HyChain 2

Cost implications of importing renewable electricity, hydrogen and hydrogen carriers into the Netherlands from a 2050 perspective

Model User Guide, Technical Documentation, First Results and Country Profiles

Hydrohub

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ABOUT THIS REPORT

This project report is part of a set of three parallel projects carried out in the period June 2018 till May 2019:

- HyChain 1 :
  Assessment of future trends in industrial hydrogen demand and infrastructure
- HyChain 2:
  Cost implications of importing renewable electricity, hydrogen and hydrogen carriers into the Netherlands from a 2050 perspective
- HyChain 3:
  Hydrogen Supply Chain – Technology Assessment

All three project reports can be found on www.ispt.eu/projects/hychain.

THE HYCHAIN PROJECT

The HyChain project is initiated by the Institute for Sustainable Process Technology (ISPT) and is part of the Hydrohub Innovation Program. Its mission is 'Largescale electrolysis-based production of sustainable, low cost, hydrogen as a driver for circular industrial chains'. The project is part of the ISPT's cluster System Integration. The HyChain central research focuses on the question: '*How can we make an optimization for all the full value chain to deliver the lowest cost, carbon-neutral hydrogen to Dutch industry (domestic and global production) and what barriers and bottlenecks stand in the way?*'.

PUBLIC FUNDING

The project received public funding from The Netherlands Enterprise Agency (RVO) under Grant TSE-18-17-01- Topsector Energiestudies.

CONSORTIUM PARTNERS

Summary

Hydrogen could play a vital role in future renewable energy systems. This report is the result of a project carried out as part of the HyChain program coordinated by the Institute for Sustainable Process Technology (ISPT). The HyChain program looks at an optimisation of a future renewable hydrogen value chain, with the Netherlands as a focal point. This report is the result of a project within this program called HyChain 2 which focusses specifically on the cost implications of importing renewable electricity, hydrogen and hydrogen carriers into the Netherlands.

To this end we developed a high-level model (which is freely available as an appendix) to evaluate these import costs and their dependencies on the various input parameters. The model calculates the costs of importing renewable electricity, hydrogen and hydrogen carriers from virtually every country in the world to the Netherlands, using a greenfield approach and 2050 as a reference year.

This model considers three main import routes. In the first route, renewable electricity is generated and transported via high voltage direct current (HV DC) electricity cables to the Netherlands, where it can be used to run an electrolyser to produce hydrogen. In the second route an electrolyser is fed with renewably produced electricity abroad and the resulting hydrogen is transported to the Netherlands via a gas pipeline. In the third route, renewable hydrogen produced abroad is used to produce a hydrogen carrier which is transported to the Netherlands by ship, where it can be used directly or the hydrogen can be retrieved.

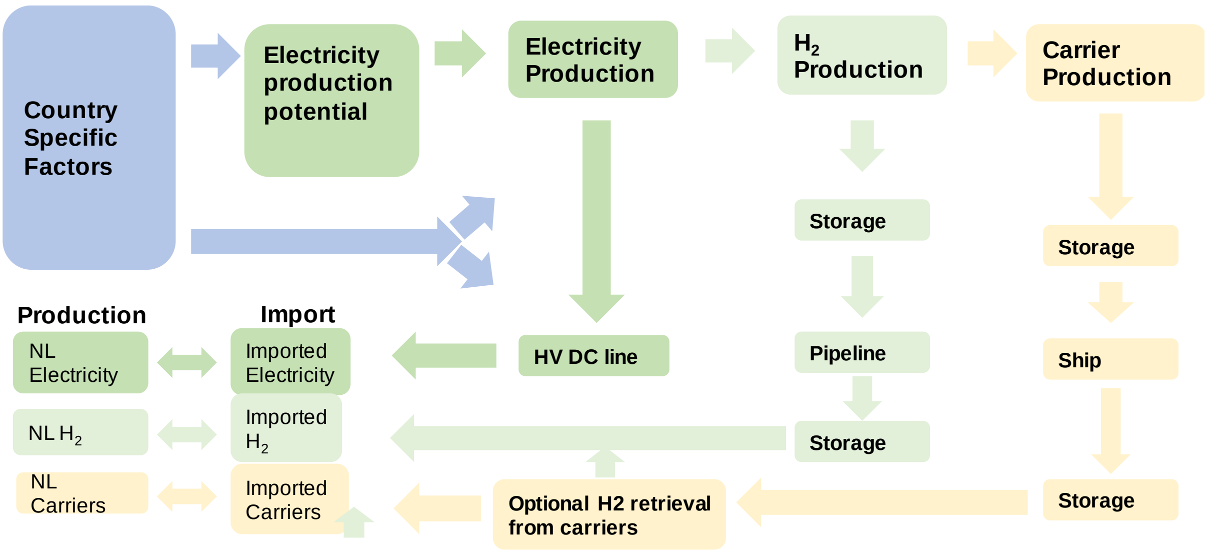

Figure 0: Model overview: three conceptually different import routes

A brief non-technical user guide as part of this report describes how to interact with this model and some of its background. It is strongly recommended you read this if you plan to use the model. Additionally, a more extensive technical documentation is available to those who would like to know more about the technical details of the modelling and data.

The first results with the model with base settings and base country and technology parameters offer various insights, some of which are summarised here. We focused on the costs comparison of imported hydrogen versus Dutch production costs. It is assumed that hydrogen in the Netherlands is produced through electrolysis fed with electricity from offshore wind farms (since onshore wind and solar potentials are relatively limited).

It appears from this specific scenario that there are limited hydrogen import opportunities on a cost basis, and that such cost competitive hydrogen is generally sourced from within Europe or from North Africa and the Middle East and transported via gas pipelines or occasionally HV DC cables (within Europe). Hydrogen carriers in this scenario are more readily imported on a cost basis, also from outside Europe, but prohibitive hydrogen retrieval cost mean this option is most interesting if the carrier is to be used itself (e.g. as a feedstock) – not for the hydrogen it contains.

If we however depart from the base scenario and explore what happens if such a supply chain could be financed with e.g. Dutch capital rather than country specific cost of capital, many more opportunities appear to import hydrogen, also from outside Europe with very large potentials, with the latter typically transported as ammonia by ship. It therefore goes to show that it is vital to explore the impact of these parameters and that conclusions are often scenario specific, but that one can get a better idea of the cost dynamics and sensitivities of such a supply chain by using the model.

The model also shows the local production costs of renewable electricity, hydrogen and hydrogen carriers. For many countries these costs are lower than the Dutch costs, if Dutch costs are based on off-shore wind electricity. A system of International Renewable Energy Certificates (IRECS) could therefore work even if the costs of physically transporting the electrons or molecules to the Netherlands are higher.

It should be noted that this is a cost model, and not a pricing model. Also, it does not include any taxes or incentives. Rather it is a simple techno-economic model that looks at the base costs. Since pricing has to result in an average price that is higher than the minimal costs (unless very large subsidies are in place), such a cost model gives an estimate of a lower bound on the price. If this is similar to or higher than Dutch production costs, it is unlikely a large supply chain to the Netherlands will emerge on economic grounds.

To get an idea of how likely it is such a supply chain would be realised, ECN part of TNO wrote eight country profiles for several promising countries regarding their ambitions to expand renewable electricity generations, barriers for implementation and experience with hydrogen. For most renewable electricity generation will still have to be expanded significantly, and most do not yet plan to do this to the extent they are able to export large quantities. Norway seems the only country which is likely to export small quantities before 2030, with the United Kingdom, Saudi Arabia, Canada and Spain likely to be able to start doing this between 2030 and 2050 with much uncertainty regarding the development for China, Morocco and Chad.

Contents

Introduction

Background

Affordable hydrogen is key to the Dutch chemical industry as feedstock for ammonia production (fertilisers), for the upgrading of heavy crudes into gasoline and distillates (mobility), and for providing paraffinic feedstocks for the production of petrochemicals and polymers (materials). Large scale Steam Methane Reforming facilities currently meet the need for cheap hydrogen.

However, in view of the energy transition the needs for fertilisers, mobility, and materials will have to be fulfilled in a decarbonized manner. Hydrogen from water electrolysis on the basis of renewable energy (wind, solar, tidal, geothermal), so-called “green hydrogen”, is key to that end.

Hydrogen production from the electrolysis of water is not a new concept. Since the early 1900’s electrolysers have been used to produce hydrogen as feedstock for the fertilizer industry. In the 50’s and 60’s, large scale electrolysers (with capacities of over 100 MW of electricity input) were built next to large hydro power plants (e.g. in India, Egypt, Zimbabwe and Norway) to produce hydrogen as renewable energy carrier. However, the availability of low-cost natural gas provided steam methane reforming (SMR) with a strong competitive advantage and water electrolysis plants were forced to close down.

In the last decade, interest in electrolysis has revived as the technology is now considered as one of the key building blocks of future energy systems required to significantly mitigate climate change. One of the most attractive features of a green hydrogen production system is that hydrogen can act as a buffer in a supply-driven electricity production system (given its supply intermittency). Given the transitions currently taking place in our energy and production systems, the demand for hydrogen is anticipated to increase significantly over the coming decades. This is not only to meet new chemical industry demands (for example to provide a means for valorising waste carbon into products), but also to provide for demands for heat, mobility, and other uses such as enabling Direct Reduction of Iron (DRI) in the steel industry. Finally, given the current role of the Netherlands as a throughput for energy to the rest of Northwest Europe, we must already anticipate the role the Netherlands may continue to fulfil in the new energy system with hydrogen.

Problem

Although hydrogen from water electrolysis is envisaged to play a central role in the energy system of the future, a significant capacity scale-up will be required. Currently, it is projected that the Netherlands will need to produce a total of 14 Mton H_2/year, which is more than 22 times the current domestic demand and a quarter of current global industrial H_2 consumption[1] .

However, carbon-neutral H_2 production, for example green H_2 from renewables and water electrolysis, is still prohibitively expensive, which makes meeting this large-scale demand with carbon-neutral hydrogen an enormous challenge. This has led many to wonder whether production of either energy or H_2 outside the Netherlands may be more efficient or feasible, even given the tradeoffs of additional transportation costs.

In addition to these issues, there are a number of additional considerations to be made around H_2 production systems, including water availability, land use for renewables, possibilities for use of heat or O_2

[1] TKI Nieuw gas (2018): Contouren van een Routekaart Waterstof

byproducts from electrolysis, and how intermittency issues related to renewable power will affect hydrogen production systems.

Finally, logistics remains a big question. H_2 can be transformed into many hydrogen-containing energy carriers: for example ammonia and liquid organic hydrogen carriers, $NaBH_4$, methanol, or methane. These energy carriers have different requirements for transportation and storage and have large implications for the production processes that industry will need to set into place to make use of these different forms of H_2.

Energy Carriers and Supply Chain project umbrella

For all of the reasons mentioned above, working on an understanding of meeting hydrogen demand for industry in the Netherlands requires a value-chain approach. By bringing together (future) users of H_2, transport and storage parties, H_2 producers, energy producers, and strong knowledge partners active in the area of hydrogen, we can answer the main research question of:

How can we make an optimisation for the full hydrogen value chain to deliver the lowest cost, carbon-neutral hydrogen to Dutch industry, and what barriers and bottlenecks stand in the way?

The Institute for Sustainable Process Technologies (ISPT) brought industries together to discover which key questions need to be understood in order to optimally meet the needs for hydrogen during the transition to a low-carbon Dutch industry. Based on these questions, we formulated the following objectives:

1. **Assessment of the current state and future trends:** Projecting needs for H_2 in industry (as well as other sectors) and understanding the current and projected future available infrastructure to accommodate these needs. Here we will need an understanding of not only how much hydrogen will be in demand, but also the implications of different energy carriers in meeting that demand.
2. **Economic analysis of energy carrier production, (import), transportation and storage:** Understanding the costs of the full value chain for hydrogen energy carrier production, transportation, storage, and conversion, both inside and outside of the Netherlands, and in the form of different energy carriers.
3. **Technology assessment for full value chain:** Gaining a comprehensive overview of the maturity/scale/learning curves/etc of available technologies for production of hydrogen, transportation, storage, and conversion of different hydrogen-containing energy carriers, as well as an idea of how the technologies will continue to develop over the coming years and where promising technologies require further scaling up.
4. **Systemic assessment of scenarios for the Netherlands:** Based on the demands, costs, and available technologies, anticipating which scenarios for energy carrier adoption are likely to play out in the coming decades and understanding what the systemic implications of these scenarios are for Dutch infrastructure and industry, both in terms of costs and impacts.
5. **Communicating with public and decision-makers to ensure the transition is feasible**: Communicating about the barriers to and implications of the transitions that will need to take place. The aims of communication includes increasing public understanding and acceptance of the transitions happening in Dutch industry, ensuring Dutch industry and infrastructure has the right type of support from policy, and informing other industry decision-makers about developments taking place in this area.

The objectives of the Energy Carriers and Supply Chain umbrella (which now goes by the acronym HyChain) are ambitious and different parties are in a position to answer different parts of the main research question. For this reason, the umbrella is split into five individual projects, each of which aims to address one of the main objectives. The first three projects are implemented in 2018 and are carried out simultaneously. These form the necessary basis for the systemic understanding required to meet objectives 4 & 5.

This project and its outcome

This report concerns project 2 of the projects listed above. It focuses on the cost implications of the supply chain and has as a main question:

Which flows of renewable energy carriers derived from renewable electricity (and of what format) could flow, based on lowest costs, through the Netherlands in 2050?

The aim of this project is to provide a first answer to this question and make it possible to see how this answer changes if one's assumptions and parameters change. To this end we have developed a Microsoft Excel model which is freely and publicly available as a separate appendix. The base settings and parameters in this model result in an output of energy carriers import cost and one possible answer to this question. By playing around the model, one can see how the output depends on the input and see other possible answers and pictures emerge. In this way, this model offers insight into the hydrogen supply chain.

The rest of this report is composed of four individual pieces which can be read on their own. The first is a short user guide of the model, which explains how the model works and how one can interact with it. For those who want to know more about the technical details of the modelling and the data, the second piece is a more extensive technical documentation. Third is a short chapter of the first results with the base settings of the model and a brief exploration of what happens when the input changes. At this stage one should be careful with drawing conclusions from this analysis. The fourth and last piece is a collection of country profiles, which for eight countries describe their energy mix, ambitions with regard to renewable electricity generation, experience with hydrogen and barriers for implementation.

User Guide of the Model

The following will be a short user guide of the possibilities and limitations of the model and we intend it to be used. This should allow you to work with the model and explore the sensitivities that lie within it. If you want to read more about how the model is set up and what data is used, you are encouraged to have a look at the technical documentation provided in this document.

Main Structure: Three Routes

The model contains three conceptually different import routes. The first route involves producing renewable solar or wind electricity abroad and transporting it directly via a High Voltage Direct Current (HVDC) cable to the Netherlands. This electricity could be used to produce hydrogen in the Netherlands. The second route would involve using the electricity abroad to produce hydrogen and transporting this hydrogen via a gas pipeline to the Netherlands. The third route would also involve producing hydrogen, then generating a hydrogen carrier and sending this carrier to the Netherlands by a ship that is capable of transporting this carrier. Hydrogen can be retrieved from the carrier in the Netherlands. This third route is considered for 10 different carriers: ammonia, formic acid, methanol, dibenzyltoluene, sodiumborohydride, dimethylether, oxymethylene ether, liquefied natural gas and liquefied hydrogen. Hydrogen, reactant and carrier storage is also taken into account where relevant (electricity storage is not included in this model). All three routes are shown in Figure 1.

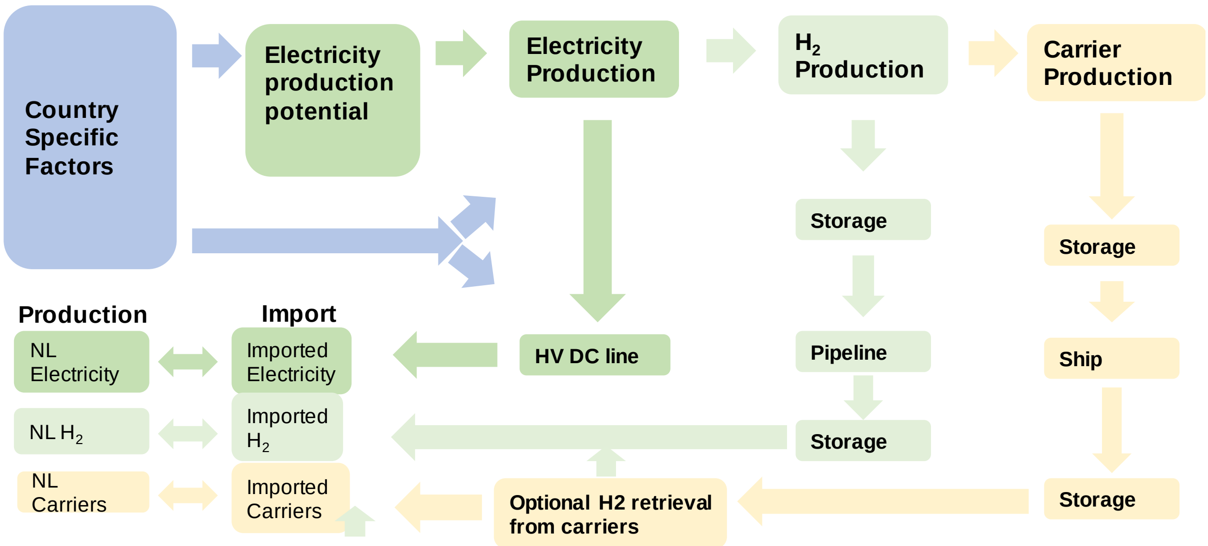

Figure 1: Model overview: three conceptually different import routes

The costs of these routes are determined based on techno-economic calculations which involve *country* and *technology* parameters.

Country parameters are specific to every country and include for instance the distance to the Netherlands (which is used to calculate transport costs), the number of wind full load hours, the weighted average cost of capital (WACC), which affects the investments done in that country as part of this supply chain.

Technical parameters are specific to a route, but sometimes are shared among routes. For instance the investment costs of an ammonia plant are specific to the hydrogen carrier route that involves ammonia, whereas the investment costs for electrolysers for hydrogen production are shared by all routes except the first one (electricity via HV DC cables).

The model uses both the country parameters to calculate the levelised costs to obtain 1 unit of electricity (kWh), hydrogen (ton), or carrier (ton) stored in the Netherlands from abroad. This includes investment costs, financing costs, operation and maintenance costs and energy costs for all steps for every possible route from every country. These costs are compared to the Dutch production costs, assuming we use Dutch offshore wind electricity. We use this electricity as a reference since the onshore wind and solar potentials are relatively limited.

The model has the following tabs:

Tab	Explanation
Overview	This tab provides a brief overview of the model
Input	Here you can change some general input parameters
Electricity	This tab includes the technology parameters to calculate the levelised cost of electricity
HV_DC_grid	This tab includes the technology parameters to calculate the electricity transmission cost via HV DC cable for route 1
Pipeline	This tab includes the technology parameters to calculate the H2 transport cost via gas pipeline for route 2
Carriers	This tab includes the technology parameters to calculate the production cost of hydrogen and H2 carriers for route 3
Shipping	This tab includes the technology parameters to calculate the H2 carrier transport cost via ship for route 3
Storage	This tab includes the technology parameters to calculate the H2 and H2 carrier storage costs for routes 2 & 3
H2_retrieval	This tab includes the technology parameters to calculate the costs of H2 retrieval from H2 carriers for route 3
Country_details	This tab includes the country parameters & performs import cost calculations using technology parameters from other tabs
Country_results	This tab presents the results of the import cost calculations from the previous tab in a simple table
Country_resultspivot	This tab presents the results of the import cost calculations from the country_details tab in a pivot table
Carrier_properties	This tab includes some properties of hydrogen and hydrogen carriers used in the calculations

Sources	This tab lists the sources used for the data in the model, arranged by tab, technology and parameter
Solar_data	This tab includes the country parameters for the number of full load hours and production potential for solar PV
Onshore_wind_data	This tab includes the country parameters for the number of full load hours and production potential for onshore wind
Offshore_wind_data	This tab includes the country parameters for the number of full load hours and production potential for offshore wind

The model has 2050 as a reference year and assumes a greenfield approach. Some technologies are still immature but are expected to have developed to a certain specification by that year. Because the exact costs and capacities of such processes, and that of many others too, are impossible to predict, we strongly encourage the user to explore these uncertainties. In the next section we discuss how this can be done.

Input

As a user one can interact with this model on several different levels: on a more general and conceptual level via the input sheet, on a country level and on a technology level.

General input sheet

The general input sheet allows you to make some more conceptual decisions regarding the supply chain. You can set the hydrogen demand (which based on the hydrogen content also sets the demand for the carriers). This is assumed to be large enough to warrant the large-scale carrier production plants and HV DC transmission. If you are looking at small scale import, it may be necessary to adjust at least the aforementioned parameters for more realistic results. Based on the demand and supply chain costs, the model calculates the levelised import costs and is therefore relatively insensitive to the demand (again, under the assumption of large-scale plants and transmission).

For the WACC for every country we use a dataset (see technical documentation for details and references) which several people have commented has a rather larger spread, but an order (if arranged from e.g. low to high) that roughly agrees with experience. For example the WACC of the Netherlands in this dataset is only 4.3% (one of the lowest in the dataset), with the mean at about 14%. In practice calculations are typically done with a WACC of about 8% in the Netherlands. We have therefore made it possible to reduce the variance of the dataset and indicate to what percentage of the original variance one would like to reduce the variance. So a value of 0% gives the mean of 14% for every country and a value of 100% the original value. Lastly we have also enabled the user to set one general WACC value that is uniform and applies to all countries.

Regarding the electricity production the user can set the source of electricity production and whether one wants to work with minimal, weighted on maximal costs corresponding to a maximal, weighted and minimum number of full load hours for that technology in this country. This reflects the fact that also within a country some areas have higher wind speeds and/or more sun hours than others. Thus picking the ‘min solar’ option means using solar electricity with maximal FLH and hence minimal costs. One can either pick solar or hybrid as a source. Hybrid is the combination of onshore wind and solar, with an assumption of 0% overlap (in practice this is between about 5% and 15%, with higher numbers for areas with more FLH).

For the first, HV DC route, one can set the whether the HV DC has a number of FLH equal to that of the electricity production or a custom number of FLH. The latter situation is possible for instance if it is connected over several timezones or has a capacity much smaller than that of the electricity generation.

For the third, carrier route, one can distinguish between two conceptually different situations. In the first situation electricity produced abroad is direct transported by HV DC cable to the port, where hydrogen production and carrier production takes place. In the second situation, hydrogen production takes places at the electricity generation facilities directly and is transported via pipeline to the port abroad.

With respect to this route one can also make some decisions about shipping. The first is regarding the bunker fuel. Ships now normally use heavy fuel oil (HFO) as a fuel, which emits CO_2. Given our pathways to reduce emissions worldwide it seems likely that ships too will ultimately have to be climate neutral. We do not know which technologies and/or energy sources will be used for that, but we do know that hydrogen and the carriers we consider are climate neutral. Therefore you can select whether all ships run on HFO, hydrogen (produced in the country of origin) or the hydrogen carrier (produced in the country of origin). Lastly you can also indicate for some carriers (methanol, dibenzyltoluene, dimethylether and oxymethylene ether) whether they are transported in standard, relatively small vessels or so-called very large crude carriers (VLCCs). These VLCCs transport oil (products) but can technically also carry these carriers and are generally more economical than smaller ships.

Country level

On a country level one can change various parameters on the country_details tab. We will cover these in column order.

The first group of parameters is the absolute distance from the electricity production facilities abroad to the Netherlands, along with an estimate the % of that distance that is over land and the % over water. Especially if the country abroad is large and one is looking at one specific region, it could be that the absolute distance is greater or smaller. These parameters are used for HV DC cable and gas pipeline transport. Note that a 'detour-factor' is used for both, to account for the fact that the actual distance is greater than the absolute distance. It can be set on the technology sheets. Similarly one can also change the nautical distance and indicate which channel(s) (if any) this new route would traverse. The HFO bunker price in the port of departure can also be set. Lastly the inland distance from the electricity generation facilities to the port (for route 3) can be adjusted too. The WACC is adjusted on the general input tab but could be set to a specific value for countries individually here.

A few columns later, after the electricity production columns, we find some parameters regarding the energy demand of the country of origin. This energy demand is not used in the import cost calculations, but is used to estimate a net export capacity. This capacity is defined as the sum of a country's solar PV, onshore wind and offshore wind electricity production potential minus the country's own energy demand.

For informative purposes, we first present the population in 2017 and a recent energy demand per capita, the product of which would estimate the current energy demand. This energy demand per capita equals the total primary energy consumption divided by the population. Hence it includes both energetic and non-energetic energy use. We estimate the general long-term energy demand per capita to be approximately equal to the current energy demand per capita of the Netherlands of about 50 MWh/capita. This is to reflect the fact that the energy demand of many countries seems set to grow but also to eventually flatten. What value an individual country's energy demand per capita will be for a specific year, we do not know. This you can change. When multiplied with the population of that year, this gives the energy demand. We use the

United Nations medium fertility projections for 2050 for each country[2] and multiply with a 50 MWh/capita energy demand to estimate a lower bound on the export capacity.

Technology

The technology parameters are adjusted on the relevant tabs (see Structure section). Here you can change for instance the investment costs of a technology, the efficiency of a process or the speed of a specific ship and see how sensitive the import costs are to these factors. For route 1 and 2 the import costs are very sensitive to the transmission investment costs of the HV DC cables and gas pipeline, respectively. You can read more on the technical modelling and data used in the Technical Documentation part of this report.

Also if you want to use this model for a different reference year, it is probably best to re-evaluate the investment costs and efficiencies of various technology as cost reduction are taken into account.

Output

The model calculates the levelised import cost for all routes and the net electricity that can be used for this supply chain. These results are presented on the tabs country_results, which is a simple table whose cell are updated automatically, and country_resultspivot, which is a pivot table *whose data has to be refreshed manually if you make any adjustment in the model*. This can be done by right-clicking the pivot table and selecting 'refresh data'.

Both tables first list the electricity export potential for every country, followed by the lowest hydrogen import cost to import hydrogen from that country to the Netherlands of all routes subject to all input parameters. The next few columns list the hydrogen import costs for all routes. After that, a column shows the electricity import costs via HV DC cable. Next, the import costs of the hydrogen carriers are displayed. And lastly we find the production costs of electricity, hydrogen and all carriers in the country of origin.

Cells are formatted to have a background colour if the value is less than the costs to produce hydrogen or that hydrogen carrier in the Netherlands (using Dutch offshore wind electricity). It should be noted that this model concerns costs, not prices. If all steps in this supply chain are to make a profit and a global renewable electricity, hydrogen and/or hydrogen carrier market emerges, the dynamics of that market will give a *price* for all of these which may be quite different from their *costs*. This note of caution especially holds for the 'cheapest' routes.

More generally, this model and these calculations are simple cost calculations, which by no means are predictions. There is no statement whatsoever on whether it is likely that this supply chain can and will be developed for a certain route. To give some context however, ECN part of TNO has made so-called country profiles of various countries which describe a.o. plans to increase renewable electricity production and can be found at the end of this report. The model for example now simply calculates the HV DC transmission costs for a cable from Peru to the Netherlands, but we do not know yet if we 'could' and would want to build a cable of several thousand kilometres that crosses the Atlantic Ocean. The user therefore effectively has the responsibility to deliver input to, explore and interpret the model and its sensitivities.

[2] UN (2017): World Population. Medium Fertility rate.

Technical Documentation

In this part of the report we provide some technical documentation of the model. We will first show its structure by means of the following scheme:

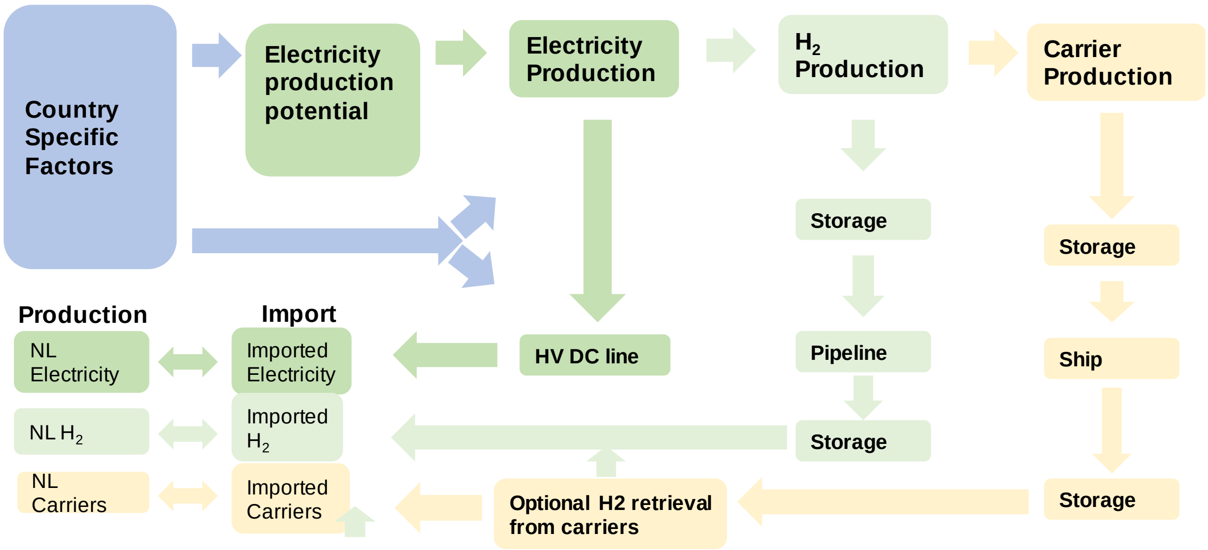

Figure 2: Model overview

The model considers three main supply chain routes and several country specific input parameters. These parameters, henceforth named 'country specific factors', are for instance the weighted average cost of capital associated with the country, the global horizontal irradiance and its distance to the Netherlands. These factors impact the cost calculations employed in the three routes.

The first route would be to produce renewable electricity abroad and transport it directly via a high voltage direct current cable to the Netherlands. The second route would involve using electricity produced abroad to generate hydrogen and transporting the hydrogen via a gas pipeline to the Netherlands. The third and last route would be to store that hydrogen in a hydrogen carrier and send the carrier to the Netherlands by ship, with the option to either use the carrier directly or retrieve the hydrogen from the carrier upon arrival.

This documentation will first go over the country specific factors and will then discuss both the modelling and data used for the cost calculations of the three routes in the order they were presented here.

Solar and wind datasets

The model draws for its electricity generation cost and potential calculations on three public National Renewable Energy Laboratory (NREL) datasets. These datasets are based on other GIS solar irradiation and wind speed datasets. The datasets we use have mapped this GIS data to intersections between full load hour (FLH) classes and areas.

From all datasets and for every country we extract the weighted, minimum and maximum FLHs for the levelised cost of electricity calculation. Besides, we determine for each technology and country the total electricity production potential. For this the user still has to set one variable, which is the rated solar PV module efficiency or installed wind power density.

The details of the datasets are explained below.

Solar PV

The solar PV dataset lists the production potential per solar class per country, for fixed tilt panels[3]. The solar class is a measure of the number of kWh a m^2 of solar panels in standard conditions would produce on average on a day. It is counted in 0.5 $kWh/m^2/day$ intervals, so solar class 9 is the interval between 4.5 and 5 $kWh/m^2/day$. We convert this parameter to a global horizontal irradiance (GHI) by multiplying the class number by 0.5 and adding 0.25, and multiplying this number by 365 days. In this way, we pick the average of each class interval and find the *rated* production of a panel of 1 m^2.

The rated production is not equal to the actual production, however, due to system losses (mostly due to temperature and inversion, more on this in the electricity production section). This is dealt with by means of the so-called performance ratio (PR), the ratio of actual output over rated output of a solar panel. Multiplying the GHI with the PR gives the number of 'actual' (rather than rated) FLH of a solar panel in a given area.

The dataset, as is, does not take into account an explicit PR but rather works with an overall efficiency of 10%. Given that the module efficiency seems set to improve, we have decided to make it possible for the user to set an explicit module efficiency. In addition a PR is taken into account. This overrides the 10% efficiency assumption of the dataset and hence results in a new production potential. The assumed module efficiency is 30%, which is roughly the average of Agora/Fraunhofer projections for 2050[4]. The PR is country-specific and discussed in the country-specific factors chapter of this manual but ranges between 75% and 90%.

An improvement in FLH can be achieved by using single-axis tracking solar panels, of about 200-600 FLH over fixed-tilt [5]. This technology has not been considered here since the solar dataset used in this model reported values for fixed-tilt panels.

Onshore wind

The onshore wind dataset lists the area per FLH class per country[6]. These FLH classes once again are intervals (but, as opposed to solar PV, directly FLH), of which we again take the average. In this dataset there is a FLH cut-off (on the lower end) in the dataset of 2,629 hours. These FLHs we can use directly for the levelised cost of electricity calculation.

To calculate the potential, however, we need to specify the installed wind power density, i.e. the number of MWs of installed wind power per square kilometer. The NREL's standard assumption is a density of 5 MW/km^2, which is the standard setting in the model. The Dutch Ministry of Economic Affairs and Climate uses 6 MW/km^2 [7]. One report suggested onshore spacing guidelines for an 'acceptable' swept area (turbine spacing) of 7 turbines diameters downstream (in the direction of prevalent wind) by 4 diameters across[8]. The power density can therefore be increased by increasing the power to rotor diameter ratio of turbines. Some of the largest turbines at the time of writing, with a 164 m rotor diameter and a 8 MW capacity[9], would according to these spacing rules have a power density of $8/(0.164*7*0.164*4) = 10.6$ MW/km^2.

[3] NREL (2014): Solar Resources by Class and Country. Tilt.
[4] Agora/Fraunhofer (2015): Current and Future Cost of Photovoltaics
[5] M. Fasihi and C. Breyer (2018): Synthetic Fuels and Chemicals: Options and Systemic Impact
[6] NREL (2014): Wind Resources by Class and Country. Integrated.
[7] Blix (2017): Offshore wind boven de wadden
[8] X. Lu et al (2009): Global potential for wind-generated electricity. PNAS 106, 10933-10938
[9] Royal Academy of Engineering (2014): Wind Energy

For truly large scale wind power implementation over very large areas some argue that lower wind power densities should be used to decrease shadowing (the effect of wind turbines effectively decreasing wind speeds for other turbines further down the direction of wind).

The standard wind power density assumption we work with is the NREL's, of 5 MW/km^2. One can of course adjust this in the model.

Combining the wind power density and area per FLH class, the model then calculates the total onshore wind power electricity production potential.

Offshore wind

The offshore wind dataset lists the number of potential GWs per FLH class per country, under the assumption of a 5 MW/km2 wind power density[10]. These FLH classes once again are intervals, of which we again take the average. In this dataset there is a FLH cut-off (on the lower end) in the dataset of 3,154 hours. These FLHs and GWs we can use directly for the levelised cost of electricity calculation. We also made it possible to change the installed wind power density.

For offshore wind turbines the aforementioned authors suggest more generous spacing rules, i.e. 10 rotor diameter downstream and 5 diameters across[11]. The 8 MW turbine with a 164m rotor diameter example would then have a power density of 8/(0.164*10*0.164*5) = 5.9 MW/km^2. This is about 40% less than the equivalent onshore wind power density for the same turbine.

Country Specific Factors

Several 'country-specific parameters' also influence the cost of importing electricity, hydrogen and various other energy/hydrogen carriers and feedstock to the Netherlands. We will discuss them in this section.

Distances

There are several distances the model takes into account. These are used for transport cost calculations.

For electricity transport via HV DC cable and hydrogen transport via pipeline we calculate the absolute distance from the centre of the country of origin to the centre of the Netherlands using an online distance calculator[12]. This absolute distance thus also includes inland transport. For electricity transport we estimate the share of the absolute distance that is over land and the share over water, as the associated investment costs are vastly different.

The nautical distance we determine as follows. We look for the main 'industrial' port of each country and then compute the nautical distance between that port and the port of Rotterdam using yet another online distance calculator[13] which takes into account actual shipping routes. If multiple routes are possible, we pick the shortest route and note the channel this route involves (if any), or the route that is not the shortest but no more than a few % longer than the shortest and does not involve a channel. This reflects the idea that there is a very minor concession in travel time but a significant saving in toll fees.

For the shipping route so far we have not yet included inland transport to the port, but only transport from port to port. This inland transport distance would be the average distance between electricity generation locations and the port. It is assumed that inland transport occurs via HV DC cable of hydrogen pipeline, i.e. the carrier conversion takes places in the port and the hydrogen generation either at the electricity

[10] NREL (2014): Global Wind Potential Supply Curves by Country, Class and Depth (quantities in GW).
[11] X. Lu et al (2009): Global potential for wind-generated electricity. PNAS 106, 10933-10938
[12] Online distance calculator used August 2018: distancefromto.net
[13] Online distance calculator used August 2018: sea-distances.org or marinetraffic.com/en/voyage-planner

generation facilities (pipeline route) or at the port (HV DC route). Clearly, this average distance depends on the size of the export streams (larger export demand calls for more dedicated electricity generation which will have a different topology), but also on how the solar and wind sites are distributed across the country.

Here we work with a simple computation to determine a generic inland distance to the port for each country. One can however adjust this easily, or even ignore inland transport altogether. The calculation goes as follows: we take a country's land area[14], treat it as if it were a circle (the optimal distribution around a point) and compute its 'radius', and multiply this radius with a factor of 1.2. By calculating the minimal radius (that of a circle) and multiplying that with a factor greater than 1, one obtains a very rough estimate of the distance of crossing half the country along the longest axis. This estimate is worse as the country's land mass distribution deviates more from that of a circle. For instance, this estimate will be far off for a country like Chile. Also, for countries with a large land area, one would most likely not have to transport energy over half its radius as there is most likely sufficient electricity generation potential within a smaller distance from the port.

WACC

The weighted average cost of capital (WACC) is an important factor in these supply chain cost calculations, as it is a single factor which impacts virtually all calculations. We work with a WACC per country. All investments done in a country are financed through the respective country's WACC. For transport infrastructure (HV DC cables and pipelines) it is the WACC of the country of origin which determines the project's overall WACC, even though it crosses various countries. In principle one would work with the highest WACC of all countries in the chain, but as a modelling short cut we work with that of the country of origin, which is generally always higher than the Dutch WACC. Ships are financed with Dutch WACC.

We use a dataset from Ondraczek et al. for a country's WACC[15]. This dataset focuses on investments in solar PV installations and dates from 2014. Often WACC are specified for a certain sector or plant type within a certain region. Investments in electricity generation arguably call for other WACC than investments in novel carrier production technologies, or long distance HV DC transmission cables. Also, sometimes governments can 'guarantee' a lower WACC for overseas projects, to remove a potential financing barrier.

We however work with a general WACC per country. One can set this equal to the WACC of the Ondraczek dataset, a readjusted WACC from the dataset with lower variance, or to a uniform or manual value per country.

Own energy demand

To determine the likely 'true' export potential of a country, we also take into account a country's own energy demand. To equate the electricity generation potential and the export potential is to assume the country imports all its energy or uses other energy sources. So if we subtract a country's own energy demand, we have a more reasonable estimate of the export potential. Also this means that adding the export potential would give the true net excess energy generated through these means (whereas adding the former would not include demand).

We estimate the future energy demand by multiplying the future energy demand per capita and the future population. The energy demand per capita is the total primary energy consumption (which includes both energetic and non-energetic (feedstock) usage) divided by the population. For each country we first show the current (or recent) energy demand per capita[16]; the current and 2050 population estimate per country

[14] World Bank (2017): Land Area in sq m.
[15] J. Ondraczek et al. (2014): WACC the dog: the effect of financing costs on the levelised cost of solar pv power. Renewable Energy 75, 888-898
[16] World Bank (2017): World Development Indicators. 2013 data.

we obtain from the latest United Nations projections[17]. For the future energy demand per capita we assume the current Dutch energy demand per capita of roughly 50 MWh/capita, but this can be adjusted. This reflects the idea that many countries still have an increasing energy demand which we assume will level out at approximately the Dutch energy consumption per capita. In fact, electrification generally results in an increase in energy efficiency, which may therefore lower the energy demand per capita.

We are not claiming that all countries will have a Dutch energy demand per capita by 2050, rather we are saying that it is likely that it will level out, at some point, around that value. Neither are we arguing that electricity will be the only energy carrier, let alone by 2050; just that it is likely that ultimately the world will be powered mainly by renewable solar and wind electricity. This electricity can (and will) of course be used to generate hydrogen and other energy carriers and feedstock.

Hence, subtracting from the total electricity generation potential, from solar PV panels and wind turbines on land as well as offshore wind turbines, the country's own energy demand gives an estimate of the long-term export potential. If this is (strongly) negative, the country is likely to become (or stay) a net importer; if this is (strongly) positive, the country could potentially become (or stay) a net exporter; if this is relatively close to zero (TWh), the country could still have significant imports or exports if it is large in energy demand, but will likely play a small role in a future renewable energy market if it is small in energy demand.

This net export potential does not influence cost calculations. It is just intended as an informative measure of each country in a world largely powered by renewable electricity from solar and wind.

We use the export potential in combination with the import cost for renewable electricity, hydrogen and/or carriers as the main criteria to select a number of countries. We want to see more in-depth for these countries how the development of solar and wind energy is forecasted until 2050, because the likelihood of the export of renewable electricity, hydrogen or derived carriers is not only dependent on costs relative to other energy sources and the theoretical export potentials but also the development of production capacity in a specific country. See for more information on country profiles the corresponding chapter.

[17] UN (2017): World Population. Medium Fertility rate.

Route 1: Electricity transport

The first route we consider involves electricity and electricity only. We discuss the three electricity generation technologies considered in this work, and the way in which electricity is transported to the Netherlands.

Production

We consider the following electricity generation technologies: solar PV, onshore wind and offshore wind, in that order. We describe our techno-economic modelling and the levelised cost of electricity (LCOE) calculation, with 2050 as a reference year. All base financial data is obtained from Agora[18]. For all technologies we determine a country's minimum, weighted and maximum LCOE, as determined by the FLH classes observed in that country.

Solar PV

Solar PV panels are estimated to cost 306 €/kW (installed), which is the optimistic 2050 estimate from Agora, with OPEX at 1.5% of CAPEX. Agora assumes a lifetime of 25 years and does not take into account a performance ratio (PR). We repeat that the PR is the ratio of the actual electricity output over the rated output of a solar PV panel and elevated temperature the main source of loss. The PR typically is somewhere between 0.75 and 0.9. The NREL has calculated a weather corrected PR of 0.85 for the US, with the summer PR around 0.75 [19].

Not only the PR, but also the lifetime suffers from high temperatures. We therefore install the following heuristic in our model: if the highest global horizontal irradiance (GHI) exceeds 2500 hours, the PR is 0.75 and the system lifetime 15 years; if the GHI is between 2300 and 2500 hours, the PR is 0.8 and the system lifetime 20 years; if between 2100 and 2300 hours, 0.85 and 25 years respectively; and if below 2100 hours, 0.9 and 25 years.

For the LCOE, we divided the annualised investment costs (total investment divided by lifetime), financing cost (WACC times total investment), and operational costs by the annual electricity production. The WACC and lifetime are country specific.

Onshore wind

Onshore wind turbines are estimated to cost 779 €/kW (installed), which is the optimistic 2050 estimate from Agora, with OPEX at 2% of CAPEX and 25 y lifetime. The LCOE calculation is performed as described under the solar PV section above, with the WACC taken from the country dataset.

Offshore wind

Offshore wind turbines are estimated to cost 1400 €/kW (installed, excluding grid connection), which is the optimistic 2050 estimate from Agora, with OPEX at 3% of CAPEX and 25 y lifetime. Depending on the route, these turbines are connected to the grid and transport electricity to the Netherlands or generate hydrogen locally which is transported via pipeline. This can be set in the inland transport section. The LCOE calculation is performed as described under the solar PV section above, with the WACC taken from the country dataset.

[18] Agora (2017): The Future Cost of Electricity Based Synthetic Fuels. Electronic appendix: Model
[19] NREL (2013): Weather-corrected Performance Ratio

Transport

Electricity generated is directly transported per high voltage direct current (HV DC) cable from the country of origin to the Netherlands (after perhaps some local transport and/or aggregation). There exist three kinds of cable installations: overhead, submarine and underground. This is also the order of increasing costs (in €/MW/km) and decreasing losses (in %/1000 km).

The model uses the country-specific distance from the centre of the country of origin to the centre of the Netherlands, as well as the shares of the distance over land and over water. We use a detour-factor of 1.2, i.e. this distance is multiplied with the detour-factor which accounts for urban or geographical features which are to be avoided in installing this cable. The distance over land is covered with overhead cables, the distance over water with submarine cables. The costs (more on that shortly) and losses are calculated for each independently.

The full load hours the user specifies. Given that we do not assume electricity storage before transport, every kWh of electricity produced is directly send onto the cable. The number of full load hours the cable has may therefore be relatively low, if only one country's combined wind and solar electricity production is taken into account (say around 5,000 FLH). If this country or the cable crosses various timezones and other regions can also send electricity on the HV DC cable, the number of FLH may be significantly higher due to different production profiles. Also, if the capacity of the HV DC cable is much smaller than the capacity of solar and wind electricity generation (and any excess electricity is absorbed in the country of origin), one would also have higher FLH. In the model one can thus either set the number of FLH of the HV DC cable to that of solar and wind electricity production combined, or specify a value. 10% additional capacity is assumed.

Costs

Investments costs, operations and maintenance costs and losses per 1000 km of cable and station are taken from [20]. This is based on a 3 GW, 800 kV cable. Given that costs depend linearly on both distance and capacity, the levelised cost of electricity transport is independent of volume (provided one meets at least the capacity of a single cable).

One last note: the model simply calculates the transport costs for every country straight to the Netherlands. This is not to be interpreted in any way as a likelihood that it will be done, especially for submarine cables across thousands of kilometres of oceans. In addition, one may want other regions to connect to form a network rather than a one-way connection between two points. If one were to connect Canada to the Netherlands, this would likely occur via Greenland, Iceland and the United Kingdom.

Storage

As described before, no electricity storage is taken into account, both in the country of origin and in the Netherlands. This could be an optimisation of the chain, as storage in the former could increase the FLH of the HV DC cable. If affordable large-scale storage is available, this could lower the costs of this specific electricity supply chain.

Once in the Netherlands, the electricity could be used to generate hydrogen, which could in turn be stored in salt caverns. We have calculated the levelised costs of hydrogen if one does that, using the hydrogen production cost parameters from the next chapter.

[20] DII (2014): Desert Power: Getting Connected

Route 2: Hydrogen pipeline transport

The second route would involve producing hydrogen using the electricity at the location where it is generated, and then transporting it via a pipeline (after compression) to the Netherlands, where it can be stored in salt caverns. For hydrogen production we consider alkaline and proton exchange membrane (PEM) electrolysis

A pipeline is a reliable and high CAPEX means of transport, with typically low levelised costs at high transport volumes. We consider gaseous hydrogen pipeline transport.

Production

For a description of how we perform our techno-economic calculations, please refer to the section Hydrogen Carrier Transport – Production. Below we mainly discuss the data for hydrogen production.

Alkaline electrolysis

Alkaline electrolysis is a hydrogen production technology that has existed for several decades. It concerns the electrochemical splitting of water into hydrogen and oxygen.

Although mature, it is however expected that its cost can still decrease significantly. According to some experts, equipment costs can drop to 150 €/kW and installation costs to 200 €/kW, giving total investment costs of 350 €/kW installed towards 2030. These costs are expected to decrease further – in academia some people work with investment costs of about 220 €/kW in 2050[21]. We are assuming an electricity demand of 52 kWh/kg H_2 delivered at a pressure of 30 bar, which corresponds to a 0.65 LHV efficiency. OPEX are assumed to be 3% of CAPEX and the lifetime to be 30 years. No revenue streams other than H_2 production are taken into account, e.g. oxygen production (by-product) is not assumed to generate any income.

PEM

PEM is a different and younger electrolysis technology, which currently incurs higher production costs than alkaline electrolysis but is also expected to undergo deeper cost reductions.

According to some experts, equipment costs can drop to 300 €/kW and installation costs to 300 €/kW, giving total investment costs of 600 €/kW installed towards 2030. Here too, further cost reductions are expected towards 2030. We are assuming an electricity demand of 50 kWh/kg H_2 delivered at a pressure of 30 bar, which corresponds to a 0.66 LHV efficiency. OPEX is assumed to be 3% of CAPEX and the lifetime to be 30 years. Again, no revenue streams other than H_2 production are considered in the hydrogen production cost calculation.

FLH

The FLH of these electrolysers depends on the way one operates them. One way would be to connect them to solar and wind electricity in a uniform capacity ratio (1 : 1 : 1, solar: wind : electrolyser), which would give FLH that are roughly equal to the sum of the solar and wind electricity generation FLHs. If no wind data is available, only solar electricity is used for the electrolyser.

Alternatively one could install an undercapacity of electrolysers relative to the solar and wind capacity. In this way one can boost the FLH of the electrolyser. This would however also mean that other processes in

[21] Based on a discussion with Mahdi Fasihi, LUT

that country would have to absorb the electricity production peaks that are thus ignored by the electrolyser; if not, one would 'throw away' some of the electricity, increasing the levelised cost of electricity.

Transport

Hydrogen is first compressed and then fed into a pipeline which connects the centre of the country of origin with the centre of the Netherlands. Here too, just like for the electricity transport, a detour-factor of 1.2 is taken into account.

The capacity of this means of transport is set by the user on the input sheet with the hydrogen demand. From this we compute the minimum flow rate (assuming continuous operation) and add 10% to account for some flexibility. Using the hydrogen density at the pipeline pressure (assumed 100 bar) and a hydrogen speed of 15 m/s, we can compute the volumetric flow rate and the pipeline diameter.

Investment costs were found to scale with the square of the diameter. We observed a significant difference in investment costs reported. The user can select the source in the model. The sources we use are [22], [23] and [24]. For a hydrogen demand of 800 kiloton, this would require a pipeline with a 0.65 m diameter at investment costs of 1.72, 1.32 and 0.78 M€/km installed, respectively. The latter Gasunie reports is in line with their experience regarding natural gas pipelines costs and expectation regarding hydrogen pipeline costs. As such, this is the default option. We assumed O&M costs of 4% of CAPEX and a 40 years lifetime, with hydrogen losses of 0.5%[25].

Hydrogen is first compressed to 100 bar, which costs about 0.7-1.0 kWh/kg from atmospheric pressure from [26]. Here we however start with hydrogen at a pressure of 30 bar. ECN part of TNO's modelling efforts show that the energy requirement to compress hydrogen to 100 bar (starting at 30 bar) is 0.20 kWh/kg. The associated investment costs for the compressor are taken and scaled from [27]. Lifetime and losses are set to 15 years and 0.5%, as per the same source.

Clearly, the costs of this transport route are extremely sensitive to the pipeline investment costs, as all costs (depreciation, WACC and OPEX) depend on it. For the aforementioned 0.65 m diameter pipeline, another source reports an investment estimate calculation method which results in investment costs of 1.30 M€/km rather than 1.72 M€/km[28]. This would reduce the levelised cost of hydrogen transport by 25%. We therefore recommend the user explores this sensitivity.

Lastly, just like for the HV DC cable, the calculations for the pipeline concern a direct end-to-end connection without any other edges or nodes. Unlike the HV DC case, where investment cost depend linearly on the capacity, here larger capacities do generate cost reductions. The volume and investment costs both increase with the square of the diameter, but the volume increases with a larger factor. Hence it is both more cost-efficient and more logical to create a network with one or more long, large volume edge(s).

Storage

Once hydrogen has arrived in the Netherlands, it can be stored in salt caverns. This is a relatively affordable large-scale storage solution. We work with a reference cavern of 500,000 m^3 with a 35 M€ investment[29], a 0.28 investment scaling factor and a 30 years lifetime[30]. OPEX are assumed to be 1.5% of CAPEX and

[22] M. Robinius et al. (2018): Comparative Analysis of Infrastructures: Hydrogen Fueling and Electric Charging of Vehicles
[23] C. Yang & J. Ogden (2007): Determining the lowest-cost hydrogen delivery mode
[24] ECN (2017): Verkenning Energie-functionaliteit Energie Eilanden Noordzee
[25] M. Robinius et al. (2018): Comparative Analysis of Infrastructures: Hydrogen Fueling and Electric Charging of Vehicles
[26] C. Yang & J. Ogden (2007): Determining the lowest-cost hydrogen delivery mode
[27] M. Robinius et al. (2018): Comparative Analysis of Infrastructures: Hydrogen Fueling and Electric Charging of Vehicles
[28] C. Yang & J. Ogden (2007): Determining the lowest-cost hydrogen delivery mode
[29] Using a 1.15 €/GBP factor and H21 North of England (2018). Confirmed to be in line with Gasunie experience
[30] M. Reuss et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302

energy requirements 0.10 kWh/kg H_2 (for pumps mainly). The storage size is assumed to be equal to 30 days of hydrogen production and all hydrogen passes through storage. The latter two assumptions are general storage assumptions which also hold for the carriers of the next chapter. Some gas will however act as cushion gas and will not be retrieved. These losses are assumed to be negligible over long-term operation.

It should be noted that we do not consider large scale storage in the country of origin. Some countries have salt caverns at their disposal; others however do not and may have to resort to other large-scale hydrogen storage techniques. This means that the actual delivered hydrogen costs are ever-so-slightly to somewhat higher than the model calculates. Alternatively and similarly to HV DC cables, one could also ignore storage in the country of origin and work a smaller number of FLHs of the pipeline.

Route 3: Hydrogen carrier transport

The third route is to not stop at hydrogen, but produce a hydrogen carrier, which is then transported by ship to the Netherlands. Upon arrival, the carrier can either be used directly, or the hydrogen can be retrieved from it.

This chapter is set up slightly differently, in the sense that it first describes a format according to which all carriers under consideration will be discussed and then discusses them according to that format. The first part also includes a description of the general assumptions and modelling, the second part only the specific data used per carrier.

The modelling structure is as before and divided in production, transport and storage and will be discussed in that order first. After that the data per carrier follows.

Production

In this section we describe the model and techno-economic calculations with respect to hydrogen carrier production. This process by definition takes hydrogen as an input, typically in addition to other molecules whose costs are either specified or calculated.

The capacity of each production plant is set to that of a representative large-scale existing plant, or what is deemed feasible in the literature for those technologies that are still under development.

Costs

To calculate the levelised production costs of each carrier, we consider five cost components:

1. **Depreciation of investments**
   Investments are depreciated linearly to zero over the plant's lifetime. The lifetime is generally assumed to be 20 years and the plant to run nearly continuously (8000 FLH), unless indicated otherwise. The investment costs are of course related to a plant's capacity. Some plants are scaled with a scaling factor from reference plants; both are typically obtained from the literature.
2. **Cost of capital**
   The cost of capital equals the WACC times the investment. For a discussion on the WACC, see the country specific factors section.
3. **Operations and Maintenance costs**
   Operations and maintenance costs are assumed to be 3% of CAPEX, unless indicated otherwise.
4. **Energy costs**
   Energy costs are calculated based on the energy requirements in kWh/kg product, which is the sum of electricity and heat requirements. For the energy costs per kWh we use the electricity source the user has selected. This implicitly assumes all processes are fed with electricity (or other

carriers which effectively have the same energetic costs). This is a simplification but avoids having to specify the costs of other energy carriers for each country. The most problematic case is high temperature heat, where electricity is likely replaced with carbon neutral hydrogen. If hydrogen is used, this would increase the total energy requirements due to efficiency losses in hydrogen production as well as the energy costs.

5. **Costs of input molecules**
   The molecules that are fed into the process are paid for on the basis of their levelised production costs or purchasing costs. If these input molecules are modelled, they are modelled in the way that is described in this section. E.g. if CO_2 is an input molecule for methanol production, the production costs of CO_2 are also modelled.

Dividing the yearly costs by the yearly product output gives the levelised production cost.

A cost distinction should be made between the situations in which the carrier itself is demanded and the situations in which the carrier merely serves as a carrier and hydrogen is demanded. In the latter case the spent fuel, i.e. the molecules one obtains upon retrieving hydrogen from the carrier, are recycled. Whereas all input in the former case ‘ends up’ in the product and is a cost, the spent fuel is an asset for which one pays capital costs. In the latter case we assume that the investment in the carrier retains its value, but that one pays capital costs indefinitely on the initial investment. In this case OPEX also includes carrier replacement to compensate for losses in the full chain.

Transport

Transport of hydrogen carriers is split into two components: inland transport and shipping transport. We will briefly discuss the first and then extensively discuss the second.

Inland transport concerns the transport from the electricity generation locations to the port where it is assumed hydrogen carriers are produced and sent off to the Netherlands. Conceptually then, there are two main options: either electricity is transported straight to the port by means of an HV DC cable and hydrogen is generated in the port, or hydrogen is generated directly at the electricity production facilities and transported by pipeline to the port. The costs of both routes are calculated using the parameters and method described in the previous chapters, and over the inland distance described in the Country chapter. One can however also decide to ignore these costs in the model, should the infrastructure necessary already be available for example.

The second component is to transport the carrier from the port of the country of origin to the Netherlands by ship. A ship is a rather flexible and relatively low CAPEX means of transporting carriers from one place to another. Which ship is capable of fulfilling a specific journey, depends on many factors. The next few paragraphs will shed some light on this. After that, we discuss how we perform the techno-economic calculations for this part of the model.

Most carriers under consideration here are liquids (including liquefied gases), which are transported in tankers. Which tankers specifically, depends on the compound and the IMO classification. The latter classification categorises chemicals into three classes, with class I calling for the most stringent safety measures and class III for the lowest safety measures. In addition, compounds can pose additional challenges. Liquefied gases for instance boil off, i.e. vaporise. These ships are semi- or fully refrigerated, to keep them at the temperature required. Tankers can also be pressurised or have specific coatings (especially for aggressive chemicals like acids).

A ship that meets all criteria can still come in various sizes. Generally, the bigger ship is the more economical. However, there are also other factors to feature in: certain ships are too large to dock at certain ports or to pass through certain channels (or incur much higher toll fees). Sometimes port development may also be necessary.

Moreover, there are various routes a ship can take between two ports. Here there are two trade-offs between costs and travel time: 1) the greater the ship's speed, the lower CAPEX and crew costs, but the higher the fuel consumption and costs, and inversely. 2) a shorter route may involve a channel, which means lower CAPEX and crew costs, but also toll fees.

We have focused on largest-in-class ships and existing regulations and practices. This means for instance that methanol is transported in the largest available methanol tanker, and not in a very large crude carrier (VLCC), which is technically possible. We have however made it possible in the model to choose the VLCC as a ship for carriers for which this is deemed technically feasible. Every type of ship in the model is modelled on an actual ship, whose technical data are used. Its carrying capacity expressed in terms of mass is assumed to be 90% of its deadweight[31].

Costs

Ships are either owned or chartered. Chartering a ship can consist of a single journey (voyage charter) or an extended period of time (time charter). In practice, many ships are chartered, with charter rates (expressed in $/day) varying wildly depending on supply and demand and utility prices. To illustrate this, chartering an LNG vessel cost between 20 k$ and 140 k$ per day in the past 5 years[32]. Sometimes charterers offer a vessel for a price below their own OPEX.

Given that transport would be a 'fixed' element of a dedicated renewable electricity and molecules supply chain, we worked out the techno-economics of owned ships. It may be possible that chartering is more financially attractive for certain individual journeys, but in the long run an ownership case provides a more solid cost baseline. Alternatively, one can in our model change the levelised capital cost to a charter rate to simulate what would happen.

A journey consists of the following costs elements:

- Levelised investment cost
- Capital costs
- O&M (including crew costs)
- Fuel cost
- Canal fees
- Port Costs
- Brokerage fees (do not apply since no charter)
- Insurance and taxes (not considered here)

Levelised investment costs and capital costs

We have taken investment costs as reported for new ships. They are either the investment costs of the specific example ship, or from a ship of the same type and capacity. All ships are assumed to have a lifetime of 20 years and are financed with Dutch WACC.

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[31] M. Fasihi et al. (2016): Techno-Economic Assessment of Power-to-Liquids (PtL) Fuels Production and Global Trading Based on Hybrid PV-Wind Power Plants. Energy Procedia 99, 243-268

[32] Oxford Institute for Energy Studies (2018): The LNG Shipping Forecast: Costs rebounding, outlook uncertain

O&M costs

Operational and maintenance cost are taken from Moore and Stephens for all ship types [33]. They include crew costs, small maintenance and a large dry-dock maintenance as well as all non-energetic operational costs.

Fuel costs

In terms of fuel, there are three options. The first and conventional option is for ships to use heavy fuel oil (HFO). This however seems inconsistent – an international renewable electron and molecule supply chain that still includes chain CO_2 emissions. The focus in shipping is now on minimising SO_x emissions, and is currently achieved through the installation of scrubbers (an end-of-pipe solution) or a switch to a cleaner but typically still CO_2 generating fuel such as LNG or methanol. Some studies into alternative and carbon neutral and carbon free energy carriers and their costs have been done recently[34] [35].

At this stage, it does not seem clear what is the carbon-neutral source of energy of ship propulsion. Also the (quantitative) impact on investment costs and various other parameters is far from evident. It is however possible and many would argue plausible that the total shipping costs will be *higher* than today's cost. This effect is very important, as it means that these higher costs may render importing renewable hydrogen carriers uninteresting from a financial point of view. The converse is also true, which however calls for very large cost reductions (to make hydrogen carriers cheaper than current fossil fuel prices). In short, with a long-term perspective, one should therefore also consider other sources of energy than HFO.

We have included two other carbon neutral options: using hydrogen as a fuel, or using the hydrogen carrier the ship carries as a fuel. In the last case, the LOHC and NaBH4 option would supply hydrogen. Since the carbon hydrogen carriers contain carbon from the atmosphere, the act of combusting these carriers is carbon neutral: e.g. combusting methanol (with carbon from the ambient air) does not add any new CO_2 to the atmosphere that previously was not there. Of course there are more energy carriers that could potentially be used in shipping, but it is beyond the scope of this work to investigate all these options. We did not consider the impact on other shipping parameters (e.g. investment costs of the engine). One can however manually adjust the ship investment costs on the shipping sheet to simulate this.

There are already regional differences in the price of HFO, and the price spread will most likely be even larger for renewable carbon neutral energy carriers given the large spread in renewable energy generation cost. We assume that these shipping fuels are produced in the country of origin. This however results in production cost partially determining transport (fuel) cost. Countries with relatively expensive hydrogen production will have relatively large shipping fuel costs, even though cheaper shipping fuel may be available from their neighbours. However, the countries with the lowest hydrogen generation cost will have also have the lowest shipping fuel cost. This does mean that 'the best' combination does exist, and that if the cost of the hydrogen/carrier thus imported is higher than that of the Dutch hydrogen/carrier, the relative fuel cost cannot be 'optimised' any further.

Hydrogen and carrier costs are thus calculated for every country. Reference HFO costs are assumed to be the same in all ports and are given the latest value from the BW380 index, 383 €/t HFO at the current exchange rate [36]. These costs are however very volatile and uncertain towards the future, but they can be adjusted by the user.

[33] Moore Stephens (2017): Ship operating costs: current and future trends
[34] Lloyd's Register (2017): Zero-Emission Vessels 2030. How do we get there?
[35] OECD International Transport Forum (2018): Decarbonising Marine Transport. Pathways to zero-carbon shipping by 2035
[36] Bunkerworld (2018): BW380 Aug. 2018

The fuel costs are multiplied with the daily fuel consumption to give the daily fuel costs on sea. Fuel consumption is calculated based on a ship's displacement and speed, according to Barras[37]. When in the port, it is assumed the ship's fuel consumption is 10% of that on sea. It is also assumed that ships that return without spent fuel carry ballast with a mass equal to 20% of their capacity.

Canal fees

Some shipping routes involve the Panama or Suez channel, whose authorities collect toll fees. We used the Wilhelmsen Toll calculators to estimate the toll fees, with the total toll fees equal to 1.9 times the ballast toll fee and the Suez Net Tonnage of each ship assumed to be equal to half its DWT[38]. It should be noted that some ships are too large to pass through the channels. Our ship selection does not pose any problems for the Suez channel, but the VLCC and Q-max LNG carrier cannot pass through the Panama channel. As such we have simply marked this journey-ship combination as impossible, and not calculated an alternative route. This however only applies to a very small number of routes and carriers (< 1%).

Port costs

Port tariffs also apply. We calculate these according to the latest Port of Rotterdam guidelines, taking into account commodity and several ship characteristics such as GT[39]. The fees in the port of origin are assumed to be the same as the Port of Rotterdam fees. Further, we assume each ship stays in any port for 3 days, and has a daily fuel consumption which equals 10% of its daily fuel consumption on sea.

Return

The ship always returns from Rotterdam to its port of origin. In the case of carbon containing carriers, DBT, NaBH4 and metalhydrides, the spent fuel is returned. In all other cases the ship carries a ballast load, assumed to have a mass of 20% of max cargo load. It would be financially interesting to ship back some commodity as that could reduce the costs allocated to this supply chain.

Calculation

Based on the ship's speed, distance and time spent in the port the model calculates the duration of a roundtrip. The fuel consumption is calculated for each part of the journey individually, and so are the associated costs. The daily CAPEX and OPEX costs are multiplied with the total journey time. Adding the journey's CAPEX, OPEX, fuel costs, port fees and channel fees (if applicable) gives the total costs of the round trip. If we divide these costs by the quantity of carrier delivered, we obtain levelised shipping costs in €/t (or per m^3 or MWh). One can then also calculate how many ships one would need to meet the hydrogen demand set by the user.

Storage

Storage is taken into account both for products (long-term) and for reactants (short-term). Day storage of reactants is assumed to be 8 hours, product storage equal to 30 days of production[40]. By product we mean the hydrogen carrier; all intermediate products fall in the reactant category.

If the carrier (rather than the hydrogen it carries) is demanded in the Netherlands, there is day storage at the production facilities and product storage in the port of origin and the port of Rotterdam.

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[37] Barras (2004): Ship Design and Performance for Masters and Mates
[38] As in Leth Agencies 2018
[39] Port of Rotterdam (2018): General Terms and conditions including port tariffs
[40] E.R. Morgan (2013): Techno-Economic Feasibility Study of Ammonia Plants Powered by Offshore Wind

If the hydrogen (rather than the carrier itself) is demanded in the Netherlands, there are two scenarios: one with spent fuel and one without. If retrieving hydrogen from the carrier also leaves other products of value, there is spent fuel. This is the case for DBT, NaBH4, metalhydrides and all carbon containing carriers (which leave CO_2). In the scenario without spent fuel, the storage required is the same as if the carrier is required: day storage at the production facilities and product storage in both ports. It is assumed that in Rotterdam hydrogen is retrieved in accord with demand, so no additional hydrogen storage is required. If there is spent fuel, we require some additional storage. This is storage of the spent fuel in Rotterdam and in the port of origin.

It is assumed that product storage capacity, both abroad and in Rotterdam, is equal to 30 days of production times an additional buffer factor of 1.1 (i.e. adding 10%, so 33 days in total).

Costs

Costs taken into account for storage modelling are, similarly to before

- Depreciation
- Capital costs
- O&M costs
- Energy costs

Storage lifetime for products is assumed to be 30 years with OPEX at 2.5% of CAPEX, unless noted otherwise. Reactant storage is at 20 years and OPEX at 2% of CAPEX. This means that the first three cost components, depreciation, capital costs and O&M costs, can be computed once the investment costs for a given tank of the carrier are specified. The bulk of the energy requirements data has been supplied by Vopak; for other compounds energy requirements are assumed to be 0.10 kWh/kg carrier for pumps[41]. Energy costs are again the minimum weighted electricity costs of the three generation technologies.

H_2 Retrieval

Once arrived and stored in the Netherlands, it is optional but possible to retrieve hydrogen from the carrier. Sometime this is intended (e.g. with a liquid organic hydrogen carrier (LOHC)), sometimes one has optionality and can choose between using (or selling) the carrier as a feedstock and the hydrogen (e.g. with ammonia).

This requires investment in a plant on Dutch soil capable of regenerating hydrogen. This of course increases cost and energetic losses. Carrier storage is modelled, but hydrogen storage post retrieval: it is assumed that one has enough flexibility given the upstream storage to produce hydrogen in such a way it can be fed directly into the process that demands it. If not, hydrogen storage costs in e.g. Dutch salt caverns would have to be added.

Costs

Costs taken into account for storage modelling are, similarly to before

- Depreciation
- Capital costs
- O&M costs
- Energy costs

[41] M. Reuss et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302

The same general assumptions as for production hold: 8000 FLH, 30 years lifetime and OPEX at 3% of CAPEX and energy costs equal to weighted electricity costs. Energy requirements vary significantly.

If hydrogen is retrieved, one is left with spent fuel in the case of $NaBH_4$ and DBT and with CO_2 in the case of the other carbon-containing carriers. The storage of the spent fuel of the former two compounds is assumed to cost the same as that of the carrier itself. For the other cases where CO_2 is the spent fuel, CO_2 is first liquefied and then stored. CO_2 liquefaction investment costs are taken from [42] and energy requirements from [43]. It is assumed that all spent fuel is sent back in the same vessels as the original carrier arrived in.

Reactant production and storage

Before going over the various carriers, we first discuss the production and day storage of their reactants: H_2, N_2 and CO_2. These costs are determined as described in the production and storage sections, with their general assumptions.

Hydrogen

The production costs of hydrogen are discussed in the previous chapter on the hydrogen by pipeline route, under Production. We have yet to touch upon hydrogen day storage however. This typically occurs in pressurised tanks at a near 100% efficiency (excluding compressions energy requirements). The IEA quotes pressurised tank storage investment costs of 6-10 USD/kWh, of which we take the average [44]. An academic paper reports similar investment costs for future hydrogen storage; current costs are much higher [45].

Nitrogen

Nitrogen can be produced in a variety of ways, but the most developed and economical large-scale production method is cryogenic air separation. Investment costs were taken and scaled from [46] and [47]. Energy requirements, 110 kwh/t N_2, were obtained from the latter source too.

Nitrogen storage is assumed to cost the same as ammonia storage, discussed in the next section.

CO_2

CO_2 is obtained through direct air capture (DAC). This is a technology which can be employed ‘anywhere’, but is yet to scale up and achieve its projected cost reductions. Carbon capture from offgases is generally cheaper, but offgases are not necessary available or available in large enough quantities nor would the resulting carrier be carbon neutral. One can in the model however replace the input costs of CO_2 (which are currently the levelised production costs of CO_2 through DAC) with the offgas capture costs.

Our CO_2 production cost calculation is based on our earlier modelling in a study on synthetic kerosene production[48]. The low temperature heat requirements are assumed to be met by the heat released in downstream synthesis processes. This is because if CO_2 is generated, it is generated to produce formic acid, methanol, DME, OME or synthetic methane. In all processes but formic acid production heat is

[42] L.E. Oi et al. (2016): Simulation and cost comparison of CO2 liquefaction. Energy Procedia 86, 500-510
[43] U. Zahid (2015): Techno-Economic Assessment of CO2 Transport for Carbon Capture and Storage. PhD Thesis
[44] IEA (2015): Technology Roadmap: Hydrogen and Fuel Cells. Technical Annex
[45] A. Maroufmashat (2017): Transition of Future Energy System Infrastructure through Power-to-Gas Pathways. Energies 10,
[46] Oxford Institute of Energy Studies (2015): Analysis of Islanded Ammonia-based Energy Storage Systems
[47] E.R. Morgan (2013): Techno-Economic Feasibility Study of Ammonia Plants Powered by Offshore Wind
[48] Kalavasta (2018): Carbon Neutral Aviation

released. Waste heat if available could also meet these requirements. The CO_2 storage investment costs are found to be about 600 €/m^3 [49].

Ammonia

Production

Traditional Haber-Bosch Ammonia plant produce up to 3,000 tons of ammonia a day at the industry standard of about 330 days a year, i.e. roughly up to 1 Mton per year. These plants need a source of nitrogen and hydrogen, typically obtained through cryogenic air separation and steam methane reforming, respectively. Here, water electrolysis generates the H_2 necessary and cryogenic air separation the N_2, as discussed previously.

$$1\, N_2 + 3\, H_2 \rightarrow 2\, NH_3$$

N_2 and H_2 are fed into the ammonia plant in a 1:3 ratio and react under 150 bar pressure and at a temperature of 450 degrees Celsius. The feed is looped due to low conversion ratios. The product is liquid anhydrous ammonia.

Investment costs are taken and scaled according to Morgan 2013[50]; energy requirements of 640 kWh/t NH_3 come from the same source. Technical lifetime is assumed to be 20 years, with the plant running 8000 hours year, and OPEX at 3% of initial investments.

Transport

Ammonia can be transported in LPG carriers, in a liquefied state. These carriers are fully or semi refrigerated and are often also capable of transporting other bulk chemicals like ethylene. Ammonia is a class II chemical and the largest vessels that can transport it are very large gas carriers (VLGCs) with capacities up to 82,000 m3. Most vessels are however smaller, falling in the Handysize range.

Here the model ship is a VLGC LPG tanker named Bu Sidra. It is estimated to have cost 64 M€[51].

Ammonia[52]	
Investment (M€)	64
OPEX (€/d)	7,837
Cargo capacity	82,200

[49] T. Suzuki et al. (2013): Conceptual Design of CO2 Transportation System for CCS. Energy Procedia 37, 2989,2996
[50] E.R. Morgan (2013): Techno-Economic Feasibility Study of Ammonia Plants Powered by Offshore Wind
[51] LNG World Shipping (2016): Fleet profile: Qatar Gas Transport Co
[52] Qship (2018): Deepsea Fleet. Bu Sidra

Storage

Product storage of anhydrous liquid ammonia occurs in refrigerated 45,000 t tanks with investment costs of about 17 M€, as scaled from [53]. Day storage is modelled as usual, for the reactants H_2 and N_2.

H_2 retrieval

Hydrogen is retrieved by cracking ammonia, which is the reverse of the Haber Bosch process. This reaction is rather endothermic and takes place at a temperature of about 600 degrees Celsius. Assuming an 0.85 heating efficiency it requires 5.88 kWh/kg H_2 [54]. Investment costs are taken from [55].

Formic Acid

Formic acid (FA) is synthesised directly through hydrogenation of CO_2. This process has low TRL, and the market for FA is much smaller than that for most chemicals listed here. The plant has a production capacity of 367 tons of FA per day. Water electrolysis generates the H_2 required and direct air capture supplies the CO_2, as discussed previously. The reaction that takes place is the following

$$1\ CO_2 + 1\ H_2 \rightarrow 1\ HCOOH$$

CO_2 and H_2 are fed into the plant in a 1:1 ratio and react under 105 bar pressure and at a temperature of 90 degrees Celsius. The product is 85 wt% formic acid.

Investment costs are taken and scaled according to VTT[56], itself based on Pérez-Fortes et al.[57] [58] from which we take the energy requirements of 3.07 kWh/kg (excluding the water electrolysis requirements).

Transport

Formic Acid is transported in small chemical tankers with stainless steel tanks. It is a class II chemical and the current largest vessels that can transport it are Handysize tankers with capacities up to 54,600 m3.

Here the model ship is a yet unnamed Handysize tanker from Odfjell. It is estimated to have cost 60 M€[59].

Formic Acid	
Investment (M€)	60
OPEX (€/d)	6,932
Cargo capacity	54,600

[53] E.R. Morgan et al. (2017): Sustainable Ammonia Production from U.S. Offshore Wind Farms: A Techno-Economic Review. ACS Sustainable Chem. Eng. 5, 9554-9567
[54] DOE (2006): Potential Roles of Ammonia in a Hydrogen Economy
[55] ISPT (2017): Power to Ammonia
[56] VTT (2017): BioCO2-project workshop
[57] M. Pérez-Fortes et al. (2016): Formic acid synthesis using CO2 as raw material: Techno-economic and environmental evaluation and market potential. International journal of hydrogen energy, 41, 16444-16462
[58] JRC (2016): Techno-economic and environmental evaluation of CO2 utilisation for fuel production
[59] Marinelink (2016): Odffjell to build record size stainless steel chemical tankers

Storage

Product storage of formic acid occurs in refrigerated 50,000 t tanks with investment costs assumed to be 1.5 times those for methanol storage. Day storage is modelled as usual, for the reactants H_2 and CO_2.

H_2 retrieval

To retrieve the hydrogen, formic acid can either be dehydrogenated (split into H_2 and CO_2) or dehydrated (split into H_2O and CO)[60]. It is possible to convert the pairs of products into one another through the (reverse) water gas shift[61]. From the perspective of a hydrogen supply chain however, the first reaction is preferred. Both processes have a low TRL. If formic acid is used as a carrier, CO_2 is liquefied, stored and sent back to the formic acid production facility abroad.

These processes take place at a temperature of about 40-250 degrees Celsius and a pressure between 1 and 250 bar. Assuming a 0.85 heating efficiency it requires 1.05 kWh/kg H_2 [62] [63]. No estimate for Investment costs has been found. Investment costs are therefore assumed to be equal to DBT dehydrogenation, scaled with a factor 0.7 and at a capacity of 300 t/d.

Methanol

Methanol (MeOH) represents a fairly large market. It is also synthesised directly through hydrogenation of CO_2. This is a fairly mature process (TRL 8) and is demonstrated in Iceland by Carbon Recycling International (CRI). One of the downsides of the process is that one third of the hydrogen input is 'lost' in the form of steam.

The plant modelled here has a production capacity of 3000 tons of methanol per day. Water electrolysis generates the H_2 required and direct air capture supplies the CO_2, as discussed previously. The reaction that takes place is the following

$$1\ CO_2 + 3\ H_2 \rightarrow 1\ CH_3OH + 1\ H_2O$$

CO_2 and H_2 are fed into the plant in a 1:3 ratio and react under 50 to 100 bar pressure and at a temperature of 250 degrees Celsius.

Investment costs are taken and scaled according to Belotti et al. [64], with VTT reporting higher investment costs[65]. Energy requirements are obtained from CRI[66] and checked with academic references[67].

Transport

Methanol is transported in chemical tankers which typically also use it as a fuel. It is a class II chemical and the most current vessels carrying methanol are Handysize tankers with capacities up to 52,560 m3. It could technically also be transported in oil carriers, up to VLCC.

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[60] M. Grasemann and G. Laurenczy (2012): Formic acid as a hydrogen source – recent developments and future trends. Energy Environ. Sci. 5, 8171
[61] P. Preuster and J. Albert (2017): Biogenic Formic Acid as a Green Hydrogen Carrier. Energy Technol. 6, 501-509
[62] J.J. Sims (2015): Formic Acid Decomposition on Cobalt Surfaces
[63] M. Grasemann and G. Laurenczy (2012): Formic acid as a hydrogen source – recent developments and future trends. Energy Environ. Sci. 5, 8171
[64] D. Belotti et al. (2017): Feasibility study of methanol production plant from hydrogen and captured carbon dioxide. Journal of CO2 Utilization 27,132-138
[65] VTT (2017): BioCO2-project workshop
[66] CRI (2015): Power and CO2 emissions to methanol
[67] E. Simões Van-Dal and C. Bouallou (2013): Design and simulation of a methanol production plant from CO2 hydrogenation. Journal of Cleaner Production, 57, 38-45.

Here the model ship is the Cajun Sun. It is estimated to have cost 44 M€[68].

Methanol	
Investment (M€)	44
OPEX (€/d)	7,837
Cargo capacity	52,560

Storage

Product storage of methanol occurs in refrigerated 50,000 t tanks with investment costs of about 12.5 M€[69]. Day storage is modelled as usual, for the reactants H_2 and CO_2.

H_2 retrieval

Hydrogen is retrieved through auto thermal reforming (ATR) with carbon capture and CO_2 is the spent fuel. This is a mature process. If methanol is used as a carrier, CO_2 is liquefied, stored and sent back to the production facility abroad.

Electricity requirements are 1.19 kWh/kg H_2 and heat requirements about 12 kWh/kg H_2[70], assumed to be produced with 0.85 efficiency. Total energy requirements are therefore 15.3 kWh/kg H_2. Investment costs are taken and scaled from the same study.

Dibenzyltoluene

Recently research has expanded on so-called liquid organic hydrogen carriers (LOHCs). These are organic compounds that can easily store and release decent amounts of hydrogen (achieving a higher H_2 density than compressed or liquefied hydrogen), while being easy to transport. Given that these are 'dedicated' hydrogen carriers, the compounds themselves often have a very limited demand, although exceptions exist. A promising LOHC is dibenzyltoluene (DBT), a relatively affordable and safe carrier which holds 6.2 w% H_2 [71]. It is a liquid that can be handled in ambient conditions and can be easily transported in a tanker. Moreover, there is already a DBT market.

DBT is hydrogenated to give perhydro-DBT, also written as H18-DBT, which is the 'loaded' carrier:

$$1\ DBT + 9\ H_2 \rightarrow 1\ H18 - DBT$$

This reaction takes place at 50 bar pressure and at a temperature of 150 degrees Celsius. This specific carrier is studied by Hydrogenious Technologies in Germany. The plant modelled here has a production capacity of 1000 tons of H18-DBT per day. Water electrolysis generates the H_2 required.

[68] Advanced Shipping & Trading (2018): Weekly shipping market report week 8
[69] Euro chlor (2018): The Energy Situation in Europe
[70] NTNU (2016): Concepts for Large Scale Hydrogen Production
[71] Hydrogenious Technologies (2015): Hydrogen storage and distribution via liquid organic carriers

Investment costs are taken and scaled according to Reuss et al. [72]. Energy requirements of 0.037 kWh/kg H_2 electricity and -9 kWh/kg H_2 heat (heat is released) are obtained from the same source and cross-checked with [73] .

Transport

DBT is also transported in chemical tankers. Here it is transported in Handysize methanol tankers with capacities up to 52,560 m3. It could technically also be transported in oil carriers, up to VLCC.

Here the model ship is the Cajun Sun. It is estimated to have cost 44 M€[74].

Methanol	
Investment (M€)	44
OPEX (€/d)	7,837
Cargo capacity	52,560

Storage

Product storage of DBT occurs in 50,000 t tanks with investment costs that are assumed to be equal to those for methanol tanks. Day storage is modelled as usual, for the reactant H_2.

H_2 retrieval

Hydrogen is retrieved through dehydrogenation of perhydro-DBT. Investment costs are taken and scaled according to Reuss et al. [75]. This requires 0.37 kWh/kg H_2 electrical energy and 9 kWh/kg H_2 thermal energy.

Sodiumborohydride

Sodiumborohydride is synthesised at an industrial scale through the Brown-Schlesinger or Bayer process[76]. These processes both require quite some different materials (costly reducing agents) and energy, with the former also consisting of many steps. Both processes also produce various co-products of limited value. Moreover, most of the sodium, which is estimated to make up 60-65% of the costs of $NaBH_4$, ends up in these co-products[77].

H_2-Fuel is developing an alternative electr(ochem)ical recycling pathway, allowing to recycle $NaBO_2$ into $NaBH_4$[78]. At low electricity prices, this can be cheaper than buying new $NaBH_4$. This technology has low TRL. At 100% efficiency, obtaining 4.7 kg of $NaBH_4$ (which in hydrogen retrieval produces 1 kg of H_2) requires 181 MJ. A conceptual design study resulted in a 52 M€ investment estimate for a 40 kton $NaBH_4$/year recycling plant with O&M at 5%[79]. We assume target energy losses of 30%.

[72] M. Reuss et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302
[73] D. Teichmann et al. (2012): Liquid Organic Hydrogen Carriers as an efficient vector for the transport and storage of renewable energy. International Journal of Hydrogen Energy 37, 18118-18132
[74] Advanced Shipping & Trading (2018): Weekly shipping market report week 8
[75] M. Reuss et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302
[76] Millennium Cell Inc. (2004): Review of Chemical Processes for the synthesis of Sodium Borohydride
[77] C.R. Cloutier (2006): Electrochemical recycling of sodium borohydride for hydrogen storage: physicochemical properties
[78] H2-fuel (2016): H2Fuel: drager van waterstof energie
[79] H2-fuel (2018): Private communication, data based on undisclosed documents and research carried out by Delft Technical University

The reaction that takes place is the following (with H_2 produced as part of the H_2-fuel production pathway)

$$1\ NaBO_2 + 4\ H_2 \rightarrow 1\ NaBH_4 + 2\ H_2O$$

Transport

$NaBH_4$ is a solid and can be transported in barrels or reusable sealed'pillow' packaging on container ships. We consider a 18,270 TEU Suezmax (up to 200 k DWT) container ship. It is assumed that 80 vol% of a TEU is filled with $NaBH_4$, keeping in mind the maximum mass the ship can carry.

Here the model ship is the Maersk Mc Kinney Moller. It is estimated to have cost 158 M€[80].

NaBH4	
Investment (M€)	158
OPEX (€/d)	8,621
Cargo capacity	485,251 m^3 (but limiting 174,738 t capacity)

Storage

Product storage of NaBH4 typically occurs in the medium it is packaged for shipping. This could be shipping containers, barrels or pillow packaging.

H_2 retrieval

Hydrogen is released through hydrolysis. Adding ultra pure water to $NaBH_4$ releases 98% of the hydrogen[81]. This process has no energy requirements. Capital costs are assumed to be approximately the same as that of a gas burner at 1.15M€ (0.8-1.5M€) for 30 MW, or just below 40 €/kW[82].

Dimethylether

Methanol has already been discussed before, but it is a precursor to a wide range of other chemicals. One such chemical is dimethylether (DME), which itself is an intermediary in for instance the methanol to olefins process. DME and steam are generated from methanol as per:

$$2\ CH_3OH \rightarrow 1\ CH_3OCH_3 + 1\ H_2O$$

This reaction takes place at 10 bar pressure and at a temperature of 240 degrees Celsius. The plant modelled here has a production capacity of 1000 tons of DME per day. Water electrolysis generates the H_2 required and DAC supplies the CO_2.

Investment costs are taken and scaled according to Frauzem [83]. Electricity requirements are given by Fasihi and Breyer to be 0.31 kWh/kg DME[84]. Steam is generated in both methanol and DME production.

[80] United States Merchant Marine Academy (2017): Economies of Scale in Container Ship Costs
[81] H2-fuel (2016): H2Fuel: drager van waterstof energie
[82] H2-fuel (2018): Private communication with Gerard Luttigheid
[83] R. Frauzem (2017): Sustainable process design with process intensification: development and implementation of a framework for sustainable carbon capture and utilisation processes. Phd thesis.
[84] M. Fasihi and C. Breyer (2017): Synthetic methanol and dimethyl ether production based on hybrid PV-wind power plants.

Transport

DME is also transported in chemical tankers. Here it is transported in Ammonia/LPG tankers with capacities up to 82,220 m^3.

Here the model ship is a VLGC LPG tanker named Bu Sidra. It is estimated to have cost 64 M€[85].

Methanol	
Investment (M€)	44
OPEX (€/d)	7,837
Cargo capacity	52,560

Storage

Product storage of DME occurs in 50,000 t tanks with investment costs that are assumed to be equal to those for methanol tanks. Day storage is modelled as usual, for the reactants H_2 and CO_2.

H_2 retrieval

Hydrogen is retrieved through auto thermal reforming (ATR) with carbon capture and CO_2 is the spent fuel. This is a mature process. If methanol is used as a carrier, CO_2 is liquefied, stored and sent back to the production facility abroad.

Electricity requirements are 1.19 kWh/kg H_2 and heat requirements about 12 kWh/kg H_2[86], assumed to be produced with 0.85 efficiency. Total energy requirements are therefore 15.3 kWh/kg H_2. Investment costs are taken and scaled from the same study.

Oxymethylene Ether

Oxymethylene ether (OME, also OME1) can also be produced from methanol. OME and steam are generated from methanol, hydrogen and carbon dioxide following:

$$2\ CH_3OH + 2\ \ H_2 + 1\ CO_2\ \rightarrow 1\ CH_3OCH_2OCH_3 + 2\ H_2O$$

In short the full reaction is:

$$8\ \ H_2 + 3\ CO_2\ \rightarrow 1\ CH_3OCH_2OCH_3 + 4\ H_2O$$

Half of the hydrogen is lost in the form of steam, which is a large penalty. The plant modelled here has a production capacity of 1000 tons of OME per day. Water electrolysis generates the H_2 required and DAC supplies the CO_2.

Investment costs are taken and scaled according to Schmitz et al. [87]. Energy requirements are found to be 1.27 kWh/kg OME[88]. Steam is generated in both methanol and OME production.

[85] LNG World Shipping (2016): Fleet profile: Qatar Gas Transport Co
[86] NTNU (2016): Concepts for Large Scale Hydrogen Production
[87] N. Schmitz et al. (2016): From methanol to oxygenated diesel fuel poly(oxymethylene) dimethyl ether: an assessment of the production costs. Fuel 185, 67-72
[88] S. Deutz et al. (2018): Cleaner production of cleaner fuels: wind-to-wheel - environmental assessment of CO2-based oxymethylene ether as a drop-in fuel. Energy Environ. Sci 11

Transport

OME is also transported in chemical tankers. Here it is transported in Handysize methanol tankers with capacities up to 52,560 m3. It could technically also be transported in oil carriers, up to VLCC.

Here the model ship is the Cajun Sun. It is estimated to have cost 44 M€[89].

Methanol	
Investment (M€)	44
OPEX (€/d)	7,837
Cargo capacity	52,560

Storage

Product storage of OME occurs in 50,000 t tanks with investment costs that are assumed to be equal to those for methanol tanks. Day storage is modelled as usual, for the reactants H_2 and CO_2.

H_2 retrieval

Hydrogen is retrieved through auto thermal reforming (ATR) with carbon capture and CO_2 is the spent fuel. This is a mature process. If methanol is used as a carrier, CO_2 is liquefied, stored and sent back to the production facility abroad.

Electricity requirements are 1.19 kWh/kg H_2 and heat requirements about 12 kWh/kg H_2[90], assumed to be produced with 0.85 efficiency. Total energy requirements are therefore 15.3 kWh/kg H_2. Investment costs are taken and scaled from the same study.

Liquefied Natural Gas

Synthetic methane is produced through direct hydrogenation of CO_2 (Sabatier's reaction), just like methanol and formic acid. The reaction that takes place is the following, at 7 bar and 290 degrees Celsius:

$$1\ CO_2 + 4\ H_2 \rightarrow 1\ CH_4 + 2\ H_2O$$

Here too half of the hydrogen is lost as steam (but used for DAC and not assumed to have any other value). The plant modelled here has a production capacity of 1000 tons of SNG (synthetic natural gas, i.e. here CH_4) per day. Water electrolysis generates the H_2 required and DAC supplies the CO_2.

Investment costs are taken and scaled according to VTT [91]. Energy requirements are found to be 0.45 kWh/kg SNG[92]. Steam is generated in this process.

Synthetic methane is then liquefied for storage and transport. Costs of a liquefaction plants can vary significantly, depending on the exact configuration of the plant. As a paper goes on to show, depending on technical or also geographical factors, investment costs can be vastly different[93]. Historically too, investment costs (per capacity unit) have changed considered and escalated as of recently[94]. This could perhaps be

[89] Advanced Shipping & Trading (2018): Weekly shipping market report week 8
[90] NTNU (2016): Concepts for Large Scale Hydrogen Production
[91] VTT (2017): BioCO2-project workshop
[92] F. Re et al. (2017): Sabatier based cycle for CO2 methanation: exergy and thermo-economic analysis. Proceedings of ASME
[93] H. Kotzot et al. (20XX): LNG Liquefaction – not all plants are created equal.
[94] Oxford Energy Institue (2014): LNG Plant Cost Escalation

partially attributed to the different design requirements these plants have, especially since vessel loading facilities can also be part of a plant's scope. We work with investment costs of 800 €/t/y for liquefaction facilities, as in the range of the source large mentioned. Energy requirements are about 0.5 kWh/kg LNG [95].

Transport

LNG is also transported in large to very large LNG vessels. Here it is transported in QMax tankers with a capacity 266,000 m^3. This is the largest class of LNG vessels in the world. This is the largest vessel that can dock in Qatar. It can unload in the Port of Rotterdam, but is too large for most ports. We therefore also include a 'large size' LNG carrier, which transports 145,700 m^3.

Here the model ship is the Mozah. It is estimated to have cost 175 M€[96].

LNG	
Investment (M€)	175
OPEX (€/d)	8713
Cargo capacity	266,000

Storage

Product storage of LNG occurs in 50,000 t tanks with investment costs of 30 M€[97]. Day storage is modelled as usual, for the reactants H_2 and CO_2.

H_2 retrieval

Hydrogen is retrieved through auto thermal reforming (ATR) with carbon capture and CO_2 is the spent fuel. This is a mature process. If methanol is used as a carrier, CO_2 is liquefied, stored and sent back to the production facility abroad.

Electricity requirements are 1.19 kWh/kg H_2 and heat requirements about 12 kWh/kg H_2[98], assumed to be produced with 0.85 efficiency. Total energy requirements are therefore 15.3 kWh/kg H_2. Investment costs are taken from the same study.

Liquid Hydrogen

Hydrogen liquefaction requires a theoretical minimum of 3.3 or 3.9 kWh/kg H_2 (LHV, HHV, respectively). The newest liquefiers approach 6 kWh/kg H_2 [99], one example process (IdealHY) calling for an estimated 6.4 kWh/kg H_2[100]. In terms of capacity, the largest liquefiers are capable of producing up to 150 tons of LH_2 per day. Investment costs are taken from the IdealHY process[101].

95 T. Nguyen et al. (2016): Techno-economic optimisation of three gas liquefaction processes for small-scale applications. Proceedings of ECOS 2016.
96 Advanced Shipping & Trading (2018): Weekly shipping market report week 8
97 Tractebel (2015): Mini / Micro LNG for commercialization of small volumes of associated gas
98 NTNU (2016): Concepts for Large Scale Hydrogen Production
99 Linde (2016): Large Scale Hydrogen Liquefaction. Economic viability.
100 NTNU (2017): Concepts for Large Scale Hydrogen Liquefaction Plants.
101 FCH JU (2013): Integrated Design for Demonstration of Efficient Liquefaction of Hydrogen (DEALHY)

Transport

Liquid hydrogen (LH2) ships do not exist yet. Research however suggests similarities with LNG[102]: large volumes are necessary for the economics to work out, there are even larger refrigeration requirement and boil-off gas poses a problem too. As such it is envisioned that large scale LH2 ships would be based on the LNG ship design, but with special LH2 tanks. When such large ships are expected to be built at this scale, is unclear. Pilot ships are being designed and will soon be built[103]. We however include LH2 with this disclaimer and modelled as LNG ships, with a 25% surplus in CAPEX and O&M costs.

Here the model ship is the Mozah. It is estimated to have cost 175 M€[104], to which we add a 25% charge giving 219 M€.

LH2	
Investment (M€)	219
OPEX (€/d)	10891
Cargo capacity	266,000

Storage

Hydrogen is stored as a gas with storage parameters as described in the previous chapter.

H_2 retrieval

Hydrogen is retrieved through evaporation with parameters from Reuss et al.[105] .

[102] P.E. Dodds and W. McDowall (2012): A review of hydrogen delivery technologies for energy system models
[103] Y. Takaoka et al. (2017): Introduction to a Liquefied Hydrogen Carrier for a Pilot Hydrogen Energy Supply Chain (HESC) project in Japan)
[104] Advanced Shipping & Trading (2018): Weekly shipping market report week 8
[105] M. Reuss et al. (2017): Seasonal storage and alternative carriers: a flexible hydrogen supply chain model. Applied Energy 200, 290-302

First explorations with and results from the model

This chapter discusses the results one obtains with the base settings of the model and the picture that emerges, and how these results change as we change some input parameters. We emphasise these are merely some explorations of the model which are by no means exhaustive, and are done with version 1.1 of the model (which is the second version, from May 2019).

We first describe the base settings, which are the base general or conceptual parameters described in the short user guide. Then we explore the effects of using other conceptual, country and technology parameters and share some observations on the emerging picture.

Results with standard parameters

The following is a list of the standard conceptual parameters

Parameter	Value
Hydrogen demand	13600 kton (HyChain 1 max demand)
€/USD exchange rate	1.16
WACC	Dataset with reduced variance, 50%
Electricity and FLH	Weighted hybrid
Inland transport to port	Hydrogen
Bunker	Hydrogen
Ship	Standard
HV DC FLH	7500 h

With this input and standard technology and country parameters, it costs roughly 3€ to produce 1 kg of hydrogen in the Netherlands using offshore wind electricity. We use offshore wind electricity as a reference since the onshore wind and solar potentials are relatively limited. One could import renewable hydrogen for a cheaper price from 32 countries (22% of total number of countries considered), 21 of which are into Europe. 9 of these 25 countries will likely have a renewable electricity deficit (negative or near zero export potential), 23 of these have a small to large export potential (greater than 7500 kton or 250 TWh or 900 PJ). 7 have a medium to large export potential (>7.5 PWh, Algeria, Canada, Libya, Chad, Norway, Saudi Arabia and the UK). Of the countries with lower costs and a positive export potential, the UK can deliver the lowest cost renewable hydrogen at around 2.1€/kg into the Netherlands. At a demand of 13,600 kton H_2 a year that amounts to maximum savings (by importing from the UK) of (3-2.1)*13600 = 12,240 M€ a year.

Let us look at the various routes. At this very high demand, pipeline transport (through scaling advantages) is typically the cheapest routes. However, when in Europe and subject to WACC, sometimes HV DC lines are cheaper. For countries outside Europe with competitive costs, pipelines win. Of the 32 countries that can deliver lower cost hydrogen, none can do that via hydrogen carriers. In general, of the hydrogen carrier routes, the hydrogen import costs are generally the lowest for ammonia (although some technology parameter values used in base settings, were reported low by Yara), $NaBH_4$ (provided it meets its TRL development targets and is scaled successfully) and DBT (the LOHC). Carbon hydrogen carriers tend to be more expensive and come in fourth at best, with methanol and LNG the cheapest of the lot.

It may seem odd that importing hydrogen via carriers is more expensive within Europe as transport costs are typically low for a ship, but there is one simple explanation: hydrogen retrieval cost. They can add as much as almost 1.2 €/kg to the hydrogen import price, which makes it a very large cost component. However, as the distance and hence the shipping costs increase, this hydrogen retrieval costs weigh in less in the total costs. So as one looks to import from countries which are further away from the Netherlands, so do the relative costs of the various routes change in favour of the shipping route – although not necessarily taking over gas pipelines when at large volumes.

The explanation that was given for the lack of hydrogen carrier routes that are competitive is also supported by another observation regarding the import of hydrogen carriers for their own use (i.e., not to retrieve hydrogen from them). If we want to use hydrogen carriers to get hydrogen, no countries (0% of the countries considered) can deliver hydrogen at competitive costs. If we want to use hydrogen carriers themselves, some 31 to 52 countries (31% - 48% of the non-landlocked countries considered) can deliver them at competitive costs (depending on the carrier). Many of these countries are found outside Europe too. However, on an energy basis these *hydrogen carrier* import costs still generally exceed the best *hydrogen* import costs for that country.

Lastly, we briefly discuss the import costs of electricity. We have set the FLH of the HV DC cable to 7500 h which exceeds the FLH of renewable electricity generation of every country. This effectively means that there is an electricity generation capacity vastly greater than the transmission capacity and/or a large connected grid that spans time and/or weather zones. With this assumption we see that countries with competitive electricity import costs are mostly located within Europe.

Hence *for this specific scenario* we can draw the following conclusions, but these may not hold at all for other scenarios

- From a select number of countries, mostly in Europe, we can import renewable hydrogen (and electricity) at lower costs mostly via gas pipelines and sometimes via HV DC cables than production costs with Dutch offshore wind electricity
- Due to high hydrogen retrieval costs hydrogen import through the hydrogen carriers considered in this study is uneconomical for imports from all but a few countries within Europe, and only for ammonia as a hydrogen carrier.
- We can however import hydrogen carriers for lower costs than Dutch production costs from a large number of countries, both within and outside Europe
- Hence it seems that to meet (part of) a large Dutch hydrogen demand for competitive costs, a select European network of HV DC cables and/or gas pipelines seems favorable
- Hence It seems unlikely we will import hydrogen from beyond the edges of Europe on a cost basis, but it does seem economically interesting to import hydrogen carriers (but not for the hydrogen) from regions that are further away if there is a demand for such carriers

It should be repeated that these are greenfield calculations and that significant cost reductions could be achieved by using existing infrastructure and plants.

Explorations with other parameters

To investigate to what extent the foregoing holds and how sensitive the model's output is to its input, we explore the effect of several parameters here. This is merely a first look and by no means a complete investigation. Moreover, we only change one parameter with respect to the base scenario at a time, unless we explicitly state otherwise.

We start by exploring the impact of the hydrogen demand. This is reflected in power scaling of pipeline transport. Most processes are assumed to be operating at a large, fully commercial scale such that no scaling is possible (only in number). This is valid for a hydrogen demand greater than approximately 200 kton or 24 PJ. In the base case we work with the upper limit of the 2050 hydrogen demand of 13600 kton or 1632 PJ as determined by HyChain 1. Here we will change that to the lower limit of 800 kton or 96 PJ. Now the number of countries with competitive import costs drops from 32 to 27, but we lose 3 of the 7 countries with a large export potential. This shows how important the scale of the hydrogen demand is and how, when reaching a certain size, it can open up connections to very large sources that one may otherwise overlook.

One of the parameters that has a very large impact on the import costs is the WACC assumed. For projects abroad, the German government sometimes 'guarantees' a WACC at a fixed, low value[106]. Suppose that in this way one could effectively give a supply chain a fixed WACC, and suppose this WACC is 8%. If we change this and only this in our standard parameters, the picture that emerges is quite different. Dutch hydrogen would be produced at 3.2 €/kg, with 115 instead of 32 countries technically able to deliver hydrogen at lower costs, 64 countries with an export potential greater than 250 TWh and 22 greater than 7500 TWh, with the cheapest hydrogen import at around 2 €/kg. $NaBH_4$ enters as a hydrogen carrier for competitive hydrogen import.

If we use the original dataset for the WACC, the results are more like those of the standard scenario. Dutch hydrogen would be produced at 2.4 €/kg, with 23 countries instead of 32 technically able to deliver hydrogen at lower costs and 17 countries with export potential >250 TWh and 5 >7500 TWh, with the cheapest hydrogen import at around 1.6 €/kg.

Another parameter that is quite important is the electricity mix. We use the weighted price of a hybrid onshore wind – solar PV system. Some countries have a very large production potential, such that the electricity costs may actually be closer to the lowest electricity generation costs than the weighted electricity generation costs. If we opt for a minimal cost hybrid system, we observe 41 countries that could deliver hydrogen at competitive costs, with 25 with an export potential greater than 250 TWh and 10 greater than 7500 TWh. Most interesting is that the costs of the countries with a large export potential indeed fall, and that now 10 instead of 5 countries with a large export potential appear. The UK still has the lowest costs of the latter category, but now at 1.8 €/kg instead of 2.4 €/kg, compared to 3 €/kg for Dutch production costs.

If we change the FLH of the HV DC cable to those of the electricity generation, import is cost competitive from 27 countries and no country with a large export potential leaves the scene. Changing just the shipping fuel or just ignoring inland transport in a scenario that is in every other respect like the standard scenario, does not change the picture very much for hydrogen import via hydrogen carrier routes. Electrolyser investment costs do matter for the hydrogen costs, but because they are central to every route, it is only the WACC and losses of each route that marginally differentiates countries upon changing these investment costs. Of course lowering the investment costs of solar PV and onshore wind or raising those of offshore wind improves the case for import, and conversely.

Lastly we perform two multiparameter sensitivity checks.

[106] Discussed with Matthias Deutsch, Agora

First, we change the WACC to a uniform 8% and the electricity mix to the hybrid minimum at the same time. Now 129 countries of which 75 with an export potential > 250 TWh and 24 >7500 TWh can deliver cost-competitive hydrogen to the Netherlands with the cheapest H_2 imported at 1.8 €/kg H_2 versus 3.2€/kg as Dutch production costs.

Second, we change the WACC to a uniform 8% and hydrogen demand to the minimal demand as determined in HyChain 1. Now the countries from which cost competitive hydrogen can be imported drops to 78 (from 115 for the max H_2 demand). 41 countries have an export potential greater than 250 TWh and 14 greater than 7500 TWh.

Scenario	Base	Low H_2 demand (HC1 min)	Uniform WACC @ 8%	Dataset WACC	Min hybrid	Uniform WACC @ 8% + Low H_2 demand	Uniform WACC @ 8% + Min hybrid
# countries w competitive H_2 import	32	27	115	23	41	78	129
# countries w competitive H_2 import + export pot. >250 TWh	19	16	64	17	25	41	75
# countries w competitive H_2 import & export pot. >7500 TWh	7	5	22	5	10	14	24
NL H_2 prod. costs with offshore wind electricity (€/t)	3.0	3.0	3.2	2.4	3.0	3.2	3.2
Lowest H_2 import costs (€/t)	2.1	2.1	2.0	1.6	1.8	2.0	1.8

The table above summarises the effects of changing some of the parameters as discussed above. We chose two export potential bounds when counting countries which can deliver cost competitive hydrogen: one of 250 TWh (or 7500 kton or 900 PJ) which is much larger than the HyChain 1 lower limit (96 PJ) and one of 7500 TWh (or 225000 kton or 27000 PJ) which is much larger than the HyChain 1 upper limit. Interestingly, in all scenarios there is a significant cost gap between the Dutch production costs and import costs of between 0.7 and 1.4 €/kg H_2. At a demand of 13,600 kiloton H_2 that amounts to maximal savings of 9,520 to 19,040 M€. It should be noted that one could consider many other scenarios, which may have smaller or larger (or no) savings.

The fact that import costs are lower than Dutch product costs means that production costs abroad are even lower than Dutch costs. One could think of a system similar to international renewable energy certificates (IRECS), where energy consumers in the Netherlands could contract renewable energy from abroad through certificates. This is an economically preferred option for the consumer if retaining its current processes and energy plus the costs of such certificates is lower than the costs of directly using Dutch renewable energy or using imported renewable energy. This would also avoid the costs and construction time of building this supply chain and would not be likely to lead to a lock-in as the demand for such certificates increases and the other options (producing or importing renewable energy) become cheaper.

Country profiles

To give more insight into where countries are standing regarding their energy system, experience and ambitions with respect to renewable energy generation, ECN part of TNO created 'country profiles' for eight countries. These profiles shed some light on the actual renewable energy production and plans and barriers to expand this, which is important information as to the question whether it is likely that these countries will export renewable energy in 2030, 2040 or 2050. These countries have been selected largely as representatives of certain geographical areas and because of their relatively low import costs and large potential (as determined by the model), location and/or ambitions to export.
Country profiles have been made for the following eight countries and are presented in this order, after a brief summary

- Canada
- Chad
- China
- Morocco
- Norway
- Saudi Arabia
- Spain
- United Kingdom

Author of the rest of this chapter: Nico van der Linden, ECN part of TNO

Summary

	Morocco	Saudi Arabia	United Kingdom	Canada	China	Norway	Spain	Chad
Population (M)	35.3	32.3	65.6	36	1391	5.3	46.4	14.5
TPEC/ capita (GJ)	23.1	272.8	128	376	85.8	224.5	126	5.3
RE capacity in 2030/-50	13 GW	54/105 GW	40/150 GW	100/124 GW	1379/1873 GW		147 GW	60MW
H_2 production	R&D	R&D	Growth	Growth	Intro-duction	Intro-duction	Intro-duction	very unlikely
H_2 export potential	medium	high	medium	medium	low	high	medium	very unlikely

Hydrogen production: the following development phases can be distinguished:

- R&D → research activities and/or pilot demonstration projects carried out
- Introduction → hydrogen fueling stations established
- Growth → > 20 MW electrolyser/hydrogen plant planned
- Maturity → > 20 MW electrolyser/hydrogen plant in operation

Hydrogen export potential:

- High: specific government objective formulated in policy documents
- Medium: export of hydrogen is a potential option but only in the long term when domestic needs are met
- Low: initiatives focus solely on meeting the domestic demand

Taken into consideration the population size, energy consumption per capita, planned RE capacity expansions and export potential the following tentative conclusions can be drawn:

- Up to 2030: limited possibilities for export of hydrogen; only Norway seems to be able to produce and export hydrogen within the coming decade at already existing offshore facilities without jeopardizing domestic needs.
- 2030 -2050: Saudi Arabia, United Kingdom, Canada and Spain are on the path to enable them to start producing hydrogen in the period to 2030 but can only start exporting after 2030 when domestic demand is met.
- 2040 - : China and Morocco probably need more time to develop the hydrogen sector to such a level that exporting becomes feasible

Country report for Canada

Current situation and future outlook

The 2017 edition of the National Energy Board's Energy Futures107 series presents the following scenarios for the Canadian energy sector up to 2040:

- The REFerence(REF) scenario is based on current economic outlook and energy and climate policies announced at the time of analysis;
- The Higher Carbon Price(HCP) scenario assumes higher carbon pricing than in the Reference scenario; and
- The TECHnology(TECH) scenario assumes in addition to higher carbon prices greater adoption of cleaner production and consumption energy technologies.

	2016	2040 (REF)	2040 (HCP)
Total Primary Energy Supply(PJ)	13,543	14,169	13,340
– Coal, Coke and coke oven gas	5.1%	1.3%	1.3%
– Refined oil products, natural gas liquids	34.5%	31.8%	32.7%
– Natural Gas	33.2%	40.4%	34.2%
– Nuclear	8.7%	7.5%	8.0%
– Hydro	9.9%	10.5%	11.1%
– Renewables and landfill gas	7.6%	8.4%	8.9%
Population size(million)	36	43.2	43.2
Primary energy consumption/capita(GJ)	376	328	309

Total primary energy supply, 2016 & 2040

Renewable energy capacity expansion plans

The planned new renewable energy capacity up to 2040 for the three scenarios is shown in the following table:

	2016	2040(REF)	2040(HCP)	2040(TECH)
Solar	2.1[108]	8.6	9.4	25.5
Onshore Wind	12.8[109]	26.6	26.4	30.8
Hydro	79.4	89.3	89.3	89.3

Generating capacity (GW), 2016 & 2040

[107] Canada's Energy Future 2017; energy demand and supply projections to 2040; National *Energy* Board
[108] Statista, the statistical portal
[109] As of August 2018

Wind energy is the fastest growing source of new electricity in Canada. Installed new wind capacity was 341 MW (investment of $800 million) and 546MW (investment of $962 million) in 2016 and 2018, respectively[110]. For solar energy the goal is to increase the installed capacity to 6,300 MW in 2020[111].

Potential barriers for realization of the plans

The IEA country study conducted in 2015 mentioned the following challenge with regard to the renewable energy sector in Canada[112]:

- No Canada-wide renewable energy outlook or targets. Provincial governments have exclusive jurisdiction over the development and management of energy resources in their respective provinces, including the support mechanisms for renewable energy and the design of their electricity markets with the exception of marine renewable energy development in Canada's federal offshore. This may hamper further market and system integration (especially the east-west interconnectivity) and the realization of regional opportunities for cost-efficient use of renewable energies.

The main barriers to accelerated uptake of solar technology mentioned in the 2020 solar roadmap[113] are:

- Unsupportive and unstable policy and regulatory environment; it is proposed to develop a more supportive and stable policy and regulatory environment that recognize the total value of solar electricity, including the externalities
- Confusing, slow and expensive electrical grid interconnection requirements; it is proposed to simplify and streamline permitting and processes for grid interconnection and metering of solar systems
- High non-hardware costs (i.e. soft costs) of solar electricity systems; these costs account for more than 60% of the system costs.
- Inadequately informed public regarding solar electricity benefits and applications; it is proposed to educate the Canadian population on the true benefits of solar electricity
- Unfulfilled relationships with conventional industry participants and synergistic sectors

Current plans, pilot projects with regard to hydrogen

The Canadian hydrogen and fuel cell sector exists for more than 10 years and is growing. Research is the largest area of focus and there is a special interest in hydrogen vehicles. Shell opened the first retail hydrogen fueling station in Vancouver in June 2018 and has plans for two more. Approximately 50% of the hydrogen and fuel cell facilities are located in the provinces British Colombia and Ontario. In July 2018 the first major energy storage power-to-gas facility(2.5MW) in North America began operating in Ontario. The facility can produce hydrogen when there is excess electricity on the grid.

In 2015, the hydrogen and fuel cell sector's turnover was $220 million ($125 million from product sales and $85 million from the provision of services). The technology focus is mainly on proton exchange membrane fuel cells and hydrogen production, storage and distribution. The amount spent in 2015 on hydrogen research and development was $ 171 million and on demonstration projects $1.8 million. Approximately 85 % of this funding came from the private sector. Canada is a member of the International Partnership for the Hydrogen Economy(IPHE).

[110] Canadian Wind Energy Association
[111] Roadmap 2020: Powering Canada's future with solar electricity; Canadian solar industries association
[112] Energy policies of IEA countries, Canada, 2015 review; International Energy Agency
[113] Roadmap 2020: Powering Canada's future with solar electricity; Canadian Solar Industries Association

Country report for Chad

Current situation and future outlook

Chad is a landlocked country in Central Africa endowed with large oil reserves (1.5 billion barrels proven reserves) and its economy is heavily dependent on oil revenues. Current oil production is around 100,000 barrels per day, of which approximately 95% is exported. The sharp decline in oil prices, which started in 2014, has had a severe impact on Chad's budgetary spending and caused an economic recession. This was compounded by severe drought and influx of large numbers of refugees from neighboring countries. With the support of donors, including the IMF, Chad is now slowly restoring macroeconomic stability and strengthening the non-oil sectors.

Traditional biomass (fuelwood, animal waste, agriculture residues) accounts for more than 90% of total energy consumption. Biomass is mainly used for cooking by households which is typical for most of the subSahara countries. Access to modern forms of energy is extremely limited in Chad. Only 8.8% of the population has access to electricity and the electricity consumption per capita in 2015 was 22.5 kWh. Electricity is also expensive and unreliable and the transmission and distribution network are inadequate. Chad has large energy solar potential and also some potential for wind energy. However, so far this potential has not been realized and currently electricity is being produced exclusively from diesel generation.

	2015
Access to electricity (% of population)	8.8
Access to clean fuels and technologies for cooking (% of population)	3.1
Installed thermal power capacity (MW)	125
Production of electricity (GWh)	325.6
Production of oil (million barrels)	36.5
Renewable energy consumption (% of total consumption)	89
Population size (million)	14.5

Country energy statistics 2015

Renewable energy capacity expansion plans

The solar photovoltaic plant at Diermaya, 30km north of the capital N'Djamena, is the first utility-scale and privately owned renewable energy project in Chad. The project will install 60MW of solar PV power which will be fed into Chad's national grid. Total project costs are estimated to be € 60.3 million and the project will be delivered in two phases, 32 MW and 28 MW. The project is backed by a EUR 6.35 million contribution from the EU-Africa Infrastructure Trust Fund (EU-AITF).

Country report for China

Current situation and future outlook

China is the largest consumer of energy of the world, accounting for 23% of global primary energy demand in 2016. China also consumes as much coal as the rest of the world combined. This has led to environmental degradation and pollution and the consequences are air pollution in urban centers, water contamination and biodiversity loss. To revert this trend the government in 2012 started the 'war on pollution' and has prioritized the 'green development' in the five-years plans and the energy development strategy action plans. This has already resulted in a significant reduction of the share of coal in the energy mix from 72% in 2009 to 62% in 2016. In the most recent five-year plan a new goal for coal of 58% in 2020 has been set and a further significant decline is foreseen for the longer-term. To offset the reduction in coal China has made strong efforts to boost investments in renewable energy. The China Renewable Energy Outlook 2017, prepared by the National Renewable Energy Centre, a think tank within the Energy Research Institute under Nation Development Reform Commission. The Outlook 2017 presents two scenarios:

- **the Stated Policy(SP) scenario** which shows how the Chinese energy system could develop when the current and planned policies are efficiently implemented; and
- **the Below 2°C (B2C) scenario** assuming a development where China's CO_2 -emission is constrained to contribute to the Paris agreements targets.

The primary energy supply for the Stated Policy and Below 2°C scenarios are shown in the following Table.

	2016	2035 SP	2050 SP	2035 B2C	2050 B2C
Total Primary Energy Consumption (PJ)	119,292	138,109	115,188	126,882	102,116
Coal	66,4%	39,4%	21,5%	32.1%	15.3%
Oil	19,6%	27,2%	28,5%	23.0%	18.4%
Natural gas	6,8%	10,1%	7,8%	11.1%	4.5%
Nuclear	1,5%	4,5%	6,8%	4.9%	7.7%
Hydro	3,5%	4,2%	5,7%	4.6%	6.4%
Wind	0,7%	8,9%	16,8%	13.3%	24.6%
Solar	0,3%	2,4%	7,2%	6.9%	15.1%
Biofuels	0,9%	3,1%	5,2%	4.0%	7.4%
Geothermal	0,07%	0,1%	0,4%	0.1%	0.5%
Population size(billion)	1.391	1.476	1.378	1.477	1.378
Primary energy consumption/capita (GJ)	85.8	93.6	83.6	85.9	74.10

Total primary energy supply 2016, 2035 and 2050[114]

[114] China RE Outlook 2017; China National Renewable Energy Centre

Renewable energy capacity expansion plans

China is the world's largest investor in renewable energy, spending USD 117 billion on the industry in 2017, with the largest installed capacities of solar, wind and hydro power in the world. Total installed renewable energy capacity in 2017 was 647 GW, or nearly 37% of global installed power capacity in that year. The estimated number of jobs created by the renewable energy sector (excluding large hydro) in 2017 was almost 4 million[115].

The 13th Five Year Plan (2016-2020) will further accelerate the deployment of renewable energy technologies. It is proposed to increase the target of RE in total energy mix from 20% to 35% by 2030. Last year China also launched the first phase of the long awaited nationwide carbon emission trading scheme (ETS) which will focus on the power sector. The Chinese ETS will be the largest in the world, close to double the size of the EU ETS.

The current and planned renewable energy capacity in China is presented in the table below

	2017(GW)[116]	2020(GW)	2030(GW)	2040(GW)
Onshore wind	164[1)]	264	429	593
Solar PV	130	213	469	738
Hydro	341	360	440	493
Bioenergy	12	17	41	49
Total	647			

1)including 2.8GW off shore wind

Generating renewable energy capacity (GW)[117]*, 2016, 2020, 2030 and 2040*

Potential barriers for realization of the plans

While much progress has been made the renewable energy sector in China still has major challenges to overcome including:

- Overcapacity in some regions due to new capacity added based on capacity targets rather than on capacity needed
- Almost 12% of wind energy produced in China was curtailed in 2017 due to network constraints and no possibility to store the power. The majority of renewable generation is concentrated in western China but the demand is very limited there.
- The subsidy scheme currently used for promoting renewable energy in China is unsustainable in the long run. The subsidy policy should be more focused on innovation rather than on renewable electricity production.

[115] REN21; 2018 global status report
[116] Chinese National Bureau of Statistics
[117] World Energy Outlook 2017: IEA; New Policy scenario

Current plans, pilot projects with regard to hydrogen

China is looking at hydrogen and fuel cells for the transport sector and for solving the intermittency challenges of renewable energy. Since 2003 China works together with the GEF and UNDP to establish five pilot demonstration regions, including Beijing, Shanghai and Zhengzhou to promote the development of hydrogen fuel cell vehicles. According to the 13th Five Year plan China aims to promote research and development of fuel cells and build hydrogen stations in order to start mass production of fuel cell vehicles in 2020. Shanghai has already set specific targets for the production of 3,000 FCEV’s per year by 2020 and 30,000 by 2025.

Country report for Morocco

Current situation and future outlook

Currently Morocco imports approximately 89% of its energy needs for its 35.3 million in habitants. 90% of its electricity production depends on imports and electricity demand is rapidly growing with almost 7% per year. These imports weigh heavily on the national budget (10-12% of BNP) and also significantly contribute to the trade deficit. In the Moroccan National Energy Strategy the government has set clear objectives to secure energy supply, to reduce the dependency on energy imports through diversification of the energy mix and development of the abundantly available renewable energy resources and to increase energy efficiency. Morocco is also vulnerable to the impacts of climate change with expected increase in temperatures of 1 to 1.5°C by 2080 and rainfall could decline by 30 % between now and the end of the century.

Total primary energy consumption has increased on average by some 5% annually since 2004 reaching 787 PJ in 2016. The breakdown by fuel is presented in the following table.

	2016
Total Primary Energy Consumption (PJ)	786.9
Natural gas	5.5%
Oil	64.0%
Coal	22.8%
Hydro	0.6%
Biofuels & waste	7.1%
Population size (million)	35.3
Primary energy consumption/capita (GJ)	23.1

Total primary energy supply 2016[118]

Research on long-term energy projections for Morocco is lacking. As part of his master programme, Khalid Raouz[119] conducted in 2015 a study that aimed to develop energy scenarios for Morocco up to 2040. His main conclusion was that energy demand is expected to increase to 1330 PJ between now and 2040 and Morocco could reach energy self- sufficiency in 2040 through developing its shale oil deposits and its solar, wind and hydro potential.

Renewable energy capacity expansion plans

To reduce import dependency the Moroccan government in its Energy Strategy has formulated a clear priority to develop its renewable energy resources, especially solar, wind and hydro energy. The initial target set at 42% renewables of total installed capacity by 2020 was raised at COP 21 to 52% by 2030.

[118] International Energy Agency
[119] Morocco´s Energy System Forecasted Using LEAP; Khalid Raouz; December 2015

The Solar plan was launched in 2009 and aims to install at least 2,000 MW by 2020 solar PV and CSP. Currently three large CSP/PV projects are being developed/constructed and once completed this would exceed the 2,000MW in 2020. The total investments planned is $ 9billion up to 2020.

With a coast line of 3,500 km Morocco has enormous wind potential. The Morocco wind plan, presented in 2010, aims to bring total wind capacity to 2,000 MW by 2020. The most recent projections from the government show that this goal most likely will be exceeded. Total investments of $3.5 billion up to 2020 are planned under the wind power plan.

Hydro also plays a role in the national energy mix and is planned to cover 12% of electrical capacity by 2030. The existing generating capacity in 2015 and targets for 2020 and 2030 are presented in the following table.

	2015 (MW)	2020 (MW)	2030 (MW)
Solar PV	180	2,235	4,964
Onshore Wind	799	2,395	4,964
Hydro	1,770	2,235	2,978
Thermal	5,411	9,102	11,914
Total	8,160	15,967	24,820

Generating capacity (MW), 2015, 2020 and 2030[120]

Potential barriers for realization of the plans

The 2009 National Energy Strategy is being implemented in accordance with the deadlines set at its launch. Major progress has already been made both at the institutional level (set up of Morocco Agency for sustainable development -MASEN) and in terms of major project development (several solar, wind and hydro projects being developed or completed). However, according to n Mr. Taoufik Laabi[121] the following barriers to further development of the renewable energy sector still exist in Morocco:

- Lack of accessible financial support for small scale projects
- High initial capital
- Barriers to entry for smaller producers
- Lack of cooperation and synergetic collaboration between the various stakeholders
- Intermittency management of renewable energies

Current plans, pilot projects with regard to hydrogen

The first wind-hydrogen system in Africa was installed in 2012 at the Al Akhawayn University in Ifrane to demonstrate that the problem of wind intermittency and excess power generation can be resolved. The system is used for training and research. Although hydrogen is currently not included in the Moroccan (renewable) energy strategy, researchers predict that coupling the huge potential of wind energy with hydrogen could significantly influence Morocco's future energy mix.

[120] The Office National de l'Electricité et de l'Eau Potable (ONEE), Morocco
[121] Office Nationale de L'electricite

Country report for Norway

Current situation and future outlook

Norway has one of the highest share (45%) of renewables in total primary energy supply. In 2012, Norway and Sweden have jointly established an electricity certificate system to support investments in renewable energy. This has boosted wind energy development and the smaller hydro systems but, unlike Sweden, Norway will not further increase its RE targets after 2020.

	2016[122]
Total Primary Energy Consumption(PJ)	1,190
– Natural gas – Oil – Coal – Hydro – Other renewables	19.5% 28.5% 2.7% 43.3% 6.0%
Population size(million)[123]	5.3
Primary energy consumption/capita(GJ)	224.5

Total primary energy supply 2017

There are only few studies that looked at the long-term development of the energy sector in Norway. This is not surprising because the country is not only self-sufficient in energy supply, but is also a major exporter of oil, gas and electricity. The policy focus therefore is more on long-term value creation through sound resource management than on securing the supply of sufficient energy for meeting future demand. A study conducted by FME CenSES[124] presented electricity demand projections towards 2050 for the following scenarios:

- REF is the reference scenario based on existing policies. General efficiency measures are not included
- REF-EE scenario assumes that profitable energy efficiency measures will be implemented
- HIGH scenario is based on the assumption of high industrial growth and no restriction of battery electric vehicles
- LOW scenario assumes low industrial activity, lower demand from transport sector and higher energy prices. The electricity trade prices in this scenario are considerable higher compared to the other scenarios.

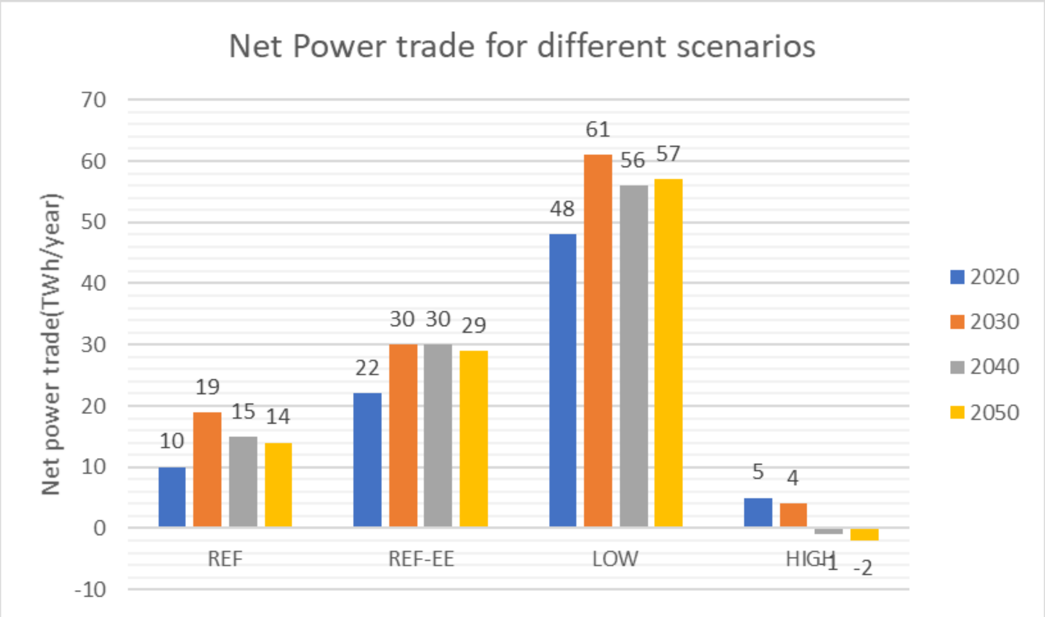
[122] International Energy Agency
[123] https://www.populationpyramid.net/spain/2030/
[124] CenSES Energy demand projections towards 2050 – Reference path; FME CenSES

	2016[125]	2030	2050
Total electricity demand (TWh)	124		
– REF – REF-EE – LOW-industry – HIGH-industry		125 118 103 140	136 120 106 150

Total electricity demand 2016, 2030 and 2050

The net electricity trade increases to 19 TWh in 2030 and is calculated to 14 TWh in 2050 in the reference path. The net power trade is strongly dependent on the exogenously given trading prices. In the LOW activity scenario the trading prices are the highest at the same time as the Norwegian electricity use is at the lowest, and therefore the net trade is highest in this scenario.

The net power trade with neighboring countries for the different scenarios is shown in the following Figure.



Renewable energy capacity expansion plans

Norway is the largest hydro power producer in Europe (excluding Russia). In 2016, Norway produced 149TWh of electricity, 98% of which by 1550 hydropower plants. More than 75% of the Norwegian hydro production capacity is flexible, which means that production can be rapidly increased or decreased as needed. Therefore, Norway can become an European 'battery' for balancing production and consumption of renewable electricity. Based on the water inflows of the past 20 years, the hydro power potential is 214 TWh/year (IEA, 2017) and this could further increase in the coming decades as a result of the predicted increase in rainfall. In 2016, Norway net power exports reached 16.5 TWh or some 11% of total domestic production.

[125] International Energy Agency

In 2016 there were 25 wind farms in Norway with a total capacity of 873 MW(2.1TWh). Investments in wind energy has increased substantially in recent years and it is expected that by 2020 there will be some 10TWh of wind power developed. Norway has also recently started to investigate the possibilities for floating offshore wind.

The other renewables comprise municipal and industrial waste (87MW), solid biofuels(79MW) and solar PV(14MW).

	2016(GW)[126]	2030(GW)
Onshore wind	.87	1.0
– Hydro	31.5	
– Thermal	.73	
– Total	33.1	

Generating capacity (GW), 2017 and 2030

The future export potential of electricity highly depends on the future renewable energy prices and on future RE production in other EU countries.

Current plans, pilot projects with regard to hydrogen

Hydrogen has so far not been high on the political agenda in Norway. This has resulted in low budgets and small-scale local initiatives rather than a national hydrogen policy. However, this is about to change now the financial support scheme for new climate friendly technologies(ENOVA) has moved from the Ministry of Petroleum and Energy to the Ministry of Climate and Environment. Currently there are seven hydrogen petrol stations in Norway but through the support of ENOVA this number will grow rapidly in the coming years and it is expected that the number of hydrogen cars will grow from 120 in 2018 to 500,000 in 2030127.These cars will then consume around 75,000 tonnes of hydrogen, which in turn, will require 4 TWh of renewable electric energy.

Hydrogen could also become a new market for the Norwegian gas industry. Norway has a large production of natural gas, with a yearly export of nearly 3412 TBtu. Hydrogen with CCS could be profitable for large-scale production from existing facilities.

[126] Norwegian Ministry of Petroleum and Energy inistry of Petroleum and Energy Ministry of Petroleum and Energy
[127] https://www.openaccessgovernment.org/hydrogen-is-finally-getting-attention-from-norwegian-politicians/47244/

Country report for Saudi Arabia

Current situation and future outlook

Saudi Arabia has one of the world's largest proven oil reserves and has a unique role as the world's most important swing producer of oil. However, due to the last decade's industrial and economic growth and the rapidly increasing population[128] domestic energy demand is growing fast and is eating away the oil reserves. Oil consumption per capita in Saudi Arabia today is one of the highest in the world and some predict that if nothing is done to reduce domestic consumption Saudi Arabia even could become a net importer of oil by 2030[129]. This gloomy forecast triggered the Saudi regime to develop 'Vision 2030', a masterplan that aims to reduce the kingdom's dependence on oil and diversify its economy away from oil. Vision 2030 was launched in April 2016 and contains ambitious targets for the development of renewable energy, in particular solar and wind energy.

According to the IEA, total energy production in 2016 was 28,051 PJ. Total net export amounted to 18,673 PJ in this year and total electricity produced in 2016 was 316.8 TWh, or almost 10,000 kWh per capita.

	2016[130]
Total Primary Energy Consumption(PJ)	8,810
– Natural gas – Oil	35.2% 64.8%
Population size(million)	32.3
Primary energy consumption/capita(GJ)	272.8

Total primary energy supply 2016

Renewable energy capacity expansion plans

Saudi Arabia has embarked on a very ambitious renewable energy strategy which is part of Vision2030 and aims to supply 10% of its power demand from renewable sources in 2023 and 30% in 2032. At the same time the country wants to create a globally competitive local renewable energy industry by setting strict requirements in the tenders for local content (more than 60%).

Saudi Arabia is greatly suited to developing solar energy with its vast stretches of deserts that can host solar systems and vast deposits of clear sand that can be used to manufacture of silicon PV cells. Saudi Arabia has approximately 3,000 hours of sunshine per year. The rapidly declining cost of solar PV and CSP also contribute to the growing interest of the Saudi government to develop the solar potential. The first large scale 300 MW solar project was awarded in early 2018 to a Saudi based developer which won the contract at a tariff of 2.3 c USD per kWh. In the same year the Saudi government and Japan's softbank Group

[128] The population of Saudi Arabia has been risen considerably over the past decades, from 9.6 million in 1980 to over 32 million today. It is expected that also in the coming decades population growth will be among the highest in the world and according to the UN total population will reach 68 million people in 2050
[129] Maya Shawayder, Saudi Arabia may run out of oil by 2030, Citygroup, 2012
[130] International Energy Agency

signed a MoU to develop 200 GW of solar power by 2030 with a price tag of USD 200 billion but this project was stalled end of 2018.

The wind map of Saudi Arabia shows that there is a vast windy regions along the Red Sea coastline. Average windspeed in these areas ranges from 4 – 6 m/sec. maximum wind speed can reach 16m/sec. The Saudi government has launched a tender for its first utility-scale 400MW wind farm project and is currently evaluating the four bids it received. It is expected that by mid-December 2018 the project will be awarded for this USD 500 million project.

In addition, Saudi Arabia has limited potential of hydropower, geothermal energy and waste-to-energy. The planned renewable energy capacity is presented in the table below

	2016(MW)	2032(GW)	2050(GW)
Onshore wind		9	27
Solar PV[1)]	50	16	35
Solar CSP	-	25	37
Waste-to-energy	-	3	5
Geothermal	-	1	1
Total		54	105

1) In 2015 the target for solar energy was pushed back to 2040

Generating renewable energy capacity (GW)[131]*, 2016, 2032 and 2050*

Potential barriers for realization of the plans

Many researchers have highlighted the barriers and challenges which need to be addressed to make renewable energy projects successful in Saudi business context. These barriers include:

- Technical barriers:
    - PV panels would never withstand the harshness of Saudi Arabia's desert[132]
    - Intermittent character of solar and wind energy. Insufficient storage capacity
- Economic/financial barriers: lack of assurance of investment security and Return On Investments to attract investor in this region[133]
- Institutional barriers:
    - Saudi Arabia's oil infrastructure has received massive investments for decades and is heavily subsidized which created a business environment that makes it challenging to promote renewable energy
    - Lack of sufficient knowledge, experience, skills and capacity with regard to renewable energy technologies.

[131] King Abdullah City for Atomic and Renewable Energy (K.A. CARE)
[132] Al-Saleh, 2009
[133] Ramli and Twaha (2015)

- Bureaucratic barriers: the political system's inability to effectively cooperate and coordinate between a host of institutions will likely obstruct a wide-reaching implementation of the national renewable energy strategy[134].

Current plans, pilot projects with regard to hydrogen

Saudi Arabia and Japan are currently exploring the possibility of extracting hydrogen from Saudi crude oil so that it can be transported to Japan in the form of ammonia. According to the Institute of Energy Economics-Japan(IEEJ), an option for Japan's contribution to reducing greenhouse gas emissions could be a supply chain for carbon-free hydrogen and ammonia produced through CCS from Saudi Arabian fossil fuels.

S. Almogren et al. already in 2004 noted that the Saudi's dependence on oil is unsustainable in the long run and will lead to an energy deficit. They argued that It becomes imperative for Saudi Arabia to exploit solar energy and this could be done by solar production of hydrogen and then utilizing hydrogen as an energy carrier, as well as exporting it to other countries. This would provide Saudi Arabia with a clean and permanent energy system, and would enable it to maintain and improve its overall GNP, as well as improving its quality of life[135].

[134] Transitioning to renewable energy in Saudi Arabia
A multi-level perspective analysis of the Saudi renewable energy policies; Katrine Wiulsrød Ratikainen; 2017

[135] Solar-hydrogen energy system for Saudi Arabia: Sulaiman Almogren,T.NejatVeziroglu; Clean Energy Research Institute, College of Engineering, University of Miami Coral Gables, November 2003.

Country report for Spain

Current situation and future outlook

During the past 20 years energy demand in Spain has followed a similar growth pattern as economic growth. However, it is expected that this is going to change significantly in the coming decades. According to recent projections developed by the Committee of Energy, Tourism and Digital Agenda[136], total primary energy consumption will decrease by 5% in 2030 and by 15% in 2050 compared to 2015. The current high dependency on fossil fuels is also expected to change drastically in the coming decades. In 2050 renewable energy will account for nearly 70% of the total primary energy consumption. The figure below shows the total primary energy supply in 2015, 2030 and 2050 according to recent projections made by the Spanish government.

	2015	2030	2050
Total Primary Energy Supply (PJ)	5,857	5,682	4,983
– Electricity exports – Natural gas – Nuclear – Oil – Coal – Wind – Biomass – Solar PV + CSP	2% 19% 12% 42% 11% 5% 5% 2%	-1% 45% 14% 16% 2% 5% 5% 8%	-2% 18% - 11% - 21% 21% 25%
Population size (million)[137]	46.4	45.9	44.8
Primary energy consumption/capita (GJ)	126	124	111

Total primary energy supply, 2015, 2030 and 2050

Renewable energy capacity expansion plans

The report prepared by the Committee presents two detailed scenarios for the future Spanish energy market. The first scenario, the 'distributed generation scenario', forecast strong development of renewable energy distributed generation coupled with storage systems. Under this scenario, renewables would have a 70% share in Spain's electricity mix in 2030. The second scenario, the 'sustainable transition scenario' is less ambitious but also expects solar to become the largest and cheapest source of power by 2030.

[136] Comisión de Expertos de Transición Energética: Análisis y propuestas para la descarbonización; Committee of Energy, Tourism and Digital Agenda of the Spanish Senate
[137] https://www.populationpyramid.net/spain/2030/

The planned new renewable energy capacity in Spain for 2030 according to the 'distributed generation scenario' is shown in the following table:

	2017(GW)[138]	2030(GW) [1]	2030(GW)[2]
Solar PV	5.0	77	40
Concentrated Solar Power	2.3		
Onshore Wind	22.9	47.5	31
Hydro	14.0	23	23

Note 1: Análisis y propuestas para la descarbonización: Distributed Generation Scenario

Note 2: Análisis y propuestas para la descarbonización: Sustainable Transition Scenario

Generating capacity (GW), 2017 and 2030

Spain has successfully auctioned 7.8 GW of new renewable projects (4.4 GW wind, 3 GW solar PV and 0.4 GW biomass) in 2016 and 2017. These plants need to be in operation before January 2020. In 2016 a new tendering system was put in place for renewables. This new system is based on market prices and this means in practice much less or no subsidies. This change can be seen as a sign that the renewable market becomes more mature and costs of production significantly decrease as a result of economies of scale.

According to the president of the Spanish solar organization, Jose Donoso, over the coming two years € 4-5 billion will be invested in solar energy projects in Spain. It is expected that from 2020 onwards new investments in solar projects will grow with € 1-2 billion annually[139].

Potential barriers for realization of the plans

Barriers to further deployment of renewable technologies mentioned by Mr Jose Donoso includes institutionalized legal insecurity represented by the risk of retroactive measures, the current regulation for the grid-connection of large scale energy infrastructure and a lack of grid expansion plans.

A barrier mentioned by Pablo del Rio[140] is power generation overcapacity in Spain leading to suboptimal allocation of resources and could be an obstacle for further investments in renewable energy technologies.

Another barrier is the integration into the grid. However, to some extent Spain seems to have addressed this problem by establishing a new control centre at Red Eléctrica de España, Spain's TSO, to help maximise renewable energy production while ensuring system reliability.

Current plans, pilot projects with regard to hydrogen

The development of the hydrogen market in Spain is still in its infancy. The main promoters of hydrogen and fuel cell technologies are the Hydrogen Association(AeH2) and the Technology Platform on Hydrogen and Fuel Cells(PTEHPC). The main (pilot) projects conducted during the past ten years include:

- Solar thermal hydrogen
- Integration with wind power

[138] http://resourceirena.irena.org/gateway/countrySearch/?countryCode=ESP
[139] Revealed by the Spanish solar organization in a hearing with the Committee of Energy, Tourism and Digital Agenda
[140] Overcapacity as a barrier to renewable energy deployment: The Spanish case; Pablo del Rio and Luis Janeiro

- Biofuel reforming
- Use of hydrogen and fuel cells in transport sector
- Construction of hydrogen filling stations (Spain will have 20 hydrogen filling stations by 2020)

According to the president of AeH2, Mr Javier Brey, the Spanish hydrogen industry is rapidly growing and is expected to generate €22 billion turnover and 227,000 jobs in 2030. However, despite these optimistic outlook the Spanish government is still very uncertain about the future development of the hydrogen industry in Spain and therefore did not include this technology in the national energy outlook. The province of Aragon however has developed the hydrogen masterplan 2016 – 2020.

Country report for the United Kingdom

Current situation and future outlook

The UK is among the most successful countries in the developed world in growing its economy while reducing greenhouse gas emissions. In 2017 Britain generated more electricity from nuclear and renewables than from coal and gas. In October 2017 the UK Government published its “Green Growth Strategy”[141] which sets out its policies to achieve the ambitious climate objective. The latest Energy and Emissions Projections(EEP) 2017 was published by the Department for Business, Energy & Industrial Strategy(BEIS) of the UK government in January 2018 and presents projections up to 2035[142]. The primary energy supply projections for the ‘High Growth’ scenario are presented in the table below[143].

	2016	2035 (High Growth)
Total Primary Energy Supply(PJ)	8,419	8,206
- Electricity net imports - Natural gas - Nuclear - Oil - Renewables & waste – Solids[144]	0,7% 38,3% 7,7% 37,7% 9,3% 6,2%	2,2% 30.4% 14,3% 36,0% 14,8% 2,2%
Population size(million)	65.6	73.0
Primary energy consumption/capita(GJ)	128	112

Total primary energy supply, 2016 & 2035

Renewable energy capacity expansion plans

The UK was Europe’s largest national investor in renewable energy in 2016 but investments plummeted 56% in 2017 to £7.5 billion[145][146]. This decline was due to an end of subsidies for onshore wind and utility-scale solar power and a substantial gap in time between auctions for offshore wind power projects. This will slow down the deployment of these technologies in the coming years but it also indicates that due to the rapidly declining cost renewables are becoming cost competitive with fossil fuels. The latest BEIS cost estimates[147] suggest onshore wind and solar will be as cheap or cheaper than gas in 2020, gaining a clear cost advantage by 2025.

[141] The Clean growth Strategy; leading the way to a low carbon future; UK Government, October 2017
[142] https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2017
[143] The assumption for economic and population growth can be found in footnote 2) Annex M
[144] Includes coal and manufactured fuels(coke)
[145] Bloomberg New Energy Finance
[146] Half of the investment in 2017 concerned a single off shore wind farm, the Hornsea 2 project with a capacity of almost 1.4 GW.
[147] Electricity generation costs ; BEIS, November 2016

The planned new renewable energy capacity in the UK for 2020 and 2050 is shown in the following table:

	2018	2020 (EEP)[2]	2050 (Level 2) [148]
Solar PV	16.8	11.1	70
Onshore Wind	14.7	13.9	20
Offshore wind	8.0	10.4	60
Tidal	23.7 MW	140MW	1.7
Wave			11.5

Note 1: according to the EEP scenarios the installed renewable capacity will reach 36 GW in 2035 and 45GW in 2035. The capacity is not broken down by source but according to business green the 2030 projection includes 10GW of small scale subsidy-free solar.

Note 2: according to BNEF 2018 New Energy Outlook, by 2050 the UK has added 158 GW of new wind and solar capacity increasing the share of renewable electricity production to 73%.

Generating capacity (GW), 2018, 2020, 2050

Potential barriers for realization of the plans

The main barriers to accelerated uptake of solar technology mentioned in the 2020 solar roadmap[149] are:

- The exclusion of onshore wind and utility solar from the Contracts for Difference support scheme is key barrier in the coming years to further develop these technologies. However, in the longer term when cost are further decreasing these technologies will become cheaper than fossil fuels.
- The electricity network in the UK was developed around large power stations, and is having problems coping with the increase in the enormous upscale of local solar and other renewable generation in the last few years. This means that in the sunniest parts of the country the network needs to be upgraded (which can be costly) or better manage the power output from solar farms using batteries.
- There is a lack of trained engineers and technicians needed for the construction and maintenance of renewable power plants.
- Trade barriers such as import tariffs
- There exist also non-economic barriers related to planning and public acceptance of new hydrogen technologies (safety issues related to hydrogen buses, cars and fueling stations)

Current plans, pilot projects with regard to hydrogen

In the 'Green Growth strategy' the UK Government recognizes the important role low carbon hydrogen could play in decarbonizing industry, power, heat and transport. This is reflected in the planned £46 million programme on hydrogen. An additional £20 million has been set aside for a programme that aims to analyse low carbon bulk hydrogen supply solutions for industry, buildings and transport.

[148] 2050 Pathways Analysis; Ministry of Energy and Climate Change, July 2010; For each renewable source four trajectories have been developed, ranging from little or no effort to reduce emissions or save energy (level 1) to extremely ambitious changes that push towards the physical or technical limits of what can be achieved (level 4). Level 2: describes what might be achieved by applying a level of effort that is likely to be viewed as ambitious but reasonable by most or all experts. For some sectors this would be similar to the build rate expected with the successful implementation of the programmes or projects currently in progress.
[149] Roadmap 2020: Powering Canada's future with solar electricity; Canadian Solar Industries Association

The Hydrogen Supply programme aims to significantly reduce the high cost of producing large volumes of low carbon hydrogen and consists of two phases: phase 1(feasibility) with a budget of £5 million looks at the development of hydrogen supply solutions; phase 2(pilot demonstration) aims to develop pilot demonstration (physical or engineering designs).

In September 2018, ITM power received funding from the UK Government to conduct a feasibility study for a 100 MW power to gas project(Centurion). The project will explore hydrogen production via electrolysis, transportation by pipeline to salt caverns and storage and will assess the business case for deployment.

Another focus area for hydrogen is the transport sector. By 2017 there were 15 hydrogen fueling stations in the UK and the government wants to further develop the UK hydrogen vehicle market and has provided up to £23m of new grant funding until 2020 to support the growth of refueling infrastructure alongside the deployment of new vehicles.

Appendix I RVO reporting requirements

This appendix is intended as a reference for the reporting requirements RVO set as part of the Topsector Energie subsidy from the Ministry of Economic Affairs granted to this project.

This report is required to give insight into

a) **The next steps the consortium will take upon completion of the project to execute and implement in the market what has been researched**
The next steps following completion of the first three projects would be to start projects 4 and 5, which deal with integrating the efforts of the first three projects to develop various detailed scenarios and with the public engagement regarding this topic, respectively. If an international supply chain to the Netherlands is found to be desirable, several other projects could be started upon completion of the current HyChain projects. These could for instance look at the market for international renewable energy carriers from the perspective of several countries which have been identified as being able and likely to export large quantities of low cost renewable energy carriers. Another possible project could look at the investments that will have to be done, both abroad and in the Netherlands and, crucially, also in the necessary infrastructure in between. Geopolitical risks are another topic that HyChain has not touched upon yet.

b) **The expected CO_2 reduction that would be achieved upon execution and implementation in the market of what has been researched**
If this international supply chain were to materialise, the CO_2 reduction would be very large but depend on the hydrogen demand. Currently the hydrogen demand in the Netherlands is about 0.8 Mton and met by SMR production, which generates about 9 kg CO_2 for every kg H_2 produced. If this hydrogen were imported as renewable hydrogen rather than produced through SMR, the CO_2 savings would be 0.8 * 9 = 7.2 Mton CO_2. Since the hydrogen demand is expected to increase significantly to enormously, so would the savings (compared to producing that hydrogen via SMR). If the demand indeed is to increase by a factor 22, so would the CO_2 reduction through import of renewable hydrogen (compared to SMR production).

c) **The financial or economic opportunities, including one or more business cases which are necessary to successfully apply the concept or technology**
Energy carriers import also offers some new economic opportunities. Within the Netherlands, such opportunities lie in storage facilities, infrastructure and (again) as a gate to the rest of Europe. If the Netherlands were to import energy carriers from say Canada or the United Kingdom (with large export potentials), these would likely be stored in Rotterdam and could be exported, via ships or pipelines, to Germany (with a potential renewable energy shortage). Such cases can be explored with the model.

d) **The non-technological factors that could play a role in the application of the concept or technology in the market and the way these factors are dealt with**
The model however only performs simple cost calculations and does not say anything about how likely it is for a general supply chain (or specific routes for that matter) to emerge. To that end ECN part of TNO has composed so-called country profiles for a number of high-potential countries, which go into potential opportunities and barriers for implementation. These country profiles can be found at the end of the report.

e) **If the project is about technology development; the embedding of this technology in the energy value chain**
Not applicable.

f) The scalability and repeatability of what has been researched

We specifically looked at the supply chain to the Netherlands. The scalability and repeatability of such a supply chain is great. This holds true in various ways. For one such supply chains could also be evaluated for other countries which for economic reasons or potential shortage are willing to consider importing renewable energy carriers. Collectively this could give rise to a global renewable energy carriers market. This itself is yet another economic opportunity; if the Netherlands gathers extensive knowledge and experience on this supply chain, it can use that abroad to help develop a global renewable energy market and supply chain and hence accelerate and advance the energy transition, globally.

Appendix II People involved in this study

Participants in the HyChain 2 project

Name	Position	Organisation
Kees Biesheuvel	Technology Innovation Manager	DOW
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Sebastiaan Hers	Senior Consultant	ECN part of TNO
Yvonne van Delft	Innovation Manager Liquid Separation and Conversion	ECN part of TNO
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Marcel van de Kar	Business Development Director	Koninklijke Vopak N.V.
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Rob Stevens	Vice President Technology Scouting	Yara
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With the cooperation of

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Mahdi Fasihi	PhD Candidate	LUT
Joris Berkhout	Partner	Quintel Intelligence
Kees Koreman	Engineering Manager Nordlink, Asset Management Offshore	TenneT
Gert van der Lee	Long Term Transmission Gridplanning	TenneT
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