CBS [9], and by using the 5% assumption. The formula we used to calculate the maximum electrical capacity that can be installed in each province of the Netherlands by 2030 is:

$$ON\_cap_{P_{2030}} = \frac{share_{A_{ON_{2030}}} \cdot A_P}{\frac{A_{ON_{2020}}}{\#T_{2020}}} \cdot \frac{ON\_cap_{NL_{2020}}}{\#T_{2030}} \cdot 2 \tag{4.5}$$

Offshore Wind Turbines

Regarding the specifications and data sources for offshore wind turbines, we downloaded a CSV file with the 2019 average hourly capacity factor of offshore wind in the Netherlands from Renewables.ninja [59, 67] and we scaled it up by the 20% for 2030, according to the projected capacity factor [35]. Furthermore, since we modelled two offshore nodes, OFF1 and OFF2, we assumed the same capacity factor for both nodes. For CAPEX, OPEX, and lifetime we gathered data from the Technology Data for Generation of Electricity and District Heating of the DEA [19]. For the location and capacity installed of stranded offshore wind turbines, we collected information from the Government of the Netherlands [53]. On the other hand, we allowed the model to install non-stranded offshore wind turbines in both OFF1 and OFF2 while leaving the maximum installable capacity unrestricted. In this way, the model will find the optimal capacity to install new offshore wind turbines, which have high potential in the Netherlands due to the possibility of exploiting the North Sea.

Solar PVs

Regarding specifications and data sources for solar PVs, we downloaded a CSV file with the hourly capacity factor per province from Renewables.ninja [59, 67] and assumed it to be the same in 2030. We modelled only one technology for electricity generated from solar power and we assumed it to be utility-scale solar PVs. Therefore, for CAPEX, OPEX, and lifetime, we gathered utility-scale solar PV data from the Technology Data for Generation of Electricity and District Heating of the DEA [19]. Finally, for the location and capacity installed, we used information from CBS [10] for stranded solar PVs, while for non-stranded solar PVs, we made some assumptions.

About the location, we assumed the new solar PVs would be installed in the same nodes as those already installed. This results in the possible installation of new panels in all 12 provinces of the Netherlands. Regarding the capacity installed, instead, we started from the claim that 1 MW of solar power corresponds to 2 hectares. Moreover, we assumed that only 1.5% of the total area of the Netherlands could be utilised for installing new solar PVs. With these two pieces of information, we calculated the maximum area that could be covered by solar panels in each province by 2030 by multiplying 1.5% by the extension of the province [9]. Then, to calculate the maximum installable capacity, we divided the multiplication just mentioned by the area needed to generate 1 MW of solar power, namely 2 hectares. The formula we used to calculate the maximum solar PV electricity generation capacity that could be installed in each of the 12 onshore nodes by 2030 is:

$$PV\_cap_{P_{2030}} = \frac{share_{A_{PV_{2030}}}}{A_{PV_{MW}}} \tag{4.6}$$

Hydrogen Production Technologies

In our model, hydrogen can be produced by SMR+CCS, which specifically generates blue hydrogen. We modelled this technology only among non-stranded assets since, in 2020, there was still no blue hydrogen production in the Netherlands [34]. However, by 2030 several projects concerning blue hydrogen should materialise in the Netherlands [72]. We collected information from the IEA [31] pertaining to lifetime, efficiency, and OPEX, while for CAPEX and fuel cost, we gathered data from The European Files [27] and Energy Brainpool [5] respectively. Finally, for the CO_2 cost, we discovered from Ayodele et al. (2020) [2] the amount of CO_2 emission generated from SMR+CCS and we multiplied it by the 2030 carbon price predicted by Statista [68]. Therefore, the formula we used to calculate the CO_2 emission cost for the SMR+CCS in 2030 is:

$$CO2\_cost_{SMR+CCS_{2030}} = CO2_{SMR+CCS} \cdot CO2\_price_{2030} \tag{4.7}$$

The figures we used are calculated considering a CCS able to capture and store the 95% of the emission generated during the SMR process. Moreover, we assumed the storage capacity for CO_2 to be infinite.

Renewable Electricity Conversion Technologies

In our model, renewable electricity can be converted into green hydrogen through the electrolysis process, which is performed by the Alkaline electrolyser or by the PEM electrolyser. We modelled these technologies only among non-stranded assets since, in 2020, there were still no operational electrolysers in the Netherlands [34]. Regarding technical specifications, we gathered data on lifetime and CAPEX from the Technology Data for Renewable Fuels of the DEA [16], efficiency from Nikolaidis et al. (2017) [54], ramping rate from IRENA [38], and OPEX and cost of water from Katebah et al. (2020) [40].

Hydrogen Conversion Technologies

In our model, hydrogen can be converted into electricity by using a CCHT. We modelled this conversion technology only among non-stranded assets since, in 2020, there were still no operational CCHTs in the Netherlands [25]. Regarding technical specifications, we gathered data on lifetime, efficiency, CAPEX, and OPEX from Oberg et al. (2022) [56], while on ramping rate from IRENA [38].

Electricity Storage Technologies

In our model, we modelled Li-ion batteries as electricity storage technologies with the aim of dealing with VRES. We modelled these technologies as both stranded and non-stranded assets because, as the Netherlands has set electricity targets which entail investing in renewables, it will also need new flexible options such as batteries. Regarding data sources, we collected data on lifetime, efficiency, storage loss, charge/discharge rate, CAPEX, and OPEX from the Technology Data for Energy Storage of the DEA [18]. Regarding the location and capacity installed, we gathered data for batteries already installed in 2020 from Frontis Energy [24], while for new batteries we left the model to decide the location and the capacity to install.

Hydrogen Storage Technologies

In our model, salt caverns work as hydrogen storage technologies. We modelled these technologies only as non-stranded assets because there were no operational salt caverns in 2020, but the Netherlands has a high technical potential to build salt caverns by 2030, particularly in the north [73]. Indeed, we modelled the salt cavern storage option in node NL11, corresponding to the province of Groningen, because large-scale underground hydrogen storage is taking place there [73]. Regarding capacity installed, we left the decision to the model, which should optimise it. In the end, for the lifetime, efficiency, storage loss, charge/discharge rate, CAPEX, and OPEX we use data points from the Technology Data for Energy Storage of the DEA [18].

Electricity Transmission Technologies

In our model, we modelled high-voltage AC transmission lines as electricity transmission technologies. We modelled this technology both as stranded and non-stranded assets because we made the assumption that the 2030 Dutch electricity grid is equal to that already existing in 2020. However, in 2020 electricity connections with offshore wind parks were not in place and therefore we defined those as new electricity lines [70]. Regarding technology specifications, we gathered data on lifetime and efficiency from the Calliope Italy Model [46]. From here we collected OPEX of stranded electricity as well, while CAPEX and OPEX for new electricity lines were already considered in those of new offshore wind technologies. Finally, we left uncapped the transmission capacity of both stranded and non-stranded electricity lines because we supposed the possibility to build parallel transmission lines as already done in the actual electricity grid [70].

Hydrogen Transmission Technologies

In our model, we modelled repurposed natural gas hydrogen pipelines as onshore hydrogen transmission technologies and dedicated hydrogen pipelines as offshore hydrogen transmission technologies. The onshore hydrogen pipelines we modelled are based on the existing natural gas grid, as mentioned in 4.1, and are defined as non-stranded because in 2020 there were no repurposed natural gas hydrogen pipelines.

On the other hand, offshore hydrogen pipelines are both non-stranded assets and not based on the actual gas grid because in 2020 there were no offshore natural gas pipelines. Regarding technology specifications, we gathered data on lifetime, efficiency, CAPEX and OPEX from the Technology Catalogue for Transport of Energy from the DEA [17]. Finally, we left uncapped the transmission capacity of both repurposed natural gas hydrogen pipelines and offshore hydrogen pipelines because we supposed the possibility to build parallel transmission pipelines as already done in the actual gas grid [28].

5

Scenarios Formulation

This Chapter explains the uncertainties regarding the future penetration in the energy system of hydrogen infrastructure in Section 5.1. Moreover, it shows in Section 5.2 the scenarios investigated to analyse the uncertainties of hydrogen regarding demand and capital costs of electrolysers in 2030.

5.1. Uncertainty Mitigation Pathways

The transition towards a low-carbon energy system presents complex challenges. One of the primary challenges in this regard is integrating fluctuating sources of wind and solar energy into the grid. The output of these renewable sources can vary significantly depending on weather conditions, making it difficult to predict and manage the energy supply. Therefore, flexibility options are needed in order to make the future Dutch integrated energy system of 2030 work without relying on conventional energy sources.

Energy storage solutions, such as batteries, can provide the necessary security, flexibility, and adequacy to the integrated energy system of the future. By storing excess energy, batteries can help balance energy supply and demand and ensure that energy is available when needed. The integration of these flexibility options will be essential to create a reliable and cost-effective energy system that can handle large-scale intermittent renewable energy sources. Moreover, hydrogen-based power also offers an excellent opportunity to store energy in a clean and efficient manner. The conversion of renewable electricity into green hydrogen enables the storage of excess energy generated from renewable sources for use when demand is high. Hydrogen storage options, such as salt caverns, are therefore also important for the creation of a flexible integrated energy system.

The realisation of the aforementioned goals requires several investments, particularly with regard to green hydrogen. These investments necessitate a financial commitment, which can only be facilitated by a growing demand for hydrogen. However, the growth of hydrogen demand is contingent upon the availability of hydrogen supply, which can only be achieved through the requisite technologies. This dilemma, the “chicken-and-egg” problem, generates uncertainty, which impairs the establishment of an energy system capable of integrating flexible solutions, as already described in Section 1.3.

To understand the impacts of these uncertainties on the future Dutch integrated energy system of 2030, we analysed the impacts of hydrogen demands and capital costs of electrolysers uncertainties on the future Dutch integrated energy system of 2030. In particular, we focused on impacts on the installed energy capacity for renewable electricity generation technologies and hydrogen generation technologies and the installed storage capacity for electricity and hydrogen storage technologies.

5.2. Scenario Investigated

According to the uncertainties we wanted to analyse and the sub-questions we wanted to answer, we created four scenarios, which are the Base Case scenario, The Demand-led scenario, the Cost-led scenario, and the No-Blue-Hydrogen scenario.

The Base Case scenario represents the future Dutch integrated energy system for 2030. We decided to model this scenario by using the parameters predicted to most likely occur in 2030 in the Netherlands with the aim of having results to compare with those obtained in front of changes in the parameters modelled. Moreover, the results of this scenario will allow us to answer SQ1, that is *“How will the Dutch integrated energy system look like in 2030?”*.

The Demand-led scenario represents the future Dutch integrated energy system in front of different demands for hydrogen for 2030. We decide to model this scenario to understand the impacts the uncertainty regarding the future hydrogen demand has on the Dutch integrated energy system of 2030, as we already explained in Section 1.3. In particular, we divided this scenario into two sub-scenarios in order to analyse how the 2030 Dutch integrated energy system will be impacted by a lower or a higher hydrogen demand compared to the hydrogen demand modelled in the Base Case. Moreover, we will use this scenario to answer SQ2, namely *“How does hydrogen demand impact the 2030 Dutch integrated energy system?”*.

The Cost-led scenario represents the future Dutch integrated energy system in front of different electrolysers’ capital costs for 2030. We decide to model this scenario to understand the impacts the uncertainty regarding the future CAPEX associated with the Alkaline and the PEM electrolysers have on the Dutch integrated energy system of 2030, as we already explained in Section 1.3. In particular, we divided this scenario into two sub-scenarios to analyse how lower or higher electrolysis capital costs will impact the 2030 Dutch integrated energy system compared to those modelled in the Base Case. Moreover, we will use this scenario to answer SQ3, namely *“How do electrolysis capital costs impact the 2030 Dutch integrated energy system?”*

Finally, the No-Blue-Hydrogen scenario represents the future Dutch integrated energy system of 2030 in the case where the government does not allow the production of blue hydrogen but only the production of green hydrogen and the use of green hydrogen imported. Moreover, we will use the results of this scenario to answer SQ4, which is *“How will the Dutch integrated energy system look like in 2030 if there is no blue hydrogen?”*

Figure 5.1 summarises the scenarios created in this study and shows the links between each scenario ad the corresponding sub-question it should answer.

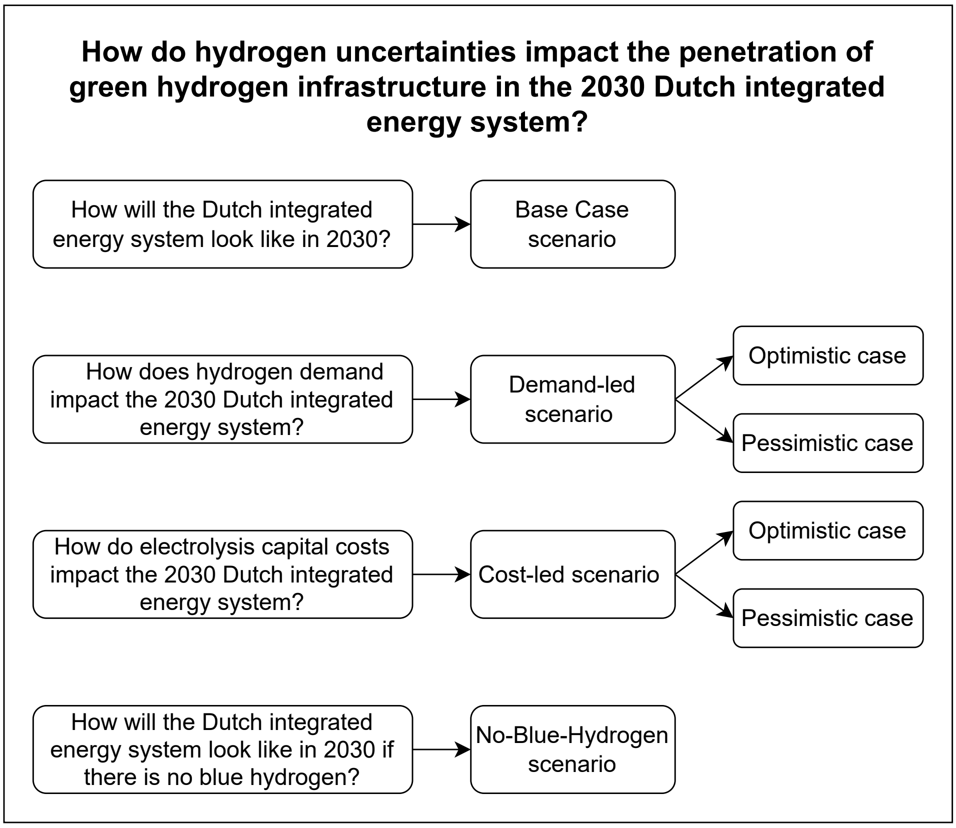

Figure 5.1: Scenarios formulated to answer the four SQs and the main RQ

5.2.1. Base Case Scenario

The Base Case scenario represents our starting point to analyse the 2030 Dutch integrated energy system. As aforementioned, to create our scenarios we assigned different values to hydrogen demand, CAPEX of the Alkaline electrolyser, and CAPEX of the PEM electrolyser. In the Base Case scenario we modelled a total hydrogen demand coming from the five ICs of 215 PJ, which is, as already mentioned in 4.3.2, the value predicted for 2030 in the Netherlands by the IEA [34]. Regarding the capital costs of the electrolysers in 2030, we modelled 450 €/kW for the PEM electrolyser and 650 €/kW for the Alkaline electrolyser, as mentioned in the Technology Catalogue for Renewable Fuels of the DEA [16]. Table 5.1 shows the values for hydrogen demand and Alkaline and PEM electrolysers capital costs in the Base Case scenario.

Table 5.1: Variables specification of the Base Case scenario

Base Case Scenario	
Hydrogen demand [PJ]	215
AEL CAPEX [€/kW]	450
PEMEL CAPEX [€/kW]	650

5.2.2. Demand-led Scenario

As mentioned in 4.3.2 the best forecast for hydrogen demand in 2030 is 250 PJ according to the IEA [34]. On the other hand, for the worst forecast, we assumed that the demand for hydrogen from ICs in 2030 would be the same as in 2019, shown in Table 4.5.

In order to build the hydrogen demand for our scenario in the optimistic case, we took the shares of the total demand of each industrial cluster reported in Table 4.5 and multiplied them for the new total hydrogen demand. Therefore, the formula we used to calculate the 2030 hydrogen demand of each industrial cluster in the optimistic case of the Demand-led scenario is:

$$HD_{IC_{2030\_best}} = \frac{HD_{IC_{2019}}}{HD_{2019}} \cdot 100 \cdot HD_{2030\_best}$$

Table 5.2 shows the 2030 hydrogen demand broken down for the five ICs in the optimistic case of the Demand-led scenario.

Table 5.2: Best hydrogen demand per each IC

Node	Industial Cluster	Best Demand 2030 [PJ]
NL33	Maasdelta	97.5
NL34	Zeeuws-Vlaanderen	75
NL42	Limburg	37.5
NL11	Eemshaven	27.5
NL32	IJmond	12.5
	Total Demand	250

Table 5.3 shows the values for hydrogen demand and Alkaline and PEM electrolysers capital costs in both the optimistic and pessimistic cases of the Demand-led scenario.

Table 5.3: Variables specification of the Demand-led scenario

Demand-led Scenario	Optimistic Case	Pessimistic Case
Hydrogen demand [PJ]	250	175
AEL CAPEX [€/kW]	450	450
PEMEL CAPEX [€/kW]	650	650

5.2.3. Cost-led Scenario

Regarding possible capital cost increases or reductions that could be experienced by electrolysis technologies by 2030, we gathered information from the HyWay 27 [69]. Table 5.4 shows the values for hydrogen demand and Alkaline and PEM electrolysers capital costs in both the optimistic and pessimistic cases of the Cost-led scenario.

Table 5.4: Variables specification of the Cost-led scenario

Cost-led Scenario	Optimistic Case	Pessimistic Case
Hydrogen demand [PJ]	215	215
AEL CAPEX [€/kW]	140	525
PEMEL CAPEX [€/kW]	220	825

5.2.4. No-Blue-Hydrogen Scenario

The No-Blue-Hydrogen scenario represents the future Dutch integrated energy system of 2030 if blue hydrogen production is not allowed. Therefore, hydrogen demand and electrolysis capital costs have the same parameters modelled in the Base Case scenario. This means that the total hydrogen demand coming from the five ICs accounts for 215 PJ, while the electrolysis capital costs are 450 €/kW for the PEM electrolyser and 650 €/kW for the Alkaline electrolyser. However, we did not model SMR+CCS technologies for this scenario. Table 5.5 shows the parameters modelled for the No-Blue-Hydrogen scenario.

Table 5.5: Variables specification of the Base Case scenario

No-Blue-Hydrogen Scenario	
Hydrogen demand [PJ]	215
AEL CAPEX [€/kW]	450
PEMEL CAPEX [€/kW]	650
SMR+CCS [GW]	0

6

Results

This Chapter describes the different results obtained in each of the modelled scenarios. We grouped these results according to the scenario presented in Chapter 5. Therefore, in Section 6.1 we reported results obtained from the Base Case scenario simulation, in Section 6.2 those obtained from the Demand-led scenario simulation, in Section 6.3 those obtained from the Cost-led scenario simulation, and in Section 6.4 those obtained from the No-Blue-Hydrogen scenario simulation.

6.1. Base Case Scenario Results

The electricity results of the Base Case (BC) scenario for the Dutch integrated energy system of 2030, reported in Figure 6.1 and Figure 6.2, show total renewable electricity installed capacity of 55.07 GW, with a total electricity production of 101.70 TWh. Non-renewable electricity installed capacity resulted in 12.86 GW with a total electricity production of 36.18 TWh. Additional energy installed capacity for electricity conversion processes resulted in 3.27 GW, with an electricity production of 0.34 TWh. The total electricity installed capacity is 71.2 GW, which generates 138.23 TWh for an electricity demand of 120 TWh in 2030.

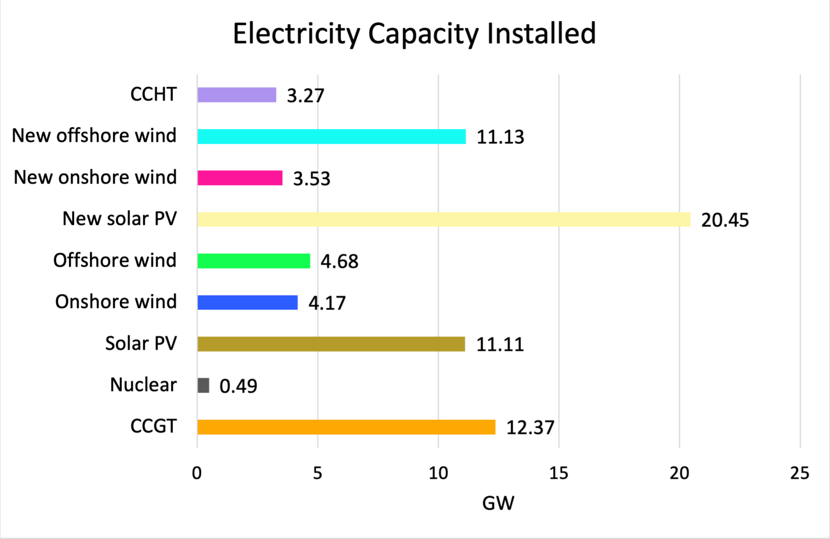

Figure 6.1: Electricity capacity installed per technology in the BC scenario

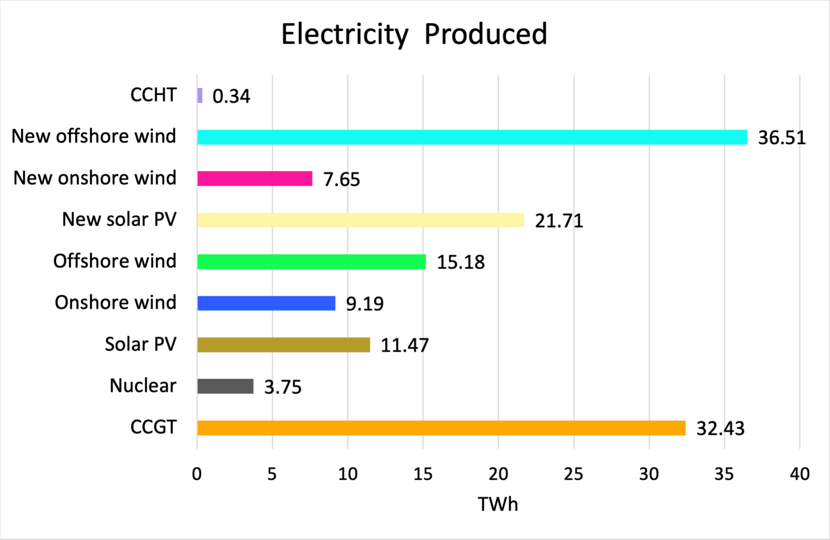

Figure 6.2: Electricity produced per technology in the BC scenario

On the other hand, the hydrogen results, reported in Figure 6.3 and Figure 6.4, show that hydrogen production technologies involve SMR+CCS, with an installed capacity of 6.82 GW and a hydrogen production of 45.89 TWh, Alkaline electrolyser, with an installed capacity of 4.47 and a hydrogen production of 7.59 TWh, and PEM electrolyser, with an installed capacity of 2.35 and a hydrogen production of 6.37 TWh. The total hydrogen installed capacity is 13.64 GW and the total hydrogen produced is 59.35 TWh. Hydrogen imports account for 0.35 TWh. Therefore, there are 60.20 TWh of hydrogen available in the BC scenario to meet the hydrogen demand of 59.70 TWh in 2030.

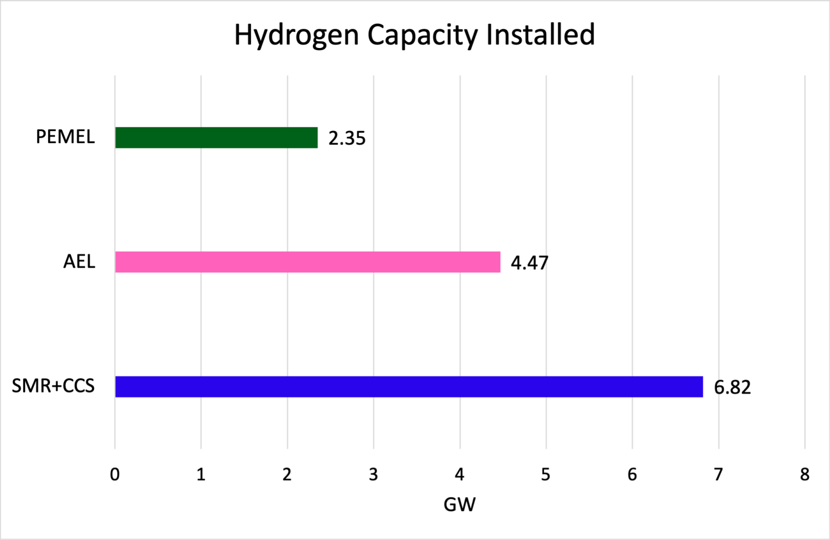

Figure 6.3: Hydrogen capacity installed per technology in the BC scenario

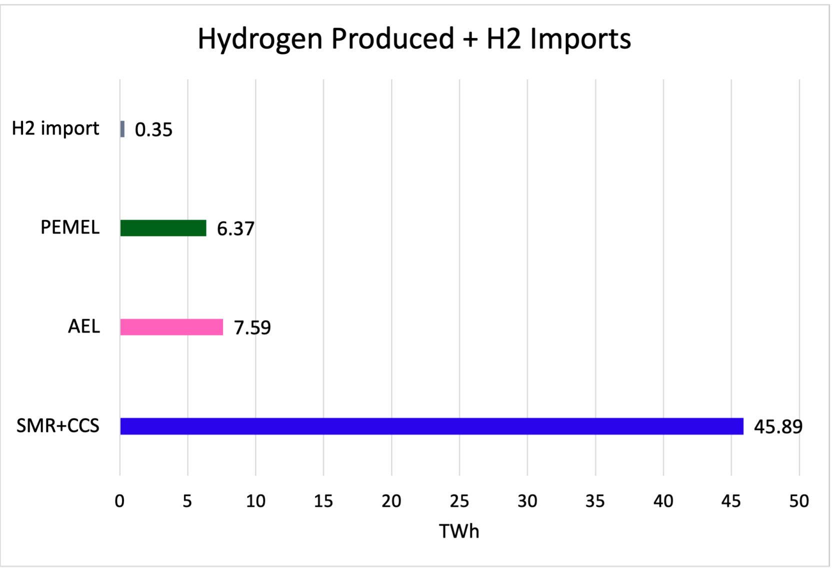

Figure 6.4: Hydrogen produced per technology and hydrogen imports in the BC scenario

Regarding energy storage technologies, Figure 6.5 displays a storage capacity installed of 14 MWh for batteries, 7348.3 MWh for new batteries, and 993.1 MWh for salt caverns.

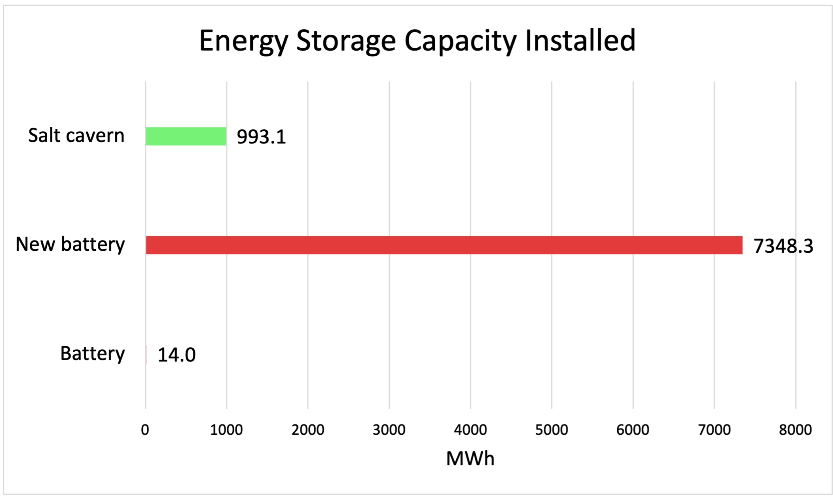

Figure 6.5: Storage capacity installed per technology in the BC scenario

Regarding transmission infrastructure, the results are shown in Figure 6.6. Onshore and offshore electricity links connect provinces with each other and offshore wind parks with the mainland. Onshore and offshore hydrogen pipelines connect industrial clusters with each other and transport hydrogen produced offshore to the mainland. Comparing Figure 6.6 with Figure 4.3 we observed that the optimisation problem in the BC scenario installed all the electricity and hydrogen links modelled in this study.

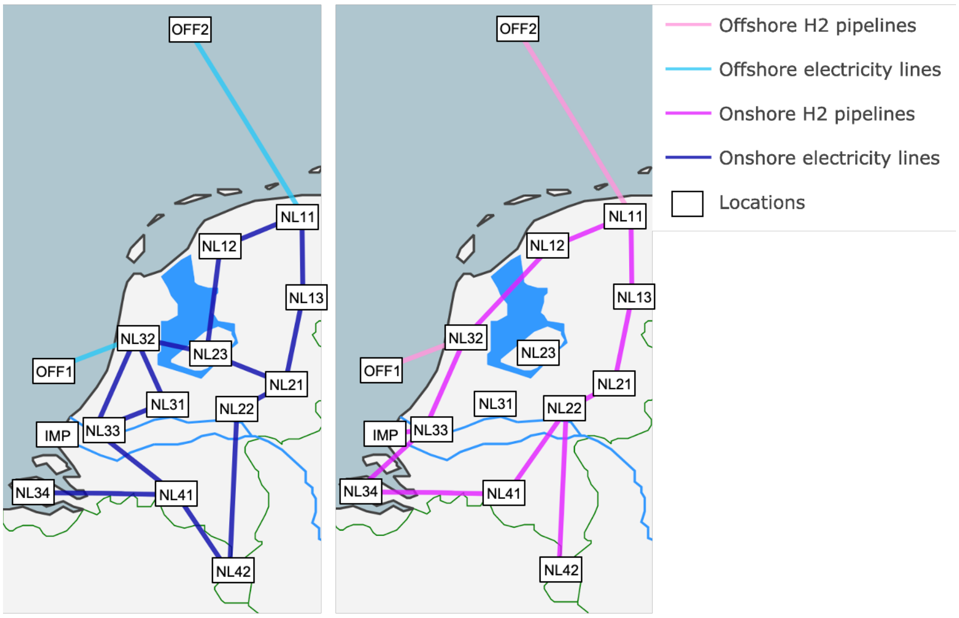

Figure 6.6: Electricity and hydrogen transmission grids in the BC scenario

System Level Results Analysis

To understand what the figures above mean in terms of energy system behaviour, we analysed the hourly electricity and hydrogen production and consumption during a period of 5 days. In particular, we studied the system from the 23th of January 2030 to the 28th of January 2030 because we wanted to analyse it during a period of low RES availability followed by a period of high RES availability.

In Figure 6.7 we observed that during periods of low RES capacity factor, the system mainly uses electricity generated from CCGTs to meet electricity demand, while it uses hydrogen produced through SMR+CCS to meet hydrogen demand, as reported in Figure 6.8. Moreover, Figure 6.7 shows that when the renewable electricity produced is significantly scarce the system uses electricity stored in batteries and converts hydrogen into electricity using CCHT technologies. This is due to the constraints we modelled for non-renewable electricity generation technologies, which do not allow the installation of additional capacity of nuclear and CCGT power plants by 2030 in the Netherlands.

Additionally, Figure 6.8 illustrates that the hydrogen converted into electricity comes from imports. Therefore, the system runs the SMR+CCS baseload to satisfy the demand for hydrogen and opts to import hydrogen from foreign sources for electricity production. This suggests that despite the potentially higher cost of imported hydrogen compared to domestically produced blue hydrogen, it represents a more economically efficient choice for the conversion process, in contrast to installing supplementary energy capacity for SMR+CCS, which would only be utilised during brief periods within the year.

On the other hand, Figure 6.7 demonstrates that during periods of high RES capacity factor, a portion of the surplus renewable electricity is stored in batteries for short-term storage, while the remaining excess is converted into green hydrogen through the utilisation of Alkaline and PEM electrolysers. This is further highlighted in Figure 6.8, which depicts that the hydrogen generated via electrolysis is subsequently utilised to fulfil the demand for hydrogen. However, it is important to note that this process occurs instantaneously, resulting in a relatively insignificant installed storage capacity for salt caverns, as indicated in Table B.2.

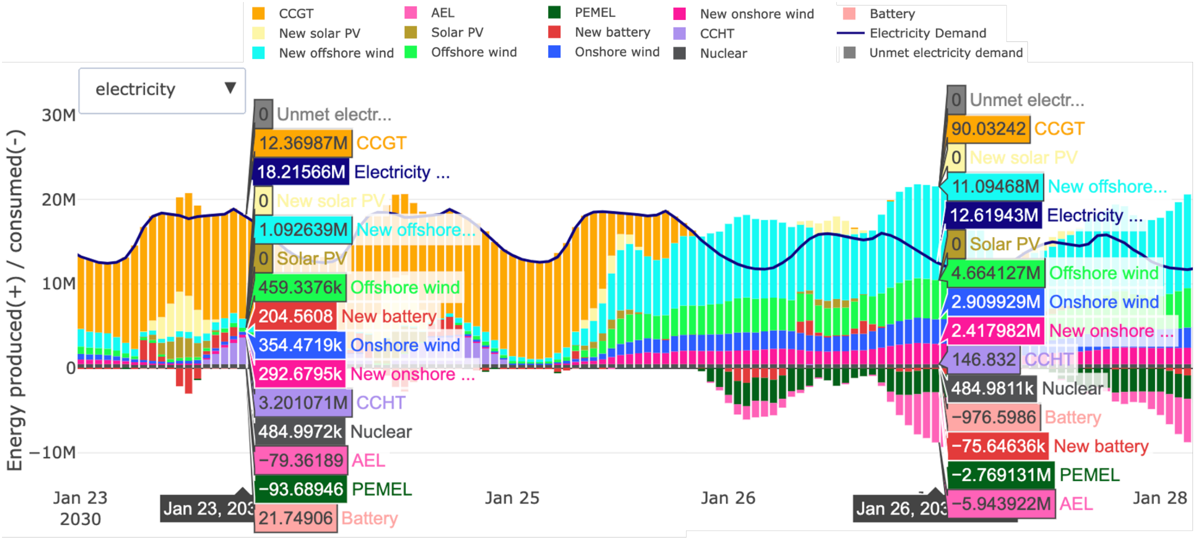

Figure 6.7: Hourly electricity production and consumption in the BC scenario

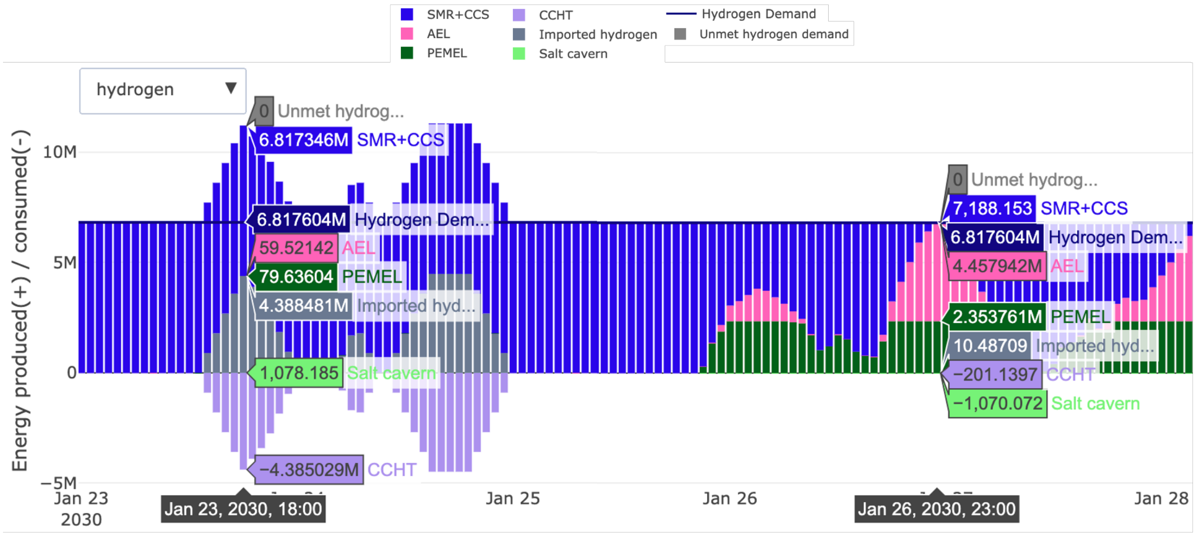

Figure 6.8: Hourly hydrogen production and consumption in the BC scenario

Electricity Production Technologies

Regarding electricity production from non-renewable energy sources, the results indicate an installed capacity of 12.37 GW for CCGT power plants and 0.49 GW for nuclear reactors in 2030. These figures correspond to the maximum capacity we allowed the model to install for these technologies, which in turn is their total generation capacity installed in the Netherlands in 2020 [34, 51]. Notably, the results of our analysis suggest that the Netherlands will not decommission any CCGT power plants or nuclear reactors by 2030, indicating that the country will likely continue to rely especially on natural gas as a significant source of electricity generation in the medium term.

To what concerns renewable electricity, the model installed new solar PV for a total electricity generation capacity of 20.45 GW, new onshore wind turbines for a total electricity generation capacity of 3.53 GW, and new offshore wind turbines for a total electricity generation capacity of 11.13 GW. Summing this new renewable capacity with that already installed in 2020, that is 11.11 GW for solar PV, 4.17 GW for onshore wind, and 4.68 GW for offshore wind, we obtained a total installed capacity of 31.56 GW for solar PV, 7.7 GW for offshore wind, and 15.81 GW for offshore wind in the Netherlands in 2030. Therefore, the model predicts in the BC scenario that, under a cost optimisation perspective, the renewable objectives mentioned in 4.1 could be overcome.

Hydrogen-related Technologies

Regarding hydrogen-related technologies, the model installed a capacity of 6.82 GW for SMR+CCS, 4.47 GW for Alkaline electrolysers, and 2.35 GW for PEM electrolysers, as previously mentioned. The first two things suggested from these results are that in 2030 the Netherlands will still rely on natural gas for the production of hydrogen and will still prefer Alkaline electrolysers over PEM electrolysers. However, the optimisation indicates that with the predicted levels of hydrogen demand, the optimal installation of electrolysers of 6.8 GW, is larger than the current target of having 3-4 GW of electrolysis by 2030 [22]. Nevertheless, the results also suggest that the Netherlands would still rely on SMR, even if combined with CCS.

Node Level Results analysis

The data presented in Table B.2, depicting the installed capacity across different nodes for each respective technology in the BC, indicates that the installation of capacity for SMR+CCS and Alkaline and PEM electrolysers is primarily focused on the five nodes that host an IC. Additionally, sorting these five nodes in descending order of installed capacity yields different results depending on the technology. Table 6.1 reports the optimal capacity installed for SMR+CCS, Alkaline electrolyser, and PEM electrolyser in each of the 5 nodes having an IC. We coloured the cells of Table 6.1 to illustrate how the capacity installed per technology varies in the selected nodes. The darkest blue colour indicates the highest installed capacity, while the white colour indicates the lowest.

H_2 Technologies	**NL33**	**NL34**	**NL42**	**NL11**	**NL32**
SMR with CCS [MW]	2629.7	2085.7	1005.5	716.1	378.4
AEL [MW]	1452.6	2004	992	9.1	4
PEMEL [MW]	1178.8	79.3	13	706.6	374

Table 6.1: Optimal energy capacity installed for hydrogen-related technologies in the 5 nodes having an IC in the BC scenario

The results show a larger installation of SMR+CCS in those nodes where hydrogen demand occurs. This is because SMR is a flexible technology that can adjust its production based on demand and because natural gas is a reliable and abundant source of energy for SMR [20]. In fact, NL33 has the largest installed capacity of SMR+CCS and hosts Maasdelta, which is the IC requiring the largest share of total hydrogen demand in 2030 (Table 4.5). Again, NL34 has the second largest capacity installed for SMR+CCS and hosts Zeeuws-Vlaanderen, the IC asking for the second largest share of total hydrogen demand in 2030 (Table 4.5). Regarding the optimal capacity installed by the model for the Alkaline electrolyser, we found a similar trend to that installed for SMR+CCS. On the other hand, while the largest installed capacity for the PEM electrolyser is still in node NL33, the second and the third largest installed capacity are respectively in nodes NL11 and NL32, which are those having the smallest installed capacity for the other two technologies.

Figure 6.9 shows the differences in the optimal capacity installed of SMR+CCS, Alkaline electrolyser, and PEM electrolyser for each node in the BC scenario.

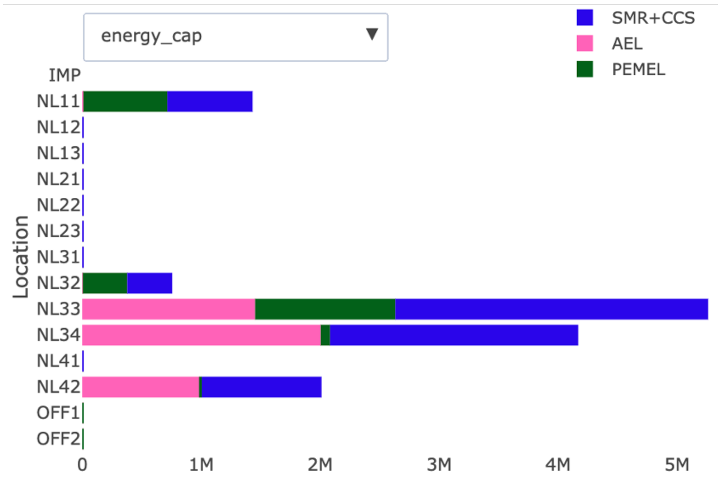

Figure 6.9: Optimal energy capacity installed for SMR+CCS technologies, Alkaline electrolysers, and PEM electrolysers per node in the BC scenario

To explain this, we observed the optimal capacity installed by the model for renewable energy production technologies in the five nodes under analysis. We did this because electrolysis technologies need renewable electricity to produce green hydrogen and, therefore, are dependent on RES deployment. We reported the results for renewable electricity generation capacity installed in 2030 in the BC scenario in Table 6.2. Even in this case, we coloured the cells of the table to illustrate how the capacity installed per technology varies in the selected nodes. The darkest blue colour indicates the highest installed capacity, while the white colour indicates the lowest.

RES Technologies	**NL33**	**NL34**	**NL42**	**NL11**	**NL32**
Onshore wind [MW]	445	525	21	618	642
Solar PV [MW]	1167.8	442.6	879.6	942.5	1107.1
New onshore wind [MW]	440.2	288.3	0.5	377.9	432.4
New Solar PV [MW]	2025	1336.6	1609.9	857.7	1998.5

Table 6.2: Optimal energy capacity installed for renewable electricity technologies in the 5 nodes with an IC in the BC scenario

The results observed in Table 6.1 and Table 6.2 suggest that the optimal installed capacity for Alkaline and PEM electrolysers in each node is determined based on hydrogen demand and amount of renewable capacity installed per each node. However, if for the Alkaline electrolyser the model weights more the former, for the PEM electrolyser it weights more the latter. In fact, the PEM electrolyser is recognised for its capability to rapidly adjust its output, which makes it a viable technology for accommodating fluctuations in the power supply from renewable sources. Specifically, the PEM electrolyser can quickly ramp up or down its power production in response to changes in the input from renewable energy sources, which makes it a flexible and adaptable solution for integrating renewable energy into the power grid [20]. On the other hand, the Alkaline electrolyser is a preferred option for large-scale and more base-load hydrogen production since it has a lower efficiency and a lower ramping rate compared to the PEM electrolyser [20].

Additionally, still analysing Table 6.1 and Table 6.2 we observed that the optimisation resulted in a higher installed capacity for the PEM electrolyser in NL11 rather than in NL32, even if the amount of capacity installed for renewable electricity generation technologies in the latter is higher than that installed in the former. This is because NL11 has a higher hydrogen demand compared to NL32 but most importantly it has storage capacity installed for salt caverns. This is in line with the role of integrating renewable energy into the power grid of the PEM electrolyser.

Figure 6.10 provides a comprehensive overview of the aforementioned aspects discussed thus far, pertaining to the decisions derived from the optimisation problem concerning the installation of energy capacity for hydrogen production technologies, their correlation with hydrogen demand, as well as with the installation of capacity for RES and salt caverns.

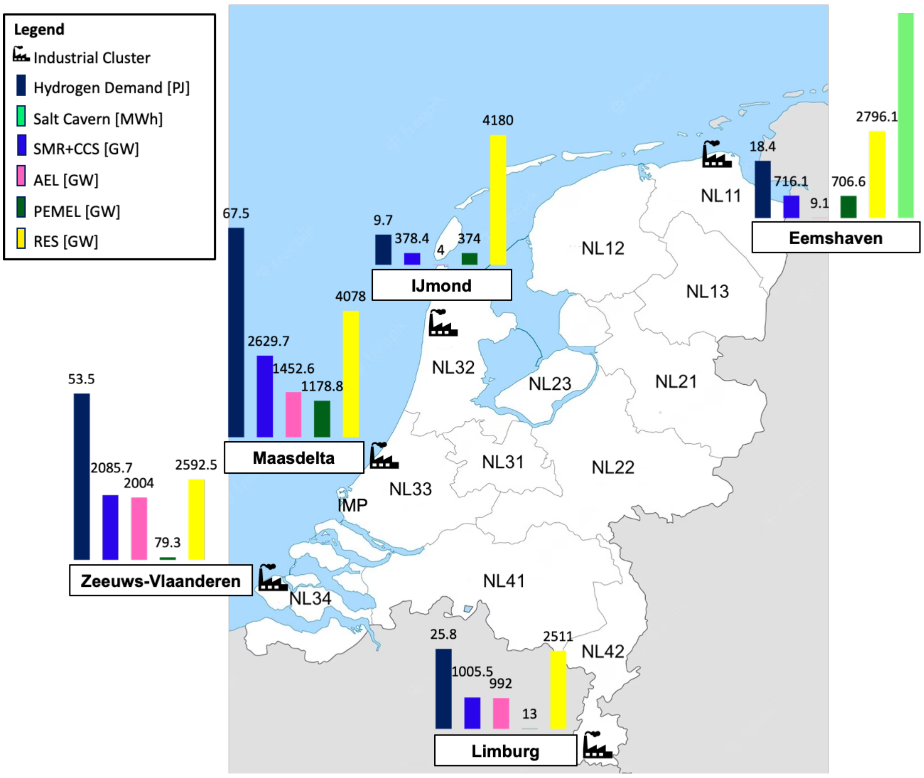

Figure 6.10: Hydrogen demand, capacity installed for hydrogen production technologies, and storage capacity installed for salt caverns in the nodes hosting an IC in the BC scenario

Regarding salt caverns, the results show that the model installed storage capacity for them in nodes NL11, NL12, and NL13. However, the capacity installed is little in each node, as reported in Table B.4, and therefore the findings highlight this relation between the energy capacity installed for the PEM electrolyser and the storage capacity installed for the salt caverns only in node NL11, which differently from NL12 and NL12 has also a hydrogen demand.

Moroever, the little storage capacity installed for salt caverns has also a relation with the energy capacity installed for CCHT technologies. In fact, almost no hydrogen conversion capacity has been installed in the nodes NL11, NL12, and NL13. On the other hand, out of a total installed capacity of 3.297 GW, 3.291 GW have been installed in NL33, which is the only node connected with the node dedicated to imports of hydrogen. This is shown in Figure 6.11.

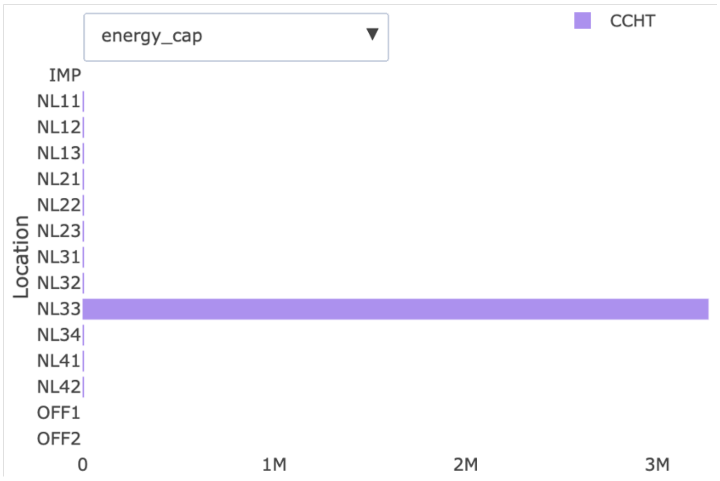

Figure 6.11: Optimal energy capacity installed for CCHT technologies per node in the BC scenario

6.2. Demand-led Scenario Results

In the Demand-led scenario, we defined a Demand-led Optimistic Case (DOC), with a hydrogen demand of 250 PJ in 2030, and a Demand-led Pessimistic Case (DPC), with a hydrogen demand of 175 PJ in 2030. We compared the results of these two simulations with those obtained in the BC scenario.

6.2.1. Demand-led Optimistic Case Results

The results of the DOC scenario for the Dutch integrated energy system of 2030, reported in Figure 6.12 and Figure 6.13, show an installed renewable energy capacity of 56.33 GW, with a total electricity production of 104.26 TWh. Non-renewable energy installed capacity resulted in 12.86 GW with a total electricity production of 35.46 TWh. Additional energy installed capacity for electricity conversion processes resulted in 3.24 GW, with an electricity production of 0.34 TWh. The total electricity installed capacity is 72.43 GW, which generates 143.85 TWh for an electricity demand of 120 TWh in 2030.

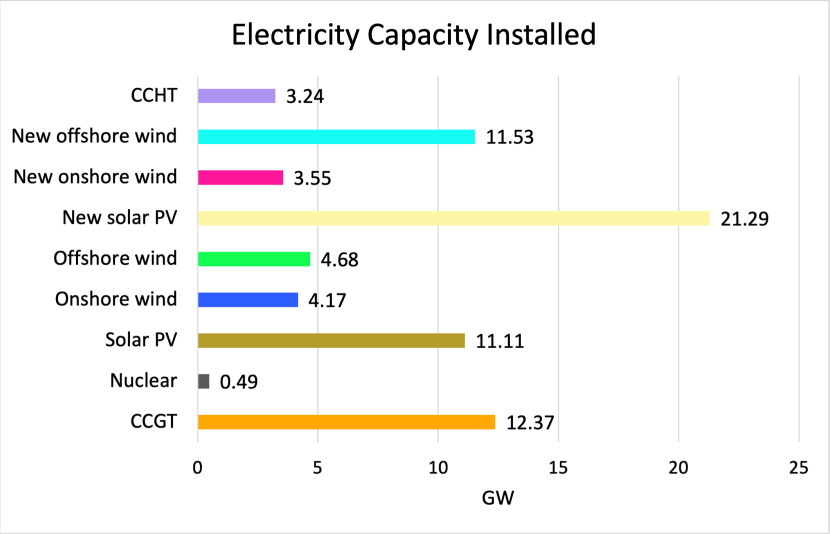

Figure 6.12: Electricity capacity installed per technology in the DOC scenario

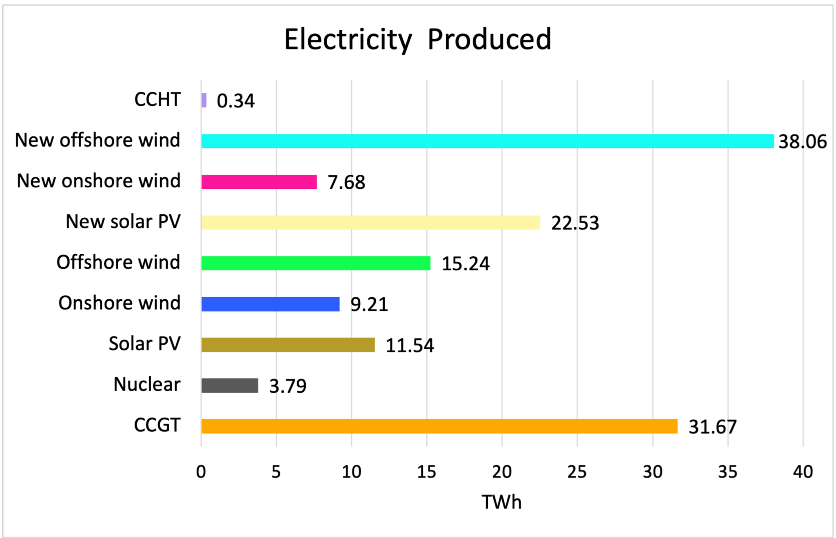

Figure 6.13: Electricity produced per technology in the DOC scenario

Moreover, results reported in Figure 6.14 and Figure 6.15, show that hydrogen production technologies involve SMR+CCS, with an installed capacity of 7.93 GW and a hydrogen production of 54.18 TWh, Alkaline electrolysers, with an installed capacity of 5.03 and a hydrogen production of 8.44 TWh, and PEM electrolysers, with an installed capacity of 2.51 and a hydrogen production of 6.95 TWh. The total hydrogen installed capacity is 15.47 GW and the total hydrogen produced corresponds to 69.57 TWh. Hydrogen imports account for 0.34 TWh. Therefore, there are 69.4 TWh of hydrogen in the DOC scenario to meet the hydrogen demand of 69.91 TWh in 2030.

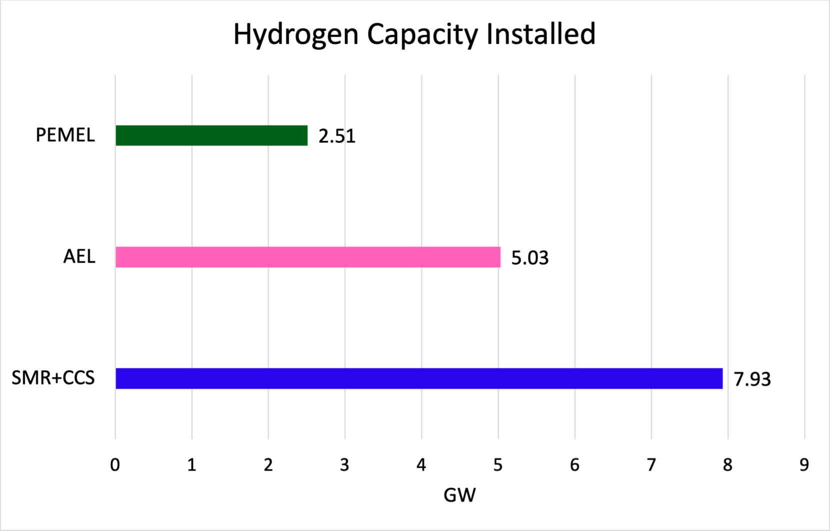

Figure 6.14: Hydrogen capacity installed per technology in the DOC scenario

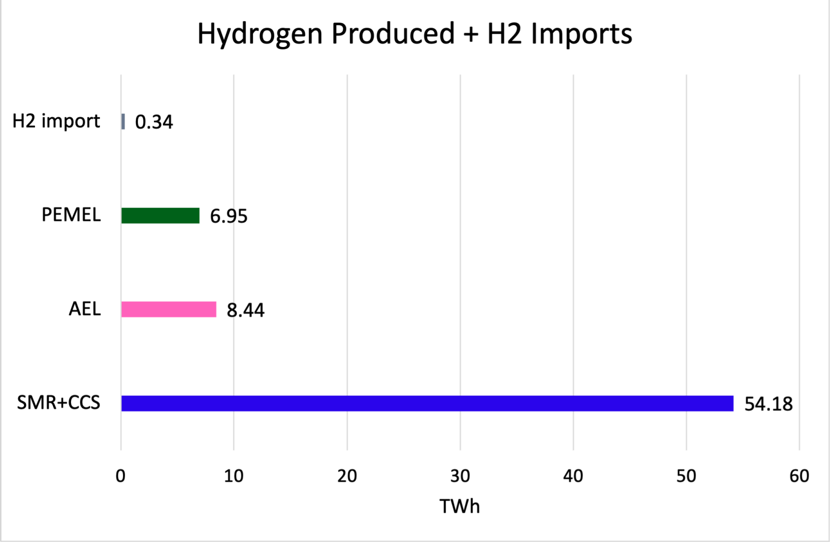

Figure 6.15: Hydrogen produced per technology and hydrogen imports in the DOC scenario

Regarding energy storage technologies, Figure 6.16 displays a storage capacity installed of 14 MWh for batteries, 7447.0 MWh for new batteries, and 1807.0 MWh for salt caverns.

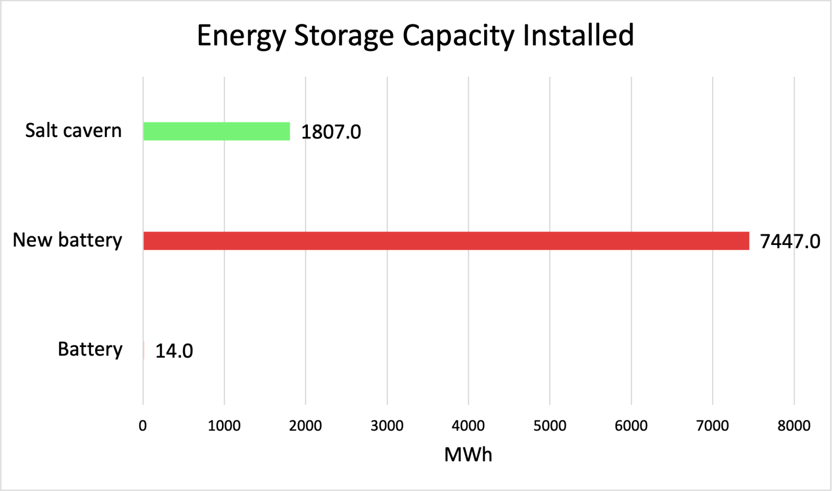

Figure 6.16: Storage capacity installed per technology in the DOC scenario

Regarding transmission infrastructure, the electricity and hydrogen grids resulting in the DOC scenario correspond to those of the BC scenario shown in Figure 6.6.

We observed from Figure 6.2 and Figure 6.13 that electricity produced from CCGT power plants in the DOC scenario is 0.76 TWh lower than in the BC scenario. This is because the increase in demand for hydrogen observed in the DOC stimulated investment in renewable electricity generation capacity obtaining a renewable electricity production 2.56 TWh higher than in the BC scenario. On one hand, the system uses part of this additional renewable electricity to meet the electricity demand as shown by the increased storage installed capacity for batteries compared to the BC. On the other hand, the system uses the remaining renewable electricity to produce additional green hydrogen.

In fact, the higher demand for hydrogen resulted in a higher installed capacity for hydrogen production technologies, as can be evinced by comparing Figure 6.5 and Figure 6.16. However, the installed capacity for the SMR+CCS has increased more than that for the Alkaline electrolyser and PEM electrolysers, compared to the BC. This means that the system continues to rely mainly on blue hydrogen to meet the demand for hydrogen. This is also confirmed by the storage installed capacity for salt caverns, which is higher than in the BC but still small to allow the system to effectively add flexibility to the system and allow it to mainly rely on green hydrogen to meet the demand.

System Level Results Analysis

To understand how the system behaved in the DOC scenario compared to the BC scenario, we analysed the same period analysed in the BC scenario. In particular, we looked at the hourly electricity production and consumption shown in Figure 6.17 and at the hourly hydrogen production and consumption shown in Figure 6.18. We observed that the system behaved almost as in the BC scenario.

During periods of low RES capacity factor, the system mainly uses electricity produced from CCGT, unloaded from batteries, and converted from imported hydrogen to meet the electricity demand. While to meet the hydrogen demand the system uses hydrogen produced through SMR+CCS.

On the other hand, during periods of high RES capacity factor the system satisfies electricity demand by producing renewable electricity. Moreover, if there is renewable electricity in excess the system put part of it into batteries, for short-term storage, and converts the remaining amount into green hydrogen by employing Alkaline electrolysers and PEM electrolysers. Even in this scenario the amount of green hydrogen produced does not exceed the demand for hydrogen, making salt caverns almost irrelevant for the system.

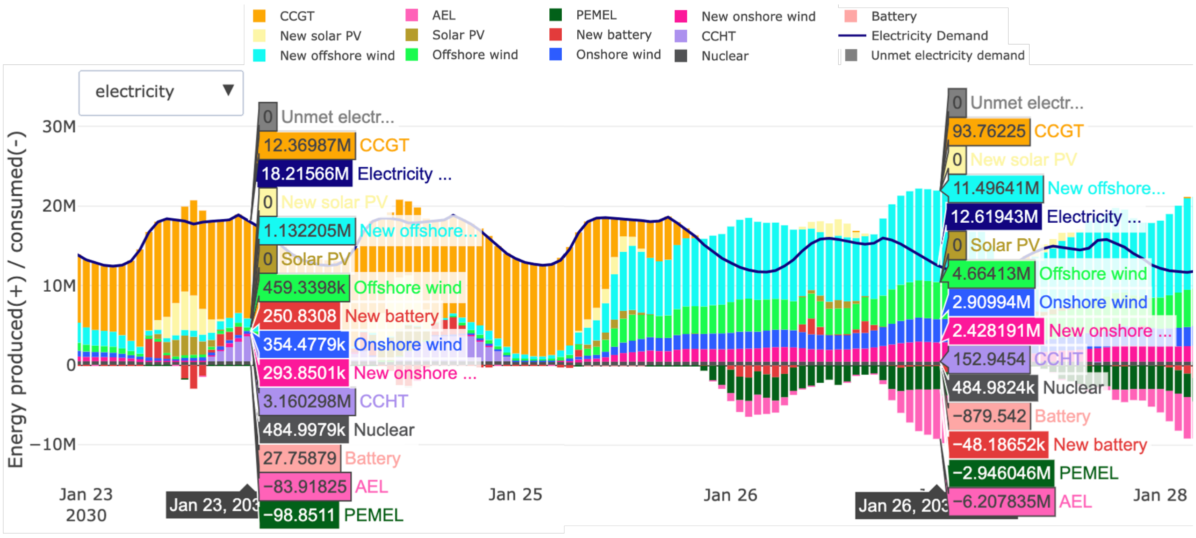

Figure 6.17: Hourly electricity production and consumption in the DOC scenario

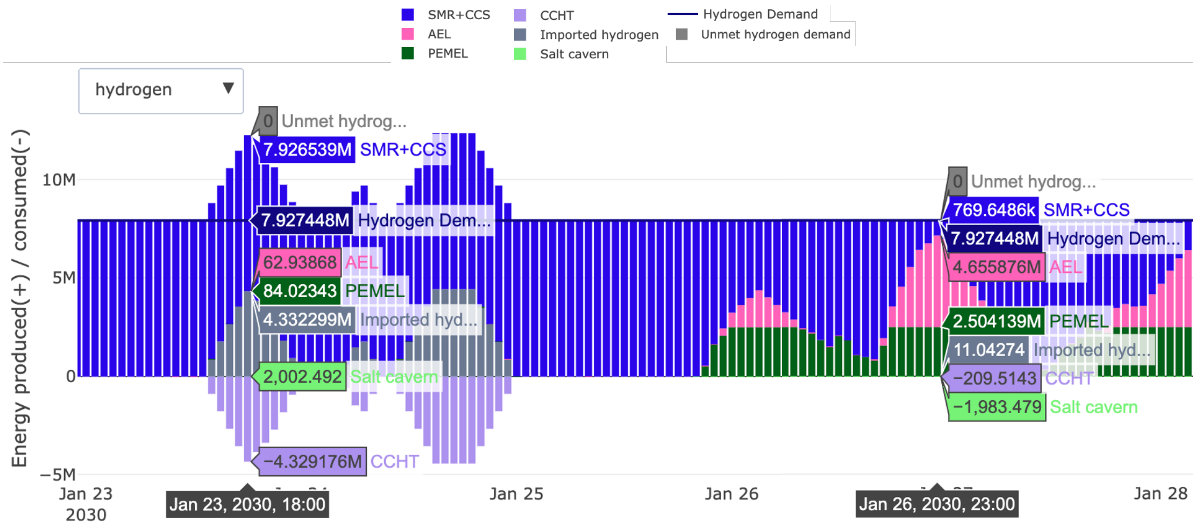

Figure 6.18: Hourly hydrogen production and consumption in the DOC scenario

Node level Results Analysis

To understand how the system behaved at the node level, we looked at the technologies and their respective capacity installed in the various node (Table C.2). In particular, we analysed hydrogen-related technologies capacity installation per node. The results show that in the DOC scenario, the optimisation followed the same logic followed in the BC scenario for installing energy capacity for SMR+CCS and Alkaline and PEM electrolysers.

In fact, to what concerns SMR+CCS installed capacity, the model installed capacity for SMR+CCS in descending order in nodes NL33, NL34, NL42, NL32, and NL11. Regarding electrolysis installed capacity, the results show that the model installed Alkaline electrolyser optimal capacity mainly according to the hydrogen demand but also considering RES installed capacity, as also evinced in the BC. Finally, the model installed optimal capacity for PEM electrolysers mainly according to RES installed capacity, but also considering storage capacity installed for salt caverns and demand for hydrogen. Table 6.3 reports the optimal capacity installed for SMR+CCS, Alkaline electrolyser, and PEM electrolyser in each of the 5 nodes having an IC.

H_2 Technologies	**NL33**	**NL34**	**NL42**	**NL11**	**NL32**
SMR+CCS [MW]	3058	2425.2	1169.2	832.2	439.9
AEL [MW]	1842.7	2001.1	1161.4	15.9	4.4
PEMEL [MW]	1217.1	25.7	7.2	816.7	435.1

Table 6.3: Optimal energy capacity installed for hydrogen-related technologies in the 5 nodes having an IC in the DOC scenario

Figure 6.19 presents the optimal installed capacity for SMR+CCS, Alkaline electrolyser, and PEM electrolyser across each node in the DOC scenario.

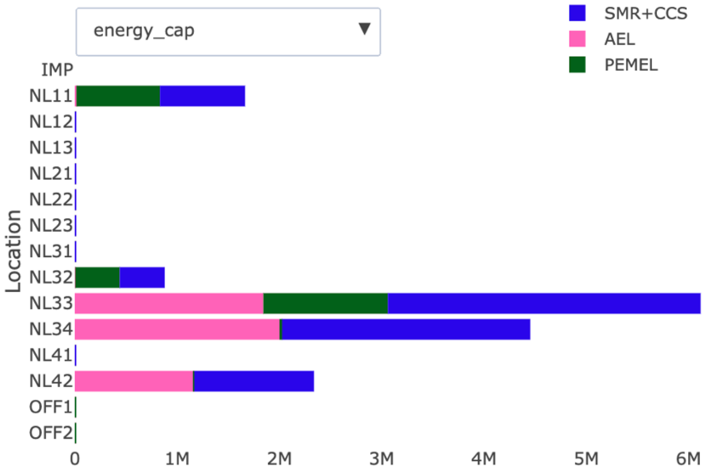

Figure 6.19: Optimal energy capacity installed for SMR+CCS technologies, Alkaline electrolysers, and PEM electrolysers per node in the DOC scenario

Regarding salt caverns, the results show that the model installed storage capacity for them in nodes NL11, NL12, and NL13. However, even if the storage capacity installed in the DOC is higher compared to the BC, it is still little in each node, as reported in Table C.4. Therefore the findings highlight the relation between the energy capacity installed for PEM electrolysers and the storage capacity installed for salt caverns only in node NL11, which differently from NL12 and NL12 has also a hydrogen demand.

Moreover, the little storage capacity installed for salt caverns has also a relation with the energy capacity installed for CCHT technologies. In fact, almost no hydrogen conversion capacity has been installed in the nodes NL11, NL12, and NL13. On the other hand, almost all of the total installed capacity has been installed in NL33, which is the only node connected with the node dedicated to imports of hydrogen. This is shown in Figure 6.20.

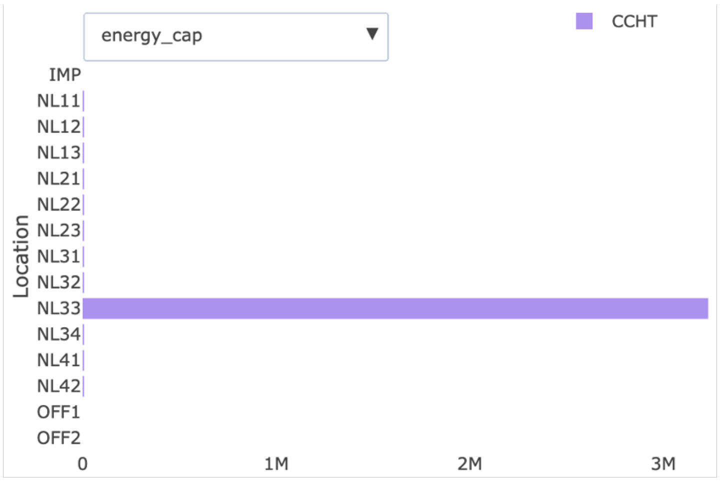

Figure 6.20: Optimal energy capacity installed for CCHT technologies per node in the DOC scenario

6.2.2. Demand-led Pessimistic Case Results

The results of the DPC scenario for the Dutch integrated energy system of 2030 show an installed renewable energy capacity of 55.02 GW, with a total electricity production of 97.40 TWh. Non-renewable energy installed capacity resulted in 12.86 GW with a total electricity production of 37.42 TWh. Additional energy installed capacity for electricity conversion processes resulted in 3.32 GW, with an electricity production of 0.36 TWh. The total electricity installed capacity is 69.20 GW and the total electricity generated is 135.18 TWh for an electricity demand of 120 TWh in 2030.

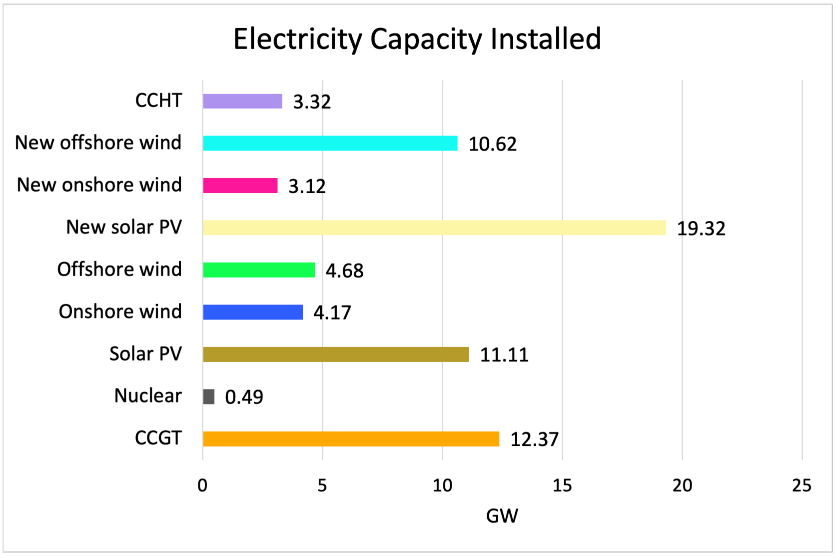

Figure 6.21: Electricity capacity installed per technology in the DPC scenario

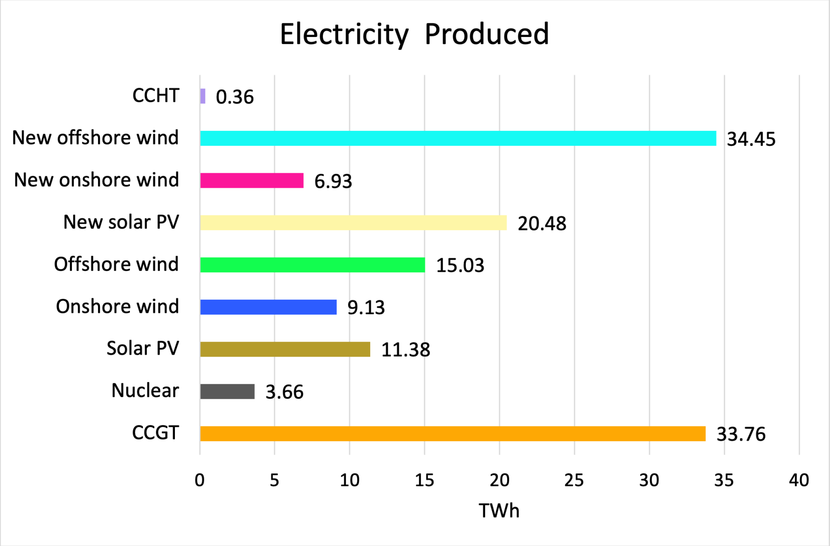

Figure 6.22: Electricity produced per technology in the DPC scenario

Moreover, results show that hydrogen production technologies involve SMR+CCS, with an installed capacity of 5.55 GW and a hydrogen production of 37.15 TWh, Alkaline electrolysers, with an installed capacity of 3.46 GW and a hydrogen production of 6.16 TWh, and PEM electrolysers, with an installed capacity of 2.09 GW and a hydrogen production of 5.40 TWh. The total installed capacity for hydrogen is 11.10 GW and the total hydrogen generated is 48.71. Imports of hydrogen account for 0.36 TWh. Therefore, there are 49.07 TWh of hydrogen in the DPC scenario to meet the hydrogen demand of 48.58 TWh in 2030.

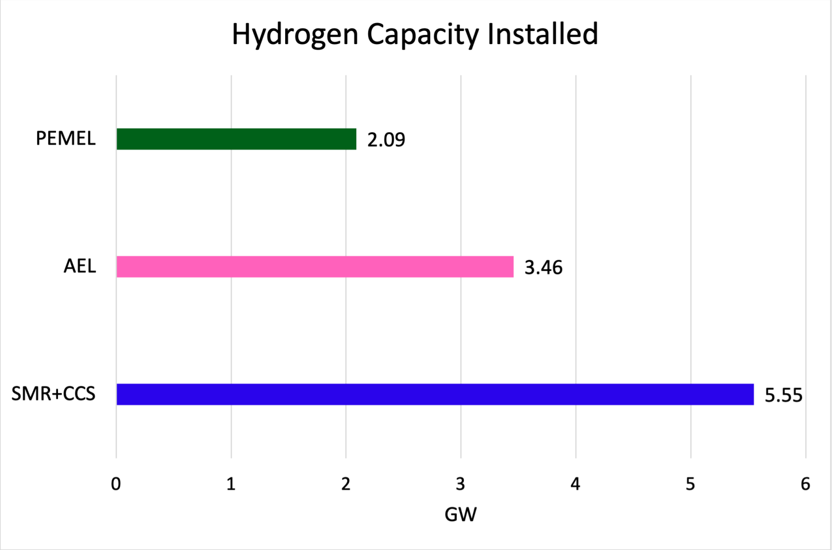

Figure 6.23: Hydrogen capacity installed per technology in the DPC scenario

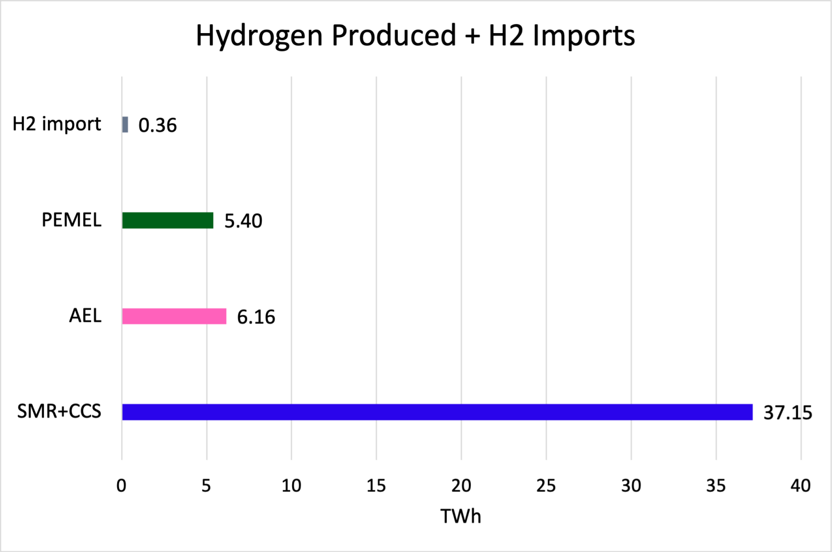

Figure 6.24: Hydrogen produced per technology and hydrogen imports in the DPC scenario

Regarding energy storage technologies, Figure 6.25 displays a storage capacity installed of 14 MWh for batteries, 7197.2 MWh for new batteries, and 888.8 MWh for salt caverns.

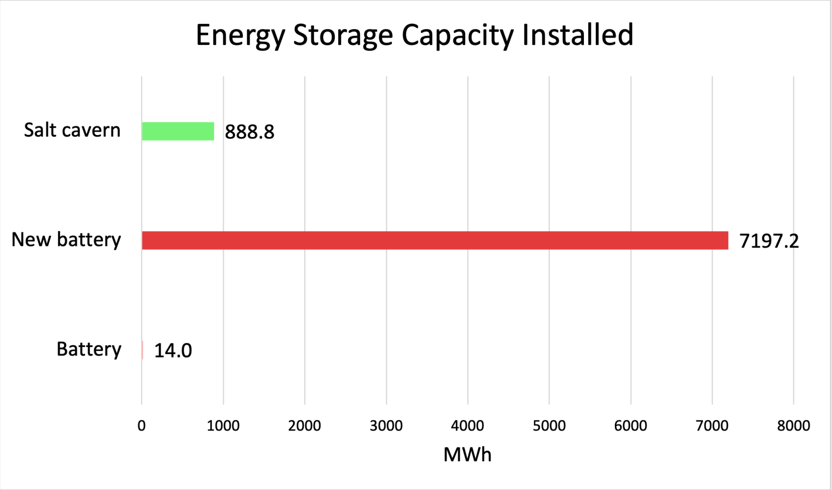

Figure 6.25: Storage capacity installed per technology in the DPC scenario

Regarding transmission infrastructure, the electricity and hydrogen grids resulting in the DPC scenario correspond to those of the BC scenario shown in Figure 6.6.

Figure 6.2 and Figure 6.22 show that the electricity generated from CCGT power plants in the DPC increased by 1.33 TWh compared to the BC scenario. This increase can be attributed to the reduced demand for hydrogen in the DPC, which resulted in lower investments in the capacity installed for renewable electricity generation technologies. Consequently, the production of renewable electricity was 4.3 TWh lower in the DPC scenario compared to the BC scenario. Additionally, the lower amount of renewable electricity produced translated into less storage capacity installed for batteries, as indicated by comparing Figure 6.5 and Figure 6.25.

The decreased demand for hydrogen also resulted in reduced investments in hydrogen production technologies. However, Figure 6.3 and Figure 6.23 show that the reduction in installed capacity for Alkaline electrolysers is greater than the reduction for PEM electrolysers in the DPC scenario. This can be explained by the fact that with a decrease in available renewable electricity for green hydrogen production, PEM electrolysers prove to be more cost-efficient than Alkaline electrolysers due to their superior efficiency. In fact, given an equal amount of renewable electricity, PEM electrolysers are capable of generating more green hydrogen in comparison to Alkaline electrolysers. Finally, the total amount of green hydrogen produced in the DPC scenario led to a lower storage capacity installed for salt caverns, as can be evinced by comparing Figure 6.5 and Figure 6.25.

System Level Results Analysis

To understand the differences in the model's behaviour between the DPC and the BC scenario, we analysed the electricity and hydrogen load curves in the same period analysed in the BC. In particular, we looked at the hourly electricity production and consumption shown in Figure 6.26 and at the hourly hydrogen production and consumption shown in Figure 6.27. We observed that even in this scenario the system behaviour has not changed.

During periods of low RES capacity factor, the system mainly uses electricity produced from CCGT, unloaded from batteries, and converted from imported hydrogen to meet the electricity demand. On the other hand, to fulfil the hydrogen demand the system uses blue hydrogen produced from SMR+CCS.

During periods of high RES capacity factor the system satisfies the demand for electricity by producing and supplying renewable electricity to the system. The renewable electricity in excess is then stored in batteries and used during periods of scarcity or it is used to produce green hydrogen and satisfy the demand for hydrogen. Moreover, since the amount of green hydrogen produced is limited the system does not significantly employ salt caverns to store it.

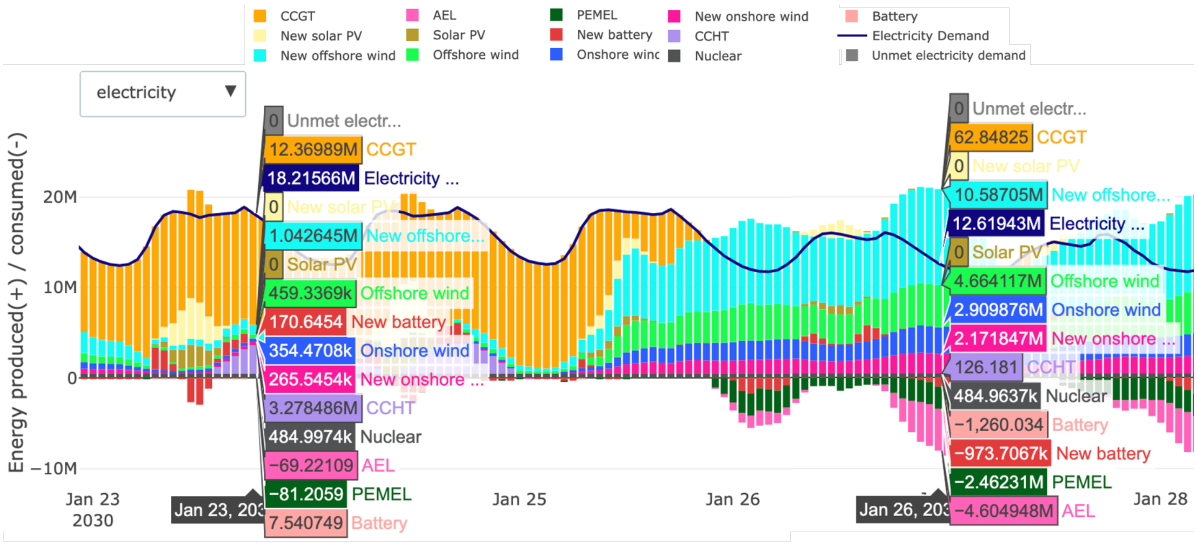

Figure 6.26: Hourly electricity production and consumption in the DPC

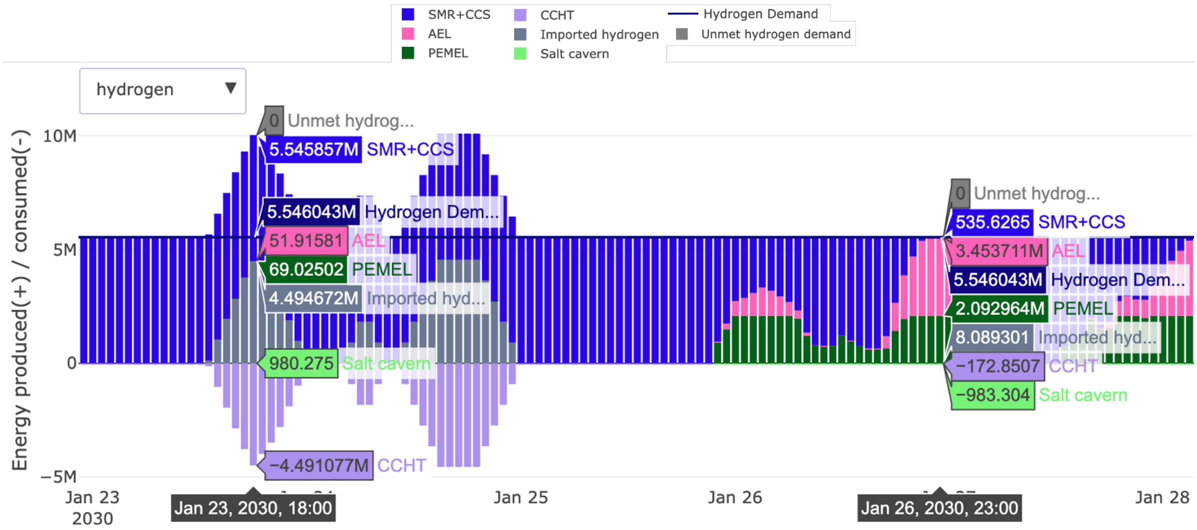

Figure 6.27: Hourly hydrogen production and consumption in the DPC

Node Level Results Analysis

To gain insights into the behaviour of the system at the node level, we conducted an analysis of the installed capacity of various technologies across different nodes, as presented in Table D.2. Specifically, we focused on the capacity installation of hydrogen-related technologies within each node. The findings indicate that in the DPC scenario, the optimisation process followed a similar approach as in the BC scenario when it came to allocating energy capacity for SMR+CCS, Alkaline electrolysis, and PEM electrolysis.

Regarding the installed capacity of SMR+CCS, the model prioritised capacity installation in descending order for nodes NL33, NL34, NL42, NL32, and NL11. As for electrolysis, the results indicate that the model determined the optimal capacity for Alkaline electrolysis primarily based on hydrogen demand, while also considering the installed capacity of RES, as observed in the BC scenario. Similarly, the model determined the optimal capacity for PEM electrolysis primarily based on the RES installed capacity, but also taking into account the storage capacity installed for salt caverns and the demand for hydrogen. Table 6.4 reports the optimal capacity installed for SMR+CCS, Alkaline electrolysers, and PEM electrolysers in each of the 5 nodes having an IC.

H_2 Technologies	**NL33**	**NL34**	**NL42**	**NL11**	**NL32**
SMR+CCS [MW]	2139.2	1696.7	817.9	582.4	307.9
AEL [MW]	1228.9	1443.6	767.2	7.5	4.4
PEMEL [MW]	911.9	251	50.4	574.5	303.1

Table 6.4: Optimal energy capacity installed for hydrogen-related technologies in the 5 nodes having an IC in the DPC scenario

Figure 6.28 presents the optimal installed capacity for SMR+CCS, Alkaline electrolyser, and PEM electrolyser across each node in the DPC scenario.

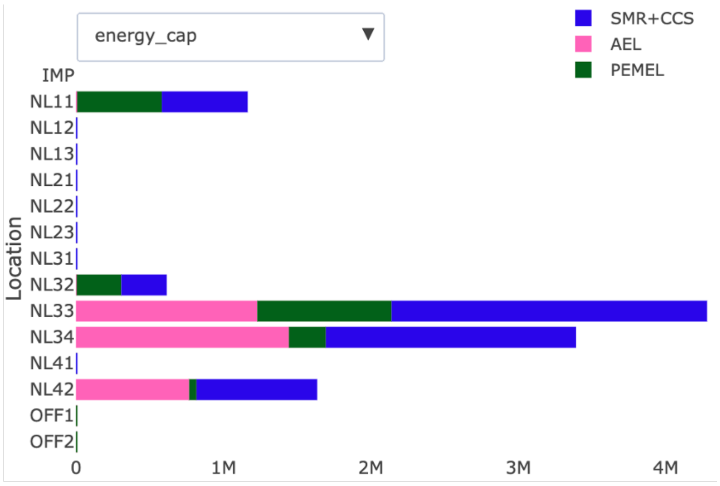

Figure 6.28: Optimal energy capacity installed for SMR+CCS technologies, Alkaline electrolysers, and PEM electrolysers per node in the DPC scenario

In conclusion, an examination of the optimal energy capacity installed for CCHT technologies per node in the DPC scenario revealed no deviations from the BC scenario in terms of the nodes where these technologies were installed through the optimization process. This lack of deviation can be attributed to the limited role played by salt caverns in both the DOC and BC scenarios.

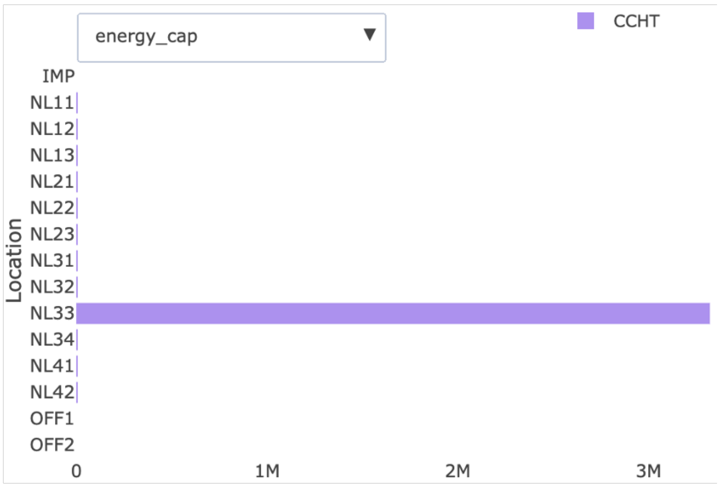

Figure 6.29: Optimal energy capacity installed for CCHT technologies per node in the DPC scenario

6.3. Cost-led Scenario Results

In the Cost-led scenario, we defined a Cost-led Optimistic Case (COC), with CAPEX for Alkaline electrolysers and PEM electrolysers of 140 €/kW and 220 €/kW, respectively, and a Cost-led Pessimistic Case (CPC), with CAPEX for Alkaline electrolysers and PEM electrolysers of 525 €/kW and 825 €/kW, respectively. We compared the results of these two simulations with those obtained in the BC scenario.

6.3.1. Cost-led Optimistic Case Results

The results of the COC scenario for the Dutch integrated energy system of 2030 show an installed renewable energy capacity of 57.44 GW, with a total electricity production of 103.88 TWh. Non-renewable energy installed capacity resulted in 12.86 GW with a total electricity production of 35.26 TWh. Additional energy installed capacity for electricity conversion processes resulted in 3.25 GW, with an electricity production of 0.26 TWh. The total electricity generation capacity installed is 73.55 GW, corresponding to a total electricity generation of 139.39 TWh for a demand of 120 TWh in 2030.

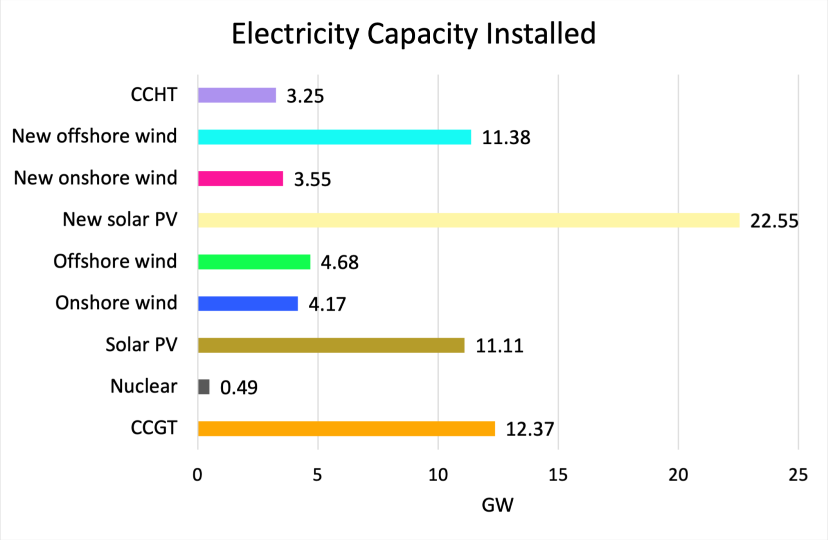

Figure 6.30: Electricity capacity installed per technology in the COC scenario

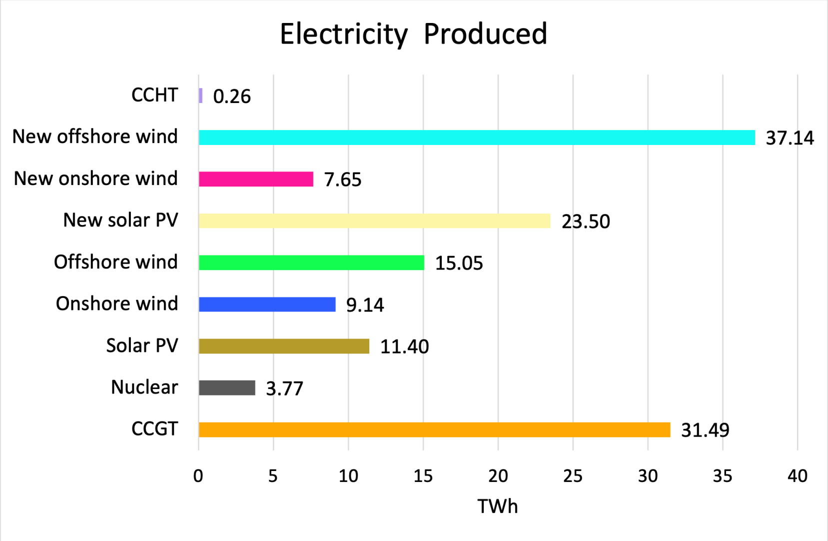

Figure 6.31: Electricity produced per technology in the COC scenario

Moreover, results show that hydrogen production technologies involve SMR+CCS, with an installed capacity of 6.71 GW and a hydrogen production of 43.82 TWh, Alkaline electrolysers, with an installed capacity of 0.03 GW and a hydrogen production of 0.03 TWh, and PEM electrolysers, with an installed capacity of 6.98 GW and a hydrogen production of 15.91 TWh. The total installed capacity for hydrogen generation is 13.72 GW, corresponding to a hydrogen production of 59.76 TWh. Additionally, hydrogen imports account for 0.33 TWh. Therefore, the total hydrogen available in the COC scenario is 60.09 TWh to satisfy a total hydrogen demand of 59.70 TWh.

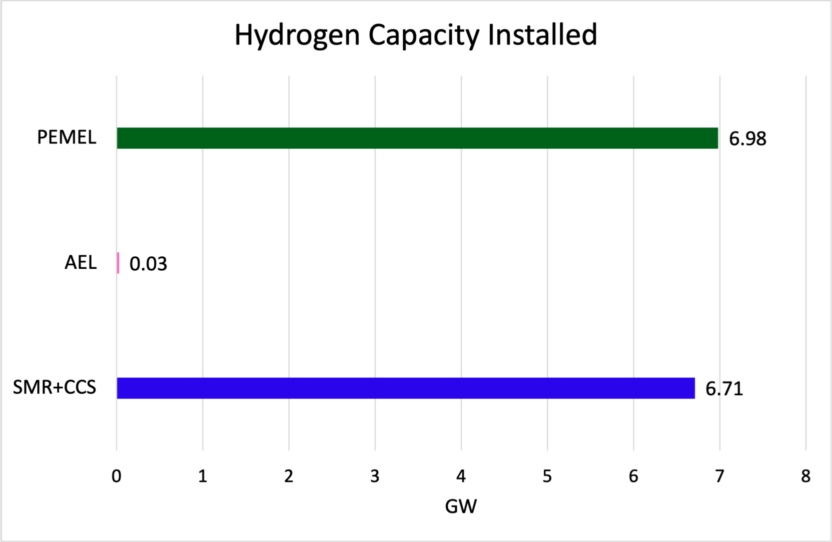

Figure 6.32: Hydrogen capacity installed per technology in the COC scenario

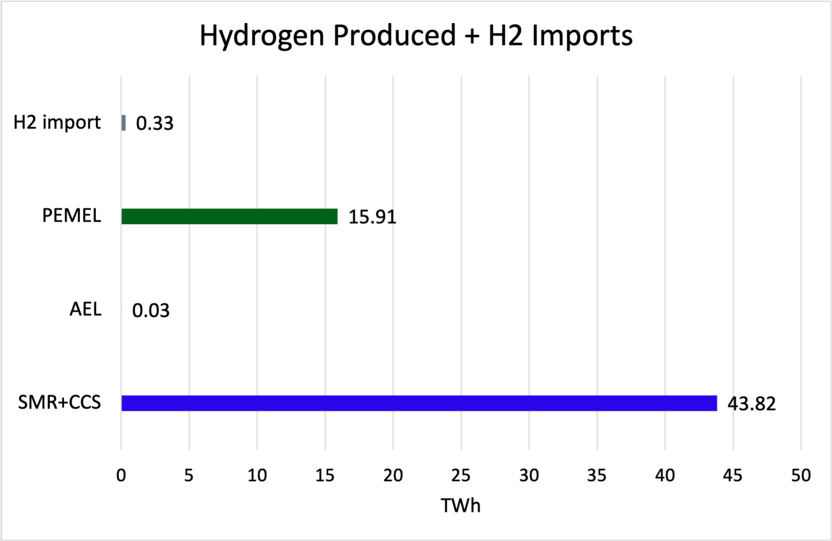

Figure 6.33: Hydrogen produced per technology and hydrogen imports and hydrogen imports in the COC scenario

Regarding energy storage technologies, Figure 6.34 displays a storage capacity installed of 14 MWh for batteries, 7383.9 MWh for new batteries, and 149593.9 MWh for salt caverns.

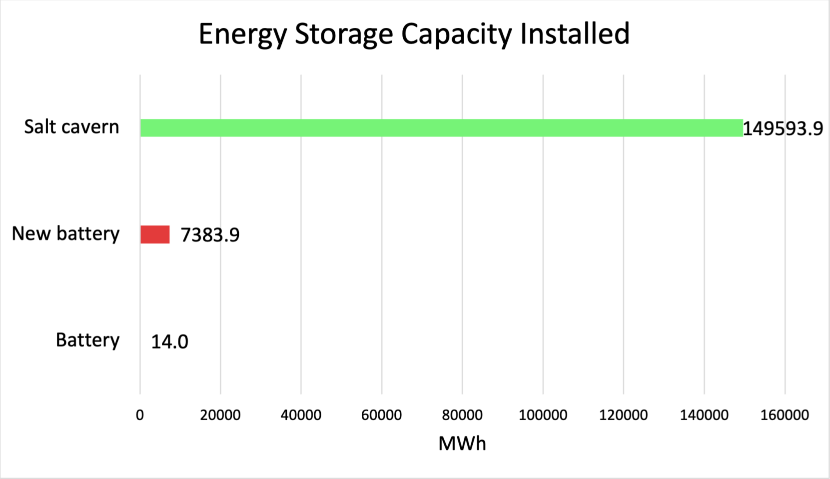

Figure 6.34: Storage capacity installed per technology in the COC scenario

Regarding transmission infrastructure, the electricity and hydrogen grids resulting in the COC scenario correspond to those of the BC scenario shown in Figure 6.6.

Figures 6.31 and 6.2 provide a visual representation of the disparities observed between the COC and BC scenarios regarding electricity production. In the COC scenario, there is a significant increase of 2.18 TWh in renewable electricity generation compared to the BC scenario. Conversely, the electricity generated through CCGT experiences a decrease of 0.94 TWh. These findings indicate that the reduction in electrolysis capital costs observed in the COC scenario has effectively incentivised investment in renewable capacity while simultaneously discouraging investment in non-renewable capacity.

Figure 6.33 reveals that while the capacity installed for SMR+CCS is nearly equivalent to that in the BC scenario, a significant portion of the capacity allocated for green hydrogen production is attributed to PEM electrolysers. This allocation is primarily driven by the superior efficiency of PEM electrolysers, enabling the system to generate a greater amount of green hydrogen with an equivalent quantity of renewable electricity. Consequently, this stimulates the installation of additional storage capacity for salt caverns in the COC scenario compared to the BC scenario, as demonstrated by the comparison between Figure 6.34 and Figure 6.5.

System Level Results Analysis

For the COC, we have conducted an analysis of the same period as the BC scenario, with the aim of identifying similarities and differences between the two and comparing them. Specifically, Figure 6.35 displays the hourly electricity production and consumption of the 2030 Dutch integrated energy system, while Figure 6.36 illustrates its hourly hydrogen production and consumption.

Our observations reveal that under conditions of limited availability of renewable energy sources, the system predominantly relies on electricity generated from CCGT power plants and hydrogen produced through the process of SMR+CCS to fulfil the respective demands. Additionally, the system utilises electricity discharged from batteries and converted from imported hydrogen to satisfy the requirements for electricity while relying on unloaded green hydrogen from salt caverns to meet the demand for hydrogen.

Conversely, during periods characterised by the abundant availability of renewable energy sources, the results obtained from the COC demonstrate that the optimisation process priorities the installation and operation of PEM electrolysers. This finding indicates that by reducing the capital expenditures for both PEM and Alkaline electrolysers, the system favours the deployment of PEM electrolysers despite their higher cost compared to Alkaline electrolysers. This preference is driven by the superior efficiency and ramping rate of PEM electrolysers, as mentioned previously. Furthermore, the system stores a portion of the green hydrogen produced in salt caverns with the intention of utilising it during periods characterised by the limited availability of renewable energy sources.

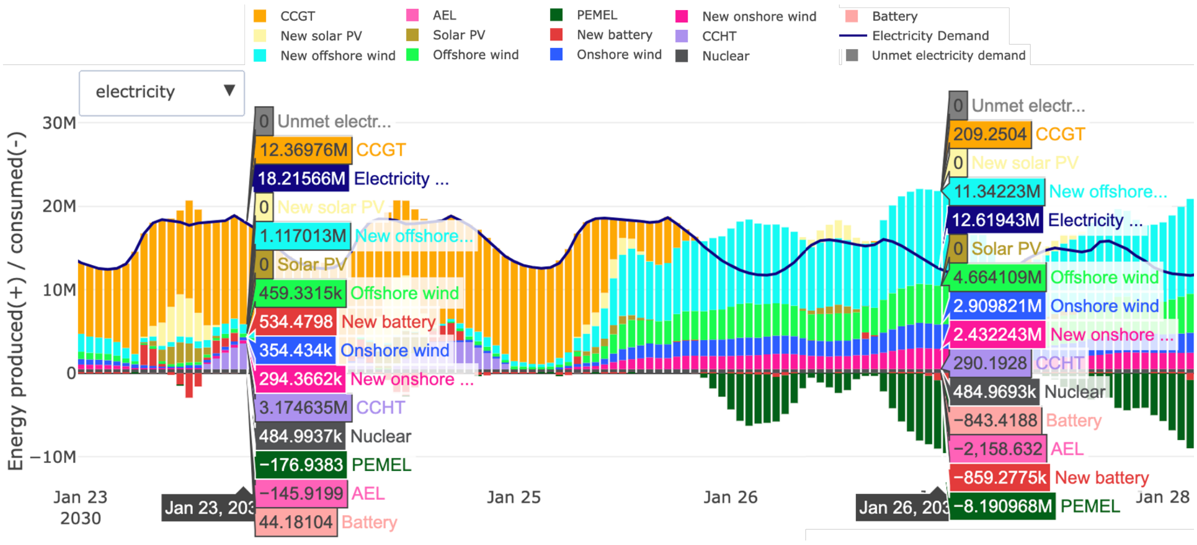

Figure 6.35: Hourly electricity production and consumption in the COC

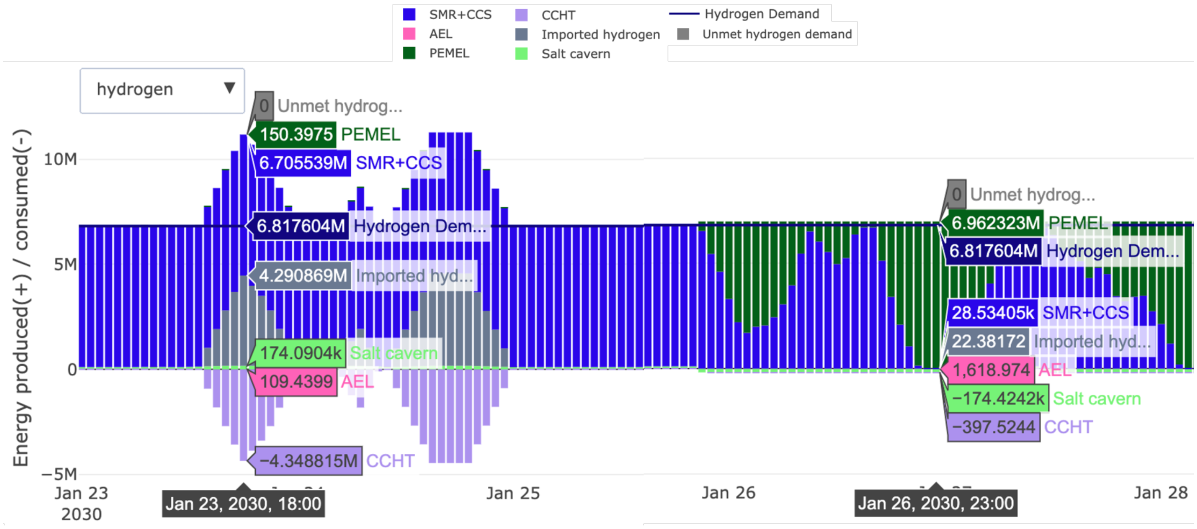

Figure 6.36: Hourly hydrogen production and consumption in the COC

Node Level Results Analysis

The analysis of the system-level results revealed that in the COC the optimisation resulted in a higher installed capacity for renewable electricity, PEM electrolysers, and salt caverns while having a lower installed capacity for Alkaline electrolysers. To further understand the implications at the node level, we performed an analysis of the installed capacity per node of hydrogen-related technologies.

With regards to SMR+CCS, the results confirm that the model installed it in accordance with the hydrogen demand (Table E.2). Furthermore, for PEM electrolysers, the results indicate that the optimal installed capacity aligns with the hydrogen demand, as demonstrated in Figure 6.37. This is because the system has insignificant capacity installed for Alkaline electrolysers, and therefore PEM electrolysers are the sole electrolysis technology utilised to meet the hydrogen demand without installing additional capacity for blue hydrogen production technologies. Table 6.5 reports the optimal capacity installed for SMR+CCS and PEM electrolysers in each of the 5 nodes having an IC.

H_2 Technologies	**NL33**	**NL34**	**NL42**	**NL11**	**NL32**
SMR+CCS [MW]	2629.8	2085.9	1005.5	604.5	377.3
PEMEL [MW]	2629.2	2078.8	1001.5	835.3	375.8

Table 6.5: Optimal energy capacity installed for hydrogen-related technologies in the 5 nodes having an IC in the COC scenario

Figure 6.37 presents the optimal installed capacity for SMR+CCS and PEM electrolysers in each node of the COC scenario.

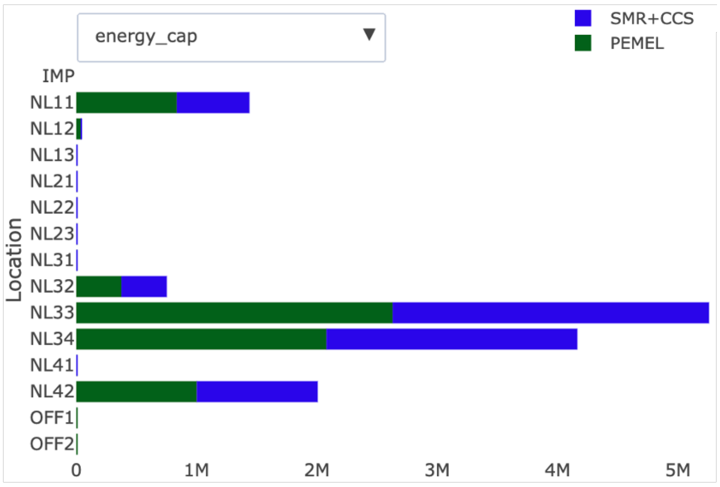

Figure 6.37: Optimal energy capacity installed for SMR+CCS technologies and PEM electrolysers per node in the COC scenario

Additionally, we noticed that in nodes NL12 and NL13, the optimisation installed more capacity for PEM electrolysers and for CCHT technologies compared to the others node not having a hydrogen demand. This is because of the storage capacity for salt caverns installed in these two nodes. The relationship between the capacity installed for PEM electrolysers, salt caverns, and CCHT technologies is illustrated in Figures 6.38, 6.39, and 6.40.

The relationship described can be attributed to the superior efficiency and ramping rate exhibited by PEM electrolysers in comparison to Alkaline electrolysers. These enhanced characteristics make PEM electrolysers highly suitable for enhancing system flexibility, thereby facilitating the integration of RES and the penetration of green hydrogen infrastructure, including storage facilities such as salt caverns.

Furthermore, given that the model we employed represents an integrated energy system, incorporating flexibility into the system necessitates addressing both the electricity and hydrogen sides. Consequently, the optimisation process installed CCHT energy capacity specifically in nodes NL12 and NL13. By combining these three technologies — PEM electrolysers, salt caverns, and CCHT — the system is capable of generating green hydrogen through PEM electrolysers, storing it in salt caverns, and subsequently utilising it to fulfil the hydrogen demand. Alternatively, the stored hydrogen can be converted back into electricity to meet the electricity demand.

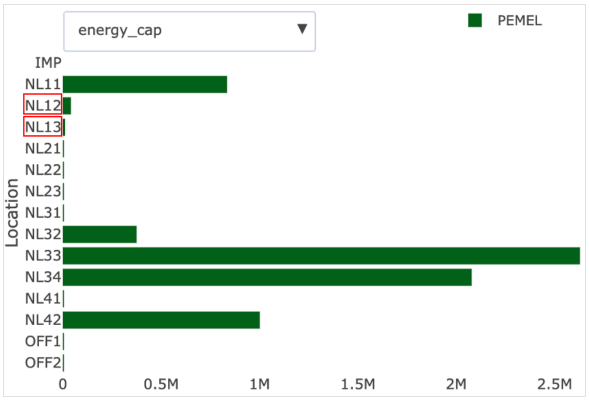

Figure 6.38: Optimal energy capacity installed for the PEM electrolyser per node in the COC scenario, with a specific focus on NL12 and NL13

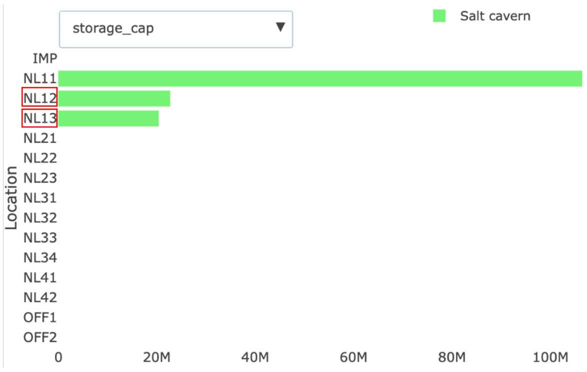

Figure 6.39: Optimal storage capacity installed for salt caverns per node in the COC scenario, with a specific focus on NL12 and NL13

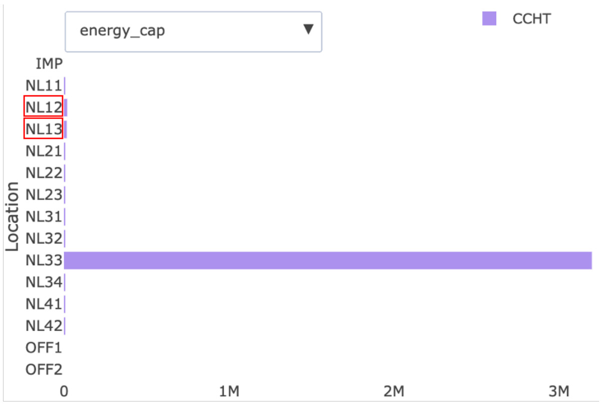

Figure 6.40: Optimal energy capacity installed for the CCHT technologies per node in the COC scenario, with a specific focus on NL12 and NL13

6.3.2. Cost-led Pessimistic Case Results

The results of the CPC scenario for the Dutch integrated energy system of 2030 show an installed renewable energy capacity of 53.23 GW, with a total electricity production of 99.11 TWh. Non-renewable energy installed capacity resulted in 12.86 GW with a total electricity production of 37.13 TWh. Additional energy installed capacity for electricity conversion processes resulted in 3.30 GW, with an electricity production of 0.43 TWh. The total electricity generation capacity installed is 69.39 GW, corresponding to a total electricity generation of 136.66 TWh for a total electricity demand of 120 TWh in 2030.

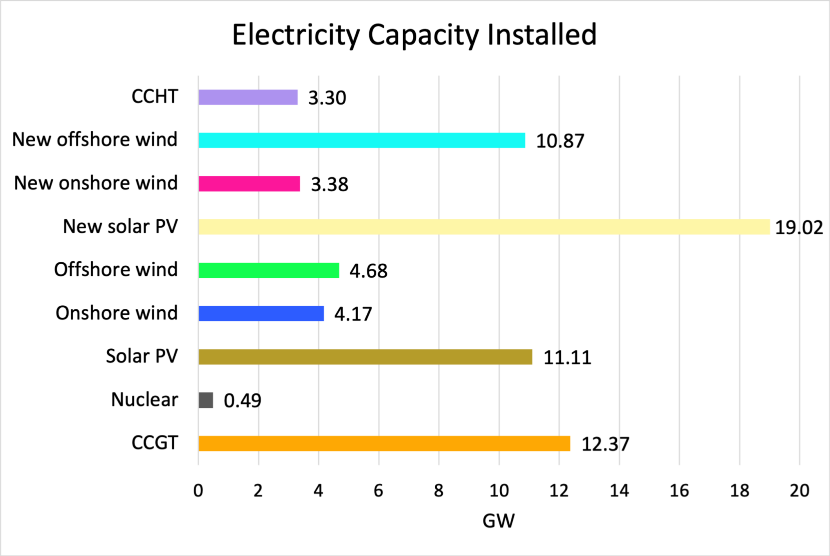

Figure 6.41: Electricity capacity installed per technology in the CPC scenario

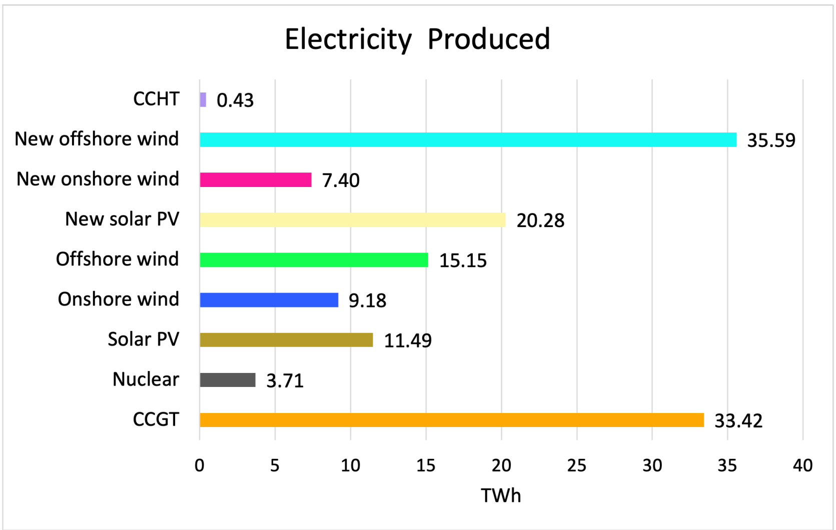

Figure 6.42: Electricity produced per technology in the CPC scenario

Moreover, results show that hydrogen production technologies involve SMR+CCS, with an installed capacity of 6.82 GW and a hydrogen production of 47.90, Alkaline electrolysers, with an installed capacity of 6.16 and a hydrogen production of 12.03 TWh, and PEM electrolysers, with an installed capacity of 0.01 and a hydrogen production of 0.02 TWh. The total hydrogen capacity installed is 12.99 and the total hydrogen produced is 59.95 TWh. Additionally, hydrogen imports account for 0.36 TWh. Therefore, the total amount of hydrogen available in the CPC scenario to satisfy the 2030 hydrogen demand of 59.70 TWh is 60.31 TWh.

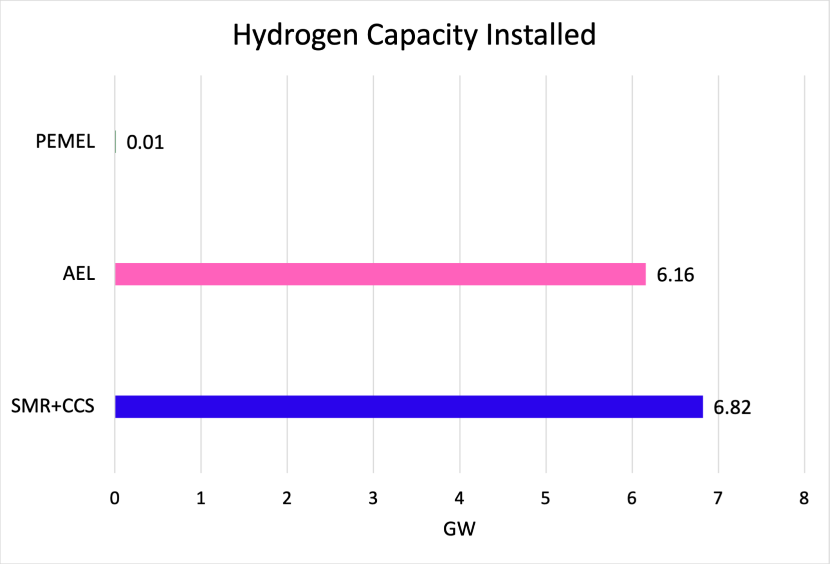

Figure 6.43: Hydrogen capacity installed per technology in the CPC scenario

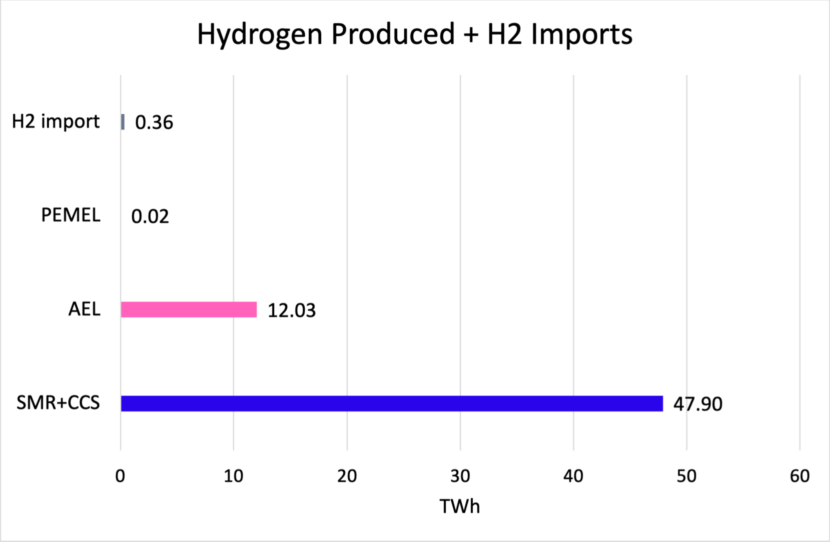

Figure 6.44: Hydrogen produced per technology and hydrogen imports in the CPC scenario

Regarding energy storage technologies, Figure 6.45 displays a storage capacity installed of 14 MWh for batteries, 7286.2 MWh for new batteries, and 773.7 MWh for salt caverns

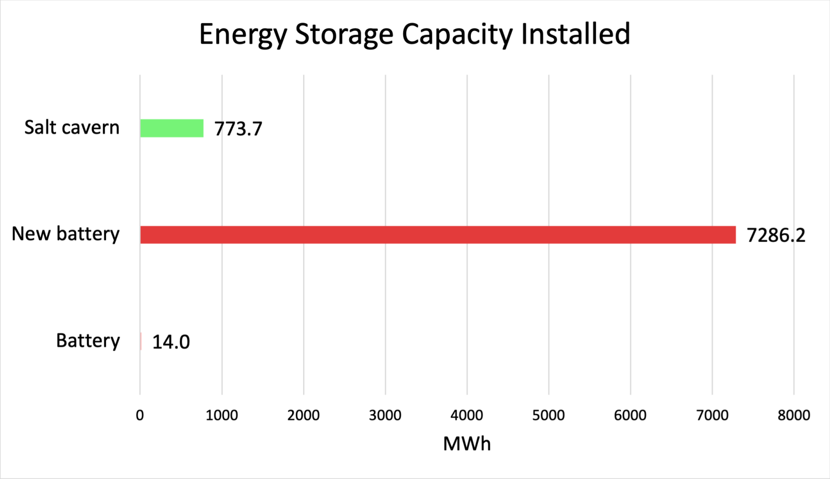

Figure 6.45: Storage capacity installed per technology in the CPC scenario

Regarding transmission infrastructure, the electricity and hydrogen grids resulting in the CPC scenario correspond to those of the BC scenario shown in Figure 6.6.

Figures 6.42 and 6.2 depict the observed disparities in electricity production between the scenarios of CPC and BC. In the CPC scenario, renewable electricity generation experiences a decrease of 2.59 TWh compared to the BC scenario. Conversely, the electricity generated through CCGT exhibits an increase of 0.99 TWh. These findings indicate that the increase in electrolysis capital costs observed in the CPC scenario has effectively discouraged investment in renewable capacity while simultaneously augmenting the system's reliance on non-renewable electricity. Moreover, the capacity installed for CCHT technologies is higher in the CPC than in the BC due to the lower amount of renewable electricity produced and the higher installed capacity of Alkaline electrolysers which, being less efficient than PEM electrolysers, requires more electricity to produce the same quantity of green hydrogen.

Figure 6.43 reveals that although the installed capacity for SMR+CCS is nearly equivalent to that in the BC scenario, a significant portion of the capacity allocated for green hydrogen production is attributed to Alkaline electrolysers. This allocation is primarily driven by the cost of the Alkaline technology, which, despite having inferior characteristics in terms of efficiency and ramping rate compared to PEM electrolysers, is more cost-effective when both technologies have high CAPEX. However, this allocation of capacity for electrolysis technologies results in a lower amount of green hydrogen generated with an equivalent quantity of renewable electricity. Consequently, it hampers the installation of storage capacity for salt caverns in the CPC scenario compared to the BC scenario, as demonstrated by the comparison between Figure 6.5 and Figure 6.45.

System Level Results Analysis

As we did for the other scenario, even for the COC we have conducted an analysis of the same period observed in the BC scenario. Figure 6.46 displays the hourly electricity production and consumption of the Dutch energy system, while Figure 6.47 illustrates the hourly hydrogen production and consumption.

Our findings demonstrate that during periods of low RES capacity factor, the energy system utilises a combination of CCGT power plants, batteries, and CCHT technologies to meet the demand for electricity. Additionally, it relies on SMR+CCS technologies and imported hydrogen to fulfil the demand for hydrogen. In contrast, during periods of abundant renewable electricity availability, the system operates renewable electricity generation technologies to produce electricity and satisfy the demand for electricity. Then if there is renewable electricity in excess, the system stores a part of it in batteries, for short-term storage, while using the rest to produce green hydrogen, by employing almost only Alkaline electrolysers.

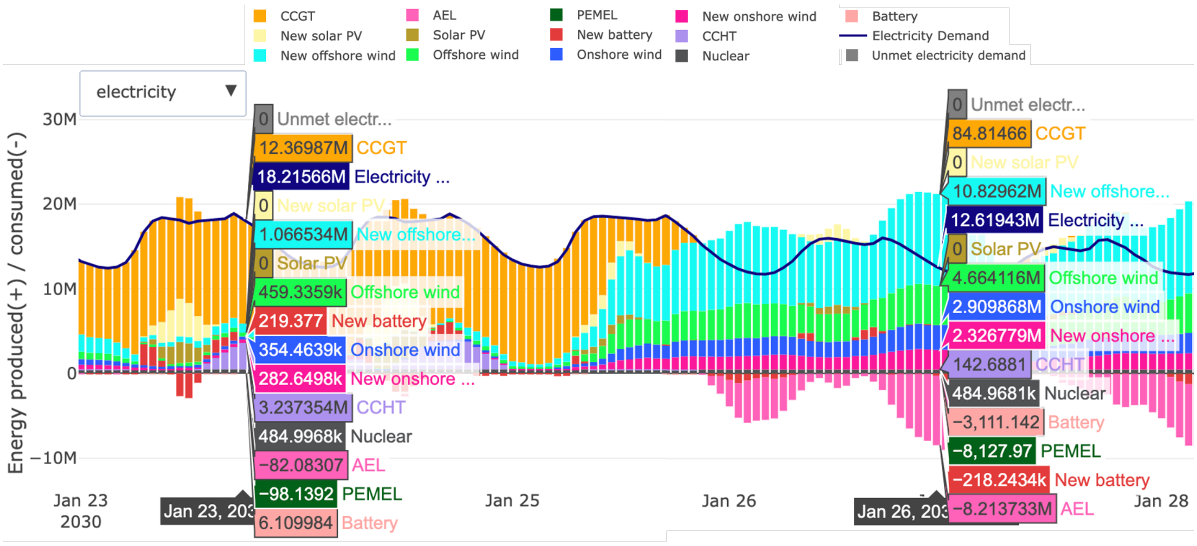

Figure 6.46: Hourly electricity production and consumption in the CPC

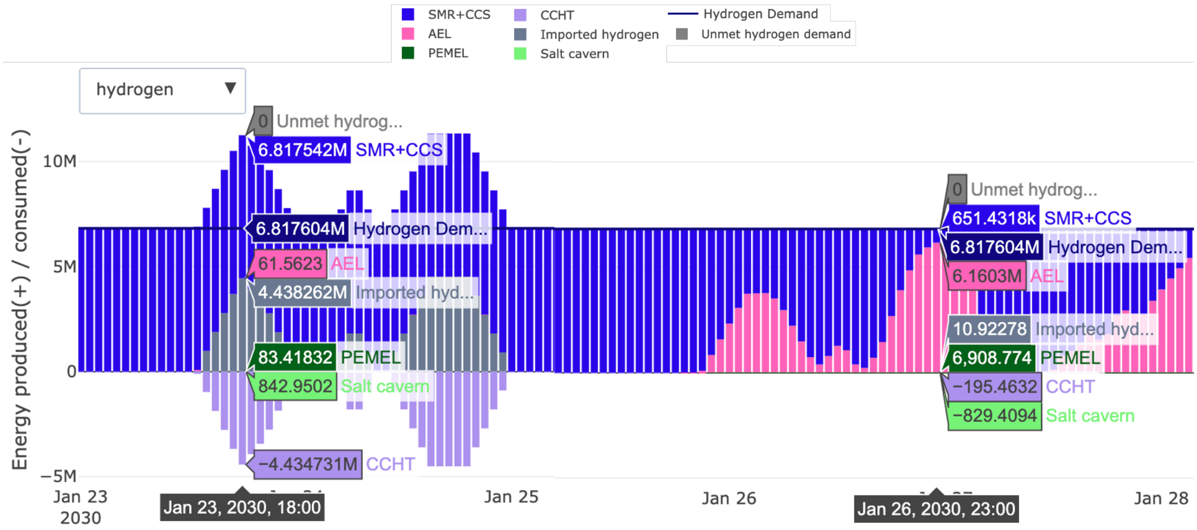

Figure 6.47: Hourly hydrogen production and consumption in the CPC

Node Level Results Analysis

The system-level analysis showed that the CPC scenario led to decreased installed capacities for renewable electricity, batteries, PEM electrolysers and salt caverns, while simultaneously resulting in an increased installed capacity for Alkaline electrolysers and CCHT technologies. To gain a more granular understanding of the implications at the node level, we conducted an assessment of the installed capacity for hydrogen-related technologies at each individual node.

The results indicate that similar to the BC scenario, the capacity installed for SMR+CCS technologies in the CPC scenario is proportional to the demand for hydrogen, as shown in Table F.2. Furthermore, also the capacity installed for Alkaline electrolysers is proportional to the hydrogen demand. Table 6.6 reports the optimal capacity installed for SMR+CCS and Alkaline electrolysers in each of the 5 nodes having an IC.

H_2 Technologies	NL33	NL34	NL42	NL11	NL32
SMR+CCS [MW]	2629.8	2085.7	1005.5	716.2	378.3
AEL [MW]	2630.3	1432.6	1004.1	714.3	376.8

Table 6.6: Optimal energy capacity installed for hydrogen-related technologies in the 5 nodes having an IC in the CPC scenario

Figure 6.37 presents the optimal installed capacity for SMR+CCS and Alkaline electrolysers in each node of the CPC scenario.

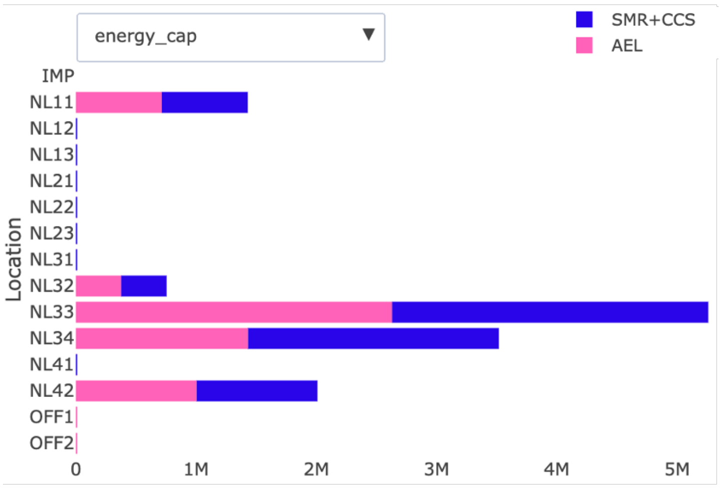

Figure 6.48: Optimal energy capacity installed for SMR+CCS technologies and Alkaline electrolysers per node in the CPC

6.4. No-Blue-Hydrogen Scenario

The results of the NBH scenario for the Dutch integrated energy system of 2030 show an installed renewable energy capacity of 66.98 GW, with a total electricity production of 125.68 TWh. Non-renewable energy installed capacity resulted in 12.86 GW with a total electricity production of 29.32 TWh. Additional energy installed capacity for electricity conversion processes resulted in 3.35 GW, with an electricity production of 0.24 TWh. The total electricity generation capacity installed is 83.19 GW, corresponding to a total electricity generation of 155.2 TWh for an electricity demand of 120 TWh in 2030.

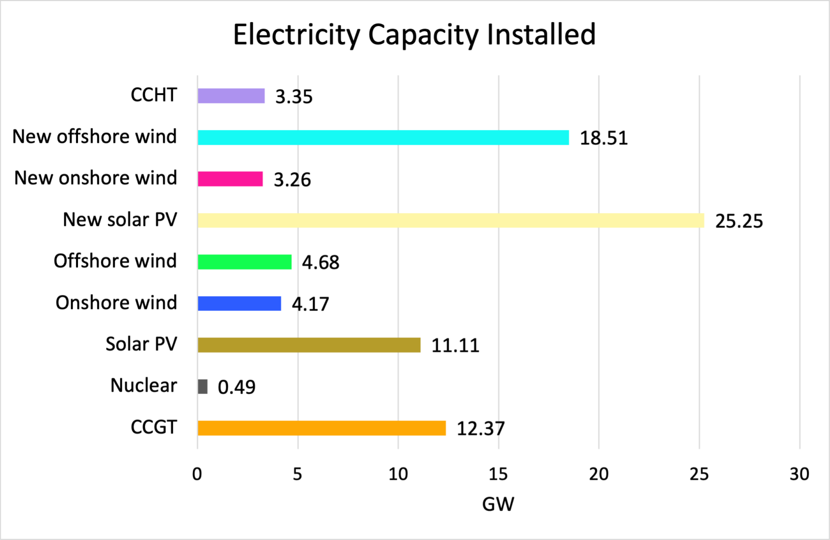

Figure 6.49: Electricity capacity installed per technology in the NBH scenario

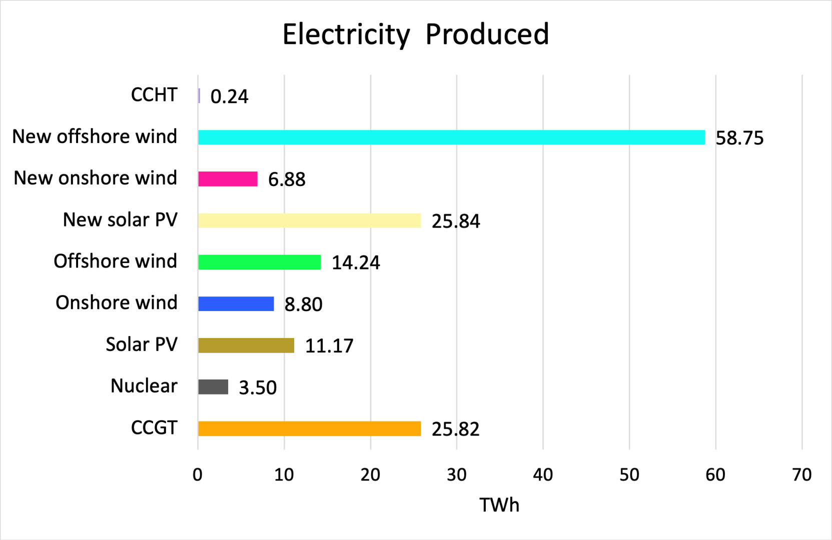

Figure 6.50: Electricity produced per technology in the NBH scenario

Moreover, results show that hydrogen production technologies involve Alkaline electrolysers, with an installed capacity of 2.35 GW and a hydrogen production of 5.98 TWh, and PEM electrolysers, with an installed capacity of 6.37 GW and a hydrogen production of 22.47 TWh. The total installed capacity for hydrogen generation is 8.72 GW, corresponding to a hydrogen production of 28.45 TWh. Additionally, hydrogen imports account for 31.80 TWh. Therefore, the total hydrogen available in the COC scenario is 60.25 TWh to satisfy a total hydrogen demand of 59.70 TWh.

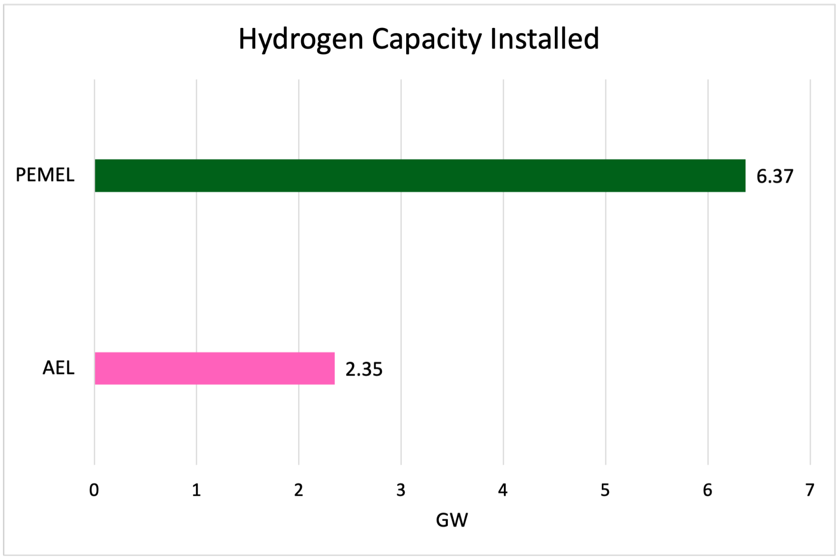

Figure 6.51: Hydrogen capacity installed per technology in the NBH scenario

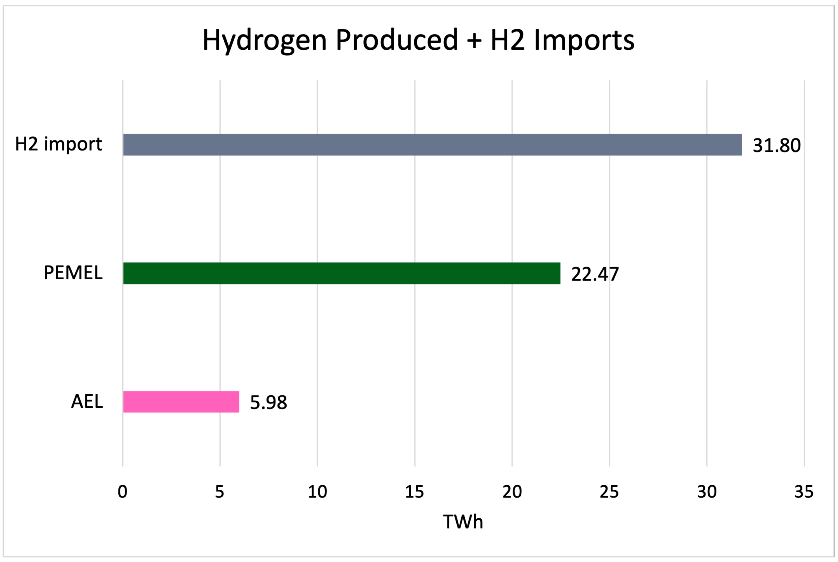

Figure 6.52: Hydrogen produced per technology and hydrogen imports in the NBH scenario

Regarding energy storage technologies, Figure 6.53 displays a storage capacity installed of 14 MWh for batteries, 6214.2 MWh for new batteries, and 1599317.2 MWh for salt caverns.

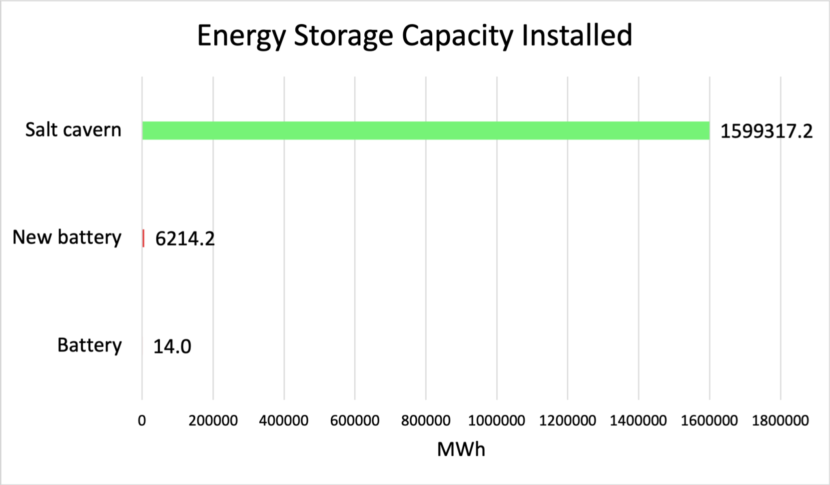

Figure 6.53: Storage capacity installed per technology in the NBH scenario

Regarding transmission infrastructure, the electricity and hydrogen grids resulting in the NBH scenario correspond to those of the BC scenario shown in Figure 6.6.

A comparative analysis of Figure 6.50 and Figure 6.2 reveals notable disparities in electricity production between the NBH and BC scenarios. In the NBH scenario, the generation of renewable electricity amounts to 125.68 TWh, representing a 23.98 TWh increase compared to the BC scenario. Consequently, while the electricity demand remains constant across both scenarios, the electricity produced through CCGT power plants totals 25.82 TWh in the NBH scenario, which is 6.61 TWh lower than in the BC scenario. Therefore, the optimisation in the absence of blue hydrogen production results in a greater investment in renewable electricity generation technologies which makes the energy system less dependent on gas. However, the significantly higher amount of renewable electricity produced does not correspond to a proportional increase in the installation of battery storage capacity, as evidenced by the comparison of Figure 6.53 and Figure 6.5. This discrepancy can be attributed to the production of green hydrogen.

An examination of Figure 6.51 and Figure 6.3 reveals that the total installed electrolysis capacity in the NBH scenario surpasses that of the BC scenario by 1.90 GW. Additionally, the NBH scenario exhibits a greater installed capacity for PEM electrolysers, in contrast to the findings in the BC scenario where alkaline electrolysers dominate. This means that, in front of unchanged hydrogen demand and electrolysis capital costs, the optimisation prefers PEM electrolysers to Alkaline electrolysers in the absence of SMR+CSS technologies. The combination of these modelling decisions results in a green hydrogen production that is 14.49 TWh higher in the NBH scenario compared to the BC scenario. Furthermore, this disparity leads to a significant increase in investments in salt caverns, as observed when comparing Figures 6.53 and 6.5.

Finally, Figures 6.52 and 6.4 demonstrate that in the NBH scenario, the amount of imported hydrogen is considerably higher than in the BC scenario due to the absence of SMR+CCS technologies. Nevertheless, despite the insufficient production of green hydrogen to meet the demand, the quantity of hydrogen imported in the NBH scenario remains lower than the combined sum of hydrogen produced through SMR+CCS and hydrogen imported in the BC scenario.

System Level Results Analysis

As we did for the other scenario, even for the NBH we have conducted an analysis of the same period observed in the BC scenario. Figure 6.54 displays the hourly electricity production and consumption of the Dutch energy system, while Figure 6.55 illustrates the hourly hydrogen production and consumption.

Our findings demonstrate that during periods of low RES capacity factor the energy system is able to utilise a combination of CCGT power plants, batteries, and CCHT technologies to meet the demand for electricity. Moreover, thanks to the large RES capacity installed, particularly for offshore wind, the system manages to satisfy a small part of the electricity demand with renewable electricity even in these periods, reducing in this way its dependency on gas and the amount of CO_2 emitted. Additionally, the system relies upon hydrogen imports and green hydrogen stored in salt caverns to meet the demand for hydrogen.

Conversely, during periods characterised by large availability of renewable electricity, the energy system operates renewable electricity generation technologies to produce electricity and cater to the demand. If there is an excess of renewable electricity, a portion of it is stored in batteries for short-term storage purposes, while the rest is employed in the production of green hydrogen, utilising primarily PEM electrolysers, along with Alkaline electrolysers. Furthermore, if an excess of green hydrogen is produced, it is stored in salt caverns for later utilisation.

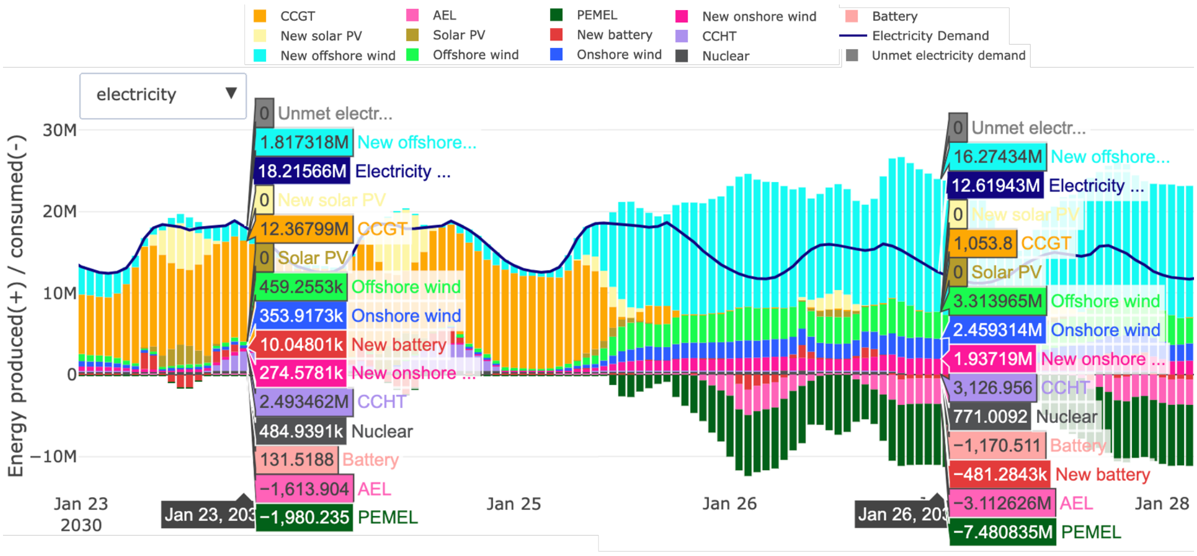

Figure 6.54: Hourly electricity production and consumption in the NBH

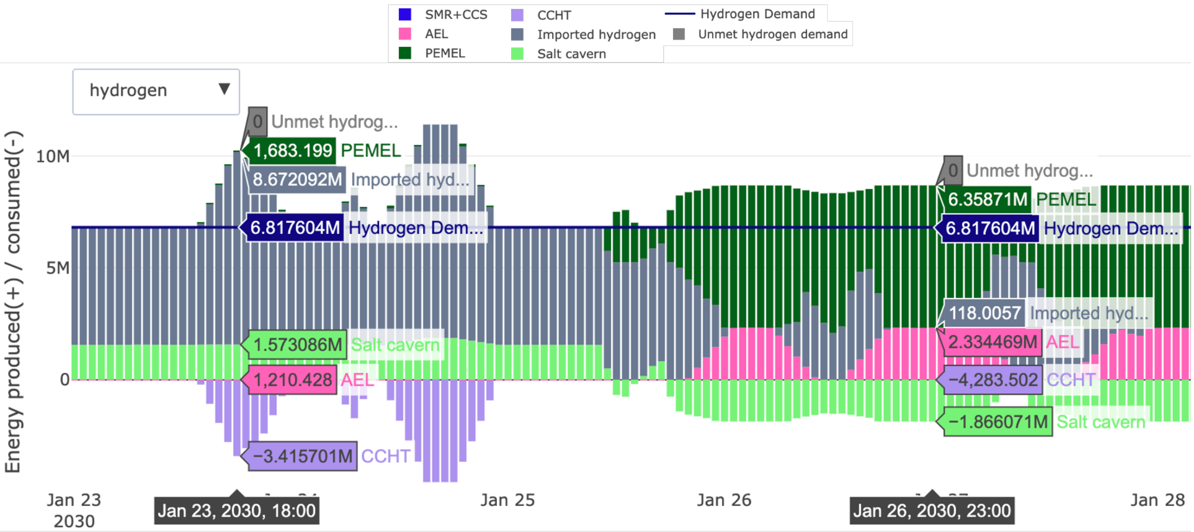

Figure 6.55: Hourly hydrogen production and consumption in the NBH

Node Level Results Analysis

The system-level analysis showed that the NBH scenario led to increased installed capacities for renewable electricity, PEM electrolysers and salt caverns, while simultaneously resulting in a decreased installed capacity for Alkaline electrolysers and batteries. To gain a more granular understanding of the implications at the node level, we conducted an assessment of the installed capacity for hydrogen-related technologies at each individual node.

The results indicate that the absence of SMR+CCS technologies significantly changed the criteria according to which the optimisation allocates the capacity installed for hydrogen-related technologies. Indeed, by comparing Figure 6.56 and Figure 6.9 we observed that the Alkaline and PEM electrolysers are not mainly installed anymore in the five nodes hosting an IC, which in descending order of hydrogen demand are NL33, NL34, NL42, NL11, and NL32.

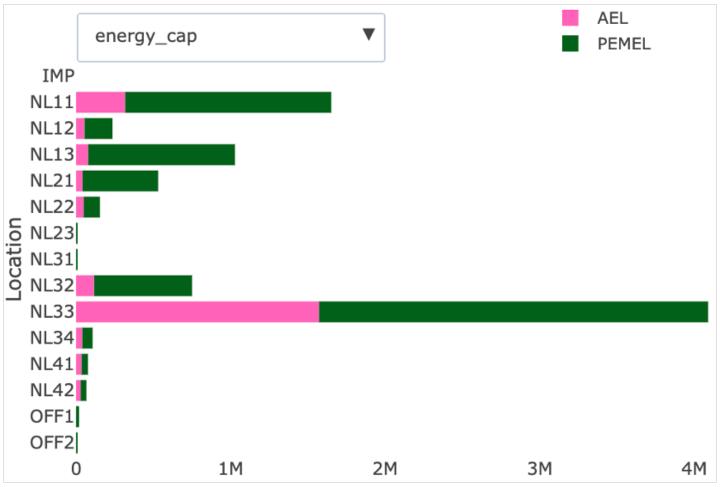

Figure 6.56: Optimal energy capacity installed for Alkaline and PEM electrolysers per node in the NBH scenario

In the NBH scenario, the model allocated most of the total capacity installed for PEM and Alkaline electrolysers in nodes NL33, NL11, NL13, NL32, and NL21. NL33 is the node hosting the IC Maasdelta, which has the highest demand for hydrogen (Table 4.5). NL11 is the node hosting the IC Eemshaven, which has the fourth highest demand for hydrogen (Table 4.5). Moreover, this node has the second-largest storage capacity installed for salt caverns, as shown in Figure 6.57. NL13 does not host any IC but has the largest storage capacity installed for salt caverns, as shown in Figure 6.57. NL32 is the node hosting the IC IJmond, which has the lowest demand for hydrogen (Table 4.5). Moreover, this node has a large capacity installed for renewable electricity generation technologies, as reported in Figure 6.58 and is also the node directly connected with node OFF1, as displayed in Figure 6.59, which has a significant capacity installed for offshore wind. Finally, NL21 does not host any IC and does not have storage capacity installed for salt caverns, but it has a large energy capacity installed for RES technologies (Figure 6.58) and is directly connected to NL13, which as previously mentioned has the largest capacity installed for salt caverns (Figure 6.57).

Regarding nodes NL34 and NL42, which host respectively the IC Zeeuws-Vlaanderen and the IC Limburg, the system satisfy their hydrogen demand by using imports. This is because these two nodes have little capacity installed for RES technologies compare to the others, as shown in Figure 6.58, and do not have storage capacity installed for salt caverns nor are they close to nodes that do.

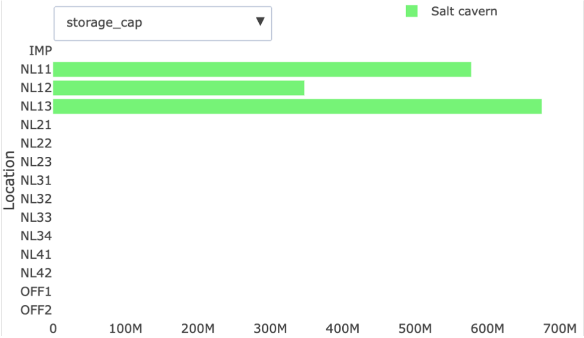

Figure 6.57: Optimal storage capacity installed for salt caverns per node in the NBH scenario

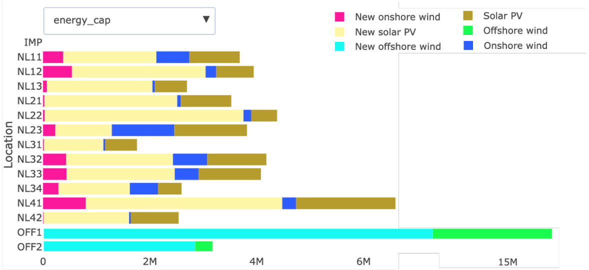

Figure 6.58: Optimal energy capacity installed for RES technologies per node in the NBH scenario

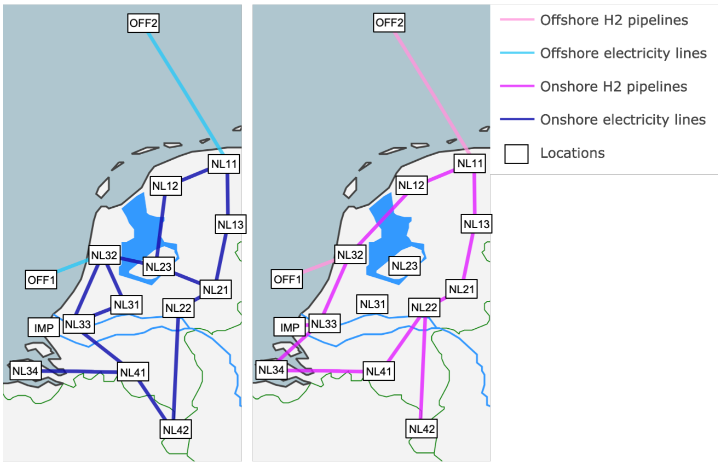

Figure 6.59: Electricity and hydrogen transmission grids in the NBH scenario

Lastly, our analysis of CCHT technologies revealed that the optimisation process allocated their installed capacity predominantly in NL33, mirroring the pattern observed in the BC scenario. However, we also noted installations in NL12, NL11, and NL13, which are nodes with storage capacity installed for salt caverns. Therefore, through the integration of electrolysis technologies, salt caverns, and CCHT technologies, the energy system demonstrates the ability to generate green hydrogen, store it in salt caverns, and subsequently utilise it to meet the hydrogen demand but also the electricity demand, by converting hydrogen back to electricity.

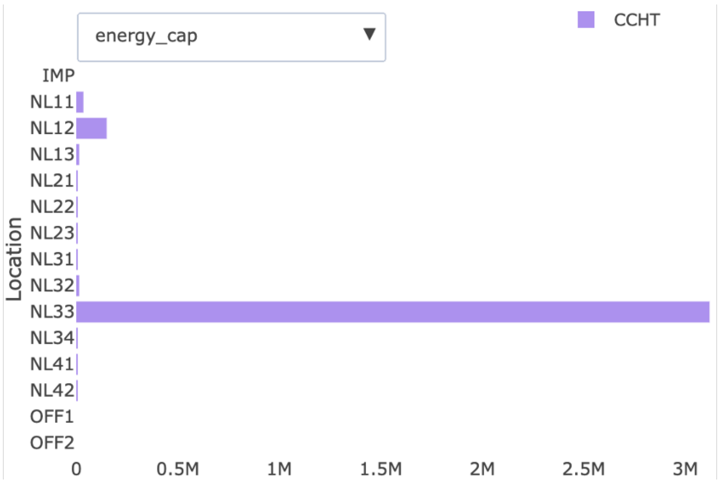

Figure 6.60: Optimal energy capacity installed for CCHT technologies per node in the NBH scenario

7

Discussion

This research focuses on the impact of hydrogen uncertainties on the 2030 Dutch integrated energy system. In particular, we wanted to asses green hydrogen infrastructure penetration and its impact on the system under different scenarios. This Chapter presents in Section 7.1 the main findings resulting from the scenario analysis, performed in Chapter 6, and our policy recommendations. Moreover, it summarises in Section 7.2 and Section 7.3 limitations and future research.

7.1. Scenario Analysis and Policy Recommendations

In the present study, we have conducted a scenario analysis to examine the uncertainties surrounding the establishment of a green hydrogen value chain within the future integrated energy system of the Netherlands in 2030. Specifically, our analysis focused on evaluating the impacts stemming from uncertainties in future hydrogen demand and capital costs associated with Alkaline and PEM electrolysers. Furthermore, we explored the effects of a policy that prohibits the production of blue hydrogen. Throughout our analysis, we also sought to understand the interplay between installed capacities of renewable electricity generation, hydrogen generation, and storage for both electricity and hydrogen across different scenarios.

With regard to installed capacities for RES technologies, our findings indicate that an increase in hydrogen demand or a decrease in electrolyser capital costs leads to a rise in installed renewable capacity. Conversely, a decrease in hydrogen demand or an increase in electrolyser capital costs results in a reduction of installed renewable capacity. Furthermore, in the case where the production of blue hydrogen is disallowed, our results demonstrate a significant increase in the overall energy capacity installed for RES technologies.

Figure 7.1 illustrates the total optimal energy capacity installed for RES technologies in each scenario, ranging from 53.02 GW to 66.98 GW. Notably, the NBH scenario stands out as the only scenario exhibiting a considerable deviation from the BC scenario. Therefore, while variations in hydrogen demand and electrolyser capital costs have a modest impact on renewable capacity investment, a policy prohibiting the production of blue hydrogen acts as a substantial catalyst for increased investments in solar and wind technologies.

The optimisation results of our study suggest that, regardless of hydrogen uncertainties, a minimum of 53.02 GW of renewable electricity generation capacity should be available by 2030 in all scenarios. This implies an investment of at least 33.09 GW in new renewable capacity by 2030. Therefore, our findings indicate that investing in additional renewable electricity capacity for the Netherlands is a no-regret investment decision, even in pessimistic scenarios concerning hydrogen uncertainties.

The Dutch target pertaining to the total installed capacity for renewable electricity generation technologies in 2030 amounts to 89.90 GW (Section 4.1). Our results suggest that this target may not be cost-optimal, as it aims to install a capacity significantly higher than those resulting from the various scenario simulations performed. Indeed, the Dutch target is 22.92 GW higher than the total capacity installed for RES technologies in the NBH scenario, which is already the scenario having the largest renewable capacity installed. Consequently, our findings, when compared to the Dutch target in question, suggest a potential overbuilding of renewable capacity in the medium term.

Figure 7.1 also presents the optimal energy capacity installed in each scenario for solar PV, onshore wind, and offshore wind. The total optimal energy capacity installed for solar PV ranges from 30.13 GW to 36.36 GW. In contrast, the target set by the Dutch government for 2030 is 59.3 GW. For onshore wind, the total optimal energy capacity installed ranges from 7.29 GW to 7.72 GW, while the government's target for 2030 is 9.1 GW. Lastly, the total optimal energy capacity installed for offshore wind ranges from 15.30 GW to 23.19 GW and closely aligns with the government's target of 21.5 GW.

These findings suggest that if the Netherlands intends to achieve the targets abovementioned, there is a likelihood of overbuilding, particularly in solar PV technologies. The target for solar PV capacity surpasses the maximum value within the range obtained from our scenario simulations by 22.94 GW. Similarly, the target for onshore wind capacity could lead to overbuilding. However, the risk is significantly lower since it exceeds the maximum value of the range by 1.38 GW. In contrast, the target for offshore wind aligns with the range of optimal values resulting from our scenario analysis. Nevertheless, it is closer to the value obtained in the NBH scenario. Therefore, if the Netherlands aims to strongly incentivise investment in offshore wind capacity, it would require the implementation of robust policies, such as the prohibition of blue hydrogen production.

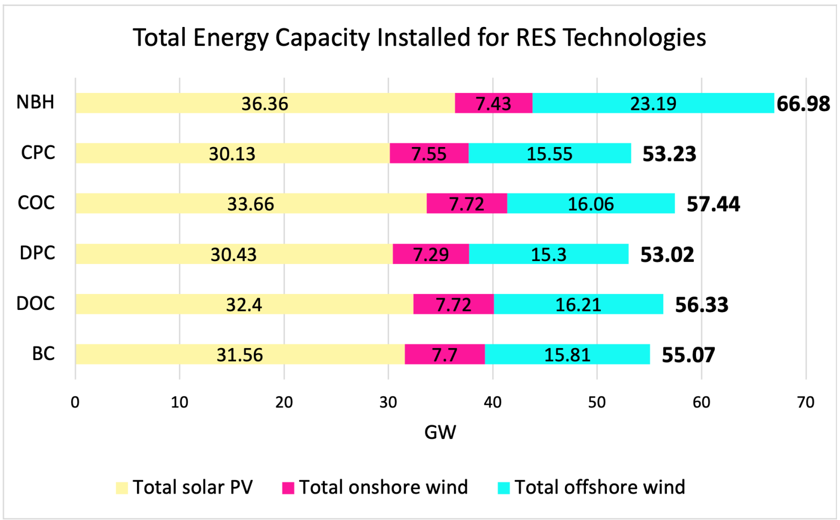

Figure 7.1: Total optimal energy capacity installed for RES technologies in each scenario

The study provides valuable insights into the sensitivity of hydrogen generation technologies to hydrogen uncertainties. It reveals that SMR combined with CCS exhibits low sensitivity to changes in hydrogen uncertainties, while green hydrogen generation technology demonstrates higher sensitivity.

The findings reported in Chapter 6 showed how the Netherlands will continue to rely heavily on natural gas to meet the hydrogen demand in 2030. However, although the CCS technology significantly reduces the number of emissions generated from the SMR process, it is important to consider that storing space for CO_2 emissions is limited in the long term. Therefore, relying mostly on blue hydrogen production may not be a sustainable solution. Moreover, Figure 7.2 presents the total optimal energy capacity installed for SMR+CCS technologies in each scenario. It ranges from 5.55 GW to 7.93 GW. The figure also shows that the capacity for blue hydrogen production remains unaffected by changes in electrolyser capital costs. However, it responds to changes in hydrogen demand by increasing or reducing proportionally, since the results of all scenarios show that SMR+CCS is installed in reaction to the occurrence of hydrogen need.

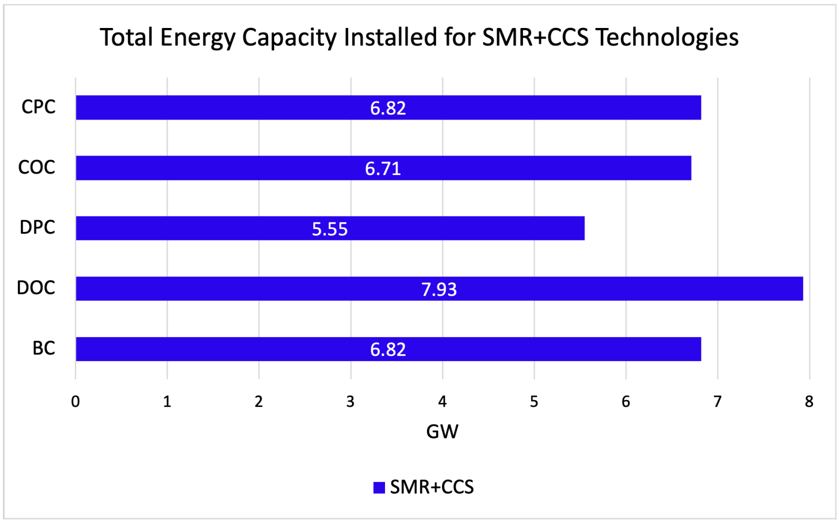

Figure 7.2: Total optimal energy capacity installed for SMR+CCS in each scenario

Figure 7.3 displays the total energy capacity installed for green hydrogen production technologies, ranging from 5.55 GW to 8.72 GW. The Dutch target for electrolysis capacity installed in 2030 falls within the range of 6-8 GW, aligning with the optimal ranges obtained from our scenario simulations. This result allows us to connect with Figure 1.1 reported in Chapter 1, which illustrates the number of electrolysis projects that should materialise by 2030. To effectively realise these projects, the Netherlands should aim for an electrolysis installed capacity of around 8 GW by 2030. According to our findings, this goal appears to be almost achievable if the Dutch government successfully mitigates the uncertainties related to hydrogen demand and capital costs of electrolysers in the mid-term period. However, if policymakers adopt more ambitious measures, such as a policy prohibiting blue hydrogen production, our results indicate that the Netherlands could exceed the 8 GW target for electrolysis capacity installed by 2030.

Furthermore, Figure 7.3 indicates that the total electrolysis capacity installed is more sensitive to changes in hydrogen demand than variations in capital costs. However, it also shows that a policy prohibiting blue hydrogen production has a significant positive impact on the total electrolysis capacity installed. However, to effectively understand the impacts of hydrogen uncertainties on electrolysis technologies we have to analyse individually the amount of capacity installed for Alkaline electrolysers and for PEM electrolysers.

In this context, Figures 7.3 also illustrate the total optimal energy capacity installed for Alkaline electrolysers and PEM electrolysers, respectively. The capacity for Alkaline electrolysers ranges from 0.03 GW to 6.16 GW, while the capacity for PEM electrolysers ranges from 0.01 GW to 6.98 GW. The findings indicate that when the capital costs are in the middle price range, the optimisation approach results in the installation of energy capacity for both Alkaline and PEM electrolysers. However, in the case of high capital costs, the optimisation approach favours Alkaline electrolysers, whereas, in the low price range, it prefers PEM electrolysers. Therefore, although the electrolysis technologies do not exhibit significant changes in total installed capacity in response to variations in electrolyser capital costs, there are differences in the allocation of this capacity between Alkaline and PEM technologies.

Furthermore, as mentioned above, the optimisation approach leads to the installation of energy capacity for both Alkaline and PEM electrolysers when the capital costs are in the middle price range. However, in the case of changes in the hydrogen demand, the optimisation adjusts the installed capacity for both electrolysis technologies accordingly, while still maintaining a higher capacity for Alkaline electrolysis compared to PEM electrolysers. However, in the absence of blue hydrogen production, the optimisation increases the installed capacity for both technologies but also gives preference to PEM electrolysers over Alkaline electrolysers.

It is noteworthy that both the reduction in capital costs and the prohibition of blue hydrogen production enhance the attractiveness of PEM electrolysers, despite their higher cost compared to Alkaline electrolysers, due to their superior technical characteristics. Consequently, these two factors not only impact the energy system by resulting in a higher installed capacity but also contribute to a greater production of green hydrogen, thanks to the improved efficiency and ramping rate of PEM electrolysers.

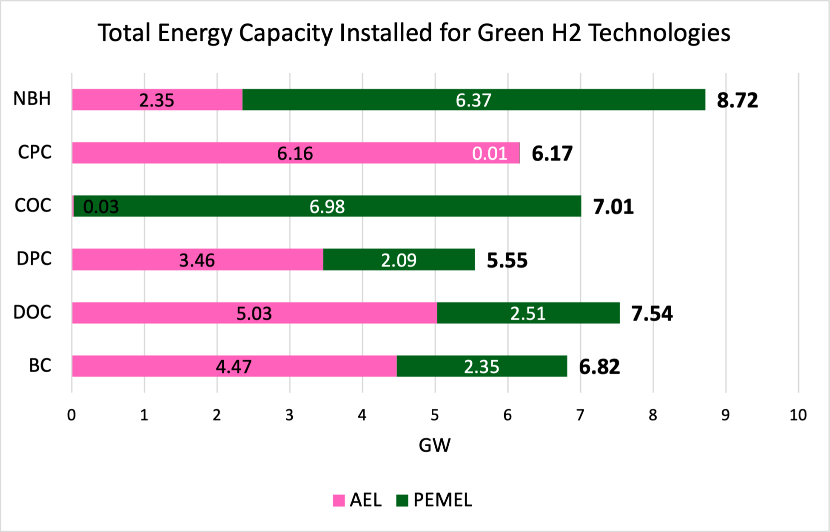

Figure 7.3: Total optimal energy capacity installed for green hydrogen production technologies in each scenario

Figure 7.4 illustrates the total optimal storage capacity installed for salt caverns in each scenario, ranging from 773.7 MWh to 1599317.2 MWh. The figure reveals that salt caverns exhibit sensitivity to both changes in hydrogen demand and variations in electrolyser capital costs. However, when the electrolyser capital costs are in the middle or high price range, the role of salt caverns becomes less significant in the energy system. Conversely, when electrolyser capital costs are in the low price range, the optimisation approach results in a considerably larger storage capacity installed for salt caverns. Furthermore, the absence of blue hydrogen production has a notable impact on the storage capacity installed for salt caverns. In this scenario, salt caverns play a fundamental role in the system, facilitating the integration of renewable electricity and meeting hydrogen demand through the utilisation of green hydrogen.

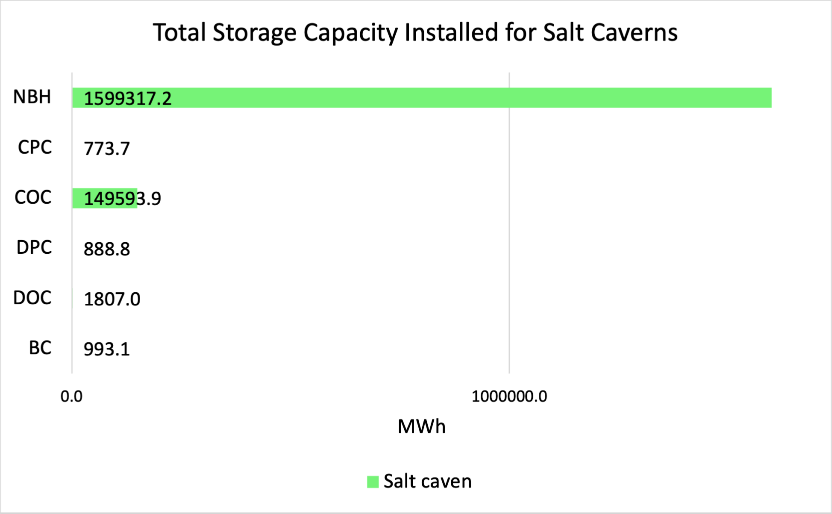

Figure 7.4: Total optimal storage capacity installed for salt caverns in each scenario

Our findings demonstrate that achieving an installed electrolysis capacity of 8 GW is feasible, but it requires the implementation of robust policies, such as the prohibition of blue hydrogen production in 2030. Furthermore, it is crucial to allocate a significant portion of this capacity to PEM electrolysis technology. PEM electrolysis has superior technical characteristics, making it well-suited for effectively managing vRES and working in conjunction with salt caverns to integrate renewable electricity into the grid and enhance system flexibility.

The study suggests that investing in blue hydrogen infrastructure in the medium term does not facilitate the penetration of such infrastructure. In fact, it hinders the transition process by perpetuating the reliance on natural gas within the Dutch energy system. This dependency on gas slows down the speed of transition. Conversely, adopting a policy that prohibits blue hydrogen production and refraining from investing in SMR combined with CCS technologies promotes the market penetration of green hydrogen infrastructure. This progress can be achieved even without a significant increase in hydrogen demand or a considerable reduction in electrolyser capital costs, enabling a faster transition to a sustainable energy system.

However, the implementation of such a policy may pose challenges, particularly in the medium term. The Netherlands is a country highly reliant on gas and phasing it out from the hydrogen by 2030 will require massive investment. Additionally, referring to Figure 1.3, extracted from the research conducted by Odenweller et al. [57] and discussed in Section 1.2 of this paper, it becomes evident that the Dutch government would need to witness an unconventional capacity growth rate for electrolysis technologies surpassing that of wind and solar power in order to effectively enforce a policy prohibiting the production of blue hydrogen. Achieving such accelerated growth rates for green hydrogen infrastructure necessitates specific conditions, such as higher demand for hydrogen or reduced capital costs for electrolysis technology.

Therefore, while the implementation of a policy prohibiting the production of blue hydrogen could potentially stimulate investments in green hydrogen infrastructure and facilitate the establishment of a green hydrogen value chain, it is essential to acknowledge that realistic success depends on the support of additional policies and the presence of certain conditions. Without such supportive measures and favourable conditions, achieving a complete phase-out of blue hydrogen may prove challenging. In the medium term, a viable option could involve implementing a policy that permits the conversion of existing SMR facilities into blue hydrogen through the installation of CCS technologies. However, it is important to note that this policy should not facilitate or provide subsidies for the construction of new blue hydrogen plants.

Additionally, the study highlights the significant role that reduced electrolyser capital costs can play in facilitating the widespread adoption of green hydrogen infrastructure and accelerating the deployment of renewable electricity generation technologies. Policymakers are encouraged to consider implementing subsidies or financial incentives to support investments in electrolysers, effectively mitigating their high capital costs. By providing financial assistance, policymakers can encourage industry stakeholders and investors to embrace green hydrogen technologies and contribute to the development of a robust and viable green hydrogen value chain.

In conclusion, the achievement of the 2030 Dutch energy targets and broader European energy goals is contingent upon the implementation of robust policies that incentivise investment in zero-carbon energy carriers. The coordinated deployment of renewable electricity generation technologies, green hydrogen generation technologies, and storage solutions for hydrogen and electricity will accelerate the transition to a future European energy system that operates with zero emissions.

However, it is crucial to recognise that the phasing out of fossil fuels in favour of renewable energy sources and green hydrogen will have societal impacts that must be carefully addressed. These impacts include potential job losses in sectors closely tied to fossil fuels, such as coal mining and oil extraction, as well as economic challenges stemming from the high initial costs associated with transitioning to renewable energy sources. These costs may lead to increased energy prices for consumers. Moreover, integrating a significant share of vRES into the energy system may introduce reliability concerns, and there is a risk of technological obsolescence for stranded fossil fuel-based assets that could become economically unviable.

Policymakers play a crucial role in proactively addressing these challenges through the implementation of effective policy frameworks. They should consider policies that create new employment opportunities in the renewable energy sector, provide subsidies to mitigate the financial burden of the energy transition and maintain affordable energy prices, and support investments in grid upgrades and energy storage technologies to ensure a reliable and resilient energy system and facilitate the repurposing or retirement of outdated fossil fuel assets to minimise negative economic impacts.

Achieving these goals by 2030 presents significant challenges. However, governments must strive to do their best. As highlighted in Section 1.1, it is essential to limit the average temperature increase to below 1.5°C compared to a 2°C scenario to preserve the essential ecosystem services provided by terrestrial and coastal ecosystems. Climate-related risks would escalate if the average temperature increase exceeds this threshold, as emphasised in the IPCC report on global warming [12].

7.2. Limitations

While the model used in this study provides valuable insights into the deployment of renewables and green hydrogen in the 2030 Dutch integrated energy system, there are several limitations that need to be acknowledged. These limitations are important to consider as they may impact the accuracy of the model's predictions.

One of the limitations of the model is that it does not take into account the demand for gas. As gas is still a significant contributor to the Dutch energy system, its exclusion from the model could affect the accuracy of the results. Another limitation is that the model assumes a constant hydrogen demand. In reality, hydrogen demand may fluctuate depending on various factors such as economic growth, technological advancements, and policy changes. The constant demand assumption may not accurately reflect the market demand for hydrogen in the future. Furthermore, the model assumes that there is no maximum capacity for transmission links. In reality, transmission links may have limited capacity, which could impact the deployment of renewables and green hydrogen in the energy system. Another limitation is that the model assumes infinite storage for CO_2. In reality, there are limitations to storage capacity and it may not be possible to store an infinite amount of CO_2. Lastly, the model does not take into account the connections with neighbouring countries. Energy systems are not isolated and may be impacted by the policies and developments in neighbouring countries. The exclusion of this factor could affect the accuracy of the model's predictions.

7.3. Future Research

The present study has provided valuable insights into the impact of hydrogen demand and electrolyser capital costs on the future Dutch integrated energy system of 2030. However, future research can enhance the study by investigating additional scenarios that would offer a more comprehensive understanding of these dynamics.

One avenue for future research is the analysis of additional hydrogen uncertainties. For example, exploring the effects of technical changes in electrolysis technologies, such as the rate of ramping for electrolysers, could provide valuable insights into system performance and optimisation. Understanding how different electrolysis technologies and their capabilities affect the energy system will contribute to better decision-making and policy formulation.

Furthermore, conducting a sensitivity analysis that combines multiple scenarios would be beneficial. This analysis would involve examining the impacts on the energy system resulting from combined changes in various parameters of interest. By considering different combinations of hydrogen demand, electrolyser capital costs, and other relevant factors, a more nuanced understanding of the system's behaviour and potential outcomes can be achieved. This approach would provide valuable insights into the interplay of different variables and their influence on the Dutch integrated energy system of 2030.

By incorporating these additional scenarios and conducting sensitivity analyses, future research can contribute to a more comprehensive understanding of the complex dynamics within the Dutch integrated energy system of 2030. This enhanced understanding will enable policymakers and stakeholders to make more informed decisions and develop targeted interventions to facilitate the energy transition effectively.

8

Conclusion

This Master's thesis aimed to make a significant contribution to the existing knowledge surrounding the deployment of renewable energy sources and green hydrogen. By focusing on the integrated energy system in the Netherlands for the year 2030, the study sought to gain valuable insights into the impact of hydrogen uncertainties on the system. Furthermore, it aimed to propose potential policy interventions to address the coordination problem associated with the adoption of green hydrogen infrastructure.

The study has been performed by using the Calliope multi-scale energy systems modelling framework, which has both strengths and weaknesses. On the positive side, Calliope exhibits flexibility, allowing for the integration of diverse energy sources, technologies, and policy scenarios. Moreover, by incorporating multiple sectors, Calliope captures the interconnectedness and interdependencies of energy systems, enabling comprehensive evaluations of cross-sectoral impacts and identification of synergies and trade-offs. However, to manage computational complexity, Calliope employs simplifications and assumptions that may not fully capture the intricacies of real-world energy systems, potentially affecting the accuracy and applicability of its results. Additionally, the model primarily focuses on techno-economic aspects and may not fully incorporate social, behavioural, and political dynamics.

Through a comprehensive analysis of the research, the main research question, "How do hydrogen uncertainties impact the penetration of green hydrogen infrastructure in the 2030 Dutch integrated energy system?" has been effectively addressed. The investigation revealed that fluctuations in hydrogen demand and increases in capital costs for electrolysis technology do not exert a substantial influence on the overall energy system. However, reductions in capital expenditures for electrolysis technology and the implementation of policies that forbid the production of blue hydrogen have proven to be impactful. These factors directly influence the uncertain adoption of green hydrogen infrastructure within the system.

The findings of the study shed light on the potential benefits derived from reducing capital expenditure for electrolysis technology. This reduction, in turn, would incentivise investments in PEM electrolysers, which play a vital role in facilitating the deployment of renewable energy sources and encouraging investments in salt caverns. The increased utilisation of these technologies would subsequently displace the use of fossil-based hydrogen and electricity, resulting in a notable reduction in carbon emissions and hastening the transition towards a low-carbon economy.

Furthermore, the implementation of a policy that prohibits the production of blue hydrogen has been found to be the most impactful policy to stimulate investments in renewable electricity generation technologies, PEM electrolysers (highly recommended for integrating variable renewable energy sources), and salt cavern storage options. However, it could be difficult to implement in the mid-term period considering the high reliance on gas in the Dutch energy system.

On the other hand, even if fluctuations in the demand for hydrogen and increases in electrolyser capital costs have not significantly impacted the future Dutch integrated energy system of 2030, they have not helped in accelerating the energy transition happening neither in reaching the energy and decarbonisation targets set. As a result, policymakers must take these factors into account and formulate policies that ensure the penetration of green hydrogen infrastructure in the medium term.

In light of the study's conclusions, it is evident that reducing electrolyser capital costs and implementing subsidies or financial incentives for electrolysers can play a crucial role in facilitating the widespread adoption of green hydrogen infrastructure. Conversely, investing in blue hydrogen infrastructure in the medium term could impede the transition to a sustainable energy system. Therefore, policies prohibiting the production of blue hydrogen are recommended, as they encourage the penetration of green hydrogen infrastructure and expedite the transition process.

Consequently, this study highlights the critical importance for policymakers to consider the impact of both hydrogen demand and the required capital expenditure for electrolysis technology when addressing the uncertain adoption of green hydrogen infrastructure within the Dutch integrated energy system in 2030. Furthermore, the effects of blue hydrogen on the deployment of green hydrogen must be taken into account. Policymakers should proactively develop strategies that not only facilitate the market penetration of green hydrogen but also effectively address the coordination problem. By doing so, policymakers can actively support the transition to a low-carbon economy, mitigate the adverse effects of climate change, and pave the way for a sustainable and environmentally friendly energy future.

Bibliography

[1] Carlos Andrade, Sandrine Selosse, and Nadia Maïzi. “The role of power-to-gas in the integration of variable renewables”. In: *Applied Energy* 313 (2022), p. 118730.

[2] Freida Ozavize Ayodele et al. “An overview of economic analysis and environmental impacts of natural gas conversion technologies”. In: *Sustainability* 12.23 (2020), p. 10148.

[3] Steve Bankes, Warren E Walker, and Jan H Kwakkel. “Exploratory modeling and analysis”. In: *Encyclopedia of operations research and management science* (2013), pp. 532–537.

[4] Massimo Beccarello and Giacomo Di Foggia. “Review and Perspectives of Key Decarbonization Drivers to 2030”. In: *Energies* 16.3 (2023), p. 1345.

[5] Energy Brainpool. *Update EU Energy Outlook 2060: Wie entwickelt sich der europäische Strommarkt in den nächsten 37 Jahren?* Apr. 19, 2023. URL: `https://blog.energybrainpool.com/update-eu-energy-outlook-2060-wie-entwickelt-sich-der-europaeische-strommarkt-in-den-naechsten-37-jahren/`.

[6] Kenneth Bruninx, Jorge A Moncada, and Marten Ovaere. “Electrolytic hydrogen has to show its true colors”. In: *Joule* 6.11 (2022), pp. 2437–2440.

[7] Alessandro A Carmona-Martínez et al. “Renewable Power and Heat for the Decarbonisation of Energy-Intensive Industries”. In: *Processes* 11.1 (2023), p. 18.

[8] CBS. *Onshore wind energy; production and capacity by province*. Centraal Bureau voor de Statistiek, Dec. 15, 2022.

[9] CBS. *Regional key figures for the Netherlands*. Centraal Bureau voor de Statistiek, Apr. 20, 2023.

[10] CBS. *Solar power; wealth and asset class, businesses and residential, region*. Centraal Bureau voor de Statistiek, 2022.

[11] *Climate action and the Green Deal*. Text. URL: `https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/climate-action-and-green-deal_en`.

[12] Intergovernmental Panel on Climate Change (IPCC). *Global Warming of 1.5°C: IPCC Special Report on Impacts of Global Warming of 1.5°C above Pre-industrial Levels in Context of Strengthening Response to Climate Change, Sustainable Development, and Efforts to Eradicate Poverty*. Cambridge University Press, 2022. DOI: `10.1017/9781009157940`.

[13] European Commission. *A hydrogen strategy for a climate-neutral Europe*. July 8, 2020. URL: `https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52020DC0301`.

[14] European Commission. *REPowerEU Plan*. May 18, 2022. URL: `https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52022DC0230`.

[15] DEA. *Levelized Cost of Energy (LCoE) Calculator*. Danish Energy Agency, 2018.

[16] DEA. *Technology Catalogue for Renewable Fuels*. Danish Energy Agency, Mar. 2023.

[17] DEA. *Technology Catalogue for Transport of Energy*. Danish Energy Agency, 2023.

[18] DEA. *Technology Data for Energy Storage*. Danish Energy Agency, 2023.

[19] DEA. *Technology Data for Generation of Electricity and District Heating*. Danish Energy Agency, 2023.

[20] DNV. *Hydrogen Forecast to 2050*. DNV AS, 2022.

[21] Nauta Dutilh. *The Dutch Hydrogen Roadmap: a map in transition – three key insights*. Mar. 15, 2023. URL: https://www.nautadutilh.com/en/information-centre/news/the-dutch-hydrogen-roadmap-a-map-in-transition-three-key-insights.

[22] The Ministry of Economic Affairs and Climate Policy. *Integrated National Energy and Climate Plan 2021-2030*. 2019. URL: https://energy.ec.europa.eu/system/files/2020-03/nl_final_necp_main_en_0.pdf.

[23] Ahmed M Elberry et al. "Large-scale compressed hydrogen storage as part of renewable electricity storage systems". In: *International journal of hydrogen energy* 46.29 (2021), pp. 15671–15690.

[24] Frontis Energy. *Energy storage in The Netherlands*. 2020. URL: https://frontis-energy.com/2020/04/30/energy-storage-in-the-netherlands/.

[25] *ENTSO-E Transparency Platform*. URL: https://transparency.entsoe.eu/.

[26] SolarPower Europe. *National Energy and Climate Plans: Discover what National Energy and Climate Plans mean for solar*. 2023. URL: https://www.solarpowereurope.org/advocacy/national-energy-and-climate-plans.

[27] The European Files. *Clean Hydrogen costs in 2030 and 2050: a review of the known and the unknown*. 2021. URL: https://www.europeanfiles.eu/energy/clean-hydrogen-costs-in-2030-and-2050-a-review-of-the-known-and-the-unknown.

[28] Gasunie. *Hydrogen network Netherlands*. 2023. URL: https://www.gasunie.nl/en/projects/hydrogen-network-netherlands.

[29] Gurobi Optimization, LLC. *Gurobi Optimizer Reference Manual*. 2023. URL: https://www.gurobi.com.

[30] IEA. *Electricity demand outlook in selected regions/countries in the Stated Policies Scenario, 2019-2030*. International Energy Agency, 2022.

[31] IEA. *Global average levelised cost of hydrogen production by energy source and technology, 2019 and 2050*. International Energy Agency, 2022.

[32] IEA. *Renewable Electricity*. International Energy Agency, 2022.

[33] IEA. *The Future of Hydrogen*. International Energy Agency, 2019.

[34] IEA. *The Netherlands 2020*. International Energy Agency, 2020.

[35] IEA. *Wind TCP Netherlands*. International Energy Agency, 2021.

[36] Hydrogen Insight. *Green hydrogen imported to Europe would be cost-competitive with locally produced H2 by 2030: analyst*. 2023. URL: https://www.hydrogeninsight.com/production/green-hydrogen-imported-to-europe-would-be-cost-competitive-with-locally-produced-h2-by-2030-analyst/2-1-1393655.

[37] IRENA. *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal*. International Renewable Energy Agency, 2020.

[38] IRENA. *Hydrogen: a renewable energy perspective*. International Renewable Energy Agency, 2019.

[39] ISPRA. *Indicatori di efficienza e decarbonizzazione del sistema energetico nazionale e del settore elettrico*. Istituto Superiore per la Protezione e la Ricerca Ambientale, May 5, 2021.

[40] Mary Katebah, Patrick Linke, et al. “Analysis of hydrogen production costs in Steam-Methane Reforming considering integration with electrolysis and CO2 capture”. In: *Cleaner Engineering and Technology* 10 (2022), p. 100552.

[41] Ministerie van Economische Zaken en Klimaat. *Government Strategy on Hydrogen*. Apr. 6, 2020. URL: https://www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen.

[42] Binod Koirala et al. “Integrated electricity, hydrogen and methane system modelling framework: Application to the Dutch Infrastructure Outlook 2050”. In: *Applied Energy* 289 (2021), p. 116713.

[43] R. Koneczna and J. Cader. “Hydrogen in the strategies of the european Union member states”. In: *Gospodarka Surowcami Mineralnymi / Mineral Resources Management* 37.3 (2021), pp. 53–74. ISSN: 0860-0953. DOI: 10.24425/gsm.2021.138660.

[44] Giovanni Lagioia, Maria Pia Spinelli, and Vera Amicarelli. “Blue and green hydrogen energy to meet European Union decarbonisation objectives. An overview of perspectives and the current state of affairs”. In: *International Journal of Hydrogen Energy* 48.4 (Jan. 12, 2023), pp. 1304–1322. ISSN: 0360-3199. DOI: 10.1016/j.ijhydene.2022.10.044.

[45] Xiaona Li et al. “Latest approaches on green hydrogen as a potential source of renewable energy towards sustainable energy: Spotlighting of recent innovations, challenges, and future insights”. In: *Fuel* 334 (Feb. 2023), p. 126684. ISSN: 0016-2361. DOI: 10.1016/j.fuel.2022.126684.

[46] Francesco Lombardi et al. “Policy Decision Support for Renewables Deployment through Spatially Explicit Practically Optimal Alternatives”. In: *Joule* 4.10 (Oct. 2020), pp. 2185–2207. ISSN: 2542-4351. DOI: 10.1016/j.joule.2020.08.002.

[47] Tuukka Mäkitie and Markus Steen. *Strategic insights on governance of hydrogen innovation and the chicken and egg problem*. Jan. 1, 2022. DOI: 10.13140/RG.2.2.13945.34403.

[48] Andrea Mazza, Ettore Bompard, and Gianfranco Chicco. “Applications of power to gas technologies in emerging electrical systems”. In: *Renewable and Sustainable Energy Reviews* 92 (Sept. 1, 2018), pp. 794–806. ISSN: 1364-0321. DOI: 10.1016/j.rser.2018.04.072.

[49] Jan Michalski et al. “Hydrogen generation by electrolysis and storage in salt caverns: Potentials, economics and systems aspects with regard to the German energy transition”. In: *International Journal of Hydrogen Energy* 42.19 (May 2017), pp. 13427–13443. ISSN: 03603199. DOI: 10.1016/j.ijhydene.2017.02.102.

[50] Landbouw en Innovatie Ministerie van Economische Zaken. *Climate policy - Climate change - Government.nl*. en-GB. onderwerp. Last Modified: 2020-01-31T12:12 Publisher: Ministerie van Algemene Zaken. Feb. 2019. URL: https://www.government.nl/topics/climate-change/climate-policy.

[51] Global Energy Monitor. *Global Gas Plant Tracker*. 2023.

[52] Netbeheer Nederland. *IP2024*. Feb. 20, 2023.

[53] Government of the Netherlands. *Offshore wind energy*. 2022. URL: `https://www.government.nl/topics/renewable-energy/offshore-wind-energy`.

[54] Pavlos Nikolaidis and Andreas Poullikkas. “A comparative overview of hydrogen production processes”. In: *Renewable and Sustainable Energy Reviews* 67 (Jan. 1, 2017), pp. 597–611. ISSN: 1364-0321. DOI: `10.1016/j.rser.2016.09.044`.

[55] Michel Noussan et al. “The Role of Green and Blue Hydrogen in the Energy Transition—A Technological and Geopolitical Perspective”. In: *Sustainability* 13.1 (Jan. 2021). Number: 1 Publisher: Multidisciplinary Digital Publishing Institute, p. 298. ISSN: 2071-1050. DOI: `10.3390/su13010298`.

[56] Simon Öberg, Mikael Odenberger, and Filip Johnsson. “Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems”. In: *International Journal of Hydrogen Energy* 47.1 (2022), pp. 624–644.

[57] Adrian Odenweller et al. “Probabilistic feasibility space of scaling up green hydrogen supply”. In: *Nature Energy* 7.9 (2022), pp. 854–865.

[58] Stefan Pfenninger and Bryn Pickering. “Calliope: a multi-scale energy systems modelling framework”. In: *Journal of Open Source Software* 3.29 (2018), p. 825.

[59] Stefan Pfenninger and Iain Staffell. “Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data”. In: *Energy* 114 (2016), pp. 1251–1265.

[60] *Project “HyUnder. Assessment of the potential, the actors and relevant business cases for large scale and seasonal storage of renewable electricity by hydrogen underground storage in Europe”*. 2014. URL: `https://cordis.europa.eu/project/id/303417/reporting`.

[61] Gunhild A Reigstad et al. “Moving toward the low-carbon hydrogen economy: Experiences and key learnings from national case studies”. In: *Advances in Applied Energy* 8 (2022), p. 100108.

[62] Bruno Henrique Santos et al. “Developing a hydrogen seasonal storage strategy to support security of supply and carbon neutrality”. In: *2022 International Conference on Smart Energy Systems and Technologies (SEST)*. 2022 International Conference on Smart Energy Systems and Technologies (SEST). Sept. 2022, pp. 1–6. DOI: `10.1109/SEST53650.2022.9898426`.

[63] Martin Scheepers et al. “Towards a climate-neutral energy system in the Netherlands”. In: *Renewable and Sustainable Energy Reviews* 158 (2022), p. 112097.

[64] Michael Schulthoff et al. “Role of hydrogen in a low-carbon electric power system: a case study”. In: *Frontiers in Energy Research* 8 (2021), p. 585461.

[65] Gondia S Seck et al. “Hydrogen and the decarbonization of the energy system in europe in 2050: A detailed model-based analysis”. In: *Renewable and Sustainable Energy Reviews* 167 (2022), p. 112779.

[66] Alessandra Sgobbi et al. “How far away is hydrogen? Its role in the medium and long-term decarbonisation of the European energy system”. In: *international journal of hydrogen energy* 41.1 (2016), pp. 19–35.

[67] Iain Staffell and Stefan Pfenninger. “Using bias-corrected reanalysis to simulate current and future wind power output”. In: *Energy* 114 (2016), pp. 1224–1239.

[68] Statista. *Average carbon price expectations worldwide from 2022 to 2030, by trading system*. Feb. 6, 2023. URL: https://www.statista.com/statistics/1334906/average-carbon-price-projections-worldwide-by-region/.

[69] Strategy. *HyWay 27: hydrogen transport through the existing gas network?* 2021.

[70] TenneT. *Grid Map Onshore Netherlands*. 2023. URL: https://tennet-drupal.s3.eu-central-1.amazonaws.com/default/2023-03/GB_DEC2022_Onshore_Netherlands.pdf.

[71] *The Paris Agreement | UNFCCC*. URL: https://unfccc.int/sites/default/files/english_paris_agreement.pdf.

[72] TNO. *From blue hydrogen to green hydrogen*. URL: https://www.tno.nl/en/technology-science/technologies/blue-hydrogen/.

[73] TNO. *Large-Scale Energy Storage in Salt Caverns and Depleted Fields (LSES) – Project Findings*. 2020.

[74] Tim Tröndle et al. “Trade-offs between geographic scale, cost, and infrastructure requirements for fully renewable electricity in Europe”. In: *Joule* 4.9 (2020), pp. 1929–1948.

[75] Hydrogen Joint Undertaking et al. “Opportunities for Hydrogen Energy Technologies Considering the National Energy & Climate Plans”. In: (2020).

[76] Marta Victoria, Elisabeth Zeyen, and Tom Brown. “Speed of technological transformations required in Europe to achieve different climate goals”. In: *Joule* 6.5 (2022), pp. 1066–1086.

[77] Wikipedia. *NUTS statistical regions of the Netherlands*. 2023. URL: https://en.wikipedia.org/wiki/NUTS_statistical_regions_of_the_Netherlands.

[78] R Yukesh Kannah et al. “Techno-economic assessment of various hydrogen production methods–A review”. In: (2021).

A

Appendix A

A.1. Case Study

Node	Province
NL11	Groningen
NL12	Friesland
NL13	Drenthe
NL21	Overijssel
NL22	Gelderland
NL23	Flevoland
NL31	Utrecht
NL32	North Holland
NL33	South Holland
NL34	Zeeland
NL41	North Brabant
NL42	Limburg

Table A.1: Names of the Dutch provinces in the model according to the NUTS

B

Appendix B

B.1. Technologies and Energy Capacity Installed at System Level in the Base Case scenario

Technology Installed	Energy Capacity Installed System Wide [GW]
CCGT	12.37
Nuclear	0.49
Solar PV	11.11
Onshore wind	4.17
Offshore wind	4.68
New solar PV	20.45
New onshore wind	3.53
New offshore wind	11.13
CCHT	3.27
SMR+CCS	6.82
AEL	4.47
PEMEL	2.35

Table B.1: Technologies and energy capacity installed at system level in the Base Case scenario

B.2. Technologies and Energy Capacity Installed at Node Level in the Base Case scenario

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**	**OFF1**	**OFF2**
Energy Capacity Installed [MW]	CCGT	3601.4	0	128	59	124	1000	472	507	3973	870	49.6	1586	0	0
	Nuclear	0	0	0	0	0	0	0	0	0	485	0	0	0	0
	Solar PV	942.5	701.6	603.4	945.4	483.7	1360.8	593.8	1107.1	1167.8	442.6	1860.2	897.6	0	0
	Onshore wind	618	198	43	66	145	1169	34	642	445	525	259	21	0	0
	Offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	4079.5	600
	New solar PV	857.7	1168.7	47.3	2489.1	3722.5	400.6	1114	1998.5	2025	1336.6	3678.9	1609.9	0	0
	New onshore wind	377.9	541.5	414.9	1.5	2.4	229.8	0.9	432.4	440.2	288.3	798.6	0.5	0	0
	New offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	9536.1	1595.1
	CCHT	0.3	0.4	0.3	0.3	0.3	0.1	0.1	0.5	3267.2	0.4	0.4	0.3	0	0
	SMR+CCS	716.1	0.4	0.4	0.3	0.4	0.2	0.2	378.4	2629.7	2085.7	0.4	1005.5	0	0
	AEL	9.1	0.9	0.6	0.4	0.4	0.3	0.3	4	1452.6	2004	0.4	992	0.3	0.3
	PEMEL	706.6	0.7	0.5	0.3	0.3	0.2	0.2	374	1178.8	79.3	0.3	13	0.3	0.2

Table B.2: Technologies and energy capacity installed at node level in the Base Case scenario

B.3. Storage Technologies and Storage Capacity Installed at System Level in the Base Case scenario

Technology Installed	Storage Capacity Installed System Wide [MWh]
Battery	14
New battery	7348.3
Salt cavern	993.1

Table B.3: Storage technologies and storage capacity installed at system level in the Base Case scenario

B.4. Storage Technologies and Storage Capacity Installed at Node Level

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**
Storage Capacity Installed [MWh]	Battery	0	0	0	0	0	0	0	4	0	10	0	0
	New battery	6.5	529	24.4	1460.7	4215	24.9	188.1	186.5	7.2	5.1	679	21.9
	Salt cavern	310.2	302.3	380.6	0	0	0	0	0	0	0	0	0

Table B.4: Storage technologies and storage capacity installed at node level in the Base Case scenario

C

Appendix C

C.1. Technologies and Energy Capacity Installed at System Level in the DOC

Technology Installed	Energy Capacity Installed System Wide [GW]
CCGT	12.37
Nuclear	0.49
Solar PV	11.11
Onshore wind	4.17
Offshore wind	4.68
New solar PV	21.29
New onshore wind	3.55
New offshore wind	11.53
CCHT	3.24
SMR+CCS	7.93
AEL	5.03
PEMEL	2.51

Table C.1: Technologies and energy capacity installed at system level in the DOC

C.2. Technologies and Energy Capacity Installed at System Level in the DOC

	Technology	NL11	NL12	NL13	NL21	NL22	NL23	NL31	NL32	NL33	NL34	NL41	NL42	OFF1	OFF2
Energy Capacity Installed [MW]	CCGT	3601.4	0	128	59	124	1000	472	507	3973	870	49.6	1586	0	0
	Nuclear	0	0	0	0	0	0	0	0	0	485	0	0	0	0
	Solar PV	942.5	701.6	603.4	945.4	483.7	1360.8	593.8	1107.1	1167.8	442.6	1860.2	897.6	0	0
	Onshore wind	618	198	43	66	145	1169	34	642	445	525	259	21	0	0
	Offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	4079.5	600
	New solar PV	1043.3	1242.5	46	2489	3722.4	985.4	1114	1998.5	2025	1336.6	3678.8	1609.9	0	0
	New onshore wind	377.9	541.5	428.5	2.9	3.9	229.8	1.3	432.4	440.2	288.3	798.6	0.5	0	0
	New offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	9864	1670.3
	CCHT	0.3	0.4	0.3	0.3	0.3	0.1	0.1	0.5	3231.5	0.5	0.5	0.3	0	0
	SMR+CCS	832.2	0.4	0.4	0.3	0.4	0.2	0.2	439.9	3058	2425.2	0.4	1169.2	0	0
	AEL	15.9	1	0.7	0.5	0.4	0.3	0.3	4.4	1842.7	2001.1	0.4	1161.4	0.4	0.3
	PEMEL	816.7	0.9	0.6	0.4	0.3	0.2	0.2	435.1	1217.1	25.7	0.4	7.2	0.3	0.2

Table C.2: Technologies and energy capacity installed at node level in the DOC

C.3. Storage Technologies and Storage Capacity Installed at System Level in the DOC

Technology Installed	Storage Capacity Installed System Wide [MWh]
Battery	14
New battery	7447
Salt cavern	1807

Table C.3: Storage technologies and storage capacity installed at system level in the DOC

C.4. Storage Technologies and Storage Capacity Installed at Node Level in the DOC

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**
Storage Capacity Installed [MWh]	Battery	0	0	0	0	0	0	0	4	0	10	0	0
	New battery	7.5	601.3	28.4	1691.3	3983.2	33	164.1	143.9	8.4	6.1	755.3	24.4
	Salt cavern	752	461.5	593.5	0	0	0	0	0	0	0	0	0

Table C.4: Storage technologies and storage capacity installed at node level in the DOC

D

Appendix D

D.1. Technologies and Energy Capacity Installed at System Level in the DPC

Technology Installed	Energy Capacity Installed System Wide [GW]
CCGT	12.37
Nuclear	0.49
Solar PV	11.11
Onshore wind	4.17
Offshore wind	4.68
New solar PV	19.32
New onshore wind	3.12
New offshore wind	10.62
CCHT	3.32
SMR+CCS	5.55
AEL	3.46
PEMEL	2.09

Table D.1: Technologies and energy capacity installed at system level in the DPC

D.2. Technologies and Energy Capacity Installed at System Level in the DPC

	Technology	NL11	NL12	NL13	NL21	NL22	NL23	NL31	NL32	NL33	NL34	NL41	NL42	OFF1	OFF2
Energy Capacity Installed [MW]	CCGT	3601.4	0	128	59	124	1000	472	507	3973	870	49.6	1586	0	0
	Nuclear	0	0	0	0	0	0	0	0	0	485	0	0	0	0
	Solar PV	942.5	701.6	603.4	945.4	483.7	1360.8	593.8	1107.1	1167.8	442.6	1860.2	897.6	0	0
	Onshore wind	618	198	43	66	145	1169	34	642	445	525	259	21	0	0
	Offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	4079.5	600
	New solar PV	417	840.7	80.5	2489	3722.5	4.2	1114	1998.1	2025	1336.6	3678.9	1609.9	0	0
	New onshore wind	377.9	541.5	8.7	1.3	1.8	229.8	0.8	432.4	440.2	288.3	798.6	0.4	0	0
	New offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	8829.8	1792.1
	CCHT	0.2	0.3	0.3	0.3	0.3	0.1	0.1	0.5	3321.8	0.4	0.4	0.3	0	0
	SMR+CCS	582.4	0.4	0.3	0.3	0.3	0.1	0.1	307.9	2139.2	1696.7	0.3	817.9	0	0
	AEL	7.5	0.8	0.6	0.4	0.4	0.2	0.2	4.4	1228.9	1443.6	0.4	767.2	0.3	0.3
	PEMEL	574.5	0.7	0.5	0.3	0.3	0.2	0.2	303.1	911.9	251	0.3	50.4	0.3	0.2

Table D.2: Technologies and energy capacity installed at node level in the DPC

D.3. Storage Technologies and Storage Capacity Installed at System Level in the DPC

Technology Installed	Storage Capacity Installed System Wide [MWh]
Battery	14
New battery	7197.2
Salt cavern	888.8

Table D.3: Storage technologies and storage capacity installed at system level in the DPC

D.4. Storage Technologies and Storage Capacity Installed at Node Level in the DPC

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**
Storage Capacity Installed [MWh]	Battery	0	0	0	0	0	0	0	4	0	10	0	0
	New battery	6.8	229.3	16.4	1018.6	4414.3	25.5	168.1	175	8.1	5.8	1107.8	21.6
	Salt cavern	242.2	260.9	385.7	0	0	0	0	0	0	0	0	0

Table D.4: Storage technologies and storage capacity installed at node level in the DPC

E

Appendix E

E.1. Technologies and Energy Capacity Installed at System Level in the COC

Technology Installed	Energy Capacity Installed System Wide [GW]
CCGT	12.37
Nuclear	0.49
Solar PV	11.11
Onshore wind	4.17
Offshore wind	4.68
New solar PV	22.55
New onshore wind	3.55
New offshore wind	11.38
CCHT	3.25
SMR+CCS	6.71
AEL	0.03
PEMEL	6.98

Table E.1: Technologies and energy capacity installed at system level in the COC

E.2. Technologies and Energy Capacity Installed at System Level in the COC

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**	**OFF1**	**OFF2**
Energy Capacity Installed [MW]	CCGT	3601.4	0	128	59	124	1000	472	507	3973	870	49.6	1586	0	0
	Nuclear	0	0	0	0	0	0	0	0	0	485	0	0	0	0
	Solar PV	942.5	701.6	603.4	945.4	483.7	1360.8	593.8	1107.1	1167.8	442.6	1860.2	897.6	0	0
	Onshore wind	618	198	43	66	145	1169	34	642	445	525	259	21	0	0
	Offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	4079.5	600
	New solar PV	1304.3	1981.4	234.5	2488.9	3722.2	1058.3	1114	1998.4	2025	1336.5	3678.7	1609.9	0	0
	New onshore wind	377.9	541.5	428	4.2	8	229.7	3	432.4	440.2	288.3	798.6	1.1	0	0
	New offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	9718.1	1661.5
	CCHT	6.7	19.6	16.7	0.9	0.9	0.2	0.2	1.3	3199.6	0.9	0.9	0.6	0	0
	SMR+CCS	604.5	0.3	0.4	0.5	0.5	0.3	0.3	377.3	2629.8	2085.9	0.6	1005.5	0	0
	AEL	2.3	2.2	2.1	1.2	1.2	1.1	1.1	2.4	3.4	4.8	1.1	4.1	1.1	1.1
	PEMEL	835.3	41.5	9.6	1.1	0.9	0.6	0.6	375.8	2629.2	2078.8	0.8	1001.5	0.7	0.7

Table E.2: Technologies and energy capacity installed at node level in the COC

E.3. Storage Technologies and Storage Capacity Installed at System Level in the COC

Technology Installed	Storage Capacity Installed System Wide [MWh]
Battery	14
New battery	7383.9
Salt cavern	149593.9

Table E.3: Storage technologies and storage capacity installed at system level in the COC

E.4. Storage Technologies and Storage Capacity Installed at Node Level in the COC

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**
Storage Capacity Installed [MWh]	Battery	0	0	0	0	0	0	0	4	0	10	0	0
	New battery	18.7	877.2	112	1355.4	3968.5	91.2	184.3	133.8	19.2	11.9	555.4	56.1
	Salt cavern	106447.5	22738.9	20407.5	0	0	0	0	0	0	0	0	0

Table E.4: Storage technologies and storage capacity installed at node level in the COC

F

Appendix F

F.1. Technologies and Energy Capacity Installed at System Level in the CPC

Technology Installed	Energy Capacity Installed System Wide [GW]
CCGT	12.37
Nuclear	0.49
Solar PV	11.11
Onshore wind	4.17
Offshore wind	4.68
New solar PV	19.02
New onshore wind	3.38
New offshore wind	10.87
CCHT	3.3
SMR+CCS	6.82
AEL	6.16
PEMEL	0.01

Table F.1: Technologies and energy capacity installed at system level in the CPC

F.2. Technologies and Energy Capacity Installed at System Level in the CPC

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**	**OFF1**	**OFF2**
Energy Capacity Installed [MW]	CCGT	3601.4	0	128	59	124	1000	472	507	3973	870	49.6	1586	0	0
	Nuclear	0	0	0	0	0	0	0	0	0	485	0	0	0	0
	Solar PV	942.5	701.6	603.4	945.4	483.7	1360.8	593.8	1107.1	1167.8	442.6	1860.2	897.6	0	0
	Onshore wind	618	198	43	66	145	1169	34	642	445	525	259	21	0	0
	Offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	4079.5	600
	New solar PV	433.4	716.7	13	2488.2	3722.4	4.6	1114	1879.8	2025	1336.6	3678.9	1609.9	0	0
	New onshore wind	377.9	541.5	262.4	1.9	3.5	229.8	1.2	432.4	440.2	288.3	798.6	0.5	0	0
	New offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	9092	1773.2
	CCHT	0.3	0.4	0.3	0.3	0.3	0.1	0.1	0.4	3294.2	0.4	0.4	0.3	0	0
	SMR+CCS	716.2	0.4	0.4	0.3	0.4	0.1	0.2	378.3	2629.8	2085.7	0.4	1005.5	0	0
	AEL	714.3	0.9	0.6	0.4	0.4	0.2	0.2	376.8	2630.3	1432.6	0.4	1004.1	0.3	0.2
	PEMEL	1.2	0.5	0.4	0.3	0.3	0.1	0.1	1.2	1.1	0.9	0.3	0.8	0.2	0.2

Table F.2: Technologies and energy capacity installed at node level in the CPC

F.3. Storage Technologies and Storage Capacity Installed at System Level in the CPC

Technology Installed	Storage Capacity Installed System Wide [MWh]
Battery	14
New battery	7286.2
Salt cavern	773.7

Table F.3: Storage technologies and storage capacity installed at system level in the CPC

F.4. Storage Technologies and Storage Capacity Installed at Node Level in the CPC

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**
Storage Capacity Installed [MWh]	Battery	0	0	0	0	0	0	0	4	0	10	0	0
	New battery	8.3	275.4	24.1	1146.4	4114.2	29.9	146.4	247.5	8.9	6.5	1256.4	22.1
	Salt cavern	234.2	240.4	299	0	0	0	0	0	0	0	0	0

Table F.4: Storage technologies and storage capacity installed at node level in the CPC

G

Appendix G

G.1. Technologies and Energy Capacity Installed at System Level in the NBH

Technology Installed	Energy Capacity Installed System Wide [GW]
CCGT	12.37
Nuclear	0.49
Solar PV	11.11
Onshore wind	4.17
Offshore wind	4.68
New solar PV	25.25
New onshore wind	3.26
New offshore wind	18.51
CCHT	3.35
AEL	2.35
PEMEL	6.37

Table G.1: Technologies and energy capacity installed at system level in the NBH

G.2. Technologies and Energy Capacity Installed at System Level in the NBH

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**	**OFF1**	**OFF2**
Energy Capacity Installed [MW]	CCGT	3601.3	0	128	59	124	999.9	472	507	3973	870	49.6	1585.9	0	0
	Nuclear	0	0	0	0	0	0	0	0	0	485	0	0	0	0
	Solar PV	942.5	701.6	603.4	945.4	483.7	1360.8	593.8	1107.1	1167.8	442.6	1860.2	897.6	0	0
	Onshore wind	618	198	43	66	145	1169	34	642	445	525	259	21	0	0
	Offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	4079.5	600
	New solar PV	1742.8	2501.3	1974.2	2488.8	3722.2	1058.6	1113.9	1998.5	2025	1336.4	3678.5	1609.9	0	0
	New onshore wind	377.9	541.5	73	23	29	228.3	15.7	432.4	440	288.1	798.5	8.4	0	0
	New offshore wind	0	0	0	0	0	0	0	0	0	0	0	0	13331.7	5182.8
	CCHT	35	149.6	11.4	3.8	3.2	1.3	1.3	11.6	3119.8	4.3	3.1	1.9	0	0
	AEL	317.6	54.3	78.3	42.2	48.6	4	4	116.6	1571.8	40.2	35.7	29.3	5.2	4.2
	PEMEL	1333.5	181.5	950.1	488.6	105.9	2.6	2.6	634.2	2518.3	66.6	41.4	37.7	4.8	3.2

Table G.2: Technologies and energy capacity installed at node level in the NBH

G.3. Storage Technologies and Storage Capacity Installed at System Level in the NBH

Technology Installed	Storage Capacity Installed System Wide [MWh]
Battery	14
New battery	6214.2
Salt cavern	1599317.2

Table G.3: Storage technologies and storage capacity installed at system level in the NBH

G.4. Storage Technologies and Storage Capacity Installed at Node Level in the NBH

	Technology	**NL11**	**NL12**	**NL13**	**NL21**	**NL22**	**NL23**	**NL31**	**NL32**	**NL33**	**NL34**	**NL41**	**NL42**
Storage Capacity Installed [MWh]	Battery	0	0	0	0	0	0	0	4	0	10	0	0
	New battery	105.7	273.9	135.5	377.2	3095.4	209	205	210.2	108.3	187.2	902	404.8
	Salt cavern	577460.1	346979.2	674877.9	0	0	0	0	0	0	0	0	0

Table G.4: Storage technologies and storage capacity installed at node level in the NBH