North Sea Energy
offshore system integration

6.2

North Sea Energy 2020-2022

Energy System and Market Analysis

North Sea Energy 2020-2022

Unlock the low-carbon energy potential North Sea with optimal value for society and nature

The North Sea Energy program and its consortium partners aim to identify and assess opportunities for synergies between energy sectors offshore. The program aims to integrate all dominant low-carbon energy developments at the North Sea, including: offshore wind deployment, offshore hydrogen infrastructure, carbon capture, transport and storage, energy hubs, energy interconnections, energy storage and more.

Strategic sector coupling and integration of these low-carbon energy developments provides options to reduce CO2 emissions, enable & accelerate the energy transition and reduce costs. The consortium is a public private partnership consisting of a large number of (international) partners and offers new perspectives regarding the technical, environmental, ecological, safety, societal, legal, regulatory and economic feasibility for these options.

In this fourth phase of the program a particular focus has been placed on the identification of North Sea Energy Hubs where system integration projects could be materialized and advanced. This includes system integration technologies strategically connecting infrastructures and services of electricity, hydrogen, natural gas and CO2. A fit-for-purpose strategy plan per hub and short-term development plan has been developed to fast-track system integration projects, such as: offshore hydrogen production, platform electrification, CO2 transport and storage and energy storage.

The multi-disciplinary work lines and themes are further geared towards analyses on the barriers and drivers from the perspective of society, regulatory framework, standards, safety, integrity and reliability and ecology & environment. Synergies for the operation and maintenance for offshore assets in wind and oil and gas sector are identified. And a new online Atlas has been released to showcase the spatial challenges and opportunities on the North Sea. Finally, a system perspective is presented with an assessment of energy system and market dynamics of introducing offshore system integration and offshore hubs in the North Sea region. Insights from all work lines have been integrated in a Roadmap and Action Agenda for offshore system integration at the North Sea.

The last two years of research has yielded a series of 12 reports on system integration on the North Sea. These reports give new insights and perspectives from different knowledge disciplines. It highlights the dynamics, opportunities and barriers we are going to face in the future. We aim that these perspectives and insights help the offshore sectors and governments in speeding-up the transition.

We wish to thank the consortium partners, executive partners and the sounding board. Without the active involvement from all partners that provided technical or financial support, knowledge, critical feedback and positive energy this result would not have been possible.

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1 Executive Summary

In order to help identify and assess opportunities and challenges of an offshore integrated energy system, an understanding of the surrounding international energy system and market is necessary. This report presents an analysis of the energy system and market dynamics of the North Sea region and the techno-economic potential of an offshore integrated energy system placed within this market.

To analyse the market dynamics of this energy system, an integrated electricity, hydrogen and methane cost-optimisation model (I-ELGAS) is deployed. The resulting lowest marginal cost commodity prices for the three energy carriers, as well as hourly dispatch throughout the year, can be used to investigate the market performance of an integrated offshore system, as well as provide context of future market developments in which it would operate. This report offers insights into future opportunities and hurdles to overcome for this offshore system development in support of hub design and the roadmap for offshore system development.

In an effort to provide data for the model to evaluate a future energy system, a scenario base was constructed based on, inter alia, the European grid operator's Ten-Year Network Development Plan (TYNDP), in combination with a more detailed Dutch Scenarios from II3050 reporting. This resulted in a scenario base of two scenarios, dubbed Distributed Energy (DE) and Global Ambition (GA) similar to the TYNDP nomenclature, providing two general directions of the European energy system to develop. The contrasts in deployment of electrons vs. molecules, installed solar and wind capacity, and electrolysis and SMR capacity, will provide insight in the influences of these factors on the overall - and the offshore energy system. A third energy system scenario that was based on recent REPowerEU plans for the transformation of the energy system away from dependency on Russian gas supply was developed in the final stages of the project, in order to account for the unprecedented shift in the energy system outlook caused by recent events. Liquid hydrogen (LH_2) and natural gas (LNG) shipping routes were proposed and their influence on the European energy system assessed. Though heavily dependent on the cost assumption of these shipping routes, the results show a transformation of hydrogen and gas markets away from local supply of green gas from biomass and electrolysis, towards a dependency on cost-competitive shipping imports.

The three scenarios offer a very wide range of possible future system developments as an outlook. Nevertheless, the assessment shows that a balanced energy system development, that maintains system integrity across the newly developing energy supply chains, is the dominant factor in market development that allows for profitable investments across the supply chain. The results show the importance of timely establishment of a vision on balanced national energy system development, with a clear view on balanced development across all segments of the energy system supply chains in roadmap development and the design of energy policies to move from vision to practice.

A more detailed description in the model of the integrated offshore energy hubs described in WP1, was added to the market model. Offshore wind production and electrolysis on hubs were modelled explicitly, and the resulting market prices and dispatch were presented. The prices of all three energy carriers are significantly lower in the pricing zones of the offshore energy hubs, as well as in the surrounding countries, compared to the case without hubs. Additionally, limiting the electricity transport capacity from the hubs can increase the amount of full load hours of the electrolysers on the hubs, while bi-directional electricity transport can allow the offshore electrolysers to produce hydrogen during hours in which (onshore) solar energy is more available than wind.

2 Introduction

The overarching goal of the North Sea Energy (NSE) program is to identify and assess synergies in low-carbon offshore energy system development.

This report presents an assessment of the energy system - and market dynamics of offshore system integration concepts covering offshore wind energy, coupled hydrogen production and transport infrastructure in integrated offshore hubs as introduced in NSE WP 1 (Energy Hubs and Transport Infrastructure) in context of Northwestern European energy system developments. This analysis provides system and market context and associated system dispatch and commodity pricing for NSE WP 1 (Energy Hubs and Transport Infrastructure) which, in turn, ties into the hub action plan development (WP7) in this project. The analysis also builds on early integral energy system modelling with OPERA that was undertaken in the 3rd phase of NSE to assess the role and value of offshore system integration options in the longer term energy system with a particular focus on offshore hydrogen production and the role of Carbon Capture and Storage (CCS) in North Sea offshore system development.[1]

A detailed assessment of the energy system and market embedding of the offshore system integration concepts and scenarios within the context of a transforming onshore electricity system and market is required to establish an understanding of the impact on system and market dynamics. Rapidly increasing levels of wind power and hydrogen production at the North Sea (and subsequent transport, conversion, storage, and deployment) will have both a system impact (i.e. transport and balancing of supply and demand on differing time scales in the Netherlands and Northwestern Europe at large), as well as a related market impact (i.e. energy commodity pricing). Yet, such would tie into a transforming (or transitioning) onshore energy system in Northwestern Europe. Hence, both development of onshore wind and solar-PV as well as parallel developments in electrification of (low- and medium temperature) heat demand in industry, in mobility and low temperature heat demand in the residential sector will be critical determinants for system- and market integration. Accordingly, development of any onshore hydrogen infrastructure and hydrogen deployment may provide for an alternative molecular route for offshore wind energy into the onshore system and markets.

[1] https://north-sea-energy.eu/static/99d902fd4445c6c7c608f22d80b0a42f/12.-FINAL-NSE3-D1.1-D1.2-Report-analyzing-the-value-of-this-technology-option-in-relation-to-alternatives-and-factsheet.pdf

3 Integral Energy Market Analysis

This work package covers an assessment of the integral energy system and market dynamics of offshore system integration concepts in the context of a Northwestern European power and gas (including future hydrogen) market scenarios. While it provides explicit dispatch profiles and commodity pricing in support of NSE WP 1 (Energy Hubs and Transport Infrastructure), it also provides guidelines regarding system and market development in support of NSE WP 7 the roadmap and action plan development.

The analysis provides insights on future energy system design and associated questions like:

- What are the main drivers for energy system development from now until 2050?
- What is the impact of the rapid transformation away from dependency on Russian gas supply, and the corresponding REPowerEU plan published by the European Commission?
- What are critical system developments for the business case of new supply chain segments?
- What is the impact of offshore system integration concepts on energy system and market dynamics?
- What are critical settings in offshore system integration concepts for conceptual design?

To this end, a previously developed I-ELGAS energy market model (TNO, 2021) is deployed. The model covers an integrated electricity -, methane - and hydrogen system model, resulting in the full hourly electricity, methane and hydrogen system allocation and resulting commodity prices. As such, this model extends the classic power market analysis with the closely related future methane – and hydrogen market and system, covering hourly production, conversion, storage and demand for the three commodities in the Northwestern European countries. Scenario development for the onshore system is largely based on long-term system scenarios developed by the network operators in Northwestern Europe, covering the Netherlands and neighbouring North Sea countries (Germany, Denmark, Sweden, Norway, UK, Ireland, Belgium, France). As such, this analysis includes a detailed perspective on the onshore hydrogen system and - market development that may both drive as well as hamper the value of offshore hydrogen production and hybrid offshore system development at large.

4 Methodology

4.1 Data Collection

In order to extend the energy system and market model I-ELGAS to other North Sea countries, energy system and scenario data needs to be collected. Energy system representation covers the current power and natural gas energy system for the Northwestern European energy system, and is based on the existing input information from TNO's power system model (COMPETES)[2] and TNO's natural gas market model (GASTALE), each covering current and future energy system covering supply, transport, storage and conversion and hourly energy demand for electricity and natural gas respectively. Additional resources on energy system development and hydrogen system development for scenario development are covered in this phase as well, notably with regard to the European Union at wide, as well as the individual Northwestern European countries.

The foundations of energy system scenario development is built largely on energy system scenario's developed (or commissioned) by the national grid operators (TenneT/Gasunie/iNET in the Netherlands, ENTSO-E/ENTSO-G for neighbouring countries). Additional information on notably hydrogen strategies for the individual neighbouring countries is considered as well. Table 1 gives a content overview of the data currently covered in the desk research.

Table 1 Overview of part of the information resources reviewed for energy system scenario development

Theme	EU	Netherlands	Germany	Denmark	Norway	United Kingdom	Belgium	France
Network development	(ENTSO-E, 2018), (ENTSO-E/ENTSO-G, 2020)	(TenneT & GTS, 2019), (Berenschot & Kalavasta, 2020)	(ENTSO-E, 2018), (ENTSO-E/ENTSO-G, 2020)	(ENTSO-E, 2018), (ENTSO-E/ENTSO-G, 2020)	(ENTSO-E, 2018), (ENTSO-E/ENTSO-G, 2020)	(ENTSO-E, 2018), (ENTSO-E/ENTSO-G, 2020)	(ENTSO-E, 2018), (ENTSO-E/ENTSO-G, 2020)	(ENTSO-E, 2018), (ENTSO-E/ENTSO-G, 2020)
Hydrogen strategies	(European Commission, 2020), (European Commission, 2020)	(Klimaatakkoord, 2019), (Ministerie van Economische Zaken & Klimaat, 2020)	(bmwi, 2020)	e(Energinet, 2019)	(Norwegian Government, 2020)	(Department for Business, Energy & Industrial Strategy, 2021)	(WaterstofNet & Hinicio, 2018)	(Gouvernement de France, 2020)

4.2 Geographical System Representation

After initial data collection, base model development is initiated. For the Netherlands a detailed regional energy system was established covering some 35 regional nodes for power, 25 nodes for natural gas and 19 nodes for hydrogen as laid down in the Dutch energy infrastructure studies commissioned/carried out by the Dutch grid operators (TenneT & GTS, 2019) (Berenschot & Kalavasta, 2020).

The energy system representation was extended from the existing Dutch system representation to the full Northwestern European energy system coverage (i.e. inclusion of Germany, Denmark, Sweden, Norway, UK, Ireland, Belgium, and France). The system extension established a nodal representation of the energy markets in the Northwestern European countries, covering both the power and natural gas

[2] https://www.pbl.nl/modellen/kev-rekensysteem-competes

energy systems (supply, transport, storage, conversion, demand) based on existing energy system information available from ENTSO-E and ENTSO-G.

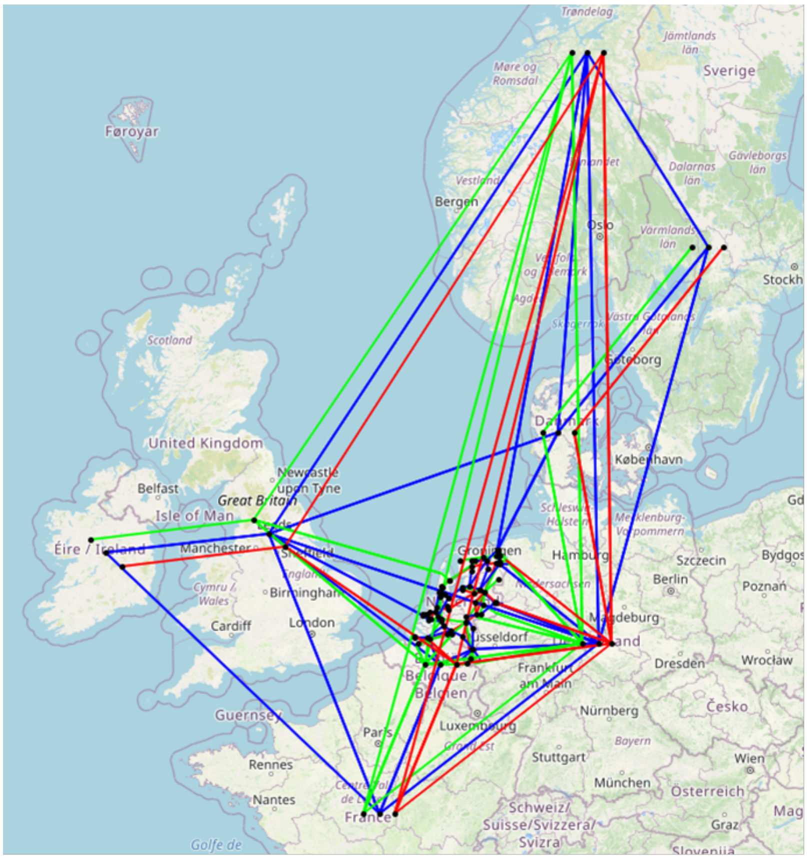


Figure 1 nodal representation of the geographical extension of the model (electricity in blue, natural gas in green and hydrogen in red)

4.3 Energy System Scenario Development

Once the base model is established, scenario development is initiated. Here, the energy scenarios for the Dutch and neighbouring markets were cross-validated against alternate information resources on notably hydrogen system development indicated in Table 1. Further initial system runs are performed in order to assess internal consistency of energy system scenarios, as it should be expected that the Dutch and Northwestern European scenario resources do not necessarily match. At large, the scenarios from these resources typically span system development across the dimension decentralized – centralized vs. electrons – molecules, but supply and demand balances as well as renewable energy resources vs. conversion resources in combination with assumed transport and storage capacities/facilities may result in imbalances and energy pricing that is not consistent with the assumed investments. Here, adjustments in scenario assumptions on notably renewable energy supply, conversion from electricity to hydrogen and cross-border (XB) transport capacities is explored through perturbation analysis to establish internally consistent energy system scenarios for 2030 and 2050. In the appendix of this report, a first sensitivity analysis on renewable electricity production capacity and electrolyser capacity is presented.

The resulting energy system scenarios were discussed in a plenary energy system scenario workshop, and an overview of intermediate results is presented in this report. In the next phase, the energy system scenarios will be geared to span the bandwidth of the main driving scenario dimensions of relevancy to future offshore hybrid system development.

4.3.1 Baseline Scenarios

The Dutch energy system scenario elements were based on the scenarios developed for II3050 of the Dutch network operators (Berenschot & Kalavasta, 2020). The Dutch scenario dimensions largely span the dimensions of import dependency and the balance between electrons and molecules, where the latter correlates with the balance between decentralized vs. centralized system development:

- **Regional:** low import dependency, strong (distributed) regional development, electricity rich, high level of (distributed) regional system development
- **National:** limited import dependency, hydrogen richer, high level of national development
- **European:** intermediate import, rich in gasses and CCS dependency, high level of national development
- **International:** high import dependency, rich in (import) gasses, high level of national development

Only the national and International scenarios were selected for implementation in I-ELGAS. The regional scenario shows strong decline in industrial activity as an additional feature. Such feature significantly affects overall energy demand, and the need for offshore system development. The European scenario shows strong correspondence with the international scenario, but assumes higher import levels for the EU, rather than international import.

The scenario elements for the other Northwestern European countries were based on the energy system scenarios developed by the European network operators (ENTSO-E/ENTSO-G, 2020). These scenarios were designed to span the balance between centralized and decentralized energy system development, correlating with the balance between molecules and electrons:

- **Global Ambition (GA):** centralized generation, offshore wind and Power-to-X, but also imports
- **Distributed Energy (DE):** de-centralised approach with small scale solutions and circularity approaches.

The base scenarios developed for I-ELGAS combine two scenario-sets from these studies. the National Scenario from II3050 is combined with the Distributed Energy scenario from TYNDP. The International Scenario from II3050 is combined with the Global Ambition scenario from TYNDP. These scenarios were paired as the combined sets correlate in nature and offered complete data for 2030, 2040 and 2050, where all scenarios are climate neutral by 2050.

In addition, the constructed scenarios were enriched with national hydrogen targets from the North Sea countries in Table 1. Nearly all these countries, with the exception of Belgium and United Kingdom (expected in 2021), have developed national hydrogen strategy covering the period up to 2050.These national targets typically target the development of electrolyser capacities for 2030 and beyond. In addition, these countries have developed a vision on the role that hydrogen should play in their long-term energy strategies and their ambitions to transform their respective energy system.

These national strategies and ambitions have many common elements. Belgium, Germany, Netherlands and the United Kingdom aim to develop both domestic capacities and import capabilities while Norway and Denmark and pursue a strategy to expand domestic capacity and export to neighbouring countries. This indicates countries will depend on each other to achieve their hydrogen ambition and targets. The objectives further seek to lower the production costs of low-carbon hydrogen and the deployment at a large scale of low carbon hydrogen technologies. To meet these objectives, governments are developing conducive policies. Review of policies targeted to low- carbon hydrogen (see Midterm Report WP2) shows growing R&D priorities and supporting mechanisms for new hydrogen projects.

Combining the II3050 and TYNDP scenarios, the base line energy system scenarios developed for this first stage of the study may be characterized as laid out in Table 2.

Table 2 Baseline energy system scenario construction

	Global Ambition (GA)		Distributed Energy (DE)	
	NL (95 nodes)	NSE (8+ nodes)	NL (95 nodes)	NSE (8+ nodes)
2030	Clim. Agreement (II3050)	GA 2030 (TYNDP)	Clim. Agreement (II3050)	DE 2030 (TYNDP)
2040	GA 2040 (TYNDP)	GA 2040 (TYNDP)	DE 2040 (TYNDP)	DE 2040 (TYNDP)
2050	International (II3050)	GA 2050 (TYNDP)	National (II3050)	DE 2050 (TYNDP)

Abbreviations: NL: Netherlands, NSE: North Sea Countries

Note: in various instances only volumes are reported in TYNDP (Auto-thermal reformer or ATR, import, production volume)

- In case volumes are reported; these are used to scale capacities
- In case of wind/solar, capacities were reported
- For 2030 electrolyser capacities, country targets (see midterm report WP2) are used for both scenarios.

4.3.2 Baseline Scenario Drivers

The I-ELGAS energy system- and market model is predominantly driven by the energy demand in the baseline energy system scenarios. These scenarios specify the balance between future demand for electrons vs. molecules. These scenarios drive conversion of electricity into hydrogen (power2gas): the higher the demand for molecules, the higher the resulting price of hydrogen (and electricity to source that through P2G).

In addition, the model is driven by the input scenario assumptions regarding installed capacities for solar-PV and wind. With increasing levels of these variable renewable energy sources (vRES), the supply of electricity is increased, lowering prices for electricity (part of which is increasingly converted into hydrogen at cost of blue hydrogen production).

Finally, scenario assumptions regard the conversion capacity (i.e. electrolyser capacity and ATR capacity) will be an important driver for the simulation results. Increasing levels of conversion capacity will increase the opportunity to capture low-cost electricity. Accordingly, higher levels of blue hydrogen production will be displaced by green hydrogen production.

These three input scenario-drivers as laid down in the baseline scenarios are presented in this section.

Electrons vs. molecules

Figure 2 illustrates these balances for the Netherlands (left-hand side) and the NSE region as a whole (right-hand side). Both figures present the input assumptions on the yearly energy demand volumes for electricity, methane and hydrogen for the two baseline scenarios in TWh. Overall, a transition towards increasing levels of electrons and hydrogen is presented for the Netherlands and the NSE region in both baseline scenarios. The Global Ambition (GA) Scenario is richer in molecules, while the Distributed Energy

Scenario is richer in electrons. More specifically, in 2040 and 2050 shows higher demand growth for hydrogen and lower demand decline for methane in the Global Ambition Scenario than in the Distributed Energy Scenario.

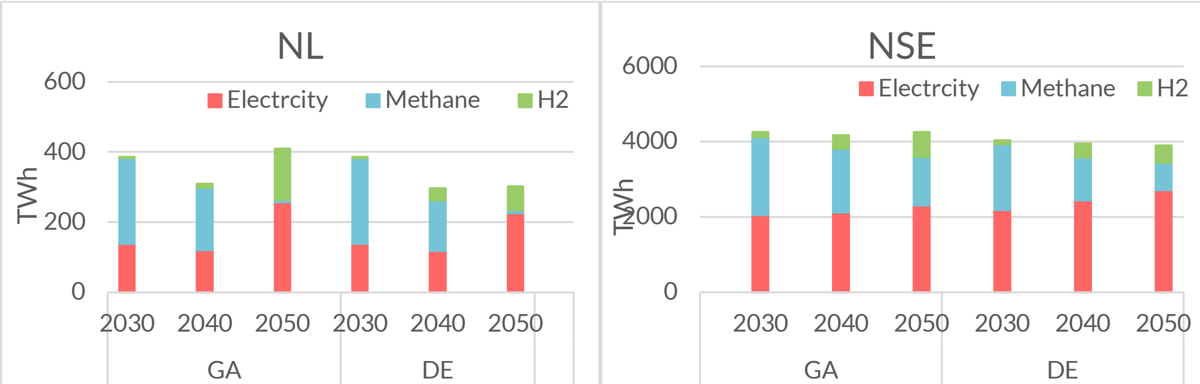


Figure 2 Electricity, hydrogen (LHV) and methane (LHV) demand of NL and NSE countries for GA and DE scenarios (excl. demand for bunker fuels).

Solar & Wind Capacity

The solar and (onshore and offshore) wind capacity assumptions in the two baseline scenarios are laid out in Figure 3. Here, the assumed capacity development for 2030, 2040 and 2050 is reported for both the baseline scenarios in the North Sea countries (left-hand side) and the EU28 as a whole for reference. Clearly, the assumptions for the Distributed Energy Scenario shows significantly higher total vRES capacity (some 50% more capacity in 2050). This aligns with the significantly higher methane deployment in the Global Ambition Scenario.

In addition, the Global Ambition Scenario assumes a slightly higher proportion of wind capacity, while the Distributed Energy Scenario considers a higher solar PV capacity proportion of vRES. These assumptions may drive seasonal storage or export results, as an indicative 45%-55% volume balance of solar-wind minimizes the seasonal balancing needs.

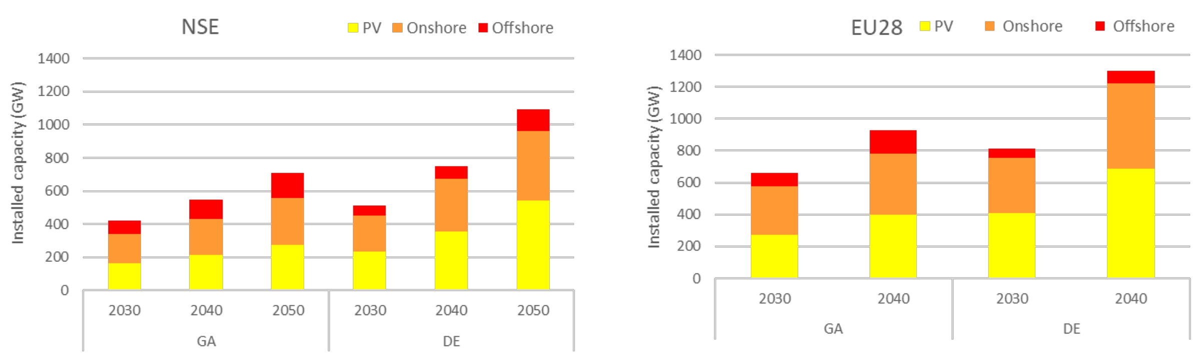


Figure 3 Solar and Wind capacities of NSE countries and EU27+ UK

Electrolyser & ATR Capacity

The electrolyser and ATR capacity assumptions in the two baseline scenarios are presented in Figure 4. Here, conversion capacity is reported for the Netherlands (left-hand side) and the North Sea countries (right-hand side). In both scenarios the overall conversion capacity increases over the years 2030, 2040 and 2050. Further, conversion capacity is lower for the Global Ambition Scenario, than for the Distributed Energy Scenario. In line with the storyline, much of the electricity is expected to be converted to produce green hydrogen in the Distributed Energy Scenario.

In case of the Dutch Global Ambition Scenario, the growing conversion capacity shows roughly a 50/50 proportion of ATR/CCS capacity vs. electrolyser capacity for 2030 and 2040, while replacing ATR/CCS capacity almost completely with electrolysers by 2050. The Distributed Energy Scenario for the Netherlands shows an aggressive growth of conversion capacity that virtually completely consists of electrolyser capacity. The Dutch installed electrolyser capacity is expected to double every decade in the Global Ambition Scenario, where as in the case of the Distributed Energy Scenario it is expected to grow by a factor of three or more every decade.

For the North Sea countries, conversion capacity is built up with both electrolyser capacity and ATR/CCS capacity, be it with higher proportions of electrolyser capacity in the Distributed Energy Scenario. The ATR/CCS capacity in the Global Ambition Scenario is relatively high and implies high levels of CCS. Jointly with post-combustion CCS, overall CCS assumptions measure up to some 500 Mt of CO_2 in the EU annually in 2050.

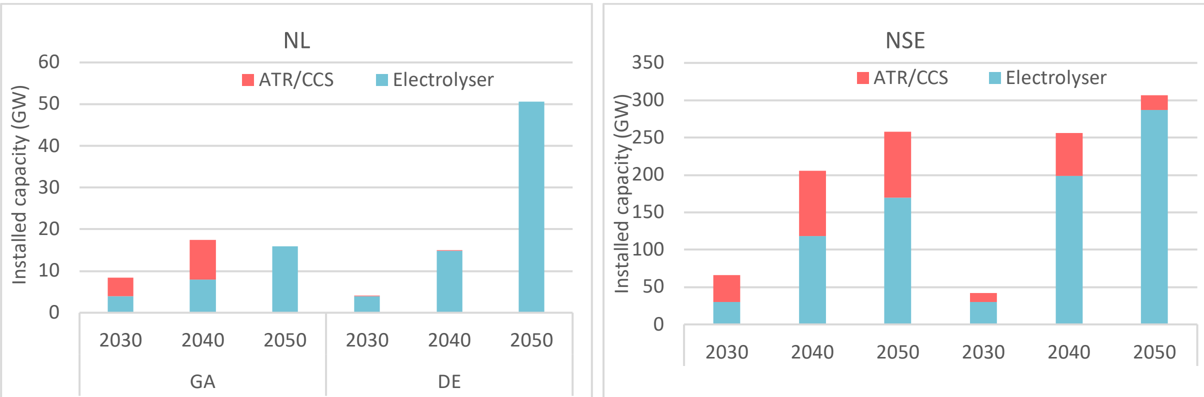


Figure 4 Installed electrolyser (in GW_e) and natural gas reformer capacity (in GW_{ch})assumptions for NL and NSE countries

4.3.3 REPowerEU Scenario Variant

Scenario Overview

In the final stage of the project, the previously introduced energy system scenarios were discredited by an unprecedented disruption of the global energy market, caused by Russia's invasion of Ukraine. To bring this turn of events into scope, an additional energy system scenario was developed. The scenario builds on the response of the European Union, presenting the REPowerEU plan. In involves a transformation of the European energy system which aims to solve both the problem of the EU's dependency on Russian natural gas, as well as tackling the climate crisis. As the North Sea area and deployment of its offshore assets are heavily affected by the design of the European energy system, these changes to the existing scenarios were analysed with energy market simulations, resulting in different configurations of the methane and hydrogen systems.

The REPowerEU scenario is constructed as an amendment of the previously described Global Ambition Scenario. Since this Scenario is more reliant on both methane and hydrogen, it requires a more extreme shift to replace Russian gas supply.

In its REPowerEU proposal, the European Commission aims to replace a large part of the Russian supply with LNG and 10 Mt of hydrogen imports by 2030 (European Commission, 2022). These two import routes, outlined below, were added to the GA scenario and the methane supply from Russia was set to zero.

Additionally, blue hydrogen production capacities were updated to recent developments. For the Netherlands, Belgium, the United Kingdom, Germany and Norway, capacities were updated to the most recent plans published by their respective governments. The export capacity of hydrogen by pipeline to the Netherlands and Germany was increased for Norway.

LNG Import Route

The constructed LNG import route assumes additional LNG supply from the United States, as it leads global liquefaction capacity additions, contributing 70% of the total global additions during 2022-2026 (GlobalData, May 18, 2022). The LNG is assumed to be shipped by LNG tankers to five countries in the North Sea region: the Netherlands, Germany, Belgium, France and the United Kingdom. The hourly export capacity is scaled to US plans of increasing the amount of LNG export terminals, which totals 280 bcm yearly (U.S. Energy Information Administration (EIA), 2022). The import capacity is taken from plans of European countries to expand their LNG import terminals, resulting in a possible total of 190 bcm of yearly LNG imports (Gas LNG Europe, 2019), some 100 bcm of which involved LNG import terminals in de NSE region.[3]

The associated costs of imported LNG are composed of local production costs, transport costs and liquefaction and gasification costs. The assumed production costs of American gas are €30,- /MWh, based on recent gas price averages in the United States. Transport costs amount to €3,30 /kcm/1000km, liquefaction and gasification discounted investments costs amount to €35,- and €12,- /kcm/day, respectively.

LH_2 Import Route

Additionally, a hydrogen import route was established. Compared to the LNG market, less concrete plans for export and import terminals are available, but a rough estimate of import and export capacities can be made. Future contenders for export chains of hydrogen produced from renewable energy sources are countries with potential for high full load hours of electrolysers due to their large amount of available renewable energy throughout the year (e.g. Australia, Chile, Tunisia) (TNO, 2022).

Morocco is chosen here as a test case due to its abundance of solar and wind energy, rapid electrification and relatively short distance to the North Sea region (CE Delft, 2018). The export capacity from Morocco was based on the 10 Mt REPowerEU target for European hydrogen imports as a proxi for low cost hydrogen imports. Scaled to the share of natural gas demand that the North Sea region has of total European demand, 4.5 of these 10 Mt of hydrogen import was set as a yearly import capacity, resulting in an hourly export capacity of 35 GW. Import capacity is evenly distributed between the United Kingdom and the Netherlands. Ammonia as an energy carrier for seaborne imports has been assessed by form of a sensitivity analysis, resulting in slightly lower import costs and associated market pricing (See also Appendix A).

Costs include CAPEX and OPEX of electricity production in solar and wind farms, assumed at €1,41 /kg H2 (IEA, 2019). Hydrogen is then produced through PEM electrolysis with an efficiency of 77%, where

[3] The projected capacity expansions match Russian gas imports for the region that totalled 95 bcm in 2020, see also Statistics | Eurostat (europa.eu).

marginal costs of electrolysis are not included to provide a fair comparison with electrolysis in the I-ELGAS model. No costs for domestic transport are included. At the export terminal, costs of liquefaction and storage buffer tanks amount to €0,69 /kg H2 (IEA, 2019). Fuel, boil-off and flash rate losses are included in the effective capacity of the ships, resulting in final round-trip costs for shipping of €0,05 /kg H2. Finally, import terminal costs include buffers with a capacity of 5% of the total yearly hydrogen demand in the import countries and hinterlands, which cost €0,34/kgh2. Gasification costs are not included. The total cost of imported hydrogen equals €2,49 /kg H2. A more detailed description of the LH_2 import route, including cost assumptions and a sensitivity analysis, can be found in the Appendix.

4.4 Offshore Hub Scenario Development

Additionally, the dynamics of offshore hubs in the North Sea were modelled. A selection of the hubs designed in WP1, consisting of a hub in the North, East and West of the North Sea, were added to the previously modelled North Sea countries scenario, to investigate price behaviour, hydrogen dispatch and energy transport. The hub scenario analysed, 'Integrated Hubs 3' is one of many configurations of hubs with different installed capacities and interconnections, and was chosen due to its high production of hydrogen. The hub configuration is shown in Figure 5.

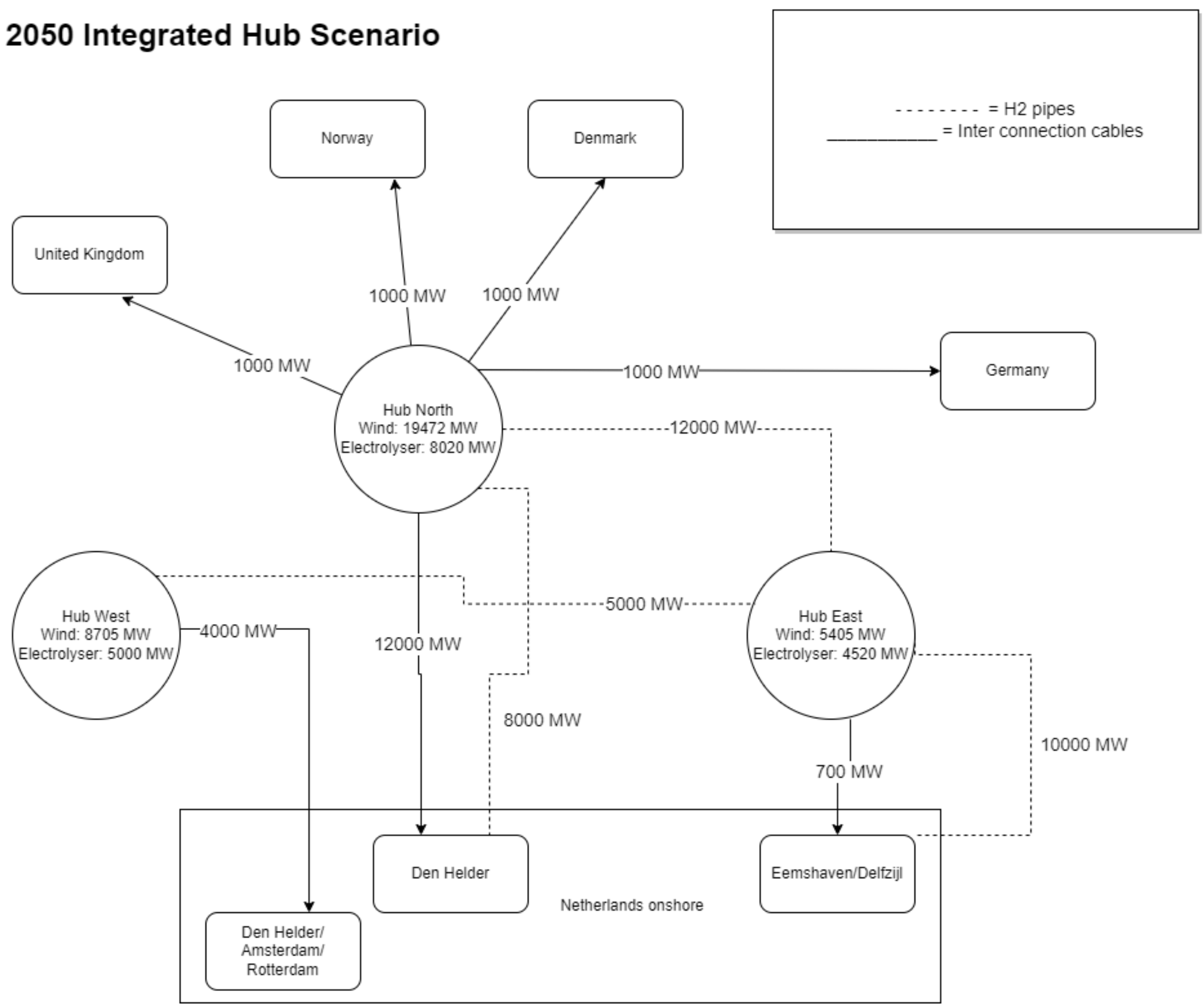


Figure 5. Overview of the offshore hub system as modelled in I-ELGAS.

Notable is that in this configuration, there is a relatively small (700 MW) electricity connection from Hub East to the Netherlands, and only a hydrogen pipeline connection exists between the hubs.

The hubs were added as nodes to the previously modelled DE and GA scenarios, as well as the additional REPowerEU Scenario, with wind and electrolysis capacities as seen in Figure 5. As the existing scenarios already included Dutch electrolysers and wind farms, the hub capacities were subtracted from the Netherlands node, which continued to operate separately.

5 Simulation Results

This Chapter presents the simulations results for the scenarios presented in the previous Chapter. First, the results for the Baseline Scenarios will be presented, followed by results for the REPowerEU Scenario, to conclude with the offshore energy hub analysis.

5.1 Baseline Simulation Results

This section presents the results from the analysis of the original baselines, i.e. the Global Ambition - and the Distributed Energy Scenario. First, system allocation is presented in the form of the systemwide yearly electricity balance and hydrogen balance for the North Sea countries in 2030, 2040 and 2050. The energy balances are followed by a series of results for cross-sectoral exchanges, and further aspects of hydrogen production and hydrogen storage by 2050. Finally, the system allocation characteristics are followed by the resulting hourly commodity prices and annual price characteristics by form of box plots.

5.1.1 Energy Balances

The integrated energy market model provides hourly energy balances for electricity, hydrogen and methane at respective geographical markets. As a first overview of the baseline scenario results, the yearly electricity and hydrogen balances for each of the North Sea countries is presented in this section.

Electricity Balance

The annual electricity balances resulting from the model simulations based on the baseline scenarios are illustrated in

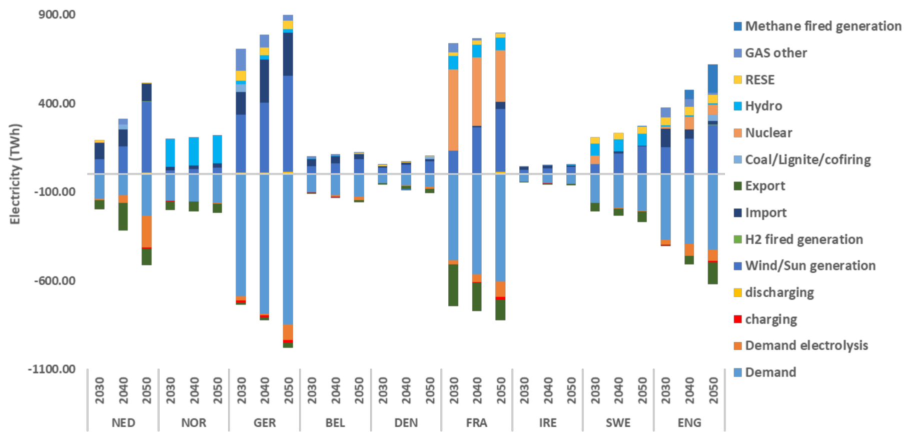


Figure 6, with results for the Global Ambition scenario (top) and the Distributed Energy scenario (bottom). The figure covers the national electricity balances and exchanges among the NSE countries.

The Global Ambition scenario shows increasing levels of wind & solar and electricity imports for supply in the Netherlands, while also showing high levels of export on top of fixed demand. Only little demand for electrolysis results in this scenario for the Netherlands. Other countries in the North Sea region reflect current characteristics in future supply. The French market, for example, shows high levels of nuclear power for historic reasons, complemented with (typically flexible) hydro power and relatively low levels of wind and solar in the early stage in 2030. Yet, wind and solar are set out to be on the rise in this scenario for France, partially displacing the existing nuclear power production. The UK market shows more moderate levels of nuclear power production, compensated by higher levels of wind and solar in the effort to reduce CO_2-emissions. The German market shows both relatively high as well as steadily increasing levels of wind and solar, displacing coal and lignite by 2040, and complemented by significant proportions of imports.

For the Distributed Energy scenario fixed demand levels are typically higher across the board. In addition, in several instances additional levels of electricity demand for electrolysis results, for periods of low electricity pricing when high levels of wind and solar production occur. Accordingly, overall Dutch demand in this scenario is higher, with a notable contribution from electrolysis in each of the major electricity markets (i.e. in NL, FR, UK, and DE). In terms of supply, higher levels of wind & solar, complemented with proportionally lower electricity imports results for supply Netherlands. The French market shows high levels of nuclear power balanced with limited levels of hydro power in this scenario as well, but displacement by increasing levels of wind and solar takes a steeper pace. Such is also the case for the German market in this scenario, with high and increasing levels of wind and solar that displaced coal and lignite already by 2030, and again complemented by significant proportions of imports. Recent developments in German energy policy, with the new Climate Action Law, seeking to bring the deadline for achieving climate neutrality forward, suggest that such development is becoming more likely to unfold.

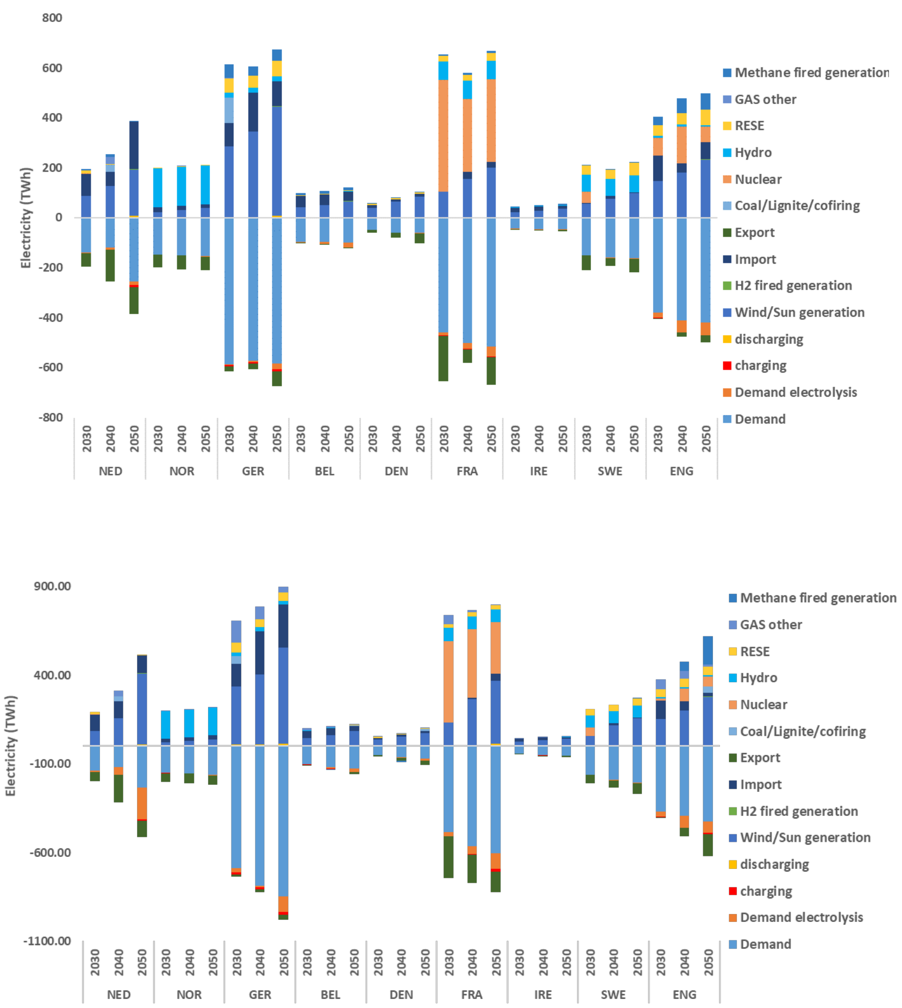
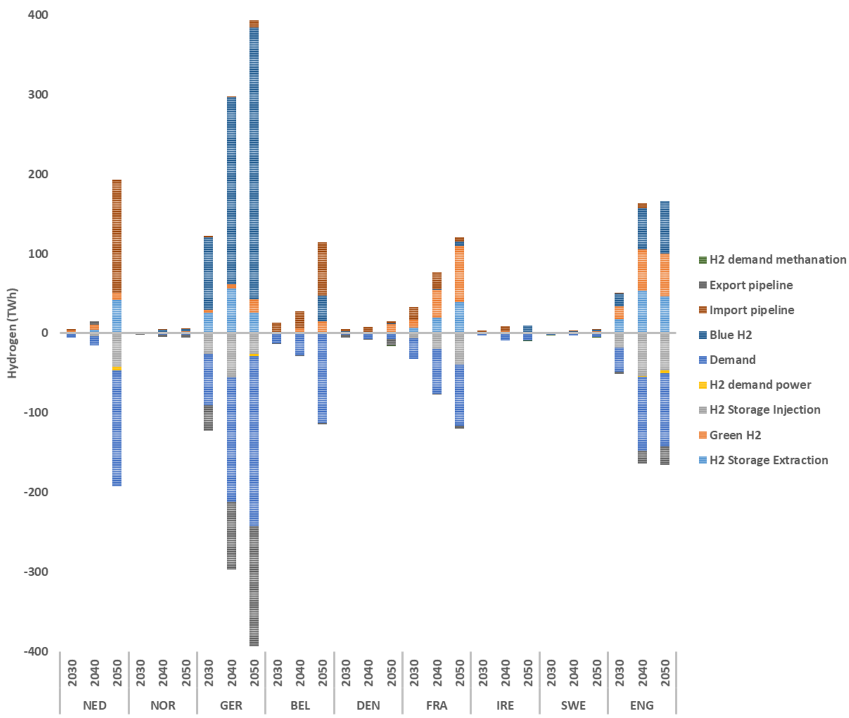


Figure 6 Annual electricity balance of NSE countries under GA (top) and DE (bottom) scenarios

Hydrogen Balance

The annual hydrogen balances resulting from the model simulations based on the baseline scenarios are illustrated in Figure 7 with results for the Global Ambition scenario (top) and the Distributed Energy scenario (bottom).

The Global Ambition scenario shows limited hydrogen market (both supply and demand) development in 2030 and 2040 in the Netherlands, while by 2050 the scenario results in high levels of hydrogen imports, reflecting the high import dependency assumed in the underlying 'International' scenario in II3050. In this case Dutch storage facilities are deployed for flexibility provision. The Dutch imports are predominantly originating from Germany, with high levels of blue hydrogen production based on natural gas imports from Russia. This is predominantly a result of the assumptions regarding high CCS capacity in Germany and limited blue hydrogen production capacity in the Netherlands, as laid down in the scenario's set-up by ENTSO-e/ENSTO-g. In this resulting simulation, Germany unfolds as a mayor export country for blue hydrogen. France and the UK show more moderate levels of domestic hydrogen production, predominantly based on electrolysis or a balanced portfolio of blue and green hydrogen production respectively.



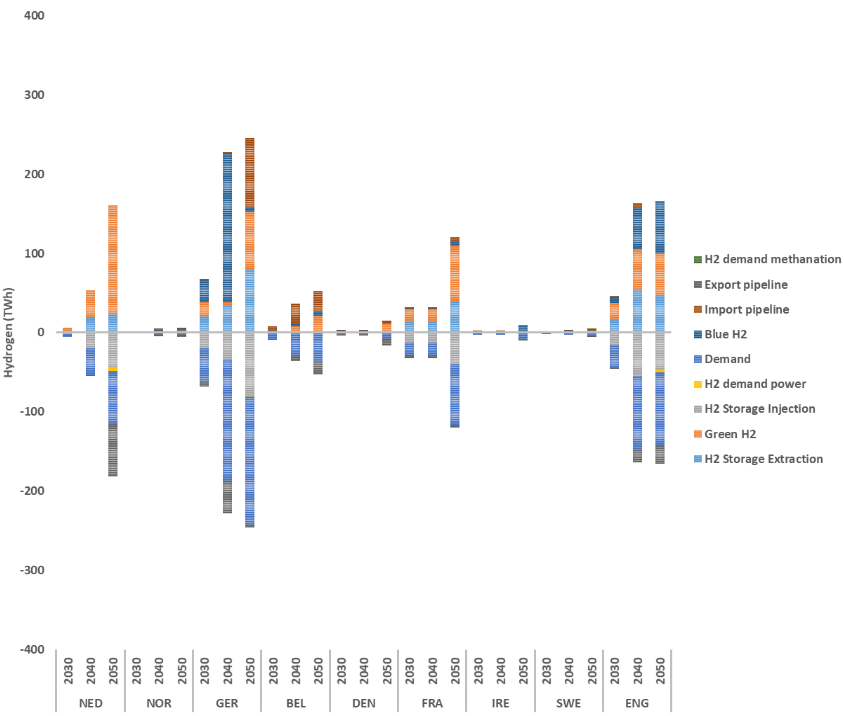


Figure 7 Annual hydrogen balance of NSE countries under GA (top) and DE (bottom) scenarios

For the Distributed Energy scenario much higher levels of green hydrogen production result, with high production levels in the Netherlands. In this case German hydrogen production sets in with high levels of blue hydrogen production, but is offset by green hydrogen production by 2050. By that time, part of German hydrogen demand is sourced through imports from the Netherlands and Norway. In this scenario, France and the UK largely fulfil national hydrogen with domestic production. Here, the proportionality of green and blue hydrogen production is comparable with de Global Ambition scenario.

5.1.2 System Allocation

In Figure 8Figure 8 the exchanges between the three sub-systems for 2050 are presented. On the left-hand side, conversion volumes for green hydrogen production (electricity to H_2), hydrogen-fired electricity production (H_2 to power), blue hydrogen production (methane to H_2), natural gas-fired hydrogen production (methane to power), and methanation (hydrogen to methane) for the results for the North Sea countries in the Global Ambition scenario in 2050 is presented, while the graph on the right-hand presents the results for North Sea countries in the Distributed Energy scenario in 2050.

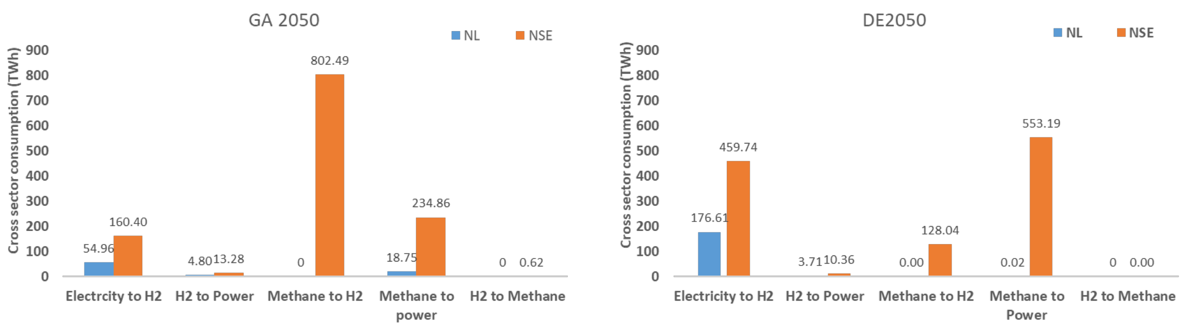


Figure 8 Cross-sectoral utilization in 2050 for the GA scenario (left) and the DE scenario (right)

Regarding the balance between blue and green hydrogen production, the conversion volumes reflect the fact that the Global Ambition scenario is predominantly methane & blue hydrogen driven, while the Distributed Energy scenario is predominantly electricity & green hydrogen driven. Here methane refers to both natural gas as well as biogas.

Some 800 TWh of methane is utilized to produce hydrogen under the Global Ambition scenario, while only some 130 TWh of methane is converted to hydrogen under the Distributed Energy scenario. However, some 235 TWh of methane is deployed to produce electricity under the Global scenario and more than double that methane volume of some 550 TWh is deployed under the Distributed Energy scenario. Here, flexibility demand in a high-electricity demand NSE region results in higher deployment of this least-cost dispatchable electricity production. The hydrogen system utilizes close to 160 TWh and some 460 TWh of electricity to produce hydrogen via electrolyser units under the Global Ambition scenario and Distributed Energy scenario respectively.

Figure 9 presents the relative volumes of green vs. blue hydrogen production in 2050 under the Global Ambition scenario and the Distributed Energy scenario for the Netherlands (left) and the North Sea countries (right) respectively. For the simulations full availability of the capacity presented in Figure 4 is assumed, while here least-cost deployment is presented. Natural gas reforming (autothermal reforming or ATR) with carbon capture and storage (CCS) results to be the dominant hydrogen production method across the NSE countries in the Global Ambition scenario, while green hydrogen production dominates in the Distributed Energy scenario.

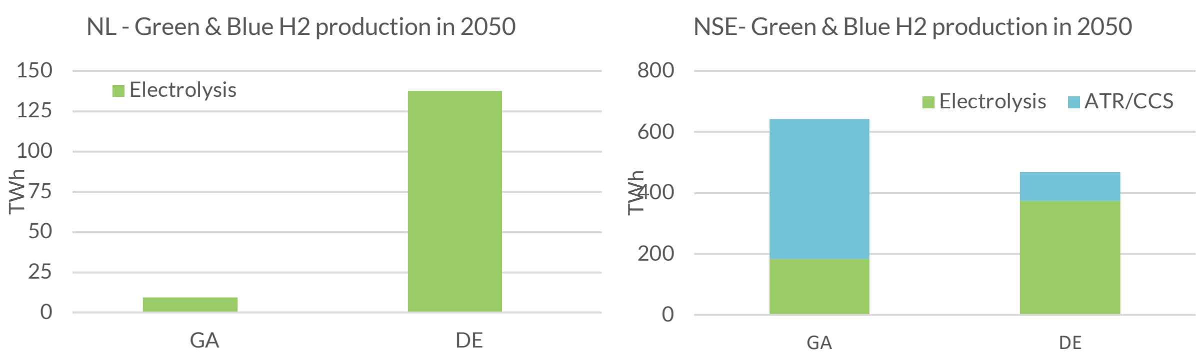


Figure 9 Extent of green and blue hydrogen production in 2050 in the Netherlands (left) and the North Sea countries (right)

Due to higher natural gas deployment for hydrogen production, the Global Ambition scenario sees a broader need for CCS to decarbonize the gas mix to reach carbon neutrality. The high share of ATR/CCS for blue hydrogen production implies heavy deployment of CCS, with high volumes of CO_2 transport and storage infrastructure in The North Sea (see Figure 10Figure 10). In the Distributed Energy scenario some 90 Mt of CO_2 resulting from blue hydrogen production is abated annually through CCS by 2050, while an additional 50 Mt of CO_2 is captured and stored annually through post-combustion CCS at industrial sites. In case of the Global Ambition scenario, with very high input assumptions on CCS capacity, the overall volume of annual CCS measures up to 500 Mt/a.

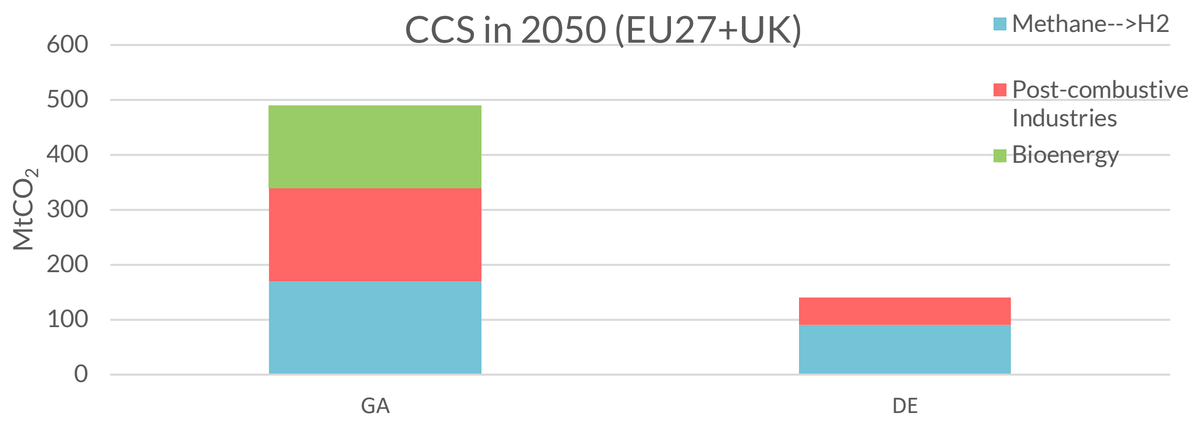


Figure 10 CCS requirements of the two baseline scenarios by 2050

5.1.3 Seasonal Storage

Overall gas storage capacity remains as a key component of the energy system providing seasonal flexibility for both the gas and electricity sector. It should be noted that here, also blue hydrogen production and cross-border trading can offer flexibility. In both scenarios, a significant growth for seasonal storage demand emerges from 2030 to 2050. The storage deployment in the Netherlands resulting from the scenarios is presented in Figure 11Figure 11. On the left-hand side, storage deployment for the Global Ambition scenario is presented for 2030, 2040 and 2050. Here, storage deployment results to be an order of magnitude higher in 2050 than in 2030 and 2040, as indicated by the secondary axis. The Global Ambition scenario, being the molecule rich scenario, results in a somewhat higher hydrogen volumes to store than the Distributed energy scenario. In addition, the more rapid fluctuations in the Distributed Energy scenario suggest higher demand for flexibility with increasing shares of renewable electricity production.

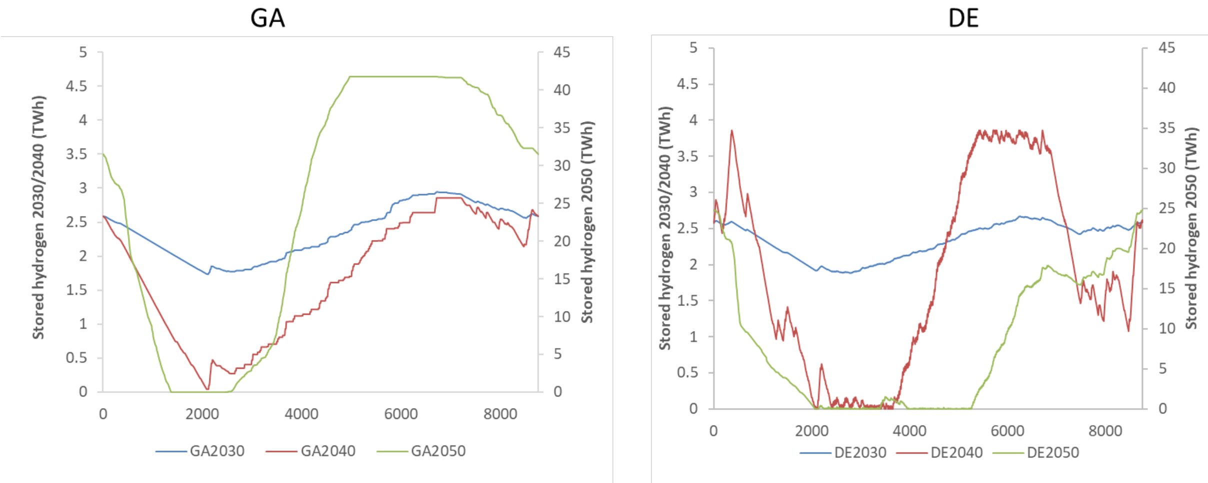


Figure 11 Hydrogen storage level in the Netherlands (2030-2050). Note that the 2050 values are an order of magnitude higher, as indicated by the secondary axis.

5.1.4 Energy Prices

The energy prices resulting from both baseline scenario simulations correspond to the hourly marginal cost of production for electricity, hydrogen and methane respectively. Here, the modelling framework assumes competitive energy markets.

The hourly prices averaged across the system as a whole is presented in Figure 12. The graph illustrates the distribution of hourly electricity, hydrogen and methane prices over the course the year 2050 for North Sea Countries. Overall, it is clear the electricity prices show significantly higher volatility than the methane and hydrogen prices. This feature reflects the relatively high cost of storage in electricity markets. The seasonal variations are also more pronounced for electricity and align with seasonality in energy demand, which is lower in summer. Seasonality in hydrogen prices is limited, indicating a significant impact of seasonal storage. The price curves across the year illustrate the price relationship between the main markets, being methane and hydrogen in case of the Global Ambition scenario and the electricity and hydrogen market in case of the Distributed Energy scenario. In the first case, hydrogen prices show a relatively moderate variability, in line with methane pricing. In the latter case, hydrogen pricing shows higher levels of correspondence to electricity pricing, as higher electrolysis deployment drives hydrogen production.

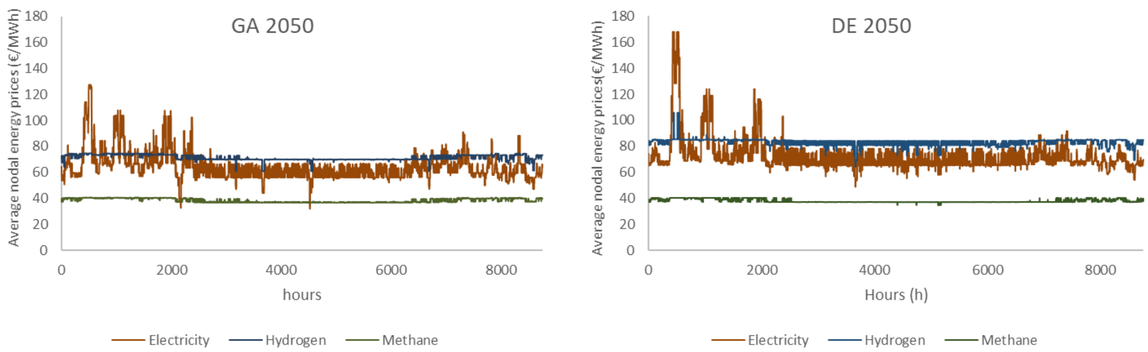


Figure 12 Average nodal hourly prices for electricity, hydrogen and methane for NSE countries in 2050

Figure 13 shows the average nodal prices for electricity, hydrogen and methane for both scenarios for the case of the Netherlands. The high share of solar and wind results in a high volatility and seasonality in electricity for both scenarios. For 2030 and 2040, the hydrogen prices in the Distributed Energy scenario result in somewhat lower hydrogen prices than in the Global Ambition scenario, due to a larger share of the hydrogen production being from methane reforming in the latter. The less fluctuating and relatively low gas price causes a lower hydrogen price floor in Global Ambition in 2040. Yet, towards 2050, blue hydrogen contributions decline in the Global Ambition scenario and, hence, hydrogen prices for the two scenarios converge by 2050.

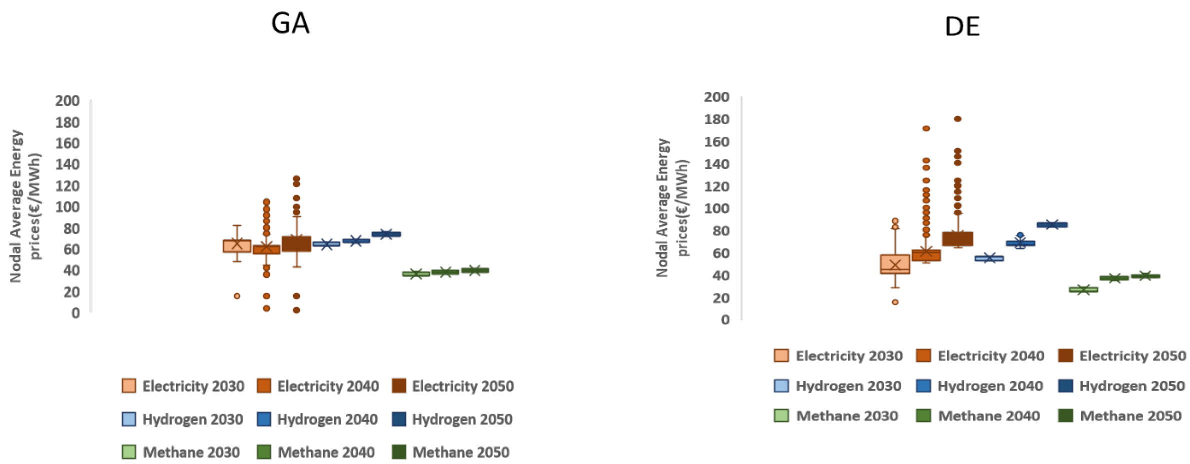


Figure 13 Average nodal electricity, hydrogen and methane prices in 2030, 2040 and 2050 for the Netherlands.

5.1.5 Sensitivity Analysis

In this section we assess the sensitivity of the Baseline Scenario results to the capacity balance for renewable energy resources (RES) vs. electrolyser capacity. The Global Ambition scenario and the Distributed Energy scenario were designed with energy balance as a basis without an integral framework for market pricing. As such, the scaling of wind/solar, conversion (electrolysers) and electricity/hydrogen demand was not balanced in terms of cost-optimal system development. To establish whether the assumed electrolyser capacity is economically viable in the baseline scenarios, a sensitivity analyses is performed by varying selected parameters which are considered as main drivers of the I-ELGAS model and to test their impact on the results. Table 3 presents the assumptions for the sensitivity analyses, with variations on:

1. the assumed renewable electricity production capacity
2. the assumed electrolyser capacity

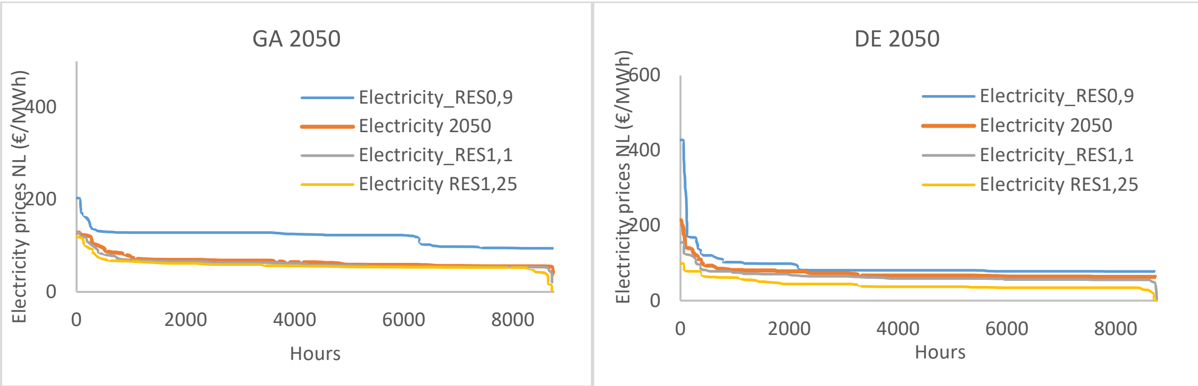
In the following sections, results for the variations are presented.

Table 3 Sensitivity analysis setup and assumptions for the year 2050

Parameters	Sensitivity changes (%)	Values for sensitivity analysis (NL)	Values for sensitivity analysis (NSE)
Variable renewable capacities	%		
Onshore wind (GW)	-10%, +10%, +25%		
Offshore wind (GW)			
Solar PV (GW)			
Electrolyser capacities (GW)	10% -100%	5.16 - 51.6	
Electrolyser CAPEX (€/kW)	100 %, -60 %, -45 % and -10%	100 , 450, 600, 1000	100 , 450, 600, 1000

RES Capacity

Figure 14 presents the electricity price result for the sensitivity analysis on assumed renewable electricity production. Here the assumed electricity production capacity is varied with respectively 90%, 110% and 125% for both baseline scenarios. On the left-hand side results for the Global Ambition scenario are presented. Here, the response to lower renewable electricity production shows significant tightening of the electricity market, with significantly higher electricity prices as a result. For the other variations, price levels for electricity remain virtually on par with the baseline scenario. This indicates that the baseline scenario offers sufficient electricity, while tightening would result in a strong incentive for additional investments in electricity production. Investments beyond the baseline assumption however offers limited impact on pricing. This suggests that the electricity markets are largely saturated in the Global Ambition scenario, as additional RES capacity brings little price declines.



In case of the Distributed Energy scenario, the variations result in relatively moderate electricity price variations. Yet, high renewable energy production (i.e. 125% of the baseline assumption) shows a Figure 14 Sensitivity of electricity price for the Netherlands in 2050 under the two scenarios.

notable decline in pricing, indicating that the impact increasing levels of renewable electricity production are dampened less and less by associated increasing green hydrogen production.

Figure 15 presents the results hydrogen price results for the sensitivity analysis on assumed renewable electricity production, with the same electricity production capacity variations of respectively 90%, 110% and 125% for both baseline scenarios. Prices range from some 50 to 125 €/MWh, or little over 1 to 3 €/kg.[4]

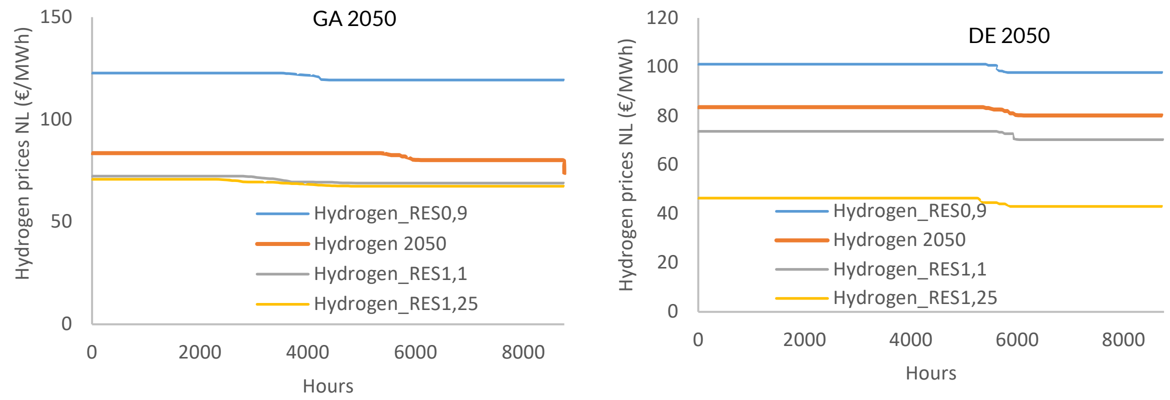


Figure 15 Sensitivity of hydrogen price for the Netherlands in 2050 under the two scenarios.

In this case price impact for the tight Global Ambition Scenario shows heightening of the hydrogen prices, much like it does for electricity prices. The variations with higher renewable electricity production capacity assumptions than the baseline result in lower hydrogen production costs, whereas electricity prices were hardly affected. Here, initial steps in increasing renewable electricity production are absorbed by increasing green hydrogen production, resulting in lower hydrogen prices. Yet, the final increase to 125% no langer affects hydrogen prices, as the market for green hydrogen is saturated. A comparable impact is shown for the results in case of the Distributed energy Scenario. As in the Global Ambition Scenario, price impact on hydrogen prices is higher than for electricity pricing. Here, hydrogen prices range from some 50 to 100 €/MWh, or little over 1 to 2 €/kg.

[4] Prices are reported Eur/MWh. For prices in Eur/kg, divide by 40.

Electrolyser Capacity

The second sensitivity analysis involves sensitivity to electrolyser capacity. In this case we varied electrolyser capacities from 20% (10 GW), increasing with 10% steps to 100% (50 GW) of the Distributed Energy Scenario in 2050 (i.e. the high green hydrogen production scenario). Figure 16 presents the results for the NPV of electrolyser investments for each of the capacity variations, plotted against the assumed CAPEX for electrolyser (x-axis) and the NPV (y-axis). Here, a wide range of CAPEX is covered. Assuming 450 €/kW to offer a proxy for electrolyser CAPEX in the long run, only three of the 20%, 30% and 40% variants of the baseline assumption result in a positive NPV. Capacities higher than 36 GW are not profitable, even under 100€/kW CAPEX assumptions. In other words, the baseline assumption would result in unprofitable investments. This suggests that electrolyser capacity should be reduced in order to offer an economically sound scenario for green hydrogen production. However, one should be aware that this result will depend on share of solar/wind in the energy system, but also CO_2, and costs of CCS among others.

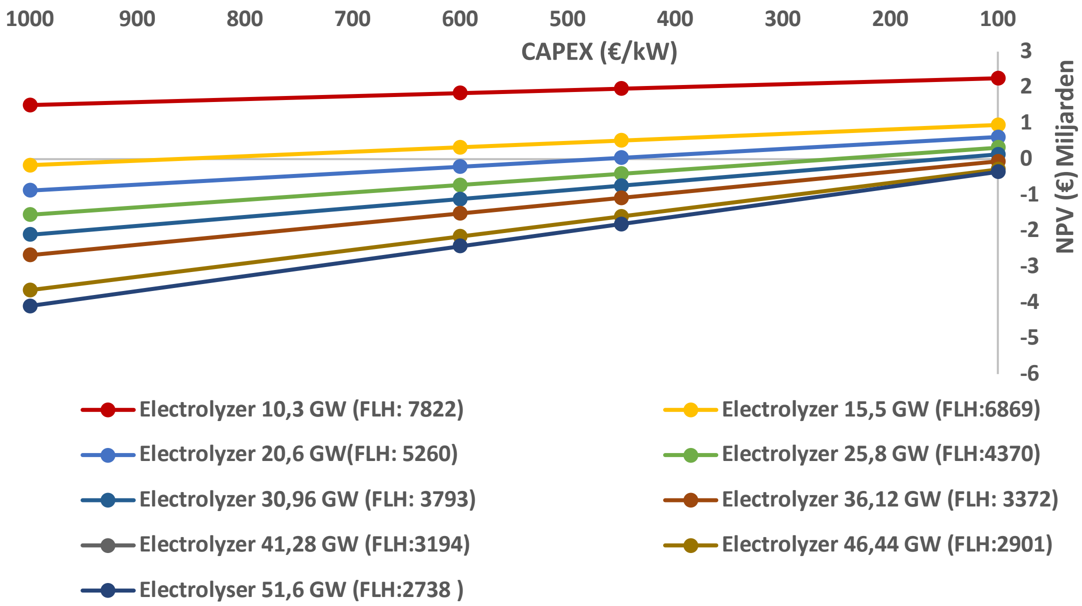


Figure 16 Sensitivity of electrolyser economics (NPV) to electrolyser capacity for NL in 2050.

Besides the economics of the electrolyser business case, both the electricity and hydrogen prices should be affected by variations on the electrolyser capacity assumptions. Figure 17 presents the impact for both markets, with electricity prices on the left-hand side and hydrogen prices on the right-hand side for the Distributed Energy Scenario. Here, the electricity price response show a relatively moderate response, showing increasing price variability with decreasing electrolyser capacity. On average price impact is relatively moderate. In case of hydrogen pricing, prices steadily increase with decreasing electrolyser capacity. Here prices range from some 80 to 120 €/MWh, or little over 2 to 3 €/kg. Notably the lowest capacity assumption, with 20% of the baseline assumption, show a significant step-up in hydrogen pricing. In this case a strong incentive for new investments results, as shown in Figure 16. Hydrogen prices associated with the positive business cases average out on 85 €/MWh or higher.

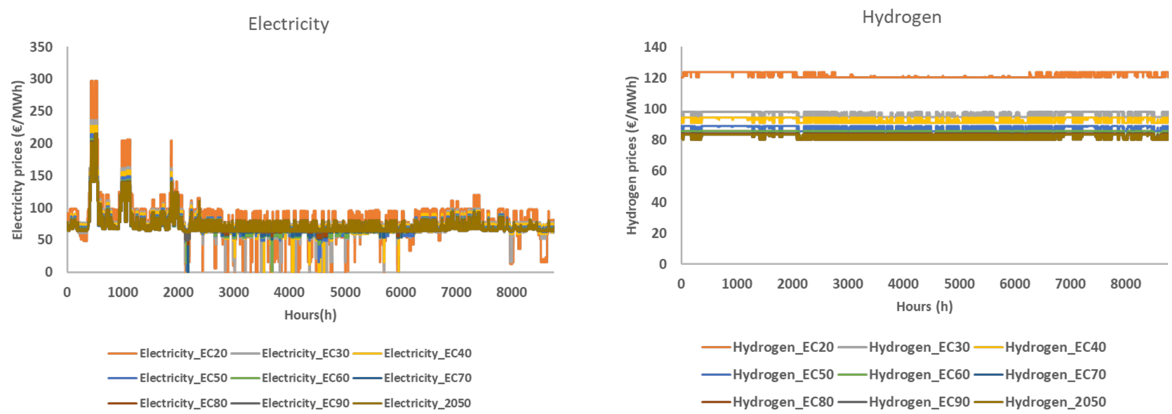


Figure 17 Impact of electrolyser capacity on hourly electricity and hydrogen prices for NL in 2050 under DE scenario

5.2 REPowerEU Simulation Results

For the year 2050, the constructed REPowerEU Scenario showed similar price curves to the old Global Ambition scenario. On average, the changes to the scenario caused a 9% price decrease in electricity prices compared to the GA Scenario, a 9% decrease in hydrogen prices and an 10% decrease in methane prices. These price reductions are driven by the availability of the hydrogen import route, providing a lower cost alternative to hydrogen supply in the baseline scenarios. This in turn reduces demand for methane and electricity, as demand is mostly covered by import.

Methane Balance

A comparison of the annual methane balance of 2050 of several countries in the North Sea area for both scenarios is shown in Figure 18.

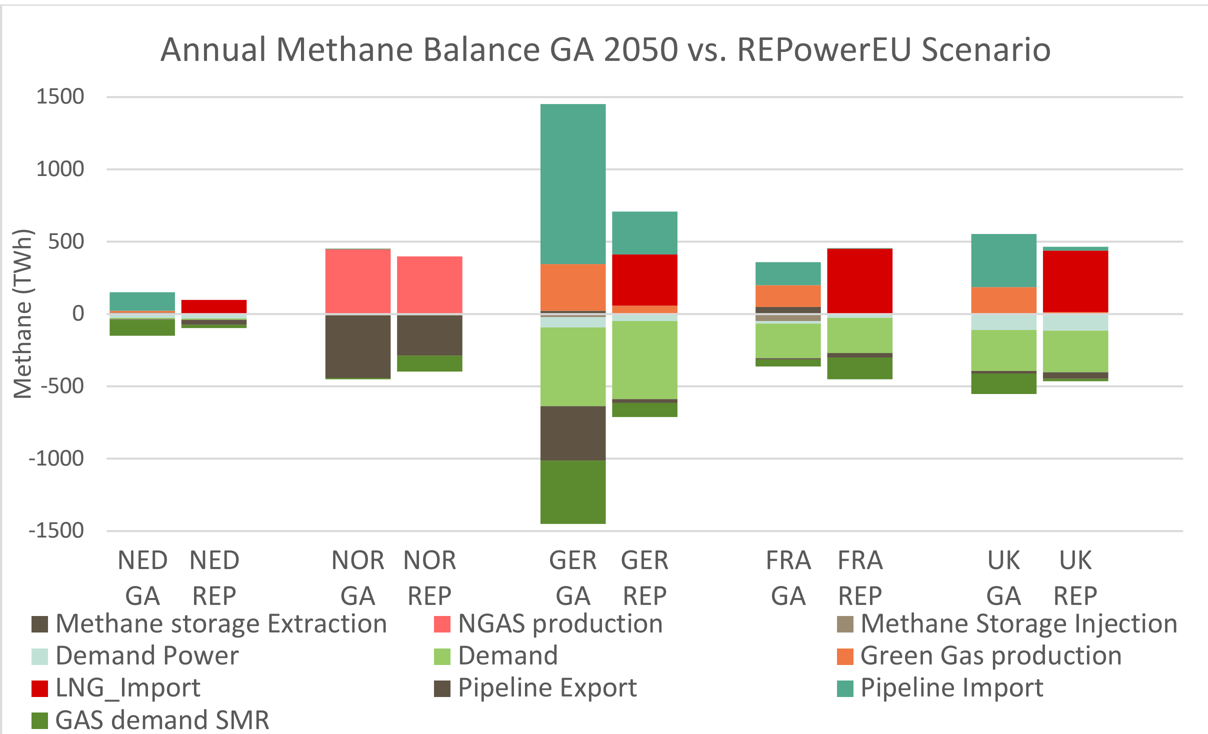


Figure 18 Annual Methane Balance for the old GA and the new REPowerEU Scenarios for the year 2050.

With the removal of Russian gas supply via pipelines and the addition of an LNG shipping import route, pipeline imports throughout Northwestern Europe are greatly reduced, with the exception of German imports of Norwegian gas.

LNG shipping is highly utilised (~7000 FLH), diminishing the role of green gas production. The addition of an import route with high capacity and availability reduces gas prices, but also shifts our dependency on methane to a different source, while it simultaneously undermines European efforts to produce green gas. It is important to keep in mind that these results are very dependent on the assumption of reasonable import prices. If the costs of shipping imports rise above certain price thresholds (e.g. the biomass price for green gas), the utilisation of the import route decreases significantly.

Hydrogen Balance

A comparison of the annual hydrogen balance of 2050 of several countries in the North Sea area for both scenarios is shown in Figure 19.

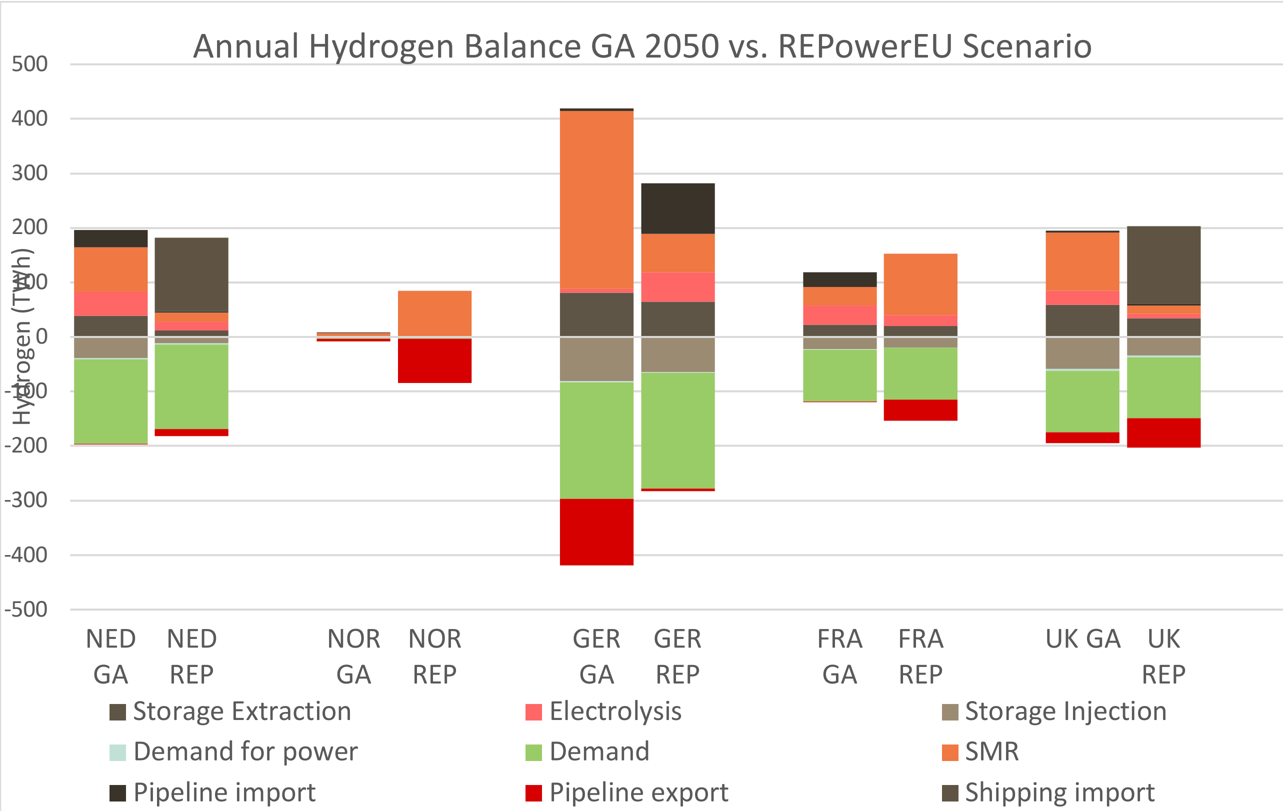


Figure 19 Annual Hydrogen Balance for the old GA and the new REPowerEU scenarios for the year 2050.

The hydrogen shipping import route is highly utilised (around 8000 FLH), replacing electrolysis and SMR in UK and Netherlands. Norway establishes a role as blue hydrogen exporter, through local production of natural gas. In the old GA Scenario, Germany met its hydrogen demand mostly through Steam Methane Reforming of imported gas, whereas in the REPowerEU Scenario, its hydrogen production is more diversified.

Similar to the methane balance, the hydrogen balance shows that a cost-competitive import route is able to meet hydrogen demand in Europe, outperforming local production through electrolysis. A comparable dependency on imports develops, but in the case of production of hydrogen from renewable sources abroad, there is a larger, more diverse set of potential suppliers, compared to LNG imports.

5.3 Offshore Hub Analysis

5.3.1 Baseline Scenarios

A least-cost optimisation was done using the I-ELGAS model for the hub configuration described in Section 4.4 in context of the Baseline Scenarios. The results for the DE scenario are presented here.

Commodity Prices

Firstly, a price comparison between the hubs and the Netherlands in the new scenario are shown in Figure 20.

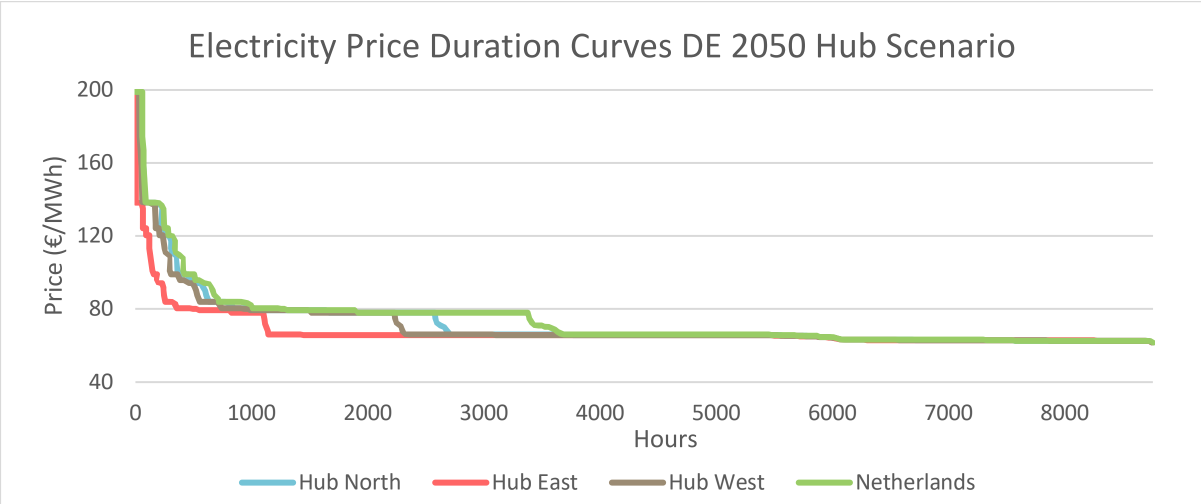


Figure 20 Electricity price duration curves for the three hubs and the Netherlands in the year 2050.

Throughout the year, hub prices are equal to or lower than the Dutch market price. The absence of a fixed electricity and hydrogen demand in the hubs, as well as the absence of competition with other producers end-users, but are undesirable for wind farm operators. Assuming a levelized cost of electricity (LCOE) for wind farms of 50 €/MWh, investment in wind farms would render profitable with these electricity prices above 60 €/MWh throughout the year.

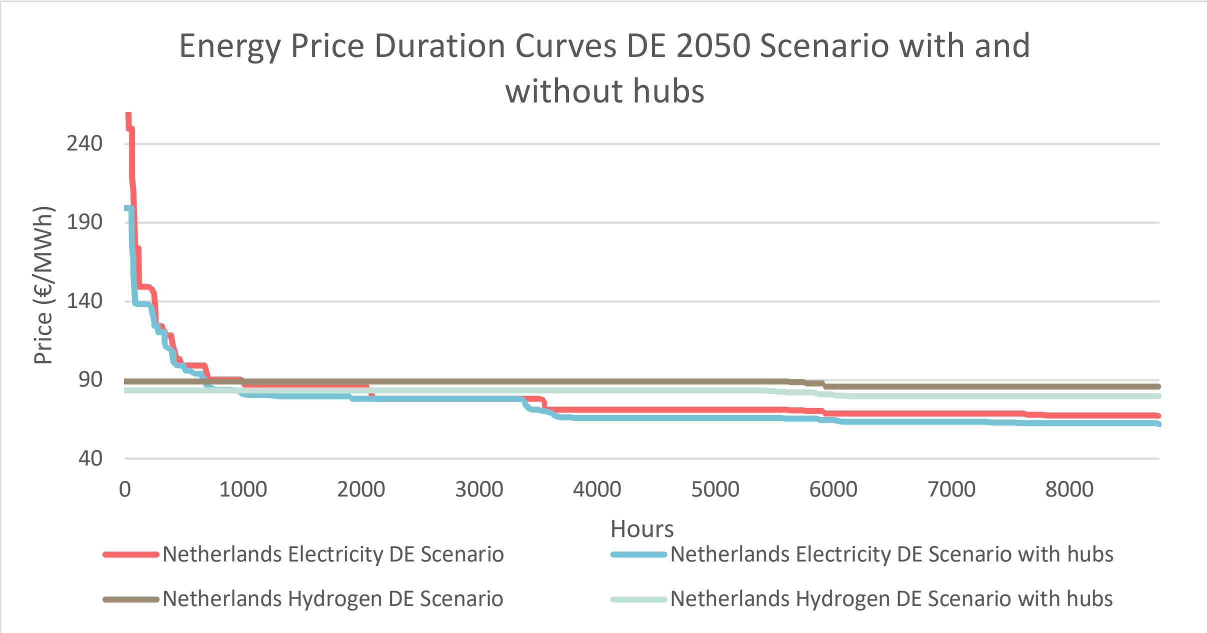


Figure 21 Electricity and hydrogen price duration curves of the Netherlands with and without an integrated offshore hub system.

Similarly, the price duration curves of hydrogen and electricity prices in the Netherlands in Figure 21 show that prices are lower in the Netherlands in the DE offshore hub Scenario in comparison to the DE scenario. Both electricity and hydrogen prices are some 5 €/MWh lower in case of the offshore hub configuration. Electricity prices bottom out at some 62 €/MWh, rendering offshore wind investment profitable in case LCOA lies below this level. Hydrogen prices in the DE offshore hub Scenario bottom out at some 80 €/MWh, while the sensitivity analysis on electrolyser capacity in Section 5.1.5 shows that some 85 €/MWh is required for positive electrolyser business cases. Nevertheless, electricity (input) prices are 5 €/MWh lower for this Scenario, resulting in slightly higher margins. Profitable margins remain in this case.

Hydrogen Dispatch

Next, the hydrogen dispatch for a cost-optimised DE system with offshore hubs was investigated. For the year 2030, the hydrogen load duration curve for electrolysers in the Netherlands in the baseline DE Scenario were compared to the sum of electrolysis on all hubs in the DE offshore hub Scenario.

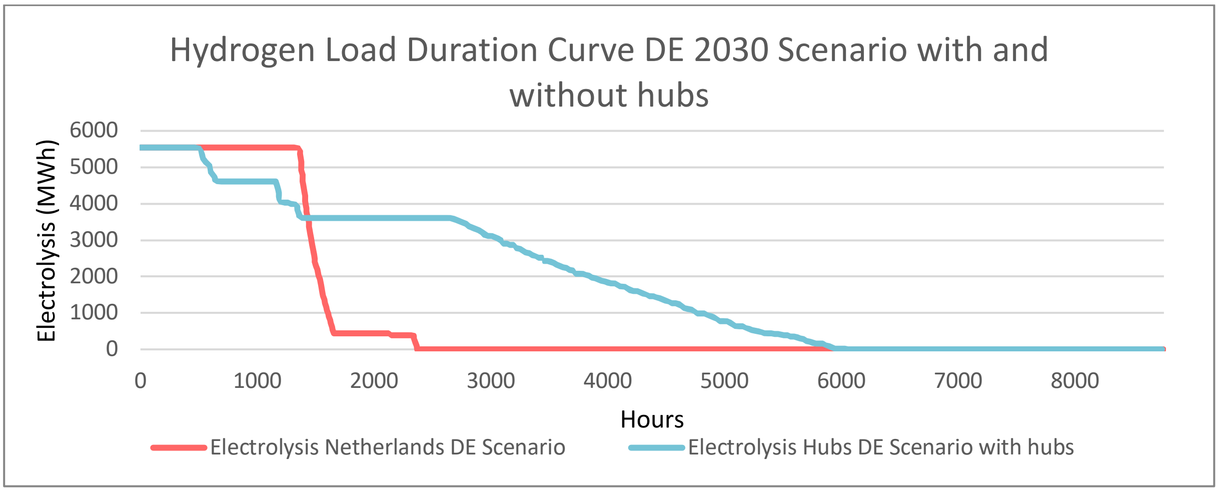


Figure 22 Hydrogen load duration curve of production of hydrogen from electrolysis in the Netherlands compared to the hub system in 2030.

The difference between the curves and the resulting full load hours of the electrolysers is striking. The large amount of full load hours is caused by the following factors: Hub East has an electricity connection to the Netherlands with a relatively small capacity (700 MW), forcing it to produce hydrogen through electrolysis whenever it is generating large amounts of wind energy, regardless of hydrogen prices in the Netherlands. The hydrogen can be transported to other hubs or to the mainland through pipelines with much higher capacities (8000 MW).

For the situation in the year 2050 presented in Figure 23, we can see different behaviour.

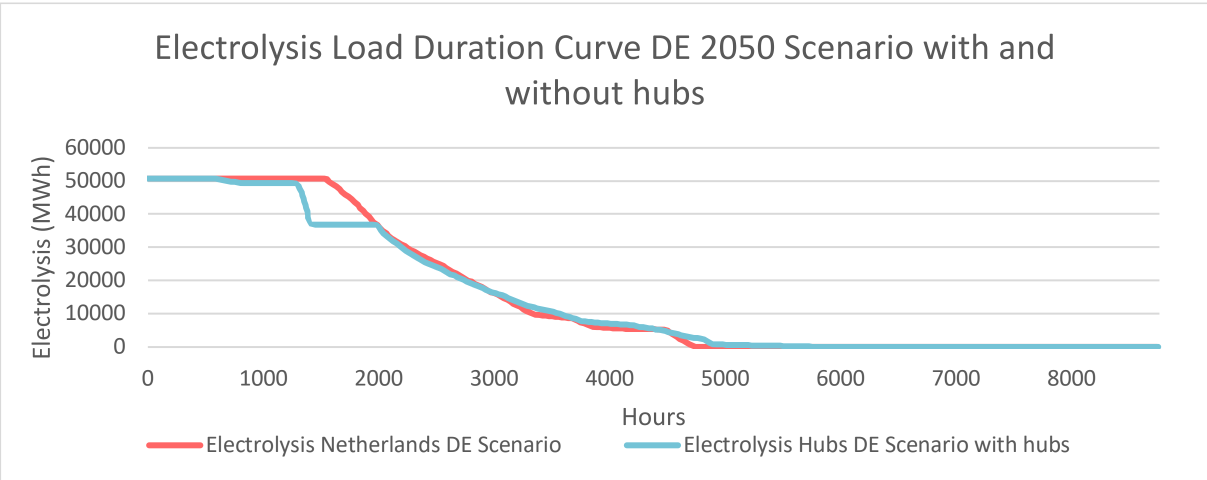


Figure 23 Hydrogen load duration curve of production of hydrogen from electrolysis in the Netherlands compared to the hub system in 2050.

Here we see the combined curve of the hubs approximating the old situation. Better interconnection between the hubs and with the Netherlands, in combination with the fact that the total share of Hub East in producing wind energy and hydrogen is smaller, no longer pushes it towards electrolysis in hours with low hydrogen prices. The hydrogen dispatch of both years show the influence of interconnector capacity on the use of assets on the hubs. Providing a very high capacity power line and hydrogen pipeline allows the hubs to only produce hydrogen at times where that is most feasible and not be constrained by congestion, lowering the total costs of the system. However, policy makers and hub operators might prefer the electrolysers to have a higher amount of full load hours, resulting in profitable investments.

The resemblance in hydrogen dispatch between the baseline and offshore hub scenarios in 2050 can be understood upon inspection of the electricity flows from and to the offshore hub as presented in Figure 24.

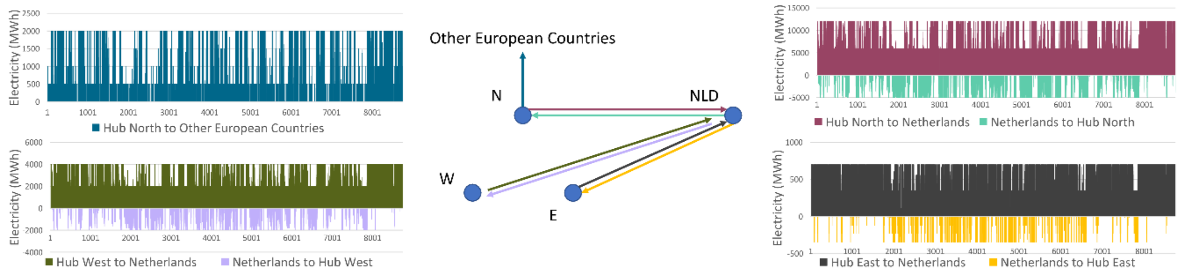


Figure 24 Electricity transport to and from the offshore hub system in the year 2050.

The electricity lines reach their capacity many times throughout the year by transport of electricity from and to the hubs. The influence of the wind profile is visible in the export from the hubs to the Netherlands. Additionally, a seasonal profile can be discerned in the import data, being more prevalent in and around the summer months, compared to the winter months. This is most likely the effect of generation of solar energy in the Netherlands being transported to the hubs, to be used for electrolysis. As such, electrolysers are also driven by onshore renewable electricity production, as is the case in the baseline scenarios. This result is of relevance to infrastructure operators, accounting for the bilateral nature of transport of electricity from *and to* the hubs. Making the electricity transport be a one-way street will most likely result in a much smaller amount of full load hours for the electrolysers.

5.3.2 REPowerEU Scenario

In this Section, the market dynamics of the offshore hub system in the REPowerEU scenario variant is analysed.

Commodity Prices

Figure 25 presents the resulting commodity pricing for the REPowerEU Scenario variant and the REPower Scenario with offshore hubs. Firstly, it may be noted that hydrogen prices for thie REPowerEU Sceanrio are significantly lower than the GA Baseline Scenario as presented in Sections 5.1.4 and 5.1.5. The hydrogen import route has e significant impact on hydrogen prices, resulting in hydrogen prices of only little over 60 €/MWh in contrast to the hydrogen prices of some 80 €/MWh or more in the Baseline Scenarios. Clearly, significantly lower electrolyser capacity should be expected to be realized in the Netherlands in such a scenario in order to result in a positive business case.

Of further interest is the change in prices when combining the two, and the change in hydrogen dispatch in the Netherlands when a hydrogen import route is added to a situation with electrolysers on offshore hubs.

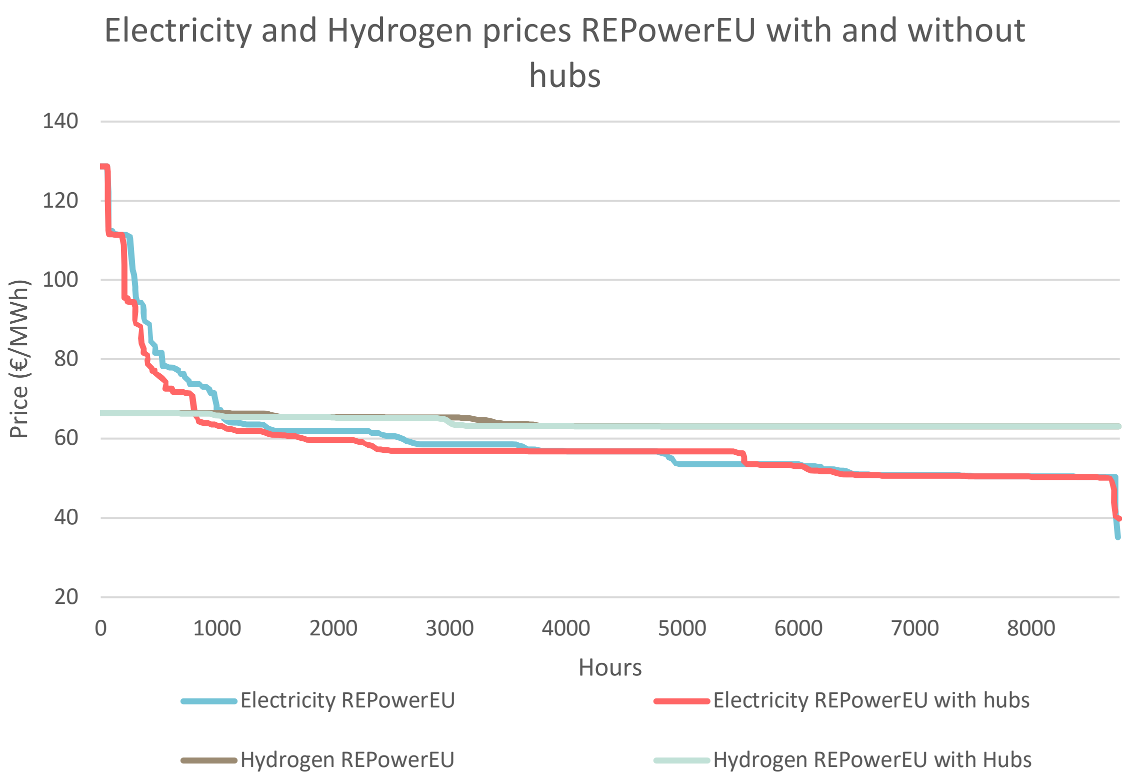


Figure 25 Electricity and Hydrogen price duration curves for the REPowerEU scenario with and without an integrated offshore hub system.

The price duration curves in Figure 25 show a slight decrease in the situation with hubs compared to the one without. A 2% decrease in electricity prices and a 0.3% decrease in hydrogen prices. The same effect of price reduction from the hubs can be seen as before, albeit relatively small.

Hydrogen Dispatch

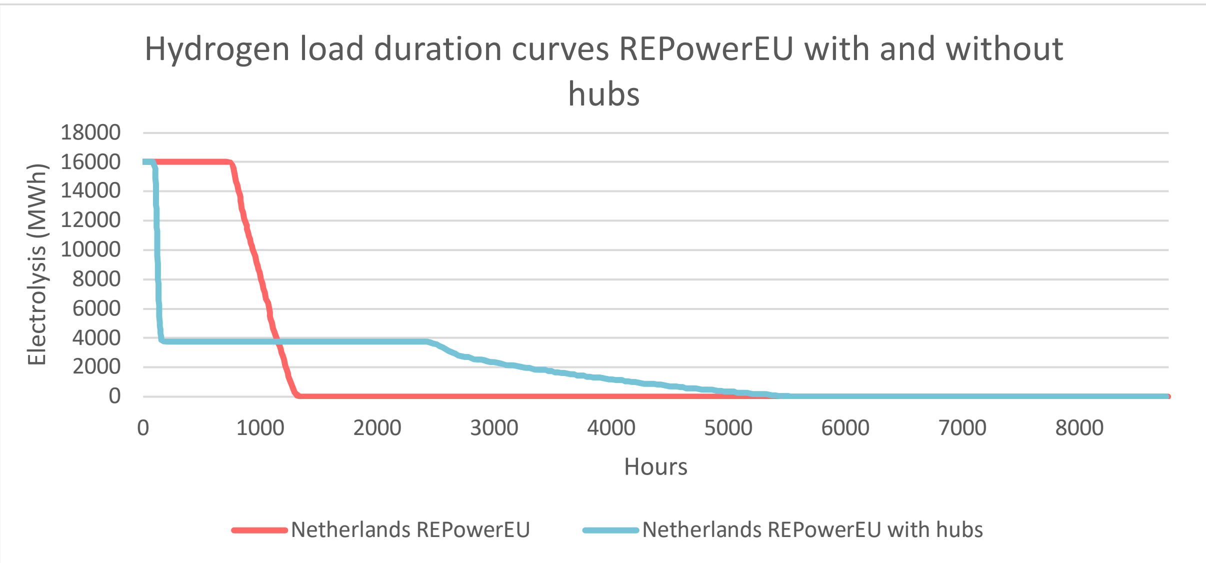


Figure 26 Hydrogen load duration curves for the REPowerEU scenario with and without an integrated offshore hub system.

Finally, the load duration curves again show the positive influence of the hubs on the full load hours of electrolysis. In the REPowerEU Scenario, the Netherlands make heavy use of the available and relatively cheap import route, relying on the favourable cost assumption for shipping imports. This results in lower full load hours for the electrolysers, as they rarely drop beneath the price level of the import route. However, adding hubs to the scenario results in similar behaviour as presented in Section 5.3.1: the interconnection between hubs and mainland restricts electricity export, forcing the hubs to produce hydrogen and export it to the Netherlands. This hydrogen has a lower associated price that dips between the import price more often, leading to a load duration curve with much higher amount of full load hours.

6 Conclusions

In this report, methodology, scenario development and first results for the baseline scenarios Global Ambition and Distributed Energy were presented. Here the two baseline scenarios present a significantly differing outlook on market development. The Global Ambition scenario develops a predominantly a blue hydrogen driven German hydrogen market suppling the Netherlands. The Distributed Energy develops a predominantly a green hydrogen driven Dutch hydrogen market suppling the German market. The scenarios largely cover two worlds with a blue hydrogen vs. a green hydrogen vision. An analysis of these two hydrogen visions, as well as the electrolyser capacity sensitivity analysis show the profound effect of the balance between renewable electricity resources and electrolyser capacity on prices and in turn on the business case for electrolysers. While the balance between blue and green hydrogen is of lesser relevance, notably system design choices on the development of renewable energy resources and electrolysers should be carefully balanced to assure a business case for both.

The analysis of the REPowerEU scenario shows the market behaviour in a transformed energy system, moving away from dependency on Russian gas supply, making use of these seaborne import routes for methane and hydrogen. Methane and hydrogen balances both show the influence of a cost-competitive import route: local production from green gas produced from biomass and electrolysis respectively are reduced and replaced by the cheaper import options. Import show a significant impact on system dynamics and overall electricity and hydrogen pricing, exerting a particularly significant pressure on hydrogen prices.
Alongside design choices for blue and green hydrogen, import capacity and costs of hydrogen through shipping imports have a high impact on the market.

The results show the importance of timely establishment of a vision on balanced national energy system development, with a clear view on balanced development across all segments of the energy system supply chains in roadmap development and the design of energy policies to move from vision to practice.

A more detailed analysis of an integrated offshore energy system was performed by examining the market dynamics of a system of three offshore hubs in the North Sea. Price curves show that the integration of offshore wind and hydrogen production can reduce the prices of the system, but the effect of lower prices on the appeal of private investments in the offshore area needs to be taken into consideration. Additionally, the hydrogen load duration curves show the importance of the transport capacity of the infrastructure transporting electricity and hydrogen from and towards the hubs. Limiting the capacity can increase the amount of full load hours of the electrolysers on the hubs, and bi-directional electricity transport can allow the offshore electrolysers to produce hydrogen during hours in which (onshore) solar energy is more abundantly available than wind.

To conclude, this study shows an optimal dispatch for a given energy system described in different scenarios developed in studies by the Northwestern European grid operators. It is not an optimisation of the system and its assets and possible investments, but instead shows for a given energy system the dynamics of system design choices and assumptions. The investigation into installed capacity of blue, green and import hydrogen assets shows their influence on the market and behaviour that should be taken into account when designing the future energy system. Equivalently, lessons can be learned from the dispatch and market behaviour of the offshore hub system, but it has also shown to be a complex research topic, with dependencies on interconnection, system design choices on the mainland and assumptions on import and pricing zones.

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Appendix A
Seaborne Hydrogen or Ammonia Imports

A.1 Sensitivity Seaborne Hydrogen or Ammonia Imports

In the baseline scenarios, the energy system is considered to consist of nine countries in the North Sea region with the ability to produce hydrogen and internally trade through pipelines.The REPowerEU assumes liquified hydrogen imports, but today's outlook based on new import initiatives suggest that (early stage) hydrogen imports may very well largely take place by form of ammonia. In this Appendix we assess the impact of hydrogen - or ammonia import on market pricing via shipping routes. In this sensitivity analysis, the results are presented for the assumption that an additional shipping route can supply hydrogen or ammonia from overseas to the North Sea region.

For the shipping routes, large-scale green hydrogen or ammonia production is assumed to take place in Morocco followed by transportation to two large Northwestern European ports: Felixstowe (UK) and Rotterdam (NL). Hydrogen and ammonia production in Morocco is based on renewable electricity from a combined Solar-PV and onshore wind set-up. The hydrogen is subsequently liquified or converted into ammonia and stored in buffers at the export terminal. Costs of production abroad and infrastructure investments were based on (CE Delft, 2018), assuming integral cost coverage for these dedicated facilities. The LH_2 and LNH_3 carriers transporting the fuel are assumed to be equivalent in cost, volume, fuel use and boil-off rate as the 2030-ready ships as described in (IEA, 2019). With ship capacities of 1.3 PJ LH_2 and 1.2 PJ LNH_3, it is assumed there are two ships arriving in the Netherlands each week and one ship in the United Kingdom to match hydrogen demand assumptions for these countries and their hinterlands. On-site facilities include buffers at the import terminal, and gasification or reconversion facilities for hydrogen and ammonia respectively. The discounted import and export terminal investment costs were incorporated in the operational costs. An overview of the cost assumptions is summarised in Table 4.

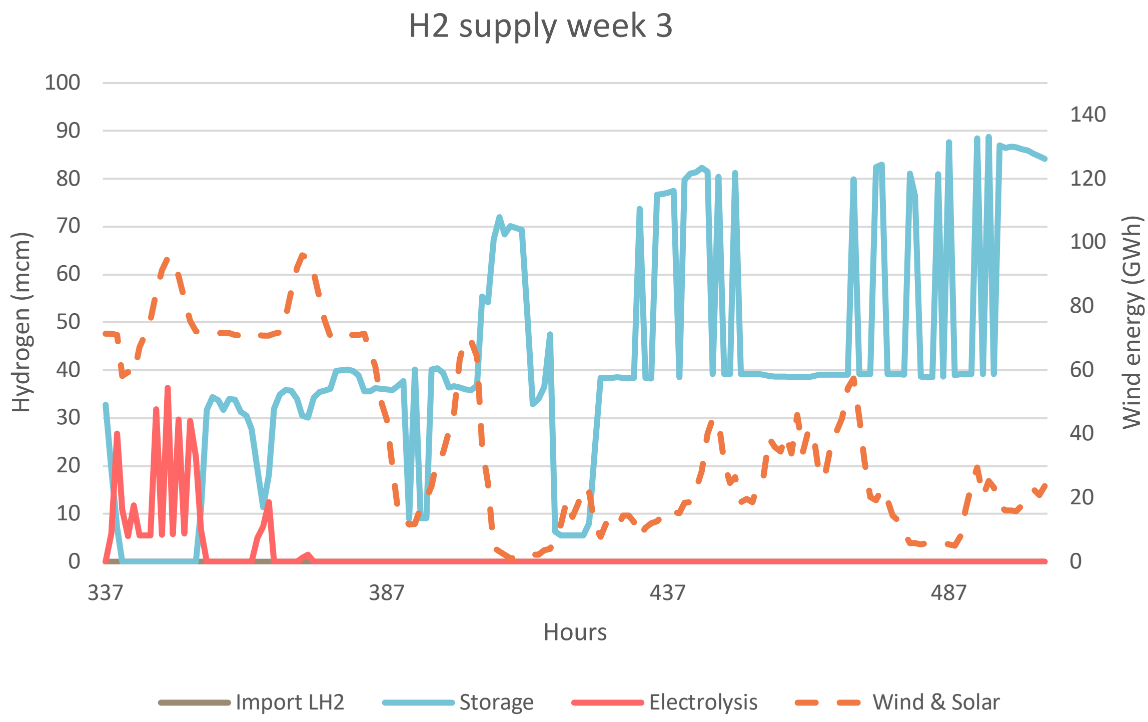
Table 4: Cost assumptions for seaborne import routes

	H_2 Shipping (MA – NL)	H_2 Shipping (MA – UK)	NH_3 Shipping (MA – NL)	NH_3 Shipping (MA – UK)
Cost of production (€/MWh)	30,72	30,72	32,23	32,23
Cost of transportation (€/MWh)	2,29	2,19	0,52	0,50
Cost of port upgrades (€/MWh)	9,58	9,58	0,96	0,96

To assess the impact of the additional shipping routes in terms of system allocation, Figure 27 presents two weeks of system hydrogen production, storage and seaborne liquid hydrogen import for the Netherlands in the DE Scenario in 2050. Electricity supply from solar-PV and wind are included in the figures, with units indicated on the right-hand side axis, in order to illustrate that the dynamics of electrolysis and renewable electricity.

In the top figure, the third (winter) week of the 2050 simulation is presented. This figure shows relatively low levels of renewable electricity production, be it that the first two days offer somewhat higher levels of renewable electricity supply. During those days electrolysis is activated, driven by lower electricity pricing levels. For the other days, hydrogen supply largely depends on storage extraction, dissipating the storage volume that is developed over the preceding summer. In this case shipping volumes do not come into play as storage offers hydrogen at relatively competitive price levels. Once the storage volumes are depleted, hydrogen supply from the shipping route will come into play (not shown in the figure).

In the bottom figure, results for (summer) week number 28 of the 2050 simulation are presented. This figure shows relatively high levels of renewable electricity production, notably driven by the high levels of solar-PV that were assumed. Electricity prices are often low in this period so that, green hydrogen production through electrolysis is relatively cost-effective. Accordingly, high levels of electrolysis occur, surmounting hourly demand. The excess production of hydrogen production is injected into the storage. Yet, during hours of low renewable electricity production and electrolysis, hydrogen demand is served by the seaborne liquified hydrogen shipping route.



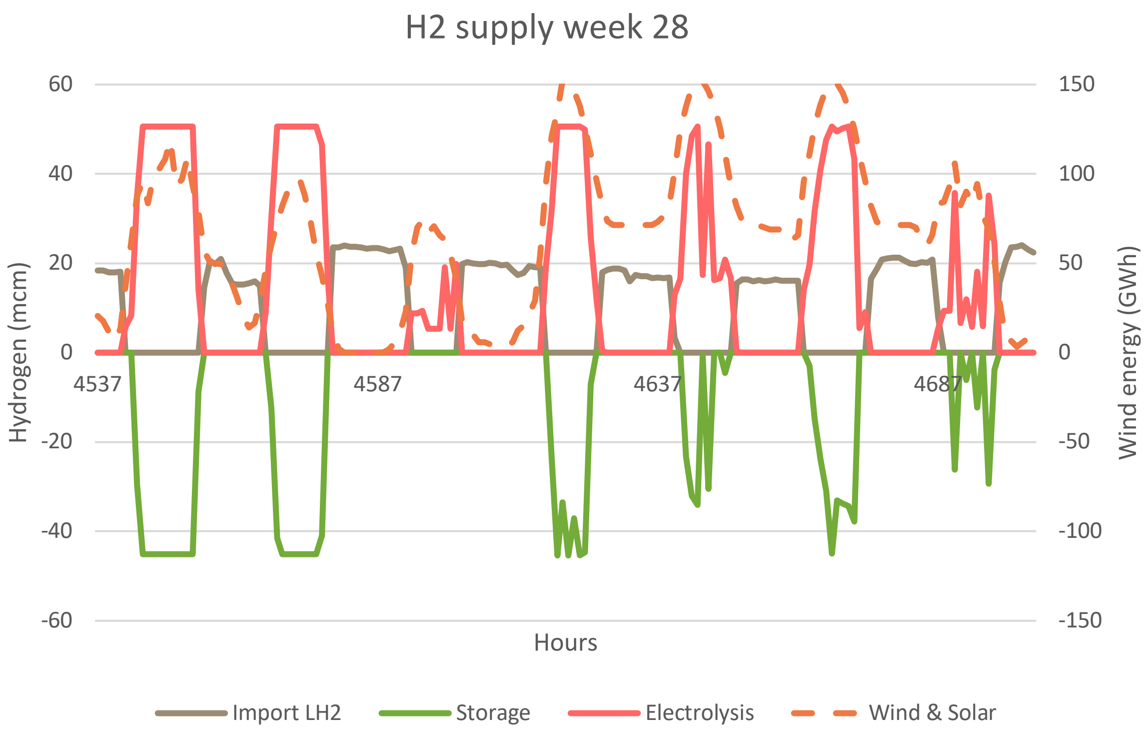


Figure 27 Two weeks of hydrogen production, storage and (seaborne liquid hydrogen) import for the Netherlands in the DE scenario in 2050. Renewable electricity production volume is indicated on the right-hand axis.

To assess the impact of the hydrogen and ammonia shipping routes on the energy markets in the North Sea region, the electricity price impact for the Distributed Energy Scenario in 2050 is presented on the right-hand side in Figure 28. In case of the assumed shipping routes, significantly lower the electricity price result throughout the year in comparison to the case without additional seaborne imports. The impact on electricity prices results from declining green hydrogen production from renewable electricity in the Netherlands and NSE region at wide. As the cost assumptions for the ammonia route are lower than for the liquified hydrogen route, higher deployment rates for the ammonia import routes result, displacing higher volumes of locally produced green hydrogen. Accordingly, the less local deployment of renewable electricity for hydrogen production results, so that electricity prices are lower for the case with seaborne ammonia imports.

The impact of the hydrogen and ammonia shipping routes on the Dutch hydrogen market in the North Sea region for the Distributed Energy Scenario in 2050 is presented on the left-hand side in Figure 28. An even higher price impact for the hydrogen market results, with 25% to 35% hydrogen price declines on average for the liquified hydrogen - and the ammonia shipping route respectively. Besides an average price difference between the cases, a difference in shape of the electricity price duration curves results for the seaborne import cases. All price curves show two pricing regimes, with a heightened price level for most of the year and a depressed period in the remainder of the year. The depressed price levels result from depressed hydrogen pricing during hours of high renewable electricity supply, typically during the day in summer as a result of high solar-PV feed-in. The heightened prices are set by stored hydrogen and, if available, imported hydrogen. In case the import route is available, the hydrogen prices are increasing set by this route.

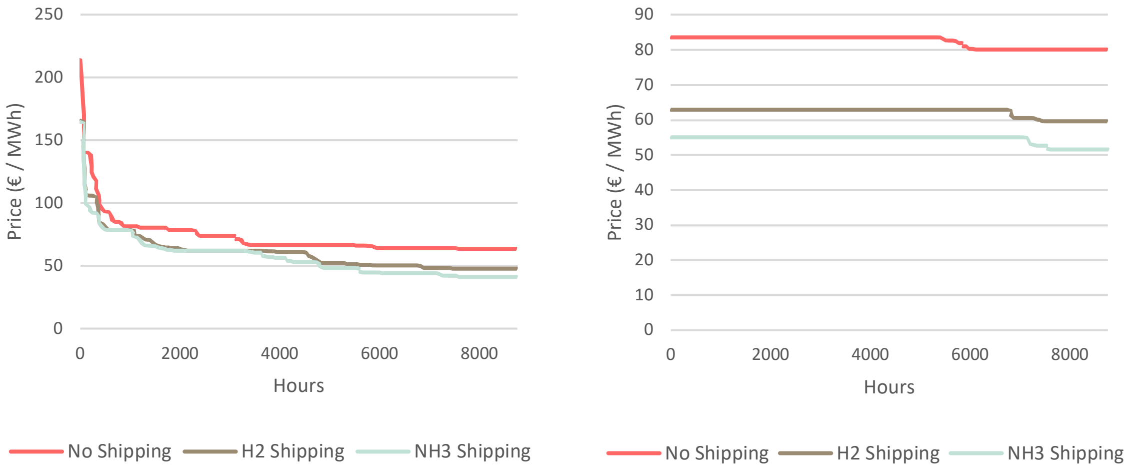


Figure 28 Impact of shipping routes on hourly electricity and hydrogen prices for NL in 2050 under DE scenario.

North Sea Energy offshore system integration

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