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Optimisation of the green hydrogen supply chain based on overseas production and import to Belgium

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Abstract

Green hydrogen has seen a growing interest in recent years, motivated by the pressing need to decarbonise the energy system. Some countries can produce cost-effective green hydrogen all year long, supported by their abundant renewable electricity, while others are limited by a deficit in renewable potential. The international trade of green hydrogen can mitigate the imbalance between countries with an excess of hydrogen supply and countries with high demand but insufficient production capabilities. An optimisation model has been designed to study the feasibility of a green hydrogen supply chain from an economic perspective. A particular attention has been paid to the case study of the Belgian industrial sector, characterised by a high energy end-use demand and low potential of carbon-free production. The optimised results reveal that it is most advantageous for Belgium to import from Spain, using liquefied hydrogen in the near term (2020). In the medium term (2030), Australia becomes a cost-competitive supplier and in the long term (2050), green hydrogen purchases from Morocco could be an option. Overall, this thesis aims to serve as a tool for designing the best green hydrogen supply chain for many countries.

Acknowledgements

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List of Abbreviations

CGH_2 Compressed gaseous hydrogen

CO_2 Carbon dioxide

H_2 Hydrogen

LH_2 Liquefied hydrogen

$LOHC$ Liquid Organic Hydrogen Carriers

NH_3 Ammonia

y Year

$ US dollar

AUS Australia

BEL Belgium

Blue hydrogen Hydrogen produced from natural gas with carbon capture and storage

BOG Boil-off Gas

CAGR Compound Annual Growth Rate

CapEx Capital Expenditure

CF Capacity Factor

CHL Chile

CRF Capital Recovery Factor

E-fuel Fuel made using electricity from decarbonised sources

EHB European Hydrogen Backbone

EIA Energy Information Administration

ESP Spain

EU European Union

GCC Gulf Cooperation Council

GHG Greenhouses Gases

Green electricity Electricity generated from natural resources such as sunlight wind or water

Green hydrogen Hydrogen produced by water electrolysis using zero-carbon electricity generated from renewable energy facilities

Grey hydrogen Hydrogen produced from natural gas or coal

IEA International Energy Agency

IPCC Intergovernmental Panel on Climate Change

IRENA International Renewable Energy Agency

LCOE Levelised Cost of Electricity

LCOH Levelised Cost of Hydrogen

MAR Morocco

MILP Mixed Integer Linear Programming

Mt Million tonnes

NECP National Energy and Climate Plan

NREL National Energy Energy Laboratory

OECD Organisation of Economic Co-operation and Development

OMN Oman

OpEx Operating Expenses

PV Photovoltaics

RES Renewable Energy Sources

VRE Variable Renewable Energy

Chapter 1

Introduction

> *Chapter overview:*
>
> – *Why should green hydrogen trade be deployed?*
>
> – *Context and state of the art at the international, European and national level.*
>
> – *Contributions of this thesis.*
>
> – *Thesis structure overview.*

1.1 Accelerating efforts to deploy hydrogen infrastructure

Climate mitigation is one of the most important challenges of current times. The urgency of the situation was highlighted by the latest report of the Intergovernmental Panel on Climate Change (IPCC) released in February 2022, which stated that global warming would have severe impacts that are not only costly in economic terms but threatening to human well-being and survival as well [1]. Furthermore, numerous studies support the importance of not violating the 1.5°C target set by the Paris Agreement in 2015 and highlighted by the recent IPCC report. This refers to the limitation of global warming to well below 2, preferably 1.5 degrees Celsius, compared to preindustrial levels.

In March 2022, the International Renewable Energy Agency (IRENA) presented its pathway [2] to reach 1.5°C goal with an accelerated deployment of green hydrogen as a key driver of the energy transition. Green hydrogen is produced through a carbon-free technology: water electrolysis. This process uses electricity from renewable energy sources such as solar photovoltaic, wind energy, and hydropower. Thus, using green hydrogen can help to reach carbon neutrality in hard-to-abate sectors such as energy-intensive industries or transport. Unfortunately, local green hydrogen production depends on the availability of renewable energy sources and thus cannot be a solution for every country. In this case, the report emphasises how international trade in hydrogen could provide a balance between renewable energy supply and demand, at the global level.

On the exporting side, Chile, North Africa, Spain and Australia are deemed for their high-quality renewable resources while Japan, the Republic of Korea and the rest of Europe are expected to import almost all of their hydrogen demand. In its analysis on geopolitics of the energy transformation [3], the IRENA suggests that about one-third of green hydrogen would be traded across borders by 2050. Figure 1.1 shows a version of new hydrogen trade relations.

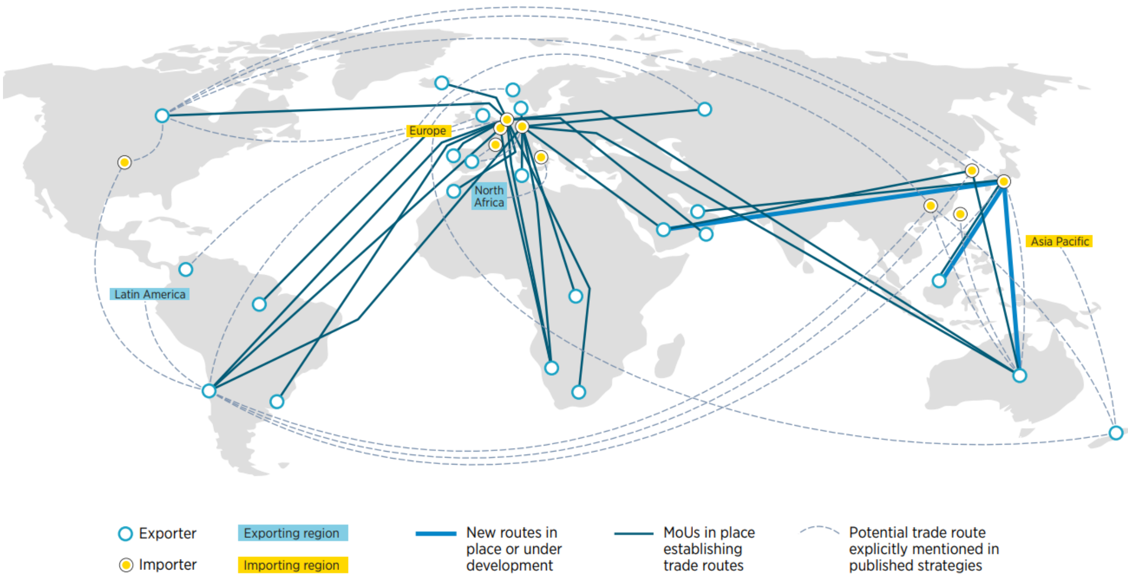


Figure 1.1: An expanding network of hydrogen trade routes, plans and agreement (IRENA)[3]. Europe and Asia pacific are expected to be importing regions while Latin America and North Africa are foreseen as exporting regions.

However, the IRENA states that this pathway to decarbonisation using green hydrogen is possible only by reducing production costs to well below 1$/kg, i.e., 26.43 €/MWh for production and transport. In particular, falling capital costs for renewables and electrolysis could make the cost of green hydrogen competitive in all the countries by 2030.

Numerous countries announced pledges to achieve net zero emissions by 2050. According to the International Energy Agency (IEA), reducing global carbon dioxide (CO_2) emissions is consistent with efforts to limit the long-term increase in average global temperatures to 1.5°C. In 2021, the IEA published its roadmap for the global energy sector to achieve this goal [4]. It insists on the need of boosting innovation in clean energy and building new infrastructures. Indeed, the net zero pledges made by several countries highlight the need of a global shift from fossil fuels to electricity, renewable energy and hydrogen.

As shown in Figure 1.2 , the initial focus for hydrogen is to convert existing uses into low-carbon hydrogen and hydrogen-based fuels. This includes hydrogen use in industry and in refineries. Then, hydrogen consumption could be expanded to all end-uses. Also, Figure 1.2 highlights the development of global trade in hydrogen over time. The IEA strongly encourages international cooperation across sectors, which is essential to reach the net zero target by 2050. Their scenario foresees the exportation of large volumes of hydrogen from renewables rich areas in the Middle East, Central and South America and Australia to demand centers in Asia and Europe. This is a situation also forecasted by the IRENA.

Sector	2020	2030	2050
Total production hydrogen-based fuels (Mt)	**87**	**212**	**528**
Low-carbon hydrogen production	9	150	520
share of fossil-based with CCUS	*95%*	*46%*	*38%*
share of electrolysis-based	*5%*	*54%*	*62%*
Merchant production	15	127	414
Onsite production	73	85	114
Total consumption hydrogen-based fuels (Mt)	**87**	**212**	**528**
Electricity	0	52	102
of which hydrogen	0	43	88
of which ammonia	0	8	13
Refineries	36	25	8
Buildings and agriculture	0	17	23
Transport	0	25	207
of which hydrogen	0	11	106
of which ammonia	0	8	44
of which synthetic fuels	0	5	56
Industry	51	93	187

Figure 1.2: Key deployment milestones for hydrogen and hydrogen-based fuel (IEA)[4]. Low-carbon hydrogen production is expected to increase in the future, either for merchant or onsite production. Hydrogen consumption will expand in all sectors except refineries.

At the European level, the Green Deal (2019) has identified green hydrogen as a priority area for reducing Greenhouse gases (GHG) emissions at least by 55% by 2030 and achieving carbon neutrality by 2050. With Russia's invasion of Ukraine, there is a double urgency to transform Europe's energy system: ending the European dependence on Russian fossil fuels, which are used as an economic and political weapon, and tackling the climate crisis. This is the reason why the European Commission published a revision of the Green Deal in May 2022, with even more ambitious goals [5]. Particularly, the new plan called "REPowerEU" sets a target of 10 million tonnes (Mt) of green hydrogen produced in Europe by 2030, as well as 10 Mt of imports, to replace coal, oil and gas in hard-to-decarbonise industries and transport sectors (to be more precise, respectively 75% and 5%). Yet, hydrogen infrastructure is still in its infancy, so accelerated efforts and huge investments are needed for producing, importing and transporting these 20 Mt of hydrogen. At the current date (June 6, 2022), this plan is still waiting for the approval of the European Council and the European Parliament.

The study of Kakoulaki et al. [6] identifies the potential producers and importers of green hydrogen in Europe. It compares the potential electricity demand to switch to carbon-free hydrogen production with the renewable energy potentials, considering existing electricity consumption and hydrogen demand, in each country.

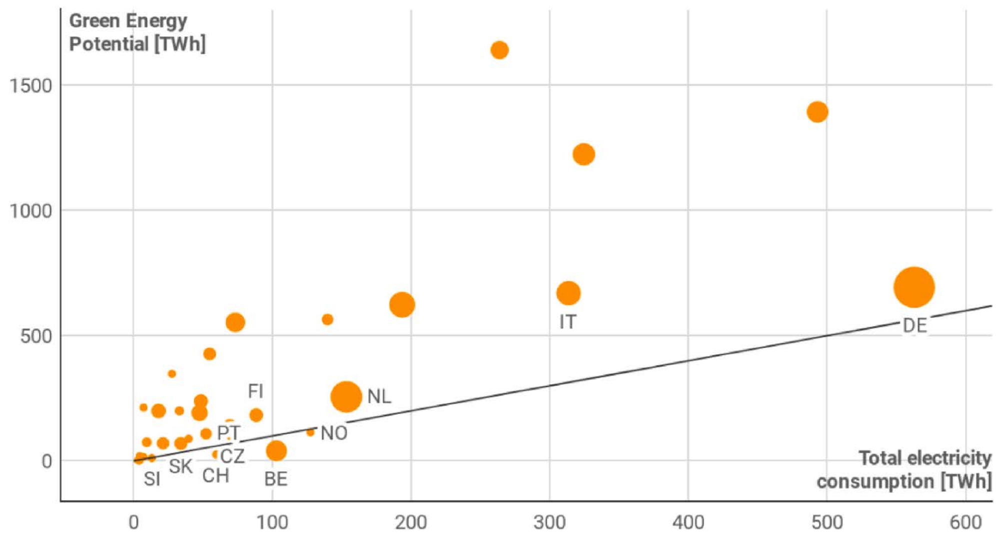


Figure 1.3: Total electricity demand (current consumption and proposed electricity for hydrogen electrolysis) in EU27 and UK compared to countries' green electricity potential [6]. The green electricity potential exceeds the total electricity demand in the majority of countries with Belgium (- 62.7 TWh) being the main exception. Note: the black line is the 1:1 line, representing the perfect balance between supply and demand.

As illustrated in Figure 1.3, the findings are promising: in many EU (European Union) countries , the total green electricity potential exceeds the total electricity demand, including that for hydrogen production. The current annual EU hydrogen production of 9.75 Mt could be easily replaced by electrolysis and the growing hydrogen demand for future years could also be satisfied. Thus, such transformation stated by European Commission is possible. However some countries reveal a deficit of renewable energy, which explain the emphasis on hydrogen imports as an alternative to the local production. This is the case for Belgium which has a negative electricity supply and demand balancing of -62.7 TWh.

Following the EU policy, Belgium published a long-term decarbonisation strategy [7]. The country aims at decreasing its GHG emissions by about 95% by 2050 with respect to 1990. Currently the reduction accounts for 22%, with the strongest reduction in the energy and industrial sectors (-43% and -32% compared to 1990, respectively). Still, the industry remains the largest GHG-emitting sector (around 33.5% of total Belgian GHG emissions in 2017). To achieve decarbonisation, the strategy implies the increased use of green hydrogen. Particularly, green hydrogen can be used as feedstock for a number of industrial processes (e.g., steel production, certain chemicals). This information inspired the case study of this thesis. In particular, this study focuses on the "feedstock-switch", from grey to green hydrogen, in the Belgian industrial sector.

To help the implementation of this strategy, a Hydrogen Import Coalition was created in Belgium. The report "Shipping sun and wind to Belgium is key in climate neutral economy" [8] informs that, because of the poor potential of renewable energy, imports will become a necessary and vital part of the Belgian energy supply in order to achieve carbon-neutrality by 2050. Still, according to the coalition, large-scale green hydrogen import is both technically feasible and cost-effective. When delivered to Belgium, the cost range of imported renewable energy from low-cost locations lies in the range of 65-90 €/MWh by 2030-2035 with a further potential cost reduction to 55-75 €/MWh or less by 2050, considering the overall supply chain. Several hydrogen-based carriers are feasible and many sourcing regions are capable of providing cost-competitive energy. The coalition identified five of the best sourcing regions for Belgium: Australia, Chile, Oman, Morocco and Spain. The case study mentioned above will be based on this relevant choices.

Figure 1.4: The possible sourcing region for Belgium according to the coalition are Australia, Chile, Oman, Morocco and Spain [8].

Based on the results presented, it is clear that the trade of hydrogen represents a viable option for countries with low renewable energy potential. The identification of optimal routes for the trade of hydrogen can be tackled as an optimisation problem. Recently, Kim et al. [9] optimise the hydrogen supply chain in South Korea through Mixed-Integer Linear Programming (MILP). Like Belgium, South Korea is expected to be one of the major hydrogen-importing countries, considering the high decarbonised hydrogen requirements and the small carbon-free production capabilities. The study published by Kim et al. concerns blue and green hydrogen.

The optimised results presented in Figure 1.5 reveal that the most cost-effective solution is to import blue hydrogen from Qatar and Russia and green hydrogen from the Unit Arab Emirates and India, using liquefied hydrogen in the near term, for a unit cost between 2.06-2.38 \$/kg, i.e., 55.44-62.89 €/MWh in 2025. In the long term, the study [9] shows that the green hydrogen supply will prevail over blue hydrogen due to an exponential drop in the renewable electricity price. The unit cost will rise to 2.19-2.95 \$/kg, i.e., 58.04-77.96 €/MWh in 2040, due to the increase in domestic demand, forcing the importing country to meet demand through a supply from countries with more expensive unit cost of hydrogen.

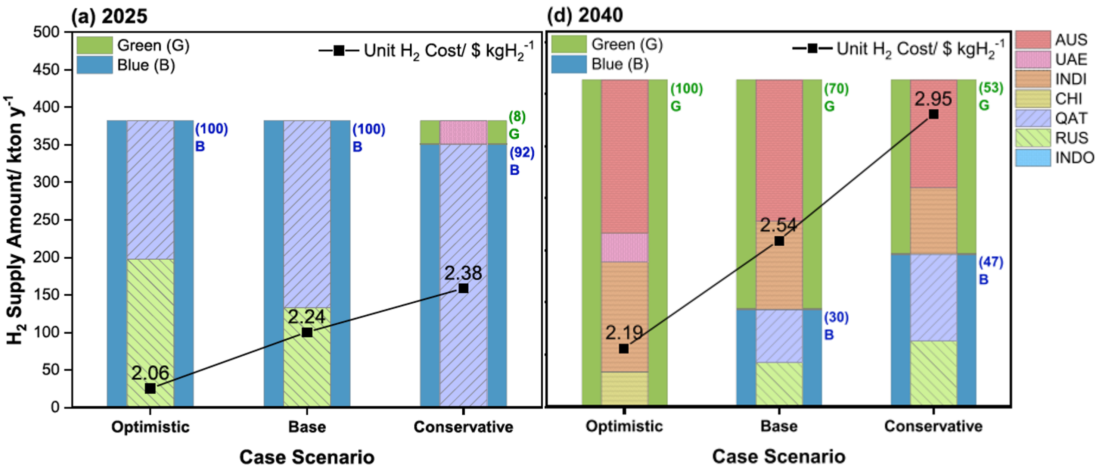


Figure 1.5: MILP optimisation results for overseas hydrogen (H_2) supply chain for the considered case scenarios in 2025 and 2040 [9]. In the near term, it is more feasible for South Korea to import blue hydrogen from Qatar and Russia, using liquefied hydrogen. In the long-term, green hydrogen supply is expected to gradually prevail over blue hydrogen, with purchases from other countries.

To summarise, this abundant and recent literature highlights the real need and desire to deploy green H_2 infrastructure at the international, European or national level. The trade of decarbonised H_2 is considered a promising solution to reduce differences in production capacity and provide benefits to both importing and exporting countries.

1.2 Research question

This thesis aims at:

- developing a general model for identification of the optimal routes for the production and export of green hydrogen to satisfy the expected hydrogen demand of one or more countries,
- applying the model to establish a long-term decarbonisation strategy for the industrial sector in Belgium.

The specific research question addressed is: from which countries and at which cost should Belgium import hydrogen to decarbonise its industrial sector?

1.3 Thesis outline

This document is organised as follows. Chapter 1 defines the context highlighting the key reasons why a global trade of green hydrogen has been taken into consideration. It specifies the role of hydrogen in the decarbonisation and the need to deploy infrastructures to support the hydrogen trade from an international, European and Belgian perspective. Chapter 2 presents the model developed to answer the research question, with a complete description of the assumptions, the parameters, the variables. The goal of the optimisation problem is to identify the optimal supply chain design that allows to meet the expected demand and minimise the total annual cost. Chapter 3 describes the different options for the green hydrogen supply chain and details the input data associated to the specific case study of the Belgian industrial sector. Finally, in Chapter 4, results of the model are presented, analysed and discussed in comparison with others reports. Final comments and future perspectives are given in Chapter 5.

Chapter 2

Model description

Chapter overview:

- *Description of the green hydrogen supply chain considered.*
- *Presentation of a MILP framework to model the supply chain : parameters, variables, constraints, objective function.*
- *Limitations of the model.*
- *Associated appendix: Energy content of hydrogen versus natural gas pipeline (B).*

2.1 Supply chain

The goal of this study is to define the optimal supply chain for the satisfaction of the demand of green hydrogen in importing countries. The model is based on the supply chain presented in Figure 2.1.

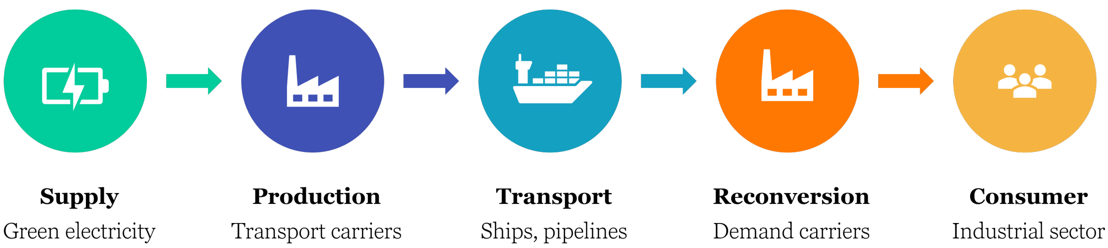


Figure 2.1: Graphical representation of the model's supply chain. Supply, production, transport, reconversion and consumption are considered as the five steps of this supply chain.

Exporting countries generate green electricity from their renewable energy installations, produce hydrogen via water electrolysis and convert it to some carrier for transport. Theses hydrogen derivatives are then transported to the importing country. There, the transport carriers are reconverted into the final demand carrier to satisfy the demand. The focus of this thesis for hydrogen demand is the industrial sector, including refineries. This sector is known as an "hard-to-abate" sector and is actually the main user of hydrogen today.

Indeed, hydrogen has long been used in the industry, either as feedstock in refineries (like for example in oil and gas industry), or as a by-product of industrial processes. As a matter of fact, the industrial sector represents more than 90% of today's hydrogen consumption in Europe [10]. Furthermore, the global hydrogen market, which has grown more than threefold since 1975 [11], is expected to rise at a compound annual growth rate (CAGR) of 4.3% up to 2030 [12]. Neverthless, this hydrogen is mainly produced through polluting processes as steam methane reforming (SMR) of natural gas, coal gasification or as a results of cracking of hydrocarbons (in refineries) [10].

The mathematical formulation of the model optimising the proposed supply chain allows to consider multiple exporting and importing countries, hydrogen transport and demand carriers, and renewable energy sources to supply green electricity. Furthermore, the model has a time resolution to take into account the effect of supply intermittency of renewables. Importations from one country or another at a certain period of time could help balance the energy system, in particular during prolonged periods of low solar and wind generation.

Sets	**Index**	**Description**
$\mathcal{E}$	i	Set of green hydrogen exporters
$\mathcal{I}$	j	Set of green hydrogen importers
$\mathcal{C}$	k	Set of transport carriers
$\mathcal{T}$	l	Set of transport technologies
$\mathcal{D}$	m	Set of demand carriers
$\mathcal{R}$	n	Set of renewable energy sources
$\mathcal{P}$	t	Time refinement

Table 2.1: Sets of the model.

The model is described by a set of parameters, a set of variables and a set of equations that establish relationships between the variables. Table 2.1 gathers the sets and indexes associated to each component of the supply chain. The parameters are noted with lower case and variables with upper case. To lighten the notations in the text, the parameters and variables are cited without indices.

2.2 Parameters

Supply and demand		
Parameter	**Description**	**Unit**
d_{jmt}	Amount of demand carrier m required by importer j for period t.	MWh
CF_{int}	Capacity factor of renewable source n in exporter i for period t.	-
q_{in}^{max}	Maximum capacity of renewable technology n allowed for green-electricity production in exporter i.	MW
g_{in}	Capital cost of installation of renewable technology n in exporter i.	€/MW
c_i	Local consumption of electricity in exporter i.	MWh$_e$

Table 2.2: Parameters appearing in the modelling of supply and demand. Notes: to avoid confusion, MWh refers to hydrogen while MWh$_e$ refers to electricity. Except for the CapEx, all units refer to values per year.

On one side of the supply chain, there is the consumer. The demand for hydrogen d considers the requirement for electrolysis to replace grey hydrogen with green hydrogen production. Specifically, this current carbon-intensive H_2 production provides mainly the feedstocks for industrial processes. In Europe, the major consumers are the chemical product manufacturers with a hydrogen market share of 63% (especially ammonia production for 84% and methanol for 12%), the refineries with a share of 30% and metal industry for 6%, according to [10].

On the other side, there is the supplier. The green electricity supply of each exporter is given by its maximum Renewable Energy Sources (RES) power generation. This is calculated with the installed capacity of renewable technologies q^{max} and a capacity factor CF that reflects the variable availability of RES depending on the location and period.

Nevertheless, efforts to produce and export green hydrogen should not affect the transition towards clean electricity system. Accordingly, it is necessary to take into account the electricity demand of the potential exporter across all sectors. The potential green electricity supply is limited by the local consumption c.

Many parameters can be taken into account in the calculation of the cost of green energy generation. In this thesis, three categories of costs are considered. First, the investment cost or Capital Expenditure (CapEx) represents the cost of acquiring the land and building the energy production unit. Second, the variable operational costs or Operating Expenses (OpEx) includes the costs for running the plant, i.e., the cost of inputs. Therefore, when it comes to renewable sources, it is zero unlike conventional power stations (gas, nuclear, coal, etc.). Finally, the fixed OpEx is the operating and maintenance costs of the installations, usually expressed as a percentage of the CapEx.

All these costs are used for the computation of Levelised Cost of Hydrogen (LCOH), expressed in euro per MWh. It represents the "minimum average price level over the lifetime that is required in order to provide an acceptable return to the investor" [8]. Even if the objective of the model is to minimise the total annual costs, LCOH will be a useful metric for the comparison of the results. The capital investment usually occurs at the beginning of the project lifecycle. To estimate the capital cost g as a fixed annual cost, a capital recovery factor (CRF) is applied:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}, \tag{2.1}$$

with i being the interest rate and n being the lifetime of the technology.
Theses assumptions on the cost composition will be used for every block of the supply chain.

The second step in the supply chain is the production of hydrogen and its derivatives. The associated parameters are summarised in Table 2.3. The first parameters to consider are the one associated to the costs. The capital cost of production p is the sum of the capital expenditures of the electrolyser and the conversion plant that transform hydrogen into a certain transport carrier. As the generation step, it is annualised with the CRF in Equation 2.1. The operating cost of production o is added to into take account the cost of electricity to feed the production technologies. However, it is assumed that renewable energy installations are directly connected to production technology (without grid connection) so that the electricity is free.

Then, the other parameters describe the characteristics of the plant. The production process is subject to a factor η representing the conversion efficiency and maximum size on the plant s^{max} as well as a certain number of working hours τ are imposed to add realism.

Production		
Parameter	**Description**	**Unit**
p_{ik}	Capital cost of production of green H_2 via electrolysis and conversion to transport carrier k in country i.	€/MW
o_{ik}	Operating cost of production of green H_2 via electrolysis and conversion to transport carrier k in country i.	€/MWh
τ_k	Maximum number of operating hours of the technology producing transport carrier k.	h
η_k	Conversion efficiency of technology producing transport carrier k.	-
s_{ik}^{max}	Maximum size of the production technology of transport carrier k in country i.	MW

Table 2.3: Parameters appearing in the modelling of production. Note: except for the CapEx, all units refer to values per year.

The third step of the supply chain is the transport, with associated parameters provided in Table 2.4. There are two main modes for transporting hydrogen across borders: pipelines and ships. Distance and volume determine which mode is cheapest, as shown in Figure 2.2 from [3]. However, in this study of the overall supply chain, production and reconversion costs could also be key factors for determining the best option. Indeed, each option for transport allows for transport for a specific hydrogen carrier. Therefore, the set of transport carriers $\mathcal{C}$ is divided into two subsets $\mathcal{C}_1, \mathcal{C}_2$ for ships and pipelines, respectively.

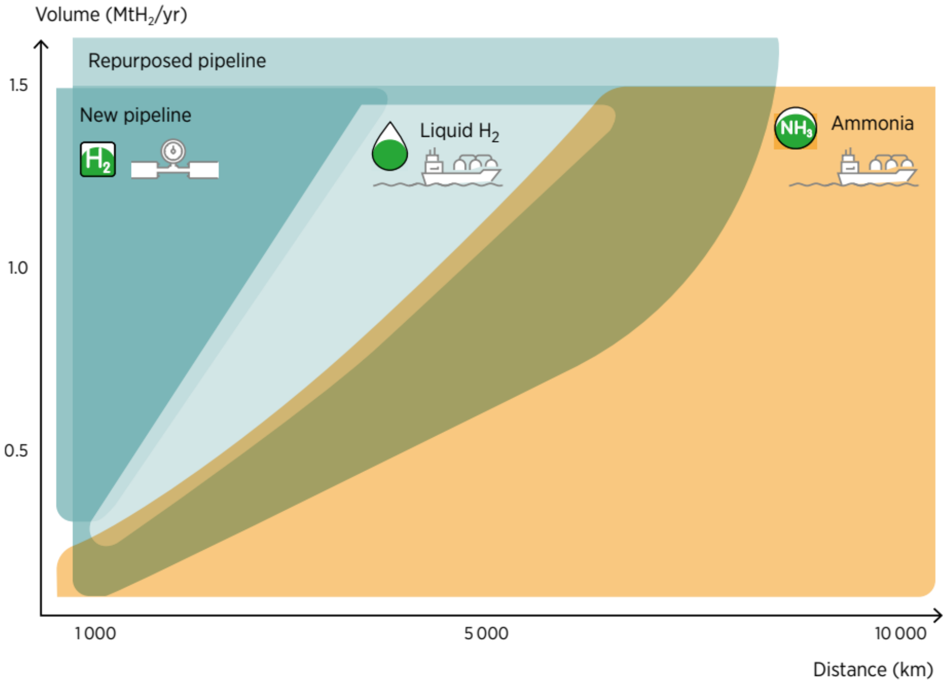


Figure 2.2: Cost efficiency of transport options when considering volume and distance [3]. For large volumes, newly built hydrogen pipelines are the most cost-effective option for distances up to 4 000 km. If repurposed natural gas pipelines are an option, the cost effective range extends to 8 000 km. Liquid hydrogen has a niche role in transport. Otherwise, shipping ammonia is seen as the best transport mode.

For transport by ship, the CapEx w represents the investment for each carrier-specialised ship. It is annualised with the CRF from 2.1. OpEx v consists of fuel consumption for the duration of the travel between the two countries. It is computed with the fuel consumption per hour of specialised ship f and the price of fuel c as: $v = fc$. It will be multiplied by a decision variable representing the number of hours required to transport hydrogen to requesting country.

Moreover, during the transport of liquefied forms of energy by ships, carriers with a low boiling point continuously lose a certain amount due to temperature differences, and the losses are commonly referred to as boil-off gas (BOG). The measure of boil-off is the amount of vapors per unit time, called boil-off rate b. Here, it is taken as a relative measure per km: % vaporised from total amount per km. Conversion from unit time to unit distance is straightforward using the vessel speed. Then, another characteristic of ship is its maximum loading m that will be used in the description of the decision variables.

For transport via pipelines, the CapEx w is the cost of building a new hydrogen pipeline. Furthermore, there are no operational costs associated with the pipeline directly but there are included in electricity costs to power the compressor in the production step. It should be mentioned that the pipelines modelling bias is to keep it simple. The smaller compressor stations needed to maintain pressure and flow rate along the length of the pipeline are not modelled. One large compressor would be installed in the production block. Also, the possibility to repurpose gas pipelines is not evaluated. These limitations of the model are developed in Section 2.6.

Transportation		
Parameter	**Description**	**Unit**
w_{ijkl}	Capital cost of transport via mode l between exporter i and importer j for transport carrier k.	€/ship or €/MW
v_{ijkl}	Operating cost of transport via mode l between exporter i and importer j for transport carrier k.	€/h or €/MWh
f_k	Ship fuel consumption of transport carrier k.	kg/h
c	Price of fuel.	€/kg
m_k	Maximum load allowed in ships for transport carrier k.	MWh
b_k	Boil-off rate of ship for transport carrier k.	%/km
l_{ijl}	Distance between exporter i and importer j for transport mode l.	km
n_{ijkl}^{max}	Maximum number of ships or maximum capacity of pipelines for transport carrier k between exporter i and importer j.	- or MW

Table 2.4: Parameters appearing in the modelling of transportation. Note: except for the CapEx, all units refer to values per year.

These two transport modes consider different distances l. For ships, it represents the maritime distance calculated on the basis of the location of seaports facilities suitable for hydrogen. It is necessary for the computation of the travelling time. For pipelines, it is assumed that the most optimal route is taken, i.e., the euclidean distance between the centroids. It is used for the CapEx computationsince this cost is given in €/km. Finally, the parameter n^{max} represents the maximum number of ships or the maximum capacity of pipelines between exporter and importer.

The final block of the supply chain is the reconversion to the demand carrier. A CapEx r is associated to each specific reconversion plant and annualised with the previous Equation 2.1. If no reconversion is needed, i.e., when the demand carrier is a transport carrier, a fictitious cost of 0 is imposed, in order to maintain mathematical coherence. OpEx u is the cost of electricity to feed the reconversion technologies, considering that they are connected to the national power grid, unlike the production. As a reminder, the goal of this thesis is to study the hydrogen supply chain for a country with a deficit of renewable energy, so it is assumed that the country will not prioritise the hydrogen reconversion plant for renewable installations. The compution of OpEx takes the form $u = ec$, with e being the national electricity price and c being the consumption of the plant. Also, a maximum size s^{max} of reconversion technologies, a number of operating hours τ and a reconversion efficiency η are imposed.

Reconversion		
Parameter	**Description**	**Unit**
r_{jkm}	Capital cost of conversion from transport carrier k to demand carrier m in country j.	€/MW
u_{jkm}	Operating cost of conversion from transport carrier k to demand carrier m in country j.	€/MWh
e_j	Electricity price per country j.	€/MWh
c_{km}	Electricity consumption of the technology reconverting transport carrier k to demand carrier m.	MWh$_e$/MWh
τ_{km}	Maximum number of operating hours of the plant converting transport carrier k to demand carrier m.	h
η_{km}	Conversion efficiency of technology converting transport carrier k to demand carrier m.	-
s^{max}_{jkm}	Maximum size of the conversion plant from transport carrier k to demand carrier m in country j.	MW

Table 2.5: Parameters appearing in the modelling of reconversion. Notes: to avoid confusion, MWh refers to hydrogen while MWh$_e$ refers to electricity. Except for the CapEx, all units refer to values per year.

2.3 Variables

Variables associated to each block of the supply chain are defined in Table 2.6. Some refer to the size of the technologies, while others refer to the flow of hydrogen and its derivatives.

The transportation block must be explained in more details. The two transport modes considered, ships and pipelines, are modelled separately. To model the shipping process, the inspiration comes from the study of Kim et al. [9]. First, the time of a round trip between the two countries is computed. It is determined by the maritime distance l and the average speed of the vessel v. Then, the number of round trips required to supply the necessary hydrogen T is defined by the division of this quantity to transport T and the capacity of a ship m. It is rounded up with the integer variable definition. Multiplying these two values provides the duration M of all round trips required to transport the specified quantity of hydrogen for the specified period.

The number of ships N needed to be built is finally determined by dividing the total travelling time M per period by the number of hours of this period, and rounded up to an integer variable.

Mathematically, it becomes:

$$\overbrace{M_{ijkt}}^{\text{Required time}} \geq \overbrace{\frac{2\ l_{ijl}}{v}}^{\text{Time roundtrip}} \cdot \overbrace{\frac{T_{ijklt}}{m_k}}^{\text{Count roundtrip}} \qquad \forall i \in \mathcal{E} \quad \forall j \in \mathcal{I} \quad \forall k \in \mathcal{C}_1 \quad \forall t \in \mathcal{P}, \tag{2.2}$$

$$\overbrace{N_{ijk}}^{\text{Number ships}} \geq \frac{M_{ijkt}}{\tau_t} \qquad \forall i \in \mathcal{E} \quad \forall j \in \mathcal{I} \quad \forall k \in \mathcal{C}_1 \quad \forall t \in \mathcal{P}, \tag{2.3}$$

with index $l=$ ship and τ_t the number of hours of the period t.

For pipelines, intermittent load profiles from renewables requires to have their dynamic capacities. Thus, two variables are defined: one for the capacity used per period P and another for the year which is the maximum capacity used over all periods P^{max}.

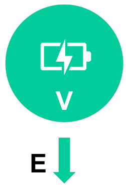
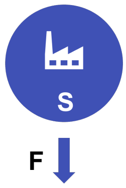
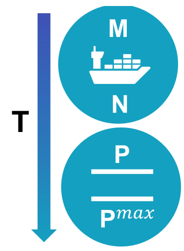
Var.	Unit	Dom.	Description	Illustration
			Generation	
E_{iknt}	MWh	$\mathbb{R}_+$	Green electricity from source n used for production of carrier k in country i per period t.	
V_{in}	MW	$\mathbb{R}_+$	Installed capacity of renewable source n in country i for hydrogen production.	
			Production	
F_{ikt}	MWh	$\mathbb{R}_+$	Output carrier k flow of the production technology in country i per period t.	
S_{ik}	MW	$\mathbb{R}_+$	Installed capacity of the production technology for carrier k in exporter i per year.	
			Transportation	
T_{ijklt}	MWh	$\mathbb{R}_+$	Transported carrier k flow with transport mode l between exporter i and importer j per period t.	
M_{ijkt}	h	$\mathbb{Z}_+$	Required time for carrier k specialised ships to travel between exporter i and importer j per period t.	
N_{ijk}	-	$\mathbb{Z}_+$	Number of carrier k specialised ships between exporter i and importer j per year.	
P_{ijkt}	MW	$\mathbb{R}_+$	Capacity of the pipeline between exporter i and importer j used per period t.	
P_{ijk}^{max}	MW	$\mathbb{R}_+$	Maximum capacity of the pipeline between exporter i and importer j per year.	
			Reconversion	
R_{jkmt}	MWh	$\mathbb{R}_+$	Input carrier flow of the reconversion plant from transport carrier k to demand carrier m exported to importer j per period t.	
Q_{jkmt}	MWh	$\mathbb{R}_+$	Output carrier flow of the reconversion plant from transport carrier k to demand carrier m exported to importer j per period t.	
S_{jkm}	MW	$\mathbb{R}_+$	Installed capacity of the reconversion plant for conversion from carrier k to carrier m in importer j per year.	

Table 2.6: Variables appearing in the formulation of the problem.

To have a clear vision of the variables, Figure 2.3 shows the overall supply chain with flows and physical characteristics for 1 renewable source (n=Solar), 1 exporter (i=Australia), 1 importer (j=Belgium), 1 transport carrier ($k = LH_2$) and 1 demand carrier ($m = H_2$).

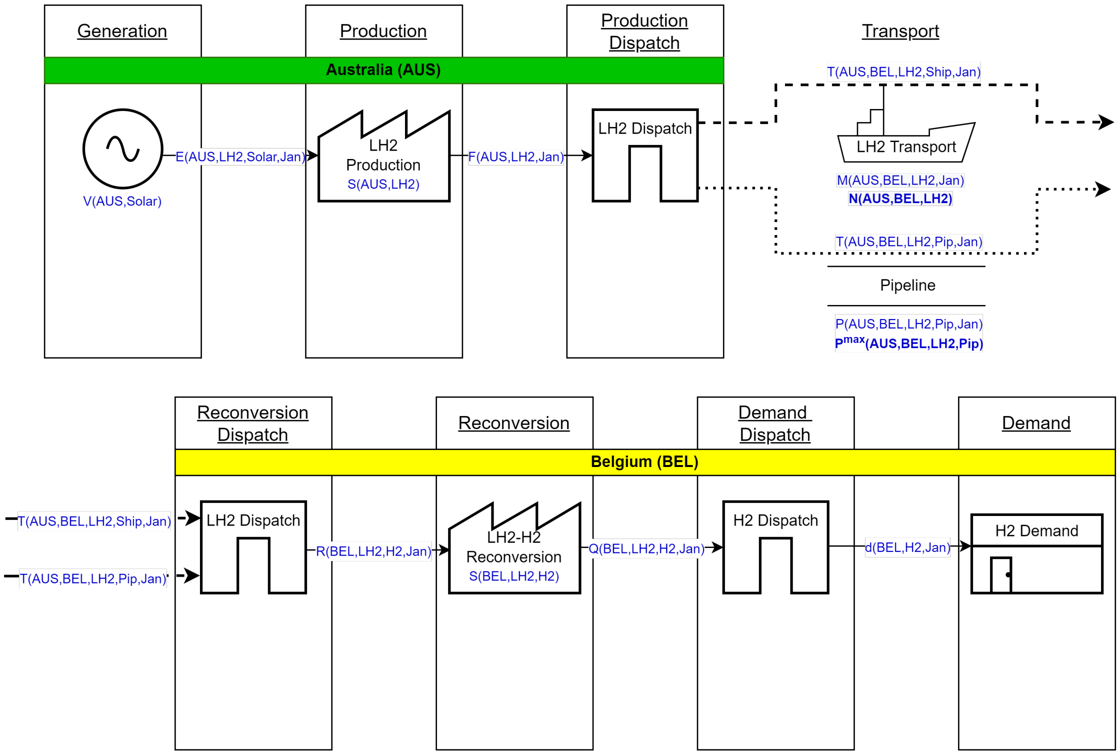


Figure 2.3: Example of the supply chain with associated variables for 1 RES, 1 exporter, 1 importer, 1 transport carrier, 1 demand carrier.

Since the objective is to minimise the costs, i.e., the CapEx and the variable and fixed OpEx for each step of the supply chain, new decision variables in € or €/y (year) have been created for the costs, in Table 2.7. It will be helpful for writing a clear objective function. CapEx (C) is in function of the size of the technologies while variable OpEx (O) is the electricity or fuels costs to power the technologies. For the objective function, the CapEx will be expressed as annual payments using the capital recovery factor (CRF), noted α [-]. Moreover, the fixed OpEx (OM) for each block is expressed as a specific percentage of the CapEx, noted β [-]. Thus the variable OM is simply equal to βC. The indices g, p, t, r refers to generation, production, transportation and reconversion, respectively.

Variable	Equation	Description
C^g [€]	$\sum_{i\in\mathcal{E}}\sum_{n\in\mathcal{R}} g_{in}V_{in}$	Capital cost of generation.
C^p [€]	$\sum_{i\in\mathcal{E}}\sum_{k\in\mathcal{C}} p_{ik}S_{ik}$	Capital cost of production.
O^p [€/y]	$\sum_{t\in\mathcal{T}}\sum_{i\in\mathcal{E}}\sum_{k\in\mathcal{C}} o_{ik}F_{ikt}$	Operating cost of production.
C^t_j [€]	$\sum_{i\in\mathcal{E}}\sum_{k\in\mathcal{C}} w_{ij,ship}N_{ijk} + w_{ij,pip}P^{max}_{ijk}$	Capital cost of transport.
O^t_j [€/y]	$\sum_{i\in\mathcal{E}}\sum_{k\in\mathcal{C}}\sum_{t\in\mathcal{P}} v_{ijk,ship}M_{ijkt} + v_{ijk,pip}P_{ijkt}$	Operating cost of transport.
C^r_j [€]	$\sum_{k\in\mathcal{C}}\sum_{m\in\mathcal{D}} r_{jkm}S_{jkm}$	Capital cost of reconversion.
O^r_j [€/y]	$\sum_{t\in\mathcal{T}}\sum_{k\in\mathcal{C}}\sum_{m\in\mathcal{D}} u_{jkm}Q_{jkmt}$	Operating cost of reconversion.

Table 2.7: Variables for costs appearing in the objective function.

2.4 Constraints

The constraints of the optimisation problem mainly concern the energy balances of the supply chain and the behavior of the production technologies.

Energy balances

Following Figure 2.3, at the beginning of the supply chain stands the potential supply of green electricity of each exporter. This must be limited by two factors. First, the capacity factor CF of the renewable sources restricts the utilisation of the associated installations of capacity V. Consequently, the maximum electricity generated E is also restricted,

$$\sum_{k\in\mathcal{C}} E_{iknt} \leq V_{in}\ CF_{int}\ \tau_t \qquad \forall i\in\mathcal{E} \quad \forall n\in\mathcal{R} \quad \forall t\in\mathcal{P}, \tag{2.4}$$

with τ_t the number of hours of period t.

Second, this potential amount of electricity cannot be entirely dedicated to the production of hydrogen via water electrolysis. The exporting country has its own local needs in green electricity. The local electricity consumption c is deducted from the maximum potential supply, on a yearly basis,

$$\sum_{k\in\mathcal{C}}\sum_{n\in\mathcal{R}}\sum_{t\in\mathcal{P}} E_{iknt} \leq (\sum_{n\in\mathcal{R}}\sum_{t\in\mathcal{T}} q_{in}^{max}\ CF_{int}\ \tau_t) - c_i \qquad \forall i\in\mathcal{E}. \tag{2.5}$$

The second step of the supply chain is the production of green hydrogen. To take into account the performance of production technologies, the output of each plant F is proportional to the input, i.e., the green electricity E and the conversion efficiency of the plant η,

$$\eta_k \sum_{n\in\mathcal{R}} E_{iknt} = F_{ikt} \qquad \forall i\in\mathcal{E} \quad \forall k\in\mathcal{C} \quad \forall t\in\mathcal{P}. \tag{2.6}$$

In Figure 2.3, a block called "Production Dispatch" has been added. Its role is to visualise the dispatch of the transport carriers barely produced into transport modes and importers. Mathematically, this is written as follows

$$F_{ikt} = \sum_{j\in\mathcal{I}}\sum_{l\in\mathcal{T}} T_{ijklt} \qquad \forall i\in\mathcal{E} \quad \forall k\in\mathcal{C} \quad \forall t\in\mathcal{P}. \tag{2.7}$$

Transport via ships induces losses related to the boil-off gas. This amount of liquid evaporating from the cargo is expressed in % of total liquid volume per km. The rate is thus multiply by the distance l to obtain a value in % of transported flow T. For gaseous form transported by pipelines, boil-off rate b amounts to zero.

The actual transported flow of hydrogen, considering these losses, is then dispatched again for reconversion. Indeed, at this step, transport carriers are transformed into demand carriers through various processes. The reconversion dispatch is translated into the equation,

$$\sum_{i\in\mathcal{E}}\sum_{l\in\mathcal{T}}(1 - l_{ijl}\ b_k)\ T_{ijklt} = \sum_{m\in\mathcal{D}} R_{jkmt} \qquad \forall j\in\mathcal{I} \quad \forall k\in\mathcal{C} \quad \forall t\in\mathcal{P}. \tag{2.8}$$

Like production, the output of the reconversion plant is reduced by a factor η, which represents the efficiency of the process,

$$\eta_{km} R_{jkmt} = Q_{jkmt} \qquad \forall j\in\mathcal{I} \quad \forall k\in\mathcal{C} \quad \forall m\in\mathcal{D} \quad \forall t\in\mathcal{P}. \tag{2.9}$$

Finally, the market clearing condition imposes that the demand of each importer per month d must be satisfied for each demand carrier,

$$\sum_{k\in\mathcal{C}} Q_{jkmt} = d_{jmt} \qquad \forall j\in\mathcal{I} \quad \forall m\in\mathcal{D} \quad \forall t\in\mathcal{P}. \tag{2.10}$$

Behaviour of the technologies

For the supply, the capacity V actually used to produce electricity is at most the net generating capacity of RES power plants q^{max},

$$V_{in} \leq q_{in}^{max} \qquad \forall i \in \mathcal{E} \quad \forall n \in \mathcal{R}. \tag{2.11}$$

The size of the production and reconversion technologies must be dimensioned in order to produce a sufficient amount of transport carrier and demand carrier, respectively. That means that the output must not exceed the total amount of energy that a plant can produce for a period, i.e., the installed capacity S times the number of operating hours τ,

$$F_{ikt} \leq S_{ik}\ \tau_k \qquad \forall i \in \mathcal{E} \quad \forall k \in \mathcal{C} \quad \forall t \in \mathcal{P}, \tag{2.12}$$

$$Q_{jkmt} \leq S_{jkm}\ \tau_{km} \qquad \forall j \in \mathcal{I} \quad \forall k \in \mathcal{C} \quad \forall m \in \mathcal{D} \quad \forall t \in \mathcal{P}, \tag{2.13}$$

with τ_k and τ_{km} the number of working hours of the production plant and the reconversion plant, respectively.

Furthermore, to add realism, maximum capacities are imposed,

$$S_{ik} \leq s_{ik}^{max} \qquad \forall i \in \mathcal{E} \quad \forall k \in \mathcal{C}, \tag{2.14}$$

$$S_{jkm} \leq s_{jkm}^{max} \qquad \forall j \in \mathcal{I} \quad \forall k \in \mathcal{C} \quad \forall m \in \mathcal{D}. \tag{2.15}$$

For modelling the size of pipelines, the transport carrier flow T is limited by the dynamic capacity per period P and the number of hours per period τ_t,

$$T_{ijklt} \leq P_{ijkt}\ \tau_t \qquad \forall i \in \mathcal{E} \quad \forall j \in \mathcal{I} \quad \forall k \in \mathcal{C}_2 \quad \forall t \in \mathcal{P}, \tag{2.16}$$

with index l = pipeline.

Then, the size of pipeline to build for the year is obtained by taking the maximum over all the periodic capacities,

$$P_{ijkt} \leq P_{ijk}^{max} \qquad \forall i \in \mathcal{E} \quad \forall j \in \mathcal{I} \quad \forall k \in \mathcal{C}_2 \quad \forall t \in \mathcal{P}. \tag{2.17}$$

The constraints associated to the transport with ships were given in the variable description (see Equations 2.2 and 2.3). The first one provides the total time per period to transport the necessary quantity of hydrogen to the importer, and go back to the point of departure. The second one gives the number of ships to build to ensure to fulfillment all the round-trips.

Finally, there is not an infinite quantity of ships and an infinite capacity for pipelines:

$$N_{ijk} \leq n_{ijkl}^{max} \qquad \forall i \in \mathcal{E} \quad \forall j \in \mathcal{I} \quad \forall k \in \mathcal{C}_1, \tag{2.18}$$

with index $l =$ ship,

$$P_{ijk}^{max} \leq n_{ijkl}^{max} \qquad \forall i \in \mathcal{E} \quad \forall j \in \mathcal{I} \quad \forall k \in \mathcal{C}_2, \tag{2.19}$$

with index $l =$ pipeline.

2.5 Objective function

The model describes the optimization for importing green hydrogen from potential exporters to a country in need, with an economic perspective. It can be formulated as a mixed-integer linear program and it has the objective to minimise the total annual cost, which is the sum of the annualised CapEx (αC), variable OpEx (O) and fixed OpEx ($OM = \beta C$) required for green electricity generation (g), hydrogen and its derivatives production (p), transportation via ships or pipelines (t), and reconversion (r),

$$\min \quad \epsilon^g C^g + \epsilon^p C^p + O^p + \epsilon^t C_j^t + O_j^t + \epsilon^r C_j^r + O_j^r \qquad \forall j \in \mathcal{I}, \tag{2.20}$$

with $\epsilon = \alpha + \beta$, α and β representing the annualisation factor and the operation and maintenance proportion, respectively.

Every country in need of green hydrogen is optimizing its import, independently of each other. To be valid for many importers, the exporters must supply only a proportion of the total production to each importer. We could also think about another objective that better translate the competition between countries on the hydrogen market. This will be further discussed in Section 5.2 for perspectives.

Finally, Figure 2.4 provides an example of a case study with 2 importers (Belgium and South Korea), 2 exporters (Australia and Oman) and 2 shipping options (NH_3 and LH_2). The model is designed in such a way that many options could be included.

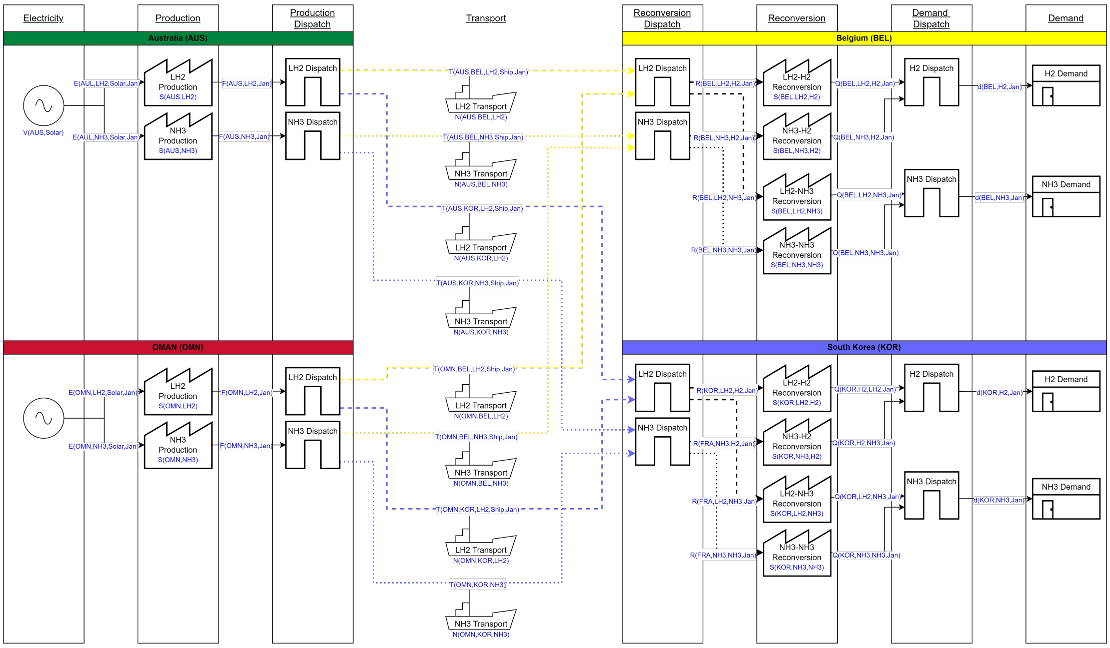


Figure 2.4: Example of the supply chain with 2 exporters and 2 importers.

2.6 Limitations

The modelling process requires some assumptions to simplify a complex reality. The truth is that models are never finished, they always evolve as our understanding of the system improves. Evaluating the best green-hydrogen supply chain implies an infinity of options that should be restricted.

The first and biggest restriction concerns transport modes, especially pipelines. The focus of this thesis for pipelines is on the capacity and costing of newly-built pipelines. However, recent and numerous studies suggests that the blending of hydrogen into natural gas distribution systems must be explored. With the capital cost of the pipeline representing the main cost contributor, repurposing existing natural gas transmission pipelines could reduce the cost by 65-94% [13]. Specifically, IRENA [2] estimates that the transport cost using these pipelines will be about USD 0.08-0.12/kg, i.e., 2.11-3.17 €/MWh per 1 000 km in 2050. Transporting hydrogen through new pipelines would be twice as high, at 0.16–0.24$/kg, i.e., 4.23-6.35 €/MWh for every 1 000 km. Thus, to further optimise costs, the model should consider the existing natural networks to be repurposed to carry hydrogen. Additional information on the comparison between hydrogen and gas are provided in Appendix B.

The major obstacle to the implementation of this option is to get the real length of the gas pipelines. That's the reason why the euclidian distance between centroids of the countries is assumed. Also, either pipelines or ships are assumed to connect the hydrogen production site directly to the consumption location. More generally, the existing infrastructure for each step of the supply chain is not considered, which increases the costs of installations and consequently the total costs.

Chapter 3

Case study definition

Chapter overview:

- *Case study: application of the model to the Belgian industrial sector.*
- *Description of the different options for the supply chain.*
- *Characterization of the input data related to the model's parameters.*
- *Sensitivity analysis: proposition of different scenarios.*
- *Impact of uncertainties on data for future years.*
- *Associated appendices: RES installed capacities analysis (C) and Capacity factors (D), for each country and source.*

The proposed optimisation framework can be applied to any case, although this thesis conducted the optimisation for the particular case of the industrial sector in Belgium. Tests on a reference case for 2020 and a sensitivity analysis are performed by designing various scenarios. It can be seen as a validation of the theoretical description given above, since results could be compared with choices and orders of magnitude from other reports.

3.1 Reference case

Before going into details, an overview of the selected case study is provided based on the table of sets defined in Section 2.1. Table 3.1 defines the elements composing each set.

Sets	Index	Description	Elements
$\mathcal{E}$	i	Exporters	Australia, Chile, Oman, Morocco, Spain
$\mathcal{I}$	j	Importers	Belgium
$\mathcal{C}$	k	Transport carriers	LH_2, NH_3 , CGH_2
$\mathcal{T}$	l	Transport modes	Ship, Pipeline
$\mathcal{D}$	m	Demand carriers	H_2
$\mathcal{R}$	n	RES	Solar PV, Wind , Hydropower
$\mathcal{P}$	t	Time refinement	Months

Table 3.1: Sets with the associated elements for the case study.

3.1.1 Description

The reference case deals with the optimal import of energy carriers to replace carbon-intensive hydrogen production in Belgium, for 2020. The country will surely be an importer of hydrogen because the renewable potential is limited in such a way that the existing electricity consumption and the potential electricity demand for moving to a green hydrogen production cannot be both satisfied [6]. Focusing on 2020 for this reference case allows to have more realistic results since the data is based on recorded values rather than estimates. It constitutes a good basis for comparison with other studies and for the sensitivity analysis.

Exporters

On the exporters' side, the choice is large for Belgium: many countries have a real potential of RES expansion. The selection of the five exporters in the set is the same as the one highlighted described in the report published by the Belgian Hydrogen Import Coalition [8]: Australia (AUS), Chile (CHL), Oman (OMN), Morocco (MAR) and Spain (ESP). These sites were selected based on the promising conditions for efficient hydrogen production. Specifically, they are characterised by high renewable potential for the generation of low-cost electricity due to their excellent wind availability and solar irradiation throughout the year, as well as the sufficient space they offer. The report [8] also takes into account the availability of ports and political stability. Figure 3.1 gives a preview of the potential RES installations that could be used for green hydrogen production and exportation.

Figure 3.1: Map representing the potential RES installations for solar PV, wind and hydropower that can be used for hydrogen production for selected exporters. Spain has the highest potential, then Australia, Chile and Morocco, and Oman as the lowest potential. Note: made with QGIS, data from [14].

More details should be provided on these potential exporters. As a reminder, the goal of the thesis is to propose a strategy for decarbonisation of the Belgian industrial sector. Clearly, the transition will take time since new infratructures have to be deployed. The strategy must be designed for the long-term. This means that the countries' potential for exports should be carefully studied. The IRENA's report [2] confirms that the countries selected by the Belgian report [8] will be part of the largest potential hydrogen producers and exporters in 2050.

According to the IRENA's report, these countries can be divided in two groups. On the one hand, there are current (fossil-fuel) energy exporting countries, such as Australia and Oman. Thereby, their goal is more a matter of boosting their clean hydrogen production than expanding their trade.

- The Government of Australia claimed in 2019 that it considered hydrogen as its next big export [15]. To achieve this, the government has invested over 1 billion $ to stimulate the domestic hydrogen industry. Nine gigawatt-scale green hydrogen projects are planned or under development.
- Even if Figure 3.1 shows that the Oman's RES installations are currently rare, the country is designing a national hydrogen strategy with the aim to become a large-scale exporter of green hydrogen and green ammonia. Several gigawatt-scale projects have already been announced, all taking advantage of the abundant solar and wind resources and eyeing the Arabian sea port

of Duqm for exports [16]. Specifically, in 2020, the Belgian company DEME Concessions and Omani partners announced an exclusive partnership to develop a "world leading, green hydrogen plant" in Duqm. The first phase of the project envisages an electrolyser capacity between 250 and 500 MW [17].

On the other hand, Chile, Morocco and Spain are currently net energy importers with green hydrogen export potential [16].

- Chile aims at reaching 25 GW of electrolyser by 2030, producing the world's cheapest hydrogen by 2030 and becoming one of the world's top three hydrogen exporters by 2040 [18]. It is estimated that the country could be exporting 30 billion $ worth of green hydrogen and derivatives by 2030 [16].
- In its Green Hydrogen Roadmap (2021), Morocco mentioned hydrogen as a key growth sector in the national economy. By 2030, the country envisages a local hydrogen market of 4 TWh and an export market of 10 TWh which, taken together, would require the construction of 6 GW of new renewable capacity [19].
- Spain is becoming one of Europe's hydrogen hubs. In its Hydrogen Roadmap, the Spanish Government suggests a "Vision 2030" with an installed capacity of 4 GW electrolysers. This vision calls for an estimated investment of 8 900 million euros during the period 2020-2030 [20]. The important point is that Spain is strongly encouraged and funded by the rest of Europe.

To sum up, all these countries have implemented a consistent hydrogen roadmap with the ambitious goal of being among the world's (or at least the region's) top exporters of hydrogen. Furthermore, they all have the potential to attract many investments. For this case study, it is considered that all of them have the same probability of achieving their goals. Therefore, it is assumed that the production technologies are similar in each of these countries, resulting in a unique production cost for all the exporters. However, the potential quantities of H_2 supplied differ due to the distinct potential in terms of green-electricity generation.

From the point of view of Belgium, the main difference between exporters concerns the shipping distance. Morocco and Spain can take advantage of their proximity to Belgium whereas transport costs in the case of Australia, Chile and Oman are much higher because of the long shipping distance.

Transport carriers and modes

The energy transport carriers also have its leverage for the optimisation of the Belgian supply chain. They have different properties and thus have different costs of production, transportation and reconversion.

The main challenge for hydrogen transport lies in its low energy density. In order to transport large amounts of hydrogen, it must be either pressurised and delivered as a compressed gas, liquefied, or embedded in energy carriers such as ammonia. The energy carriers are then delivered by a specific infrastructure. The viable transport infrastructures considered in this thesis are pipelines for compressed gas and ships for the liquefied form of hydrogen and its derivatives (e.g., e-fuels). Usually, pipelines would be cost-competitive for short distances (as for Spain, Morocco) while ships would be the most attractive option for longer distances (as for Australia, Chile, Oman), as shown in Figure 2.2.

The reference case examines three carbon-free transport carriers, considered as the most promising in the literature ([8], [13], [21]): compressed gaseous hydrogen under pressure, liquefied hydrogen (LH_2) and ammonia (NH_3). The newly developed Liquid Organic Hydrogen Carriers (LOHC) are also brought to the fore by numerous papers. However, this technology is still not at a stage of maturity so its potential competitiveness has been studied in a distinct scenario. These transport pathways are discussed in details in a recent IRENA report [13] (April 2022) and summed up in Figure 3.2. The following part addresses each of the pathways presented:

- Compressed gaseous hydrogen is typically compressed to 50-80 bar for transmission by pipelines, through a hydrogen compressor [21]. This infrastructure increases the pressure of hydrogen by reducing its volume. For this transport pathway, the main cost contributor is the capital cost of the pipeline.
- Liquefied hydrogen is produced through liquefaction. The major advantage of this carrier lies in the absence of chemical transformation. Nonetheless, the main challenge is the cryogenic temperatures needed (-253 °C), leading to high equipment cost and high energy consumption to reach and maintain such conditions, or alternatively to high boil-off losses that impacts the overall efficiency [13]. Particularly, the process consumes approximately one third of hydrogen's energy content, but increases the volumetric energy density by a factor of more than 10 compared to gaseous hydrogen at 80 bar according to the European Hydrogen Backbone [21].
- Ammonia is part of the e-fuels. This molecule is formed by the reaction of gaseous hydrogen with gaseous nitrogen via the Haber-Bosch process. This production process presents the advantage of having a moderate boiling point of -33°C. Compared to LH_2, the transport losses due to the boil-off are lower and the energy density and hydrogen content is higher [13]. The main drawbacks consist in its high toxicity and its relatively inefficient reconversion to hydrogen [13]. However, the chemical compound is widely used as a feedstock in the chemical industry, so not all of the ammonia delivered necessarily needs to be cracking back to hydrogen [21].

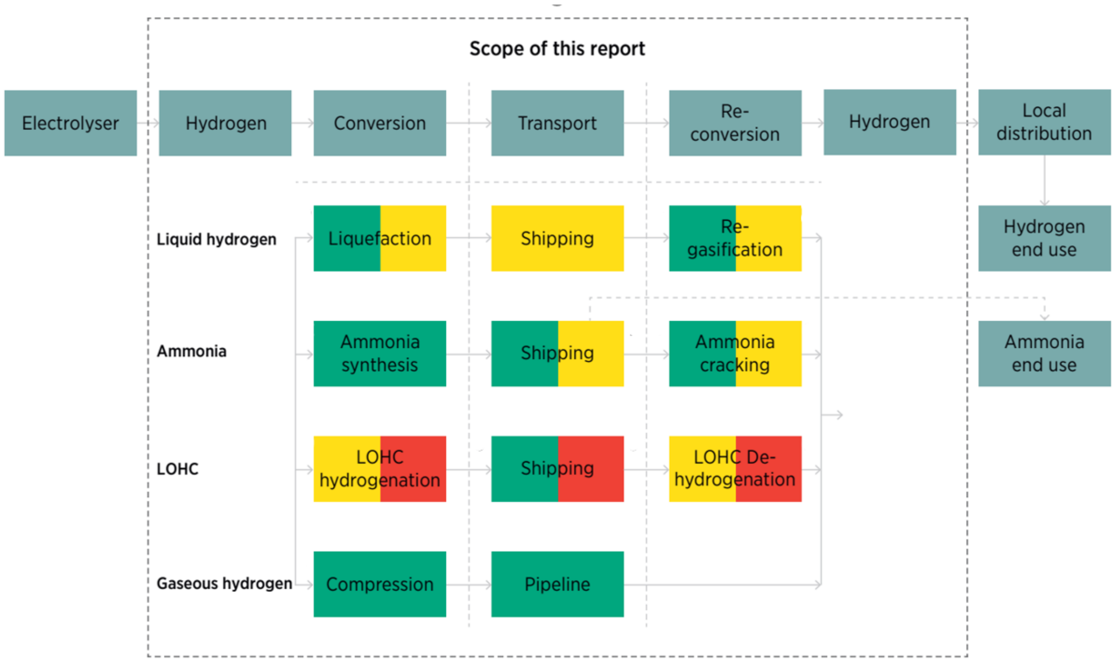


Figure 3.2: Processing steps of the hydrogen value chain for each hydrogen transport options, adapted from [13]. Note: the colour code represents current technology maturity. Green = Commercial; yellow = Demonstration; red = Prototype. Left side of the box refers to small scale (< 50 tonnes of H_2 per day) and right side refers to the scale needed for global trade ($> 500\ t_{H_2}$/d).

It should be noticed that the methods for shipping ammonia or liquefied hydrogen incur high upfront costs and significant energy losses related to the installations of conversion and reconversion, whereas pipelines for compressed gaseous hydrogen have especially high installation costs [21]. Table 3.2 compares the main characteristics of the three carriers chosen for this reference case.

Unit	**CGH2**	**LH2**	**NH3**
Pressure [bar]	80	atmospheric	atmospheric
Temperature [°C]	-	- 233	- 33
Power density [kWh/kg]	33.3	33.3	5.2
Energy density [kWh/l]	0.2	2.4	3.5

Table 3.2: Comparison between of the main characteristics of hydrogen and ammonia for transport, adapted from [22].

Demand carrier

The reference case supposes the purest form of hydrogen as demand carrier, i.e., gaseous hydrogen. Most applications require great demand for pure hydrogen, and technology solutions are likely to evolve with demand [8]. The consideration of ammonia as a demand carrier will be also investigated in the sensitivity analysis.

Renewable energy sources

At the beginning of the supply chain, there is the green electricity supply. The set of renewable sources used for generation is composed by solar photovoltaics (PV), wind (onshore and offshore) and hydropower. According to IRENA [2], worldwide renewable installed capacity for electricity generation accounts for 2 500 GW in 2010, composed of 189 GW of hydropower, 580 GW of solar, 594 GW of onshore wind and 28 GW of offshore wind. By 2030, the trend will be reversed: wind and solar PV are expected to dominate the growth of renewables in the electricity sector as a result of the availability of plentiful resources, cost competitive markets and low electricity supply costs. These two energies could supply 42% of the total electricity generation by 2030 (from just over 10% today). Figure 3.3 shows the current and forecast global installed capacity of power generation sources according to the 1.5°C scenario [2].

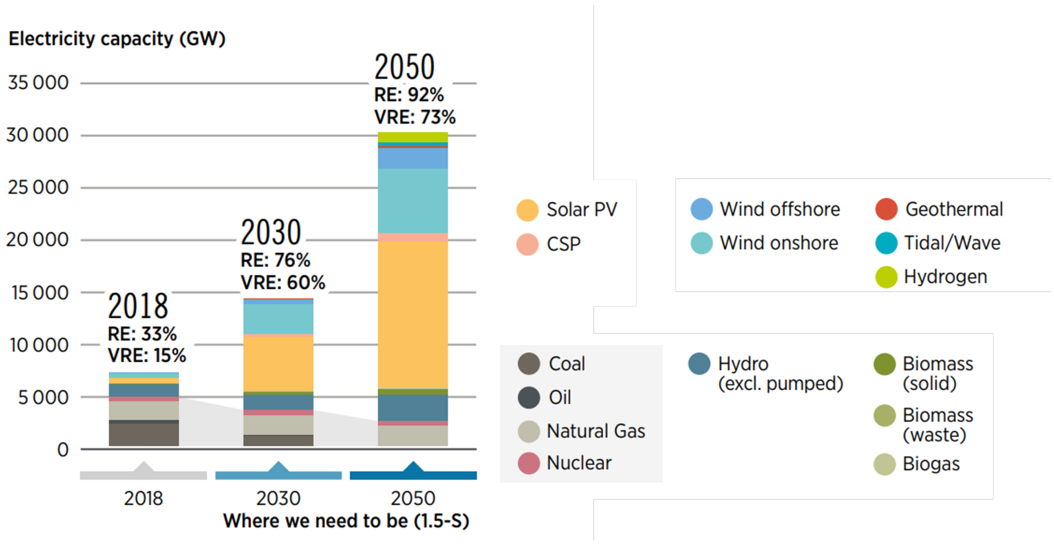


Figure 3.3: Global installed capacity of power generation sources in the 1.5°C Scenario in 2018, 2030 and 2050, adapted from [2]. Renewable energy is expected to increase a lot, especially solar PV and wind onshore.

However, the use of electricity infrastructure connected to wind or solar installations is limited to the capacity factor of these sources, as they are part of the Variable Renewable Energy (VRE) sources. Hydropower can thus provides flexibility and a reliable support for power systems by balancing the seasonal variability of solar and wind. As an illustration, Figure 3.4 shows these fluctuations in the supply for wind in Spain. The capacity factor is about 24.57% in October and rise to 55.04% the next month [23]. Other capacity factor plots are available in Appendix D.

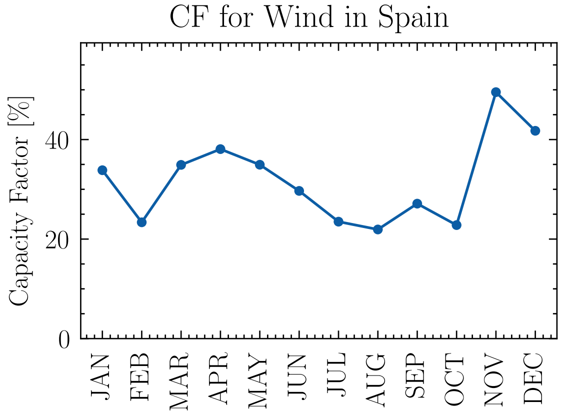


Figure 3.4: Monthly capacity factor of wind in Spain in 2019 with data from [23].

This supply intermittency should be considered as it is currently an important barrier to switching to carbon-free hydrogen production based on renewable energy sources. For this reason, the model has a monthly resolution. Moreover, hydrogen trade could overcome this barrier: depending on the sun and wind electricity generation at a certain month, the importing country (e.g., Belgium) could import hydrogen from one country or another.

To put it in a nutshell, this thesis analyses the optimisation of the H_2 supply chain of Belgium from five countries (Australia, Chile, Oman, Morocco, Spain) and renewable installations (Solar PV, Wind, Hydropower) with several H_2 carriers (LH_2, NH_3, CGH_2) for two transport modes (Ship, Pipeline) and with a monthly resolution.

3.1.2 Input Data

The input data of the reference case refers to year 2020. It allows to have a starting point with accurate data. First of all, the common financial part of the supply chain should be precised. Indeed, the optimisation criterion is the total annual cost, which is expressed as the sum of CapEx, variable and fixed OpEx for each step of the supply chain, i.e., generation, production, transportation and reconversion (see Equation 2.20). The capital recovery factor (CRF) helps to convert the capital investment, into an annual expenditure such that it can be compared equitably with the other annual expenditures (e.g., variable and fixed OpEx),

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}, \tag{3.1}$$

with i [-] being the interest rate and n [y] being the lifetime of the technology.

The interest rate is assumed to be 7.5% for Organisation of Economic Co-operation and Development (OECD) countries like Australia, Chile, Spain and Belgium [24]. This low interest rate is strongly correlated with the low risk perceived in renewable power generation and hydrogen projects. For this reason, the same value is acceptable for less-developed countries like Morocco and Oman, that have been proven to be reliable future exporters. Thus $i = 0.75$ for all countries and for all steps of the supply chain. The lifetime n will be specified below. It is also necessary to point out that most of the data was in US dollars. It was converted to euros using an exchange rate of 0.88, taken in February 2022.

Demand

The demand of hydrogen d is taken from the study of Kakoulaki et al. [6]. They estimate the electrolysis requirement for the replacement of grey hydrogen with green hydrogen production in all the European countries in 2019. The considered demand of H_2 for Belgium is 15.9 TWh for all the year. The consumption of hydrogen in the industrial sector is assumed to be equally distributed over the months. Thus, we have a demand of 1.325 TWh per month.

Supply

Parameters' description for the supply block can be found in Table 2.2. The global supply of green electricity for each exporter is given by the installed electricity capacity per country and per source q^{max} and a capacity factor CF which takes account of the intermittency of the electricity generation. The data for the first parameter is provided by IRENASTAT [14] and displayed in Table 3.3. For the second parameter, the monthly CF for variable energy sources as solar PV and wind are taken from renewables.ninja [23], whereas an average capacity factor of 46% is assumed for hydropower [24].

This total supply must be reduced by the effect of the local electricity demand c in the exporting country. However, the overall needs in electricity are too significant to be satisfied by the current renewable installations. Thus, without loosing realism, only the green electricity consumption is taken into account. It is a reasonable assumption since each country planned a total decarbonisation of the electricity system for 2050. The net electricity consumption by country is taken from the Energy Information Administration (EIA) [25] with a share of renewables given by IEA [26]. Data is summarised in Table 3.3:

Country	**Green consumption [TWh$_e$]**	**Installed capacity [MW]**	
AUS	$237 \times 0.101 = 23.94$	Solar PV	12 967
		Wind	6 279
		Hydro	5 913
CHL	$75 \times 0.253 = 18.98$	Solar PV	2555
		Wind	1 620
		Hydro	6 683
OMN	$32 \times 0 = 0$	Solar PV	108
		Wind	50
		Hydro	0
MAR	$39 \times 0.173 = 67.48$	Solar PV	194
		Wind	1225
		Hydropower	1 306
ESP	$233 \times 0.075 = 17.48$	Solar PV	8 972
		Wind	25 578
		Hydro	13 803

Table 3.3: Data for the computation of green-electricity supply for the reference case ([25],[26],[14]). Note: the multiplication refers to the the renewable proportion in total electricity consumption.

About the financial part, the capital costs of installation g per renewable technology (before annualisation) are provided by the National Renewable Energy Laboratory (NREL) [27]. A unique cost for all the countries is assumed since the technologies are quite the same whatever the location. Lifetime n for solar PV, wind and hydropower are respectively 30, 25 and 50 years [28]. They will be used in the CRF Equation 3.1. Then, the fixed OpEx representing the operating and maintenance cost of the installations is in average 2% [24], while there is no OpEx associated to the green electricity generation, as explained in the model description.

It should be noticed that the cost and lifetime for wind refer actually to onshore installations. Offshore wind is a minority in the RES, especially in the selected countries. To give orders of magnitude, onshore amounts to 23.8% of the worldwide renewable installed capacity while offshore is only 1.12%, taking the data from IRENA [2] indicated in the case study definition. Data used for generation costs are collected in Table 3.4.

RES	CapEx [M€/MW]	OpEx fix [% CapEx]	Lifetime [y]
Solar PV	1.224		30
Wind	1.211	2	25
Hydropower	2.225		50

Table 3.4: Data for computation of the generation costs for the reference case ([27], [24], [28]).

Production

Parameters' description for production block can be found in Table 2.3. The capital cost of production p combines the capital expenditures of the electrolyser that produces hydrogen and the conversion plant that transform it into transport carriers (liquefier for LH_2, Haber-Bosch process for NH_3 or compressor for CGH_2). For the same reason of the generation, i.e., the similarity of the technologies in the countries, a unique cost of production is assumed for all the exporters, but which is different depending on the transport carrier produced.

The case study refers to pressure alkaline electrolysers that have been used for years to produce hydrogen for the chemical industry. The benefits are their quick response to load changes from intermittent energy sources and the relatively low capital costs compared to other electrolyser technologies, due to the avoidance of precious materials [11]. Polymer electrolyte membrane (PEM) water electrolysers present also many advantages, but for the moment they are 50%-60% more expensive than alkaline, representing a barrier to market penetration [29]. The CapEx of the alkaline electrolyser is taken from the IRENA report [16], with an electrolyser efficiency of 65%.

The second part of the production CapEx looks at the cost of installation of the conversion plant to produce each shipping transport carrier, i.e., LH_2, NH_3 and the one of the compressor for CGH_2. It is provided by the European Hydrogen Backbone (EHB) [21], which also indicates that the fixed OpEx is about 2.5% of the CapEx. Then, the variable operating cost of production o is zero, since the production technology is assumed to not be connected to the grid and thus to be fed directly by the renewable electricity generated from the exporter's infrastructures.

Other key parameters in the production process are the conversion efficiencies (79.7% for liquefaction, 80.4% for Haber-Bosch process and 80% for compression [30]), the lifetime of the electrolyser and the conversion technologies (30 years) [28]. Data for the production of each transport carrier is summarised in Table 3.5.

Carrier	**CapEx [k€/MW]**	**OpEx fix [%CapEx]**	**OpEx [€/MWh]**	**Lifetime [y]**	**Efficiency [%]**
LH_2	739 + 1350 = 2089	2.5	0	30	65%× 79.9% = 51.94
NH_3	739 + 808 = 1547				65%× 80.4 % = 52.26
CGH_2	739 + 3400 = 4139				65%× 80% = 52

Table 3.5: Data for the production of transport carriers for the reference case. Notes: the mathematical operations for CapEx and Efficiency refer to the combination of electrolyser and conversion technology ([16],[21],[30],[28]). The fixed and variable OpEx refer to values per year.

Finally, the maximum size s^{max} of the production technologies is assumed to be infinite. Nonetheless, all the technologies in the supply chain are implicitly constrained by the size of renewable installations. Another simplification is to consider that the different plants are in most ideal conditions. That means that they are operating nonstop, i.e., the number of working hours τ is equal to the number of hours per month (720h) for every technology. Again, this is implicitly dependent on the variable electricity supply in the beginning of the supply chain.

Transportation

Parameters' description for transportation block can be found in Table 2.2. Transport by ships is modelled by defining two variables: the total time to transport the required quantity of hydrogen per month M and the number of ships that must be built annually N to be able to achieve all the monthly round-trips. The characteristics for shipping come from the paper of Kim et al. [9]. The CapEx w per ship associated to variable N, the lifetime of ships n, the maximum loading or capacity m, the fuel consumption f and the boil-off rate b for shipping transport carriers LH_2 and NH_3 appear in Table 3.6.

Carrier	**CapEx [M€]**	**Lifetime [y]**	**Fuel [kg/h]**	**OpEx [€/h]**	**Capacity [MWh]**	**Boil-off [%/km]**
LH_2	142.57	25	940	329	360 072	0.001
NH_3	70.4		1200	423.5	260 568	0.00003

Table 3.6: Data for the transportation with ships [9].

Few clarifications on these data are needed. Firstly, the boil-off rate represents the hydrogen losses due to the evaporation when the liquid carriers reach their boiling point. It is given as a value per km, but it is used as a relative efficiency of transport in constraint 2.8. It must be multiplied by the maritime distance l given in Table 3.7. The average vessel speed v considered is about 10 knots or 18.52 km/h. Thirdly, the OpEx v associated to this variable M represents the fuel consumption f per hour. It is assumed that conventional marine diesel fuel is used with a price $c = 0.35$ €/kg. Then, OpEx is computed as $v = fc$. About the fixed OpEx, it amounts to 4% of the CapEx for ships and pipelines [21].

Transport via pipelines is modelled with respect to their dynamic capacity P, i.e., the capacity actually used per month, and the capacity that must be built P^{max}, taken as the maximum dynamic capacity over the year. About the costs, the one for installation of the pipeline w is a cost per km and per MW installed of 8.2 10^3 €/(MW km) [31]. Thus, it is multiplied by the capacity P^{max} and the euclidean distance l given in Table 3.7. The annual expenditures are computed based on the typical lifetime n of 50 years [32].

Country	**Euclidean distance [km]**	**Sea distance [km]**	
AUS	14 900	Gladstone	21 644
CHL	11 597	Valparaiso	13 684
OMN	5 568	Qalhat	11 038
MAR	2 288	Jorf Lasfar	2 445
ESP	1 309	Huelva	2 263

Table 3.7: Transportation distances l between Belgium and the potential exporters. The euclidean distance is between centroids of countries. The maritime distance is between selected ports for exporters and the port of Zeebrugge for Belgium [33].

The transport cost via pipelines also includes an OpEx v. However, it is assumed to be 0 in this case study. The reasons are that the electricity consumption for the large compressor is already considered in the production step and that the potential recompression stations along the pipelines are not modelled.

Finally, both the maximum number of ships and the maximum capacity of pipelines n^{max} are assumed infinite. In reality, pipelines cannot have an infinite capacity, the maximum for hydrogen pipeline is set to 85 MW by [31]. However, given our CapEx per MW, several pipelines could be used to reach the required capacity.

Reconversion

Parameters' description for reconversion block can be found in Table 2.5. The conversion to pure gaseous hydrogen (as the set of demand carriers contain only GH_2 for the reference case) consists in the regasification for LH_2 and the cracking of NH_3. Their associated CapEx r is taken from the European Hydrogen Backbone [21] and annualised with the previous equation 3.1. To keep a mathematical coherence in the model, a fictitious cost of 0 is associated to the transport carrier CGH_2 since it must not be converted.

The second contribution to the reconversion costs is the operating expenses. On the one hand, the fixed OpEx for operating and maintenance expenses represents 2.5% of the CapEx [21]. On the other hand, the variable OpEx u is added to take into account the cost of electricity to feed the reconversion technologies. Unlike production, it is assumed that the plants located in Belgium are connected to the grid, as the country has a deficit of renewable energy. As the market electricity price is quite unstable, it should be noticed that the Belgian price used of 102 €/MWh is the price for businesses at the time of searching for data (March 2022) [34]. The OpEx is then obtained by multiplying this price with the electricity consumption per plant c ($u = ec$). Data is summarised in Table 3.8.

Carrier	**CapEx [k€/MW]**	**OpEx fix [%CapEx]**	**Consumption [MWh$_e$/MWh]**	**OpEx [€/MWh]**	**Efficiency [%]**
LH_2	273		0.003	0.306	100
NH_3	235	2.5	0.14	14.3	100
CGH_2	0		0	0	100

Table 3.8: Data for the reconversion to gaseous hydrogen for the reference case [21]. Note: the fixed and variable OpEx refer to values per year.

Another important parameter is the reconversion efficiency which is is $\eta = 100\%$ for every process, according to the EHB [21]. Finally, as for the production, the maximum size s^{max} of the reconversion technologies is assumed to be infinite, the lifetime of plants n is 30 years and the number of operating hours τ is 720 h.

3.2 Scenarios

As a sensitivity analysis, some alternative scenarios are proposed to investigate more deeply the model. Each of them uses the bases laid by the reference case.

3.2.1 Ammonia as demand carrier

As mentioned in the case study definition, the main limitation for using ammonia as a transport carrier is the reconversion to hydrogen (called cracking), which can consumes the equivalent of 13-34% of the energy contained in the hydrogen [13]. However, ammonia can be used directly as feedstock and fuel for some applications rather than reconverted to hydrogen (e.g., for fertilisers, power generation, maritime fuel) [13]. Specifically, the majority of hydrogen consumption is associated with two industries: ammonia production (50%) and oil refineries (33%) [10].

This inspires this first scenario, which assumes that 50% of the hydrogen demand is actually a demand for ammonia. Ammonia is thus a transport carrier and a demand carrier. The data to add to the reference case is:

- **Demand:** 7.95 TWh for H_2 and 7.95 TWh for NH_3 per year [10],
- **Reconversion CapEx:** 1081 k€/MW for LH_2 to NH_3 , 808 k€/MW for GH_2 to NH_3 [21],
- **Reconversion OpEx:** 14.6 €/MWh for LH_2 to NH_3 , 14.3 €/MWh for GH_2 to NH_3 [21],
- **Reconversion efficiency:** 80% for LH_2 to NH_3, and for GH_2 to NH_3 [30].

The pathway from LH_2 to NH_3 includes the reconversion to GH_2 and the conversion from GH_2 to NH_3.

3.2.2 LOHC as transport carrier

The newly developed Liquid Organic Hydrogen Carriers (LOHC) are compounds that can react with hydrogen and be used multiple times. While other carriers production requires extremely high pressures or extremely low temperatures, the

LOHC are formed by the absorption of hydrogen through a process called "hydrogenation". At the end, hydrogen is released through "dehydrogenation". The conversion and reconversion happen at ambient temperature, making them safer. Also, the LOHC provides a cost-efficient alternative to the other carriers by eliminating the need for compression, the boil-off losses during transport and by using existing transport infrastructures as it has similar properties to oil [13]. However, the scalability, the costs and the hydrogenation and dehydrogenation steps remain uncertain and challenging [8].

Toluene is chosen to represent the broader LOHC group of carriers. It is the most promising LOHC candidate because it is relatively non-toxic, inexpensive and has relatively low temperatures of conversion and reconversion reactions [21].

The data to add is:

- **Conversion CapEx:** 84 k€/MW [21],
- **Transport CapEx and OpEx:** 76.428 k€ and 448.5 €/h [9],
- **Fuel consumption, capacity and boil-off:** 1240 kg/h, 2497.5 GWh [9] and 0%/km [21],
- **Reconversion electricity consumption:** 0.39 MWh_e/MWh [21],
- **Reconversion CapEx and Opex:** 237 k€/MW and 39.8 €/MWh [21],
- **Conversion and reconversion efficiency:** 100% [30] and 90% [21].

3.2.3 No hydropower

In 2020, hydropower accounts for the biggest part of the RES installed capacity for electricity generation. Using the figures from IRENA [2], it represents 48% of the worldwide RES installations. Besides, the capacity factor is quite stable, with an average of 46% for the whole year, while the ones for solar and wind are only about 16%, 36% [24] with possible strong variations, as illustrated in Figure 3.4. This hydropower stability is useful for establishing an optimal supply chain, but can conceal supply fluctuations due to VRE. Furthermore, solar PV and wind onshore installed capacity are expected to increase significantly in the future, exceeding hydropower, as shown in Figure 3.3.

Thus, this scenario considers the variable energy sources (i.e., solar and wind) as the only sources for green electricity supply. Consequently, hydropower is removed from the set of RES presented in Table 3.1.

3.2.4 Export proportion

With the actual model, all the green electricity potential can be dedicated to produce hydrogen for the satisfaction of Belgian demand. Indeed, the implicit export proportion is unconstrained and determined by the optimiser that dispatches the supply between the importers. Since our case study contains a unique importer, the potential exporting rate is automatically set to 100%. To add realism, we imposed the export proportion, meaning that the exporter allocate only a share of its production to a requesting country. This proportion could be justified by some geopolitical drivers or by the trading relationship. In this scenario, the potential hydrogen export from each country to Belgium will be restricted to 25%. Also, the value close to the minimum allowed to keep a feasible model (i.e., 20%) will be studied to see how the model behaves in an extreme situation.

3.2.5 Forecasts for 2030 and 2050

As a reminder, this thesis aims at establishing a long-term decarbonisation strategy for the industrial sector in Belgium. Usually, the targets set by the wide range of policies, plans and strategies for energy transition are broken down into two phases. The first one from now until 2030 aims at implementing the most ambitious innovation plans and investments, while the second one from 2030 until 2050 aims at maintaining the efforts in order to achieve the ultimate goal of carbon neutrality by 2050.

According to the Hydrogen Roadmap mentioned in the case study definition, the exporters chosen promised an accelerated deployment of hydrogen infrastructures for future years. Specifically, it mainly concerns the renewable energy infrastructures, leading to an increase in installed capacity and decrease in cost of investment, as well as the infrastructure for hydrogen production, e.g., the electrolyser. The challenge these infrastructures are facing is to be able to meet the growing energy needs and support the switch towards a decarbonised system. In this thesis, the energy needs considered are restricted to hydrogen for industrial and local electricity in exporting countries, both increasing. In particular, in the second phase, i.e., 2030-2050, the demand for green hydrogen in industry will further increase, even if the demand from refineries is gradually decreasing [6]. Indeed, refineries currently consume approximately 30% of the total hydrogen production for the processing of oil products in Europe [10]. With the phasing out of liquid fossil fuels, the associated hydrogen consumption is expected to decrease to zero over time. However, the deep decarbonisation of other industries like the chemical industry (e.g., ammonia and methanol production) or steel industry is expected to outbalance this decline.

Following data is assumed to evolve in the future:

- **Demand:** 17.86 TWh per year for 2030 and 63.3 TWh per year for 2050 [21],
- **Local electricity consumption:** increase of 2.1% per year to 2050 [35] (23% until 2030 and 86% until 2050),
- **Share of renewables in electricity consumption:** 61% for 2030 and 88% for 2050 [4],
- **Electrolyser CapEx and efficiency:** 363 k€/MW for 2030 and 248 k€/MW for 2050 [28] , 71% for 2030 and 80% for 2050 [21],
- **Generation CapEx,**
- **Installed capacity.**

Renewable power generation technologies are already the cheapest sources of electricity generation in most regions. Indeed, the global weighted-average levelised cost of electricity (LCOE) of newly commissioned utility-scale solar PV projects fell by 85% between 2010 and 2020 and onshore wind farms by 56% [2]. By 2030, the LCOE for solar PV and wind is expected to have a respective additional 58% and 25% reduction, based on a survey on G20 countries [36].

The CapEx evolution for renewable installations follows this drastic fall. It can be visualised in Figure 3.5, from the NREL [27]. As the costs strongly depend on the technology improvements, three scenarios reflecting different levels of adoption of innovations are evaluated: conservative in blue, moderate in orange and advanced in green.

Figure 3.5: CapEx projections until 2050 for utility-scale solar PV, onshore wind and hydropower [27]. The greatest cost reduction concerns solar PV and wind. Note: the blue curve refers to the conservative case, the orange curve refers to the moderate case and the green curve refers to the advanced case.

Data from the moderate case is used in this scenario. Costs are given in [k€/MW] in the following Table 3.9:

	Solar PV	Wind	Hydro
2030	683	836	2225
2050	561	669	2136

Table 3.9: Input data for the CapEx [k€/MW] of renewable installations in 2030 and 2050 for the base case [27].

Finally, the projections in renewable installed capacity are drawn from official deployment targets for 2030:

- The Australian Government as represented by the Department of Industry, Science, Energy and Resources details the country's greenhouse gas emissions trends to 2030 and estimates the effort needed to meet emissions reduction targets, which implies a strong uptake of renewables [37].
- The Government of Chile with the help of Ministry of Energy puts its long-term energy planning online [38]. It consists in a 30 years simulation updated every 5 years where supply projections, including installed capacities can be found.
- As reported by the Gulf Cooperation Council (GCC) market analysis of IRENA [39], Oman has incorporated its renewable energy targets into its Nationally Determined Contributions (NDCs) under the United Nations Framework Convention on Climate Change (UNFCCC). Oman's NDC focuses on measures such as raising the share of renewable energy, with a specific interest in solar and onshore wind energy.
- The Moroccan National Energy Strategy establishes the intention of increasing the share of renewables in the total power capacity to 52% by 2030 (20% of solar, 20% of wind, of 12% hydrower). The specific installed capacities required in order to reach this goal are estimated by GlobalData [40].
- The Spanish government has submitted an ambitious National Energy and Climate Plan (NECP) to the EU [41]. The NECP is a ten-year integrated document mandated by the European Union to each of its member states in order for the EU to meet its overall greenhouse gases emissions targets [42].

Country	RES	Installed capacity [MW]		Sources
		2030	2050	
AUS	Solar PV	49 000	166 000	[37], [43]
	Wind	23 000	56 000	
	Hydro	5 913	5 913	
CHL	Solar PV	9 819	23 808	[38]
	Wind	8 341	19 713	
	Hydro	6 683	6 683	
OMN	Solar PV	2 420	15 000	[39], [44]
	Wind	1 210	4 000	
	Hydro	0	0	
MAR	Solar PV	2 100	30 000	[40], [45]
	Wind	4 300	45 000	
	Hydro	3 300	3 300	
ESP	Solar PV	39 181	98 000	[41], [46]
	Wind	50 333	90 000	
	Hydro	13 803	13 803	

Table 3.10: Installed capacity forecasts per renewable energy sources per country for 2030 and 2050. Note: as hydropower is already a mature and large-scale technology, no capacity addition is considered.

Except for Chile, it was necessary to extend the projections beyond these national plans to 2050. Indeed, official forecasts don't go further than 2030 as there is too much uncertainty surrounding this issue. Thus, estimates for 2050 were found in the following studies:

- For Australia, the University of Technology Sydney has produced a scenario model for a transition towards a renewable energy system [43]. The results include an assessment of technology pathways, in particular by giving the renewable installed capacity projections.
- For Oman, the energy model from the Lappeenranta University of Technology (LUT) [47] was applied to the case of Oman [44]. This model provides forecasts on installed capacities considering a global energy system based on 100% renewable energy. In Oman, results reveal that solar PV increasingly drives most of the system, while wind energy complements.

- For Morocco, the paper [45] identified that policy objectives for a long-term perspective up to 2050 remain largely understudied. It fills this gap by identifying the RES installed capacities in a scenario featuring 100% renewables for the long-term.
- For Spain, the study [48] provides an investigation into the sustainability of its electrical system. It analyses a decarbonisation scenario that take into account the ambitious reduction of GHG emissions and uses data from [46].

Data projections for 2030 and 2050 are summarised in Table 3.10. The plausibility of these forecasts has been evaluated in the Appendix C.

3.2.6 Impact of uncertainties

This optimisation model can help countries to define or rethink their energy strategy. So far, the model is deterministic, i.e., it does not consider uncertainty and relies on long-term forecasts for important parameters. However, forecasts often prove to be inaccurate, leading to overcapacity and underutilisation of the installed technologies, with over or underestimated costs.

For 2030 and 2050, we consider demand for hydrogen, electricity consumption and the associated share of renewables, installed capacity of renewable sources, and their investment costs as the most uncertain parameters. Furthermore, it is considered that the 2050 horizon is much more unpredictable than 2030. For the sake of simplicity, the rest of parameters as costs of other technologies and efficiencies are assumed as fixed.

An uncertainty analysis was conducted by defining three cases: a base case, an optimistic case and a conservative case. The first one refers to the data given above. The optimistic case uses the following assumptions:

- **Demand:** from an optimistic point of view, the quantity of hydrogen imported could be higher than the industry's planned demand. If this implies a surplus in hydrogen, it could be used for another hard-to-decarbonise sector (e.g., transport). The uncertain scenario considers an expansion of demand by 15% for 2030 and 20% for 2050,
- **Local electricity consumption:** if a behavioral change occurs (e.g., reducing excessive energy use, switching transport mode or gains in materials efficiency [4]), the energy consumption could increase less than expected, or even decrease. It is assumed that the real local electricity demand could be 15% less than the forecast for 2030, and 25% less for 2050,

- **Renewables' share:** this rate strongly depends on annual capacity additions of wind and solar between 2020 and 2050, which is also an uncertain parameter. In its Net Zero Scenario [4], the IEA states that the share of renewables in electricity consumption will attain 61% for 2030 and 88% for 2050. With accelerated actions, it could reach 70% for 2030 and 100% in 2050, i.e., the total decarbonisation of the electricity system, as claimed in some policies,

- **Installed capacity of RES:** in the best case, the potential hydrogen producers will exceed the targets announced and reported in Table 3.10. The revision of the national plans could propose some 15% higher capacities for 2030 and 25% higher for 2050,

- **CapEx of RES:** the NREL [27] provides data for the investment costs for renewable installations in their "advanced case". The cost reduction is stronger than the moderate case.

	Solar PV	**Wind**	**Hydro**
2030	592	616	2130
2050	423	462	1922

Table 3.11: Input data for the CapEx [k€/MW] of renewable installations in 2030 and 2050 for the optimistic case [27].

For the conservative case, the opposite situation is designed, considering the following assumptions:

- **Demand:** the huge potential demand for hydrogen might be hard to satisfy, knowing that most countries will have growing needs in hydrogen. The imports to Belgium could be reduced by 15% 2030 and 20% for 2050 because of this strong concurrency,

- **Local electricity consumption:** energy consumption has rapidly increased because of the economic development, rising population and technological developments. Furthermore, with the electrification as a key pillar of the decarbonisation [4], the local electricity demand could be 15% more than the forecast for 2030, and 25% more for 2050,

- **Renewables' share:** the ambitions for renewables deployment are high. Thus, it seems more realistic to assume a renewables' share of 50% for 2030 and 80% for 2050 in electricity consumption,

- **Installed capacity of RES:** in the worst case, countries might be unable to meet the forecasts of the different studies cited previously. They could install 15% less capacity than the expectation for 2030, and 25% less capacity for 2050,
- **CapEx of RES:** the NREL [27] proposes data in their "conservative case", with a lower cost reduction than the moderate case.

	Solar PV	**Wind**	**Hydro**
2030	1023	880	2225
2050	683	792	2225

Table 3.12: Input data for the CapEx [k€/MW] of renewable installations in 2030 and 2050 for the conservative case [27].

Chapter 4

Results

> *Chapter overview:*
>
> – *Graphs showing the main results for each scenario.*
>
> – *Description of the results and explanation with the input data of the case study.*
>
> – *Comparison between scenarios.*
>
> – *Discussion: interpretation of the main results in light of the published reports.*
>
> – *Associated appendices: Implementation (A) and Additional results (E).*

As a reading guide, the results of the model are presented and compared according to the following points of interest: the composition of total costs, the selection of exporting countries, the transport carrier and mode used, the RES origin of the electricity supply and the presence of time variations.

To facilitate the discussion and comparison with other reports, a new metric is added: the levelised cost of hydrogen (LCOH). It accounts for all the capital and operating costs behind the importation of hydrogen (i.e., costs for generation, production, transportation, reconversion) and therefore enables different hydrogen supply chains to be compared on a similar basis. It is computed as the ratio of the total annual costs to the total amount of hydrogen imported over the year, and expressed as a cost per energy unit of hydrogen (€/MWh).

4.1 Reference case

For the reference case, the total annual costs amount to 2.22 billion €, with a cost composition presented in Figure 4.1. It highlights that the most expensive step in the supply chain is the generation of green-electricity, accounting for 76.7% of the total costs. In particular, the generation CapEx is leading the optimization with a share of 60.8% of the total costs. The production, transport and reconversion contributes to the costs with a share of 19.4%, 1.3% and 2.7% respectively. In terms of LCOH, the overall supply chain is 139.6 €/MWh.

Figure 4.2 informs about some optimal choices of the optimiser. The entire hydrogen demand of Belgium is satisfied with the production of Spain. The country uses 7.9 MW of its hydropower installed capacity, which generates 2.60 TWh of green-electricity per month. This electricity then powers the liquefied hydrogen production plant having a 1.9 GW capacity. By looking at data, liquefied hydrogen was expected to be selected. Indeed, the other carriers have huge costs for some steps of the supply chain: in particular, the CapEx for pipeline transporting compressed gaseous hydrogen and the OpEx for the reconversion of ammonia are high. The large quantity of LH_2 produced can be transported from Spain to Belgium using only two ships per month. As a final observation, the stability of hydropower creates a uniform situation over the year, meaning that there are no monthly variations in the results.

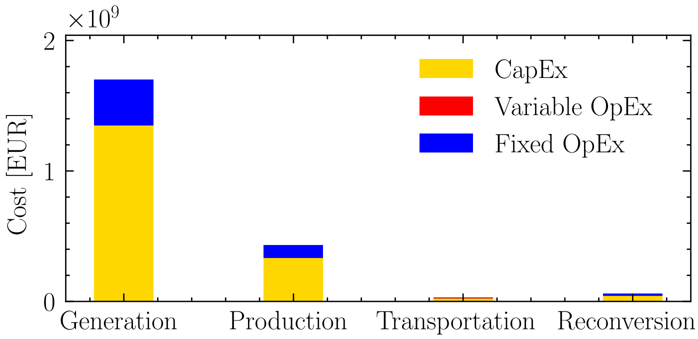


Figure 4.1: Cost composition for the reference case. The generation step leads the optimisation (especially the generation CapEx).

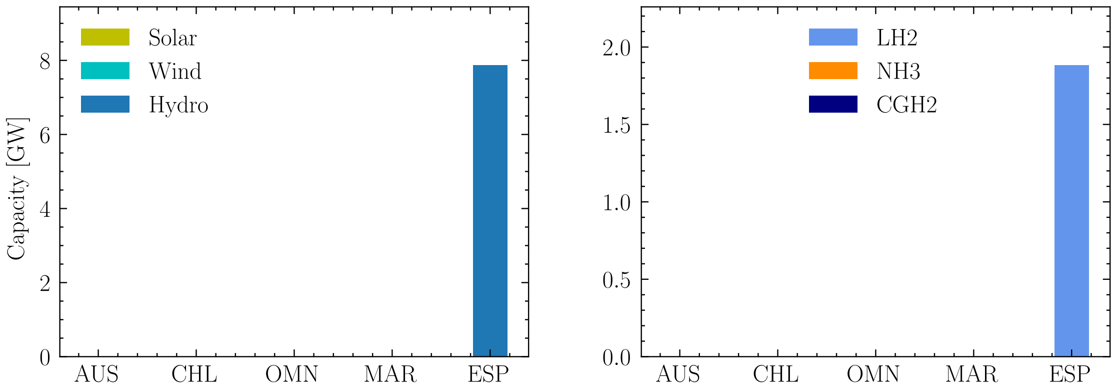


Figure 4.2: Size of the renewable energy installations (left) and the production plants (right) for the reference case. The hydrogen demand of Belgium is satisfied with the supply from Spain using hydropower as RES electricity generation and producing LH_2 as transport carrier.

4.2 Scenarios

Ammonia as demand carrier

As explained in Section 3.2, the main barrier of using ammonia as a transport carrier is the expensive reconversion to hydrogen. The CapEx for production is cheaper than for the other carriers, suggesting that ammonia could be a cost-competitive transport carrier when the reconversion is avoided. Moreover, ammonia is widely used as a feedstock in industrial processes. Consequently, it is realistic to have ammonia as demand carrier, accounting for 50% of the demand according to [10]. As expected, Figure 4.3 reveals that ammonia is produced and thus selected for transport. In particular, the production plant for LH_2 has a 941 MW capacity while the one for NH_3 has a 933 MW capacity. The quantity of carrier produced corresponds exactly to the imposed demand of H_2 and NH_3, respectively. The small difference in capacities is due to the bigger boil-off losses during transport of liquefied hydrogen. Furthermore, one ship for transporting each amount of carrier is sufficient. In terms of totals costs, the use of ammonia incurs a reduction of 5.5% compared to the reference case, mostly occuring at the production step. Other results (distribution of the costs, hydropower installations in Spain) are similar to the reference case.

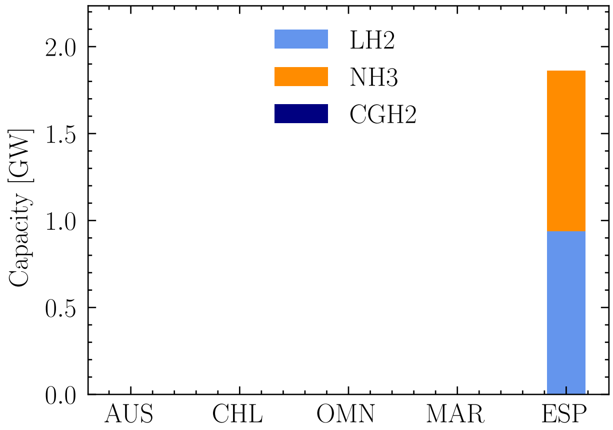


Figure 4.3: Size of the production plants with NH_3 as demand carrier. The hydrogen and ammonia demand of Belgium are satisfied with the supply from Spain producing LH_2 and NH_3 as transport carriers.

LOHC as transport carrier

In this scenario, the LOHC is added among the options for transport carriers. As expected by inspecting the data, LOHC is not selected by the optimiser, leading to the same results than those of the reference case. Even if most of the costs are lower than the ones of other carriers, the OpEx for reconversion is much higher.

For a deeper investigation of the model, the use of LOHC is imposed to satisfy the whole demand of Belgium. This carrier is described as promising in the literature and is therefore analysed to determine if it is actually less advantageous to use it. The variation in the cost composition is illustrated by Figure 4.4. Using LOHC increases the total costs by 5.8%. In particular, generation accounts for 62.9%, production for 7.9%, transportation for 0.3% and reconversion for 29%. By comparison with the reference case, the reconversion OpEx increases drastically (130 times more important) while all the other steps of the supply chain are less costly when using LOHC. Thus, this carrier could be cost-competitive if the reconversion process is improved. As a final remark, the production of LOHC is powered with the hydropower installations in Spain, as previous scenarios.

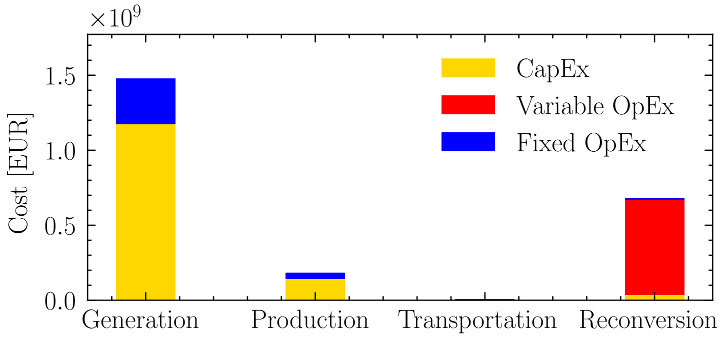


Figure 4.4: Cost composition with LOHC as transport carrier. The reconversion OpEx has increased significantly compared to the reference case.

No hydropower

Previous results reveal that hydropower-based electricity generation from Spain provides a stable support to power the production. By removing this source from the set of RES, results should differ from the reference case. As a first observation, the total costs distribution is comparable to the reference case in terms of proportions. However, the total costs increase by 17.1%. This is mainly due to the generation step where a larger capacity must be installed for variable energy sources, which are constrained by a lower and fluctuating capacity factor. Moreover, Figure 4.5 exposes that the origin of the electricity supply is wind, which has a higher average capacity factor than solar. Also, the demand is not only satisfied by Spain, but the supply from Australia is required. Specifically, in Spain, the installed capacity for wind is 11.56 GW (reaching the maximum capacity available) and attains 3.5 GW in Australia. Another major change is the transport carrier chosen, as shown in Figure 4.6. Spain produces liquefied hydrogen, with a 1.4 GW capacity while Australia produces ammonia, with a 556 MW capacity. The underlying reason is the following: on one side, LH_2 is cost competitive for transport and reconversion, so it is usually chosen in scenarios. On the other side, ammonia has a lower CapEx for production. Consequently, for relatively small productions, ammonia can be competitive since the reconversion plant is small too. It is the case of Australia which has a role of complementary supplier to Spain. Then, it should be highlighted that even if the installations for generation and production in Spain are 2.6 times more numerous than in Australia, building one ship is sufficient to make all the round-trips per months between Spain and Belgium while travelling from Australia requires 5 ships (Figure 4.7), because of the difference between shipping distances. As a final observation, Figure 4.8 illustrates the presence of monthly variations in the supply, and so in the importations. These variations are compensated by each other.

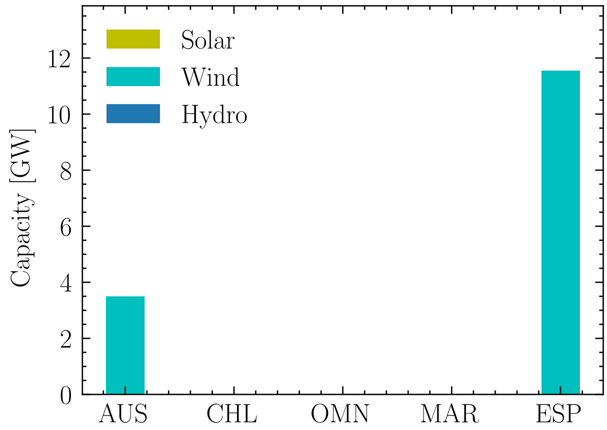


Figure 4.5: Size of the renewable energy installations without hydropower. The source of electricity supply is replaced by wind in Spain (mostly) and Australia.

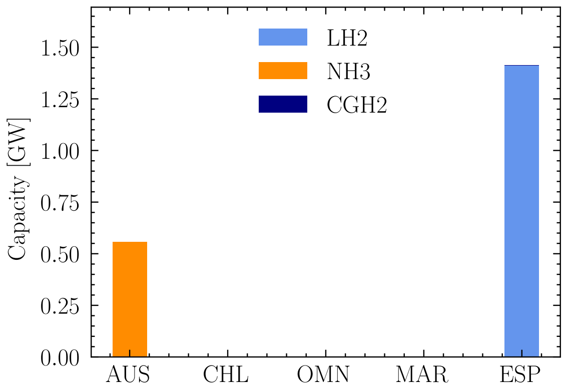


Figure 4.6: Size of the production plants without hydropower. NH_3 is produced in Australia while LH_2 is produced in Spain.

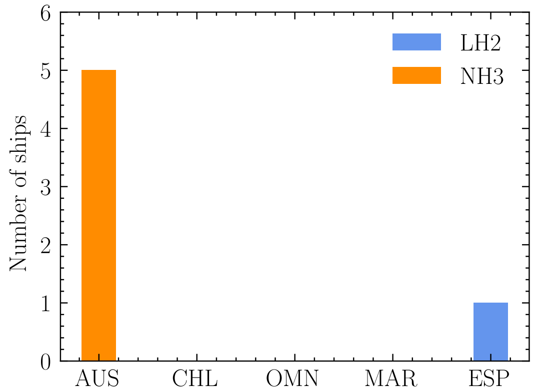


Figure 4.7: Number of ships per year without hydropower. Five NH_3 ships are required for the transport between Belgium and Australia while one LH_2 is sufficient for travelling from Spain.

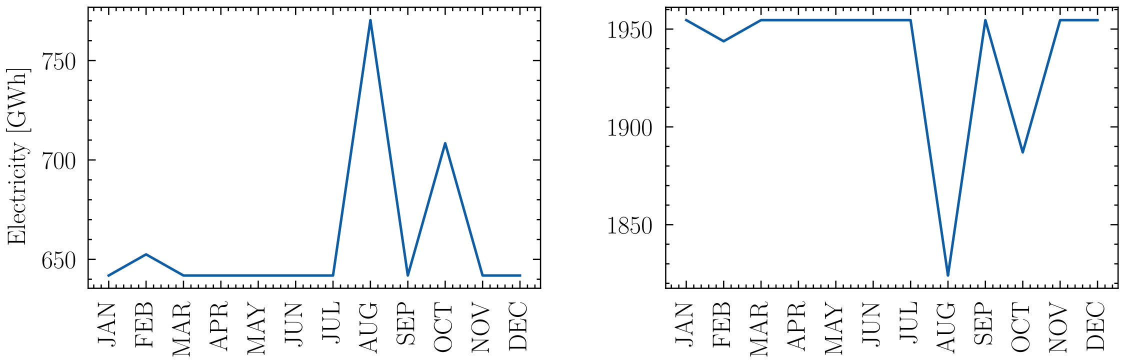


Figure 4.8: Electricity generated by wind and used by Australia (left) and Spain (right). Monthly variations in the supply are compensated by each other.

Export proportions

To add realism, the potential exporters' production cannot be fully devoted to the satisfaction of Belgian hydrogen demand. It is modelled by imposing a fixed export proportion on the production. Two possibilities are studied: 25% and 20% which is close to the minimum value allowed to keep a model feasible.

The cost composition of these two scenarios is quite similar to that for the reference cost (except a larger variable reconversion OpEx for the 20% case, see Figure 4.11). In fact, constraining the potential exports of each country's production by 25% or 20% implies that the total costs increase by only 1.3% and 3.2%, respectively. The selection of exporting countries is also affected. Figures 4.9 and 4.10 allow to make a comparison. For the least constrained case, Spain (mostly), Australia and Chile are the suppliers for Belgium, using their hydropower capacity. For the second case, supply from Australia is more important and an additional supply from Morocco is required. As explained previously, relatively small productions are dedicated to ammonia while liquefied hydrogen is a better choice for large productions as in Spain for the 25% scenario. As a final comment, with the stable support provided by the hydropower, there are no monthly variations.

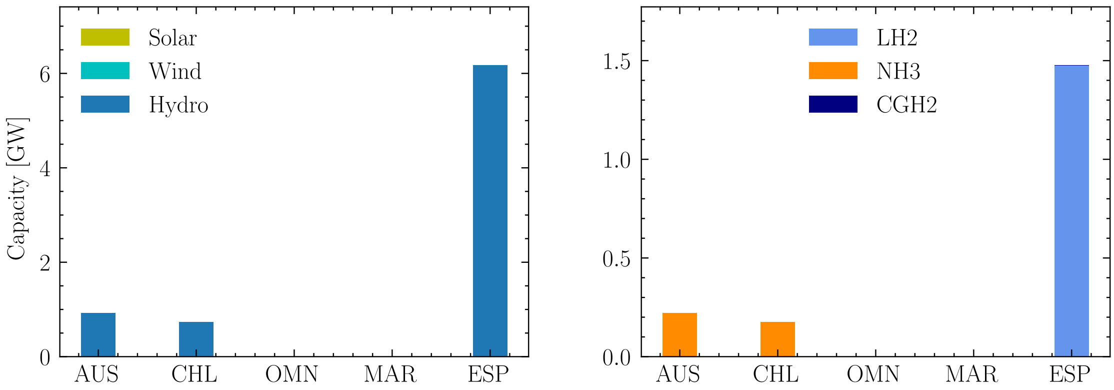


Figure 4.9: Size of the renewable energy installations (left) and the production plants (right) with an export proportion of 25%. The hydrogen demand of Belgium is satisfied with the supply from Spain (mostly), Australia and Chile using hydropower as RES electricity generation. Spain produces LH_2 as transport carrier while Australia and Chile produce NH_3.

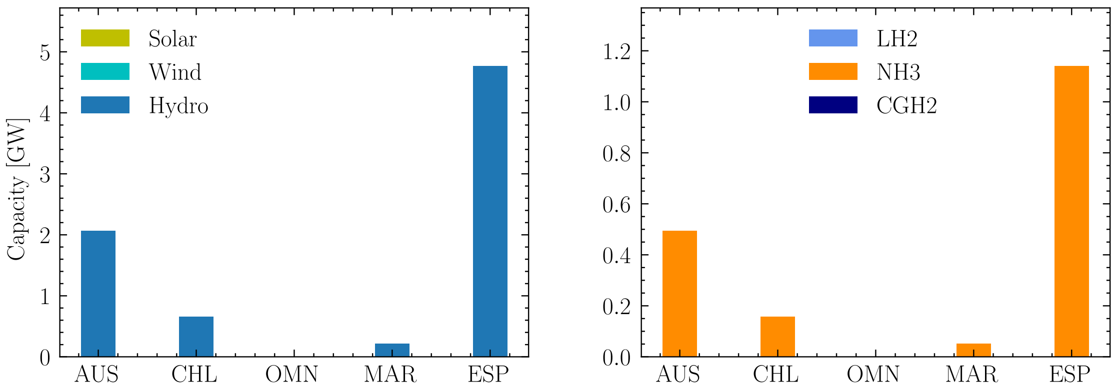


Figure 4.10: Size of the renewable energy installations (left) and the production plants (right) with an export proportion of 20%. In an extreme situation, the supply from Morocco is added. All the exporters produce ammonia.

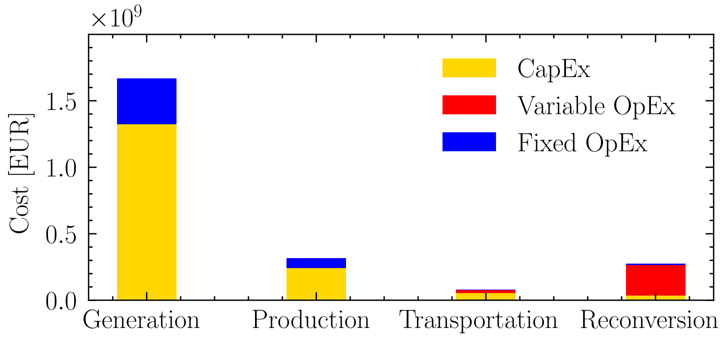


Figure 4.11: Cost composition with an export proportion of 20%. The reconversion OpEX has increased compared to the reference case.

2030: optimistic, base and conservative case

By 2030, significant changes will take place with respect to the RES capital costs reduction and installed capacities boost, together with the growing energy needs. Thus, it is expected that results differ a lot from the ones for 2020.

The potential supply chain for 2030 is analysed considering an optimistic (O), base (B) and conservative (C) scenario. Figure 4.12 shows that for all the cases, wind becomes the most attractive resource, overtaking the competitiveness of hydropower. Specifically, in the optimistic case, the supply comes from the wind (mostly) and solar generation in Spain in the form of liquefied hydrogen, and from the wind generation in Australia, with a small production of ammonia. In the base case, a part of the wind installations is replaced by solar, which becomes the most competitive resource for Spain. Also, a small part of the production is replaced by ammonia. This is explained by the fact that liquefied hydrogen ships have a greater capacity and are more expensive than ammonia ships. Thus, this small amount of ammonia produced corresponds exactly to the capacity of one ship. For the conservative case, the supply entirely comes from Spain with its wind power.

In terms of total costs, it amounts to 1.86 billion € for the optimistic case, 1.91 for the base case and 1.82 for the conservative case. This smaller last value could be surprising but, as a reminder, the conservative case was defined by assuming that the demand of hydrogen satisfied by imports is smaller. Thus, the more appropriate metric for comparison of costs is the LCOH which is respectively 90.6, 106.9 and 119.9 €/MWh. Regarding the monthly variations, the use of variable energy sources as solar and wind induces intermittency in the supply. They are illustrated in Appendix E.

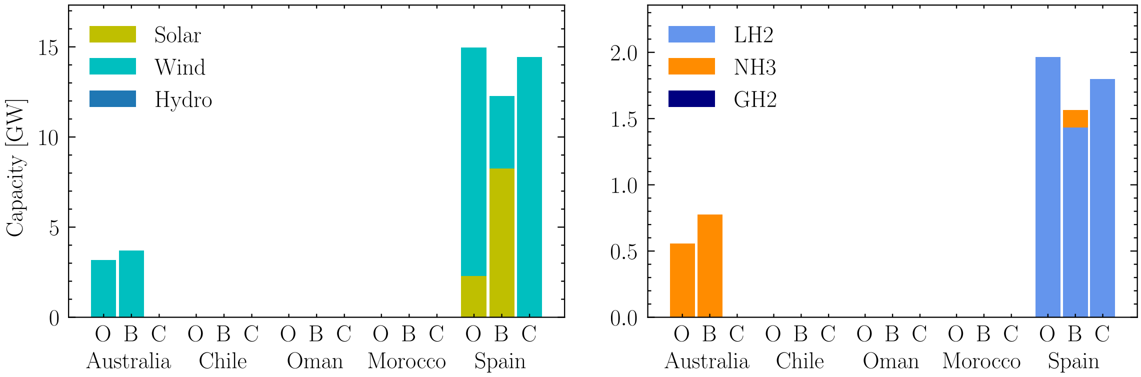


Figure 4.12: Size of the renewable energy installations (left) and the production plants (right) for 2030. The hydrogen demand of Belgium is satisfied with the supply from Spain (mostly) and Australia. Wind (mostly) and solar are the RES selected for electricity generation. Australia produces NH_3 as transport carrier while Spain mainly produces LH_2. Note: "O" refers to the optimistic case, "B" refers to the base case and "C" refers to the conservative case.

2050: optimistic, base and conservative case

For this scenario, the results must match with the long-term decarbonisation policies. The high ambitions are coupled with a strong evolution of data regarding energy needs and technologies deployment. A long-term energy scenario is inherently uncertain. Results are provided with respect to the same cases than 2030.

The first element to notice is that the conservative case for 2050 is infeasible: the energy requirements (i.e., local electricity consumption in the exporting country and hydrogen demand in Belgium) are too high for the forecast RES installed capacity. For the optimistic and base case, the total costs are expected to increase at least twofold by 2050 compared to 2020, reaching 5.27 and 5.08 billion €. The main reason of this rise lies in the much higher hydrogen demand. The LCOH allows to make a better comparison between supply chains: its value is 66.6 €/MWh for the optimistic case and 80.25 for the base case for 2030, which is much smaller than the LCOH of 2020. In terms of supply, three countries are selected, sorted by importance (Figure 4.13): Morocco with its solar power, Spain with its solar and wind power and Australia with its wind power. The small generation of Australia implies that ammonia is produced while large-scale liquefied hydrogen plants are installed in Morocco and Spain. As a final observation, the monthly variations are displayed in Appendix E.

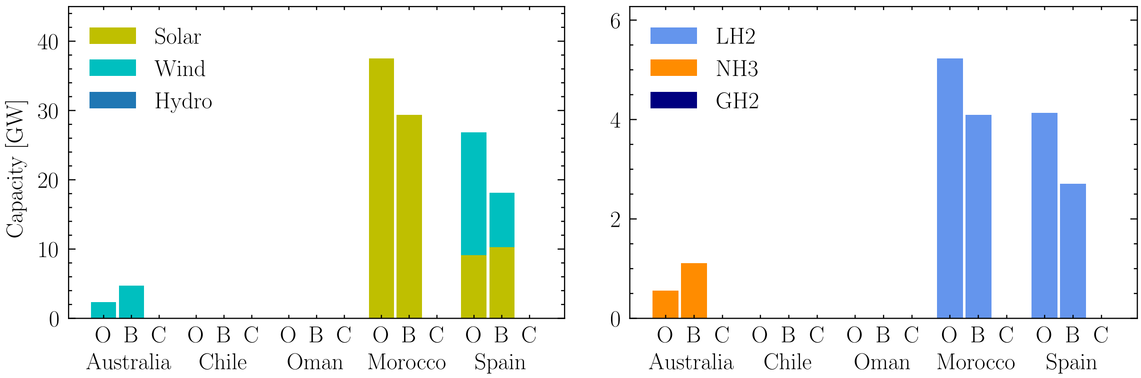


Figure 4.13: Size of the renewable energy installations (left) and the production plants (right) for 2050. The hydrogen demand of Belgium is satisfied with the supply from Morocco (mostly), Spain and Australia. Solar (mostly) and wind are the RES selected for electricity generation. Australia produces NH_3 as transport carrier while Morocco and Spain produces LH_2. Note: "O" refers to the optimistic case, "B" refers to the base case and "C" refers to the conservative case.

Conclusion

To conclude, a certain pattern emerges from all these scenarios. Based on the information gathered, the reading guide presented in the beginning of the chapter is completed to illustrate this pattern:

- **Costs:** the levelised cost of hydrogen lies in the range of 132 to 206.9 €/MWh for scenarios related to 2020 and reaches 106.9 €/MWh for 2030 and 80.25 €/MWh for 2050. Figure 4.14 provides a visual comparison of the LCOH for the main scenarios,
- **Exporting countries:** Spain is the most competitive supplier for Belgium followed by Australia that can serve as a complementary supplier. For 2050, Morocco becomes competitive too,
- **Transport carrier and mode used:** pipelines are never used because of their high cost of installation. LH_2 is usually preferred as transport carrier by ships but NH_3 can be used when small amounts of energy are involved,
- **RES origin of the electricity supply:** hydropower is the exporters' most available, reliable and affordable energy source for 2020, while wind become the more efficient power source in the future,
- **Time variations:** monthly fluctuations in the supply appear when using VREs such as solar and wind.

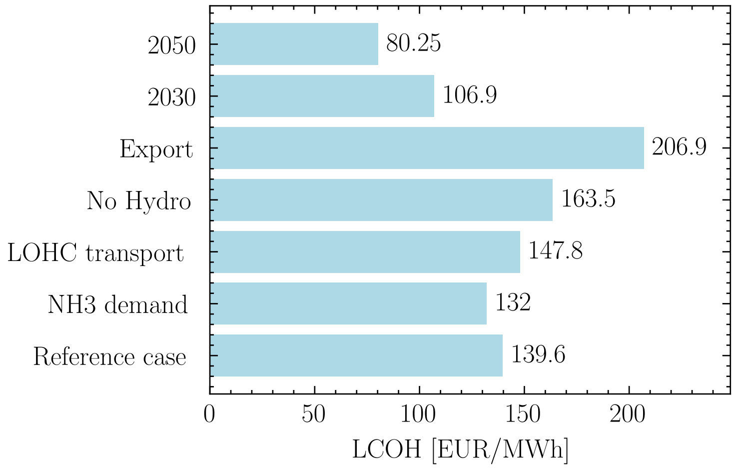


Figure 4.14: Comparison between levelised cost of hydrogen for all scenarios. For 2020 (the 5 lower scenarios), the LCOH lies in the range of 132 to 206.9 €/MWh. For 2030 and 2050 (the 2 higher scenarios), it decreases to 106.9 and 80.5 €/MWh, respectively. Note: "Export" refers to the minimum export proportion (20%) and "2030", "2050" refers to the base case.

As a final comment, Appendix A on implementation explains how these results were obtained and how results for other scenarios could be easily provided.

4.3 Discussion

This discussion aims at validating the results by comparing them with the optimal choices and the order of magnitude from other reports.

First of all, the most consistent comparison is the one with the report of the Belgian Hydrogen Import Coalition [8]. Indeed, the set of exporters in the case study is identical to the one described in this report. Figure 4.15 shows the cost distribution considered for their optimisation of the Belgian supply chain. It should be mentioned that their production step takes into account the generation of electricity and the production of hydrogen and its derivatives. Furthermore, Figure 4.15 indicates that the renewable electricity generation contributes to the costs at a rate between 60% and 95%. Thus, it validates the cost distribution of this thesis where the electricity generation represents 76.7% of the total costs and the hydrogen production 19.4%, regarding the reference case.

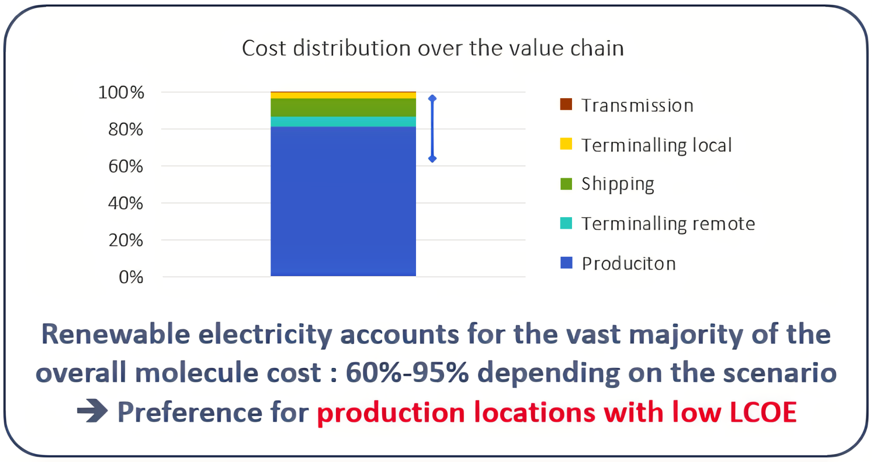


Figure 4.15: Cost distribution over the supply chain according to the Belgian Hydrogen Import Coalition [8].

Then, the coalition summarises and compares the levelised cost of green hydrogen delivered to Belgium for 2030-2035 and for 2050 in Figures 4.16 and 4.17 respectively, for the different regions. Specifically, the cost of renewable imported energy lies in the range of 65-90 €/MWh by 2030-2035 with a further cost reduction potential down to 55-75 €/MWh by 2050. By comparison, this thesis found a LCOH between 120 and 90.6 for 2030, and 80.25 and 66.6 for 2050: those values are very close.

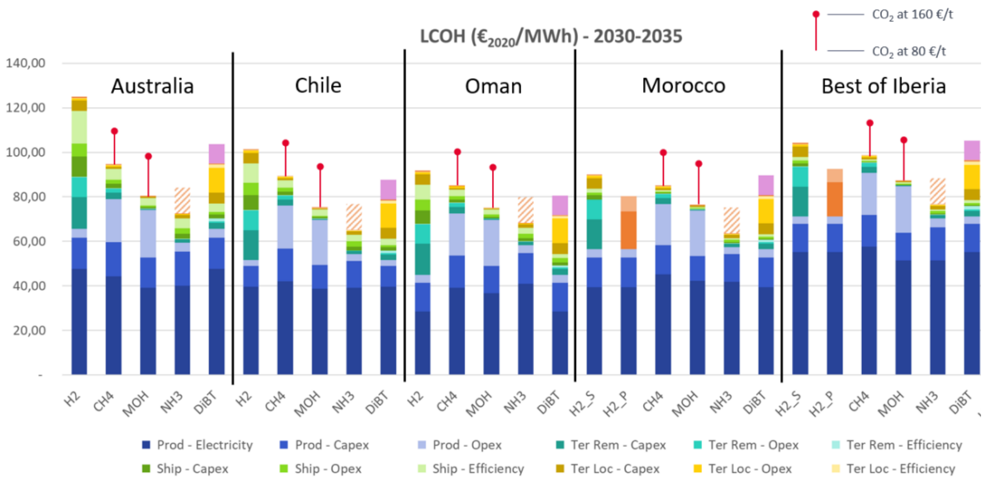


Figure 4.16: LCOH for 2030-2035 for different transport carriers and exporters [8].

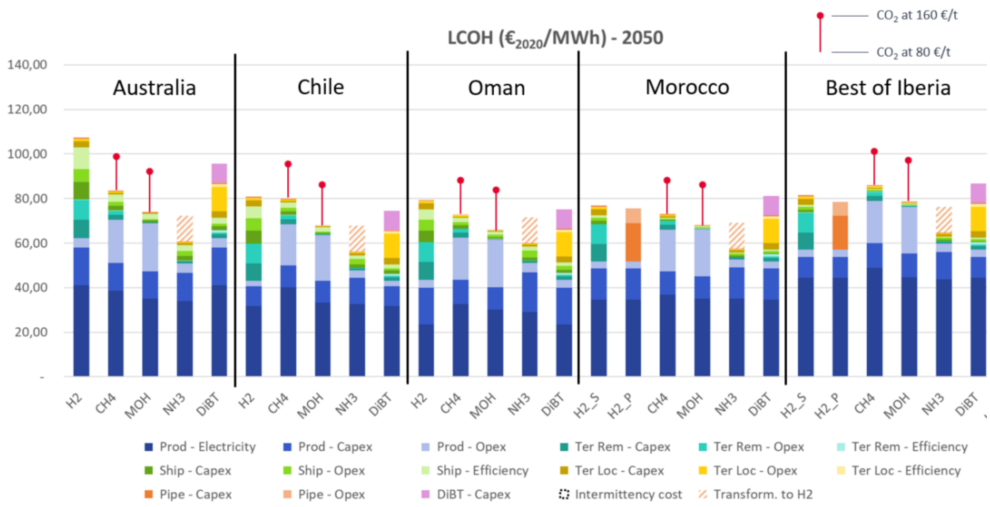


Figure 4.17: LCOH for 2050 for different transport carriers and exporters [8].

More precisely, Figures 4.16 and 4.17 highlight the most competitive potential exporters and carriers in terms of LCOH. At first glance, importing from Australia seems to be on the expensive side, but the costs differ according to the carrier and ammonia appears cost-effective. Contrariwise, the cost of liquefied hydrogen in Australia is strongly affected by long shipping distance. Thus, our results obtained for the case study of 2030 are consistent with the report of the coalition: a production of ammonia in Australia is an optimal choice.

By taking a look at the coalition's results regarding other countries competitiveness, some differences appear but can be explained. Unlike this thesis, they use different production costs depending on the location. Specifically, they justify their results by indicating the compensation of long shipping distance with lower energy production costs for Chile and Oman, and proximity with higher costs in the case of Morocco and Iberia (which is quite equivalent to Spain). Thus, with the assumption of a unique production cost for all exporters, the main criterion for countries' selection of our optimisation are the production capacities and proximity to Belgium. In this context, Spain is the best supplier because of its larger installed capacity and short distance to Belgium.

It must also be noted that the coalition found the overall feasibility of liquefied hydrogen to be significantly lower than ammonia, especially for long-distance transportation per ship. One reason for this difference with our results is that they considered larger losses during production and transport of liquefied hydrogen.

For 2050, Figure 4.17 shows similar results to 2030, with further cost reductions due to additional scale and technology maturity. In this thesis, the results for 2050 reveal that, in addition to Spain and Australia, Morocco can be a competitive supplier. It is consistent with the results of the coalition that found that liquefied hydrogen from Morocco has a relatively low LCOH.

Another comparison can be made with the study of Kim et al.. As explained in the first chapter, their research aims at optimising the hydrogen supply chain in South Korea. Like Belgium, South Korea has high hydrogen requirements but small carbon-free production capacities. Their study concerns blue and green hydrogen, while this thesis focuses the attention on green hydrogen only. The optimised results of the Korean report reveal that the most cost-effective solution is to import green hydrogen from the United Arab Emirates and India, using liquefied hydrogen, for a unit cost between 55.44-62.89 €/MWh in 2025. Meanwhile, the Belgian supply chain is expected to have a unit cost between 90.6-120 €/MWh for 2030. In the long term, the study published by Kim et al. [9] shows that the unit cost will rise to 58.04-77.96 €/MWh in 2040, due to the increase in domestic demand forcing the importing country to use supply from countries with more expensive unit H_2 costs. It is not the case for Belgium where the unit cost could decrease to 66.6-80.5 in 2050. The difference between this thesis and the Korean publication can be explained by the fact that they predict the green hydrogen export capacities and electricity generation costs using only curve fitting methods, whereas long-term energy forecasts are inherently irregular.

As a final comment, the results provided by an optimisation model may be far from reality, whether for this thesis or studies presented. Geopolitical, regulation and fiscal factors as well as compliance with carbon neutrality objectives have a significant weight in decision-making for the production and transport of hydrogen.

Chapter 5

Conclusion and perspectives

> *Chapter overview:*
>
> – Recap of the research question, methodology and main results.
>
> – Future perspectives: pipelines modelling improvement, new case study, robust optimisation.

5.1 Summary

The research question motivating this thesis covers two dimensions. The first dimension consists in the development of a general model to identify the optimal routes for hydrogen decarbonisation of a country via green hydrogen and is of methodological nature. It concerns the mathematical description of the proposed green hydrogen supply chain, from supply of hydrogen to its consumption with a production, transportation and reconversion steps. The flexibility of the model allows multiple exporting and importing countries, hydrogen transport and demand carriers, and resources for renewable energy generation. The second dimension consists in the establishment of a long-term decarbonisation strategy for the industrial sector in Belgium and is of applicative nature, as it concerns the application of the model to a specific case study. The model identifies the optimal suppliers and the best options for the production and transport in order to meet demand and minimise the total annual cost. The main findings of this work are the following:

- Based on the 2020 data, Belgium should import liquefied hydrogen from Spain, that have a production powered by hydropower. The total annual costs are estimated at 2.22 billion euros (LCOH = 139.6 €/MWh),

- Given forecasts for 2030, Belgium could satisfy its hydrogen demand with the production of liquefied hydrogen from Spain and with the production of ammonia from Australia, mainly powered by wind. The estimated LCOH is between 90.6 and 119.9 €/MWh,
- In light of forecasts for 2050, the optimal suppliers for Belgium could be Morocco and Spain, both thanks to their solar capacity, and Australia, on the grounds of its wind potential. Liquefied hydrogen remains the most optimal transport carrier. The LCOH could reach values between 66.6 and 80.25 €/MWh.

Overall, this thesis offers a complete framework covering the considered phases of the green-hydrogen trade, from the modelling of the supply chain to its optimisation under various scenarios. This framework, together with a full description of the model and the data, can support either Belgian decision-makers to implement the proposed optimal green-hydrogen supply chain, or researchers to carry out more refined analyses built-up on top of this work.

5.2 Perspectives

Future improvements of the presented work are envisaged along three main research tracks. Firstly, from the modelling point of view, pipeline design has been identified as the main limitation in Section 2.6. If repurposed gas pipelines are included, the model would gain in realism. The main challenge lies in the availability of the data on technical aspects as the length, capacity or pressure.

Secondly, the specific case study of Belgian hydrogen imports for its industrial sector has been examined in this thesis. However, the model was developed as a general model with the possibility of extending its application to many importers and exporters. Therefore, it would be interesting to study the competition between countries. Two scenarios could be compared: an importer-by-importer optimisation versus a collaboration. The first scenario uses the objective function 2.20 described in this thesis, where every country in need of green hydrogen is optimising its own imports. The second scenario includes another objective function,

$$\min \qquad \sum_{j\in\mathcal{I}} C^g + C^p + O^p + C^t_j + O^t_j + C^r_j + O^r_j. \tag{5.1}$$

In this scenario, the goal is not only to have a sufficient quantity of green hydrogen in a specific country, but also to ensure that all countries can have green energy. This is consistent with the current context described in Section 1.1, as various strong cooperation policies, like the Green Deal in Europe and the COP26 (United Nations

Conference of the Parties on Climate Change) worldwide, have been implemented. However, the benefit of some countries could decrease in this scenario. Thus, one could compare the sum of the benefit obtained independently for each country with the first function and the total benefit obtained with the second one, as well as check if it engenders economic losses for some countries.

Lastly, robust optimisation must be applied to the medium-term and long-term scenarios. Although the impact of uncertainties has been studied on few data, the model can be qualified as deterministic because it relies on fixed values and long-term forecasts for important parameters (e.g., resources cost and installed capacity, energy needs). Yet, over the long time horizon of energy transition, forecasts often prove to be inaccurate. Thus, robust optimisation is an appropriate approach for handling optimisation problems with uncertain data, by using methods as polynomial chaos expansion (PCE) or Monte Carlo simulation.

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Appendices

Appendix A

Implementation

The green hydrogen supply chain was modelled in a deterministic way, using Mixed-Integer Linear Programming (MILP) and a single objective of minimising the total costs. MILP involves problems in which only some of the variables are constrained to be integers, while others are allowed to be non-integers. The problems are most commonly of the form:

Objective:	minimise $c^T x$
Constraints:	$Ax = b$ (linear constraints)
	$l \leq x \leq u$ (bound constraints)
	some or all x_j must take integer values (integrality constraints)

The integrality constraints allow MILP models to capture the discrete nature of some decisions. In our case, it allows the number of ships to have a realistic integer value.

The model was developed using the Julia programming language with the package JuMP for mathematical optimisation, and solved with Gurobi [49]. All tests were performed in Julia v1.7 with Gurobi Optimizer v9.5 on a 2.3 GHz AMD Ryzen 5 4500U processor with 16 GB RAM. Based on a branch-and-bound algorithm, the solver found a solution in 0.16 seconds on average.

It should also be noticed that the model was developed with a general approach. From the modelling point of view, flexibility was the guideline of this thesis. This means that the equations were generalised (with indices) to allow many options as new carries, countries, etc. From the implementation point of view, several design choices were made to ensure a high-quality, easy to understand and reusable code. First of all, input data can be loaded from an excel file to easily investigate a new case study of the model. The excel file uses macros to automate the addition of new parameters. Input data can also be set manually using dataframes and arrays as an alternative method. Secondly, output of the code, composed by results as text and relevant figures (in png and svg format), is automatically saved in a structured manner. Finally, the source code has been thoughtfully commented to facilitate code comprehension and reuse of this thesis in future research projects.

Appendix B

Energy content of hydrogen versus natural gas pipeline

The future of a hydrogen economy will rely on the development of infrastructures for low-cost distribution of hydrogen. As highlighted in Section 2.6, the blending of hydrogen into natural gas distribution systems could provide a cost-effective option. An important issue to discuss is the energy that can flow in a pipeline dedicated to the transport of natural gas versus H_2. The report [32] studies the difference in pipeline energy when transporting methane, which is the primary component of natural gas, and hydrogen. Their conclusions are summarised in Figure B.1.

	Methane	Hydrogen
LHV (MJ/kg)	50	120
LHV (MJ/m^3)	35.5	10.78
Required flow rate (m^3/s) to get same energy flowing through pipeline	X	= 35.5/10.78 = 3.29X (Required)

Figure B.1: Energy content of pipeline carrying hydrogen versus natural gas (= methane), adapted from [32].

Even if hydrogen has a high energy density per unit mass (120 MJ/kg) compared to methane (50 MJ/kg), the challenge lies in its low volumetric energy density (10.78 MJ/m^3) which is about 3.29 times lower than methane (35.5 MJ/m^3). In other words, to ensure the same energy content in the pipeline, the H_2 flow rate must be 3.29 times higher than methane.

It is important to note that the higher flow rates required for H_2 will result in higher compression energy. Since the compression power depends on the molar flow rate, it takes about three times as much energy to compress a MJ's worth of energy when it is supplied as hydrogen than as natural gas [32].

Appendix C

RES installed capacities

The RES installed capacity forecasts for 2030 and 2050 provided by official or scientific reports can be challenged. Indeed, when looking at past trends of solar and wind capacities for each exporter, some forecasts seem to be unreasonable. To give them consistency, we analyzed 20 years (from 2000 to 2020) of energy capacities data of the respective exporters, and made a comparison with the forecasts.

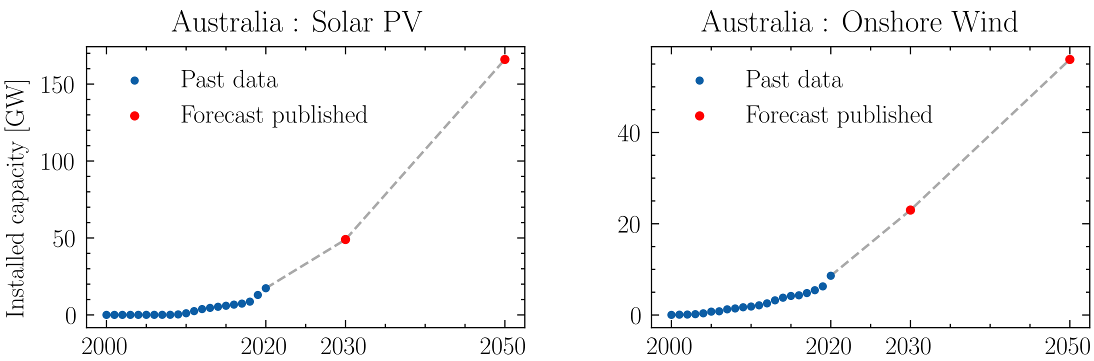

Figure C.1: Installed capacity of solar PV (left) and wind (right) in Australia from 2000 to 2020 [14] and forecast for 2030 [37] and 2050 [43].

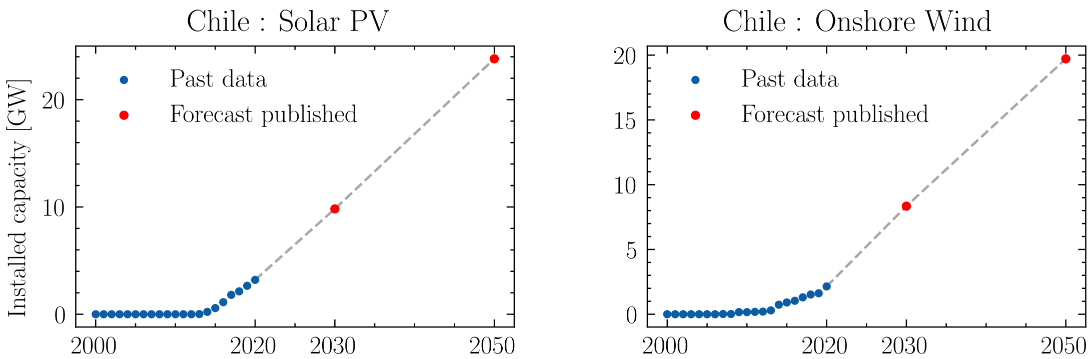

Figure C.2: Installed capacity of solar PV (left) and wind (right) in Chile from 2000 to 2020 [14] and forecast for 2030 and 2050 [38].

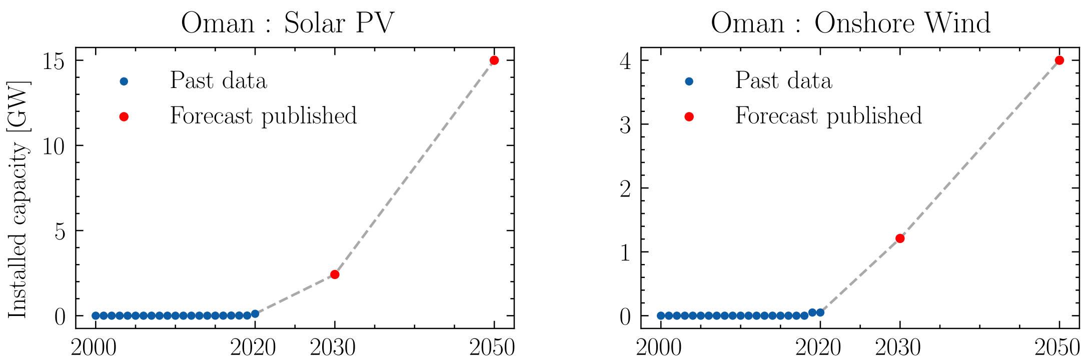

Figure C.3: Installed capacity of solar PV (left) and wind (right) in Oman from 2000 to 2020 [14] and forecast for 2030 [39] and 2050 [44].

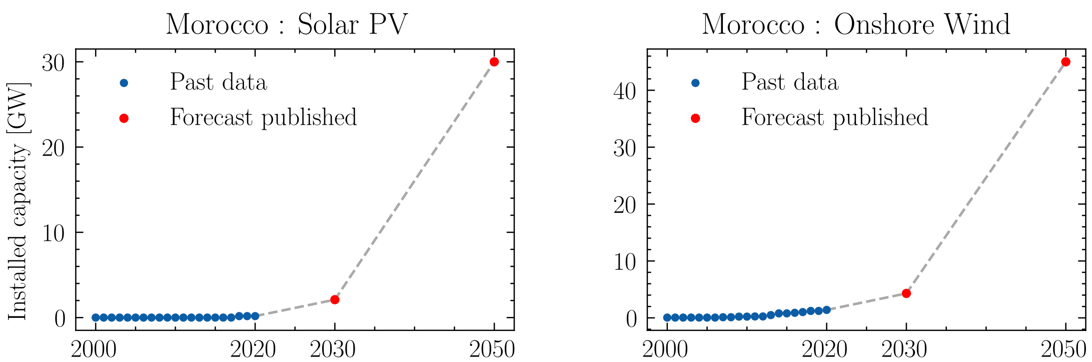

Figure C.4: Installed capacity of solar PV (left) and wind (right) in Morocco from 2000 to 2020 [14] and forecast for 2030 [40] and 2050 [45].

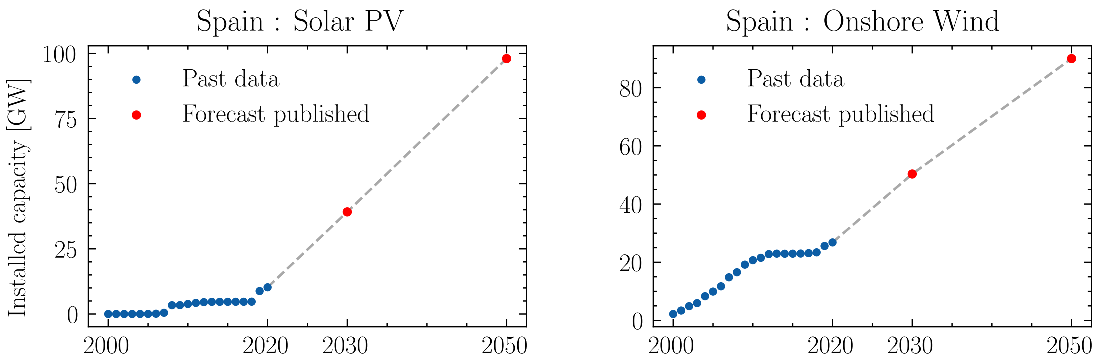

Figure C.5: Installed capacity of solar PV (left) and wind (right) in Spain from 2000 to 2020 [14] and forecast for 2030 [41] and 2050 [46].

For Australia and Chile, the deployment of renewable infrastructures has intensified since 2010. Looking at the grey curve, the high forecasts for future years could be reached by maintaining strong efforts. For Morocco and Oman, the solar and wind installations are currently marginal. As shown by the grey curve, the expansion of renewable installations for 2030 and 2050 must be drastic. Finally, Spain has already developed its wind potential, and the evolution of the installed capacity for future years follows a linear trend. For solar PV, the actual deployment remains weak compared to the huge ambitions, which will require strong additional efforts.

Appendix D

Capacity factors

The following graphs are obtained with data from renewables.ninja [23] for 2019 and have the same scale to facilitate comparison.

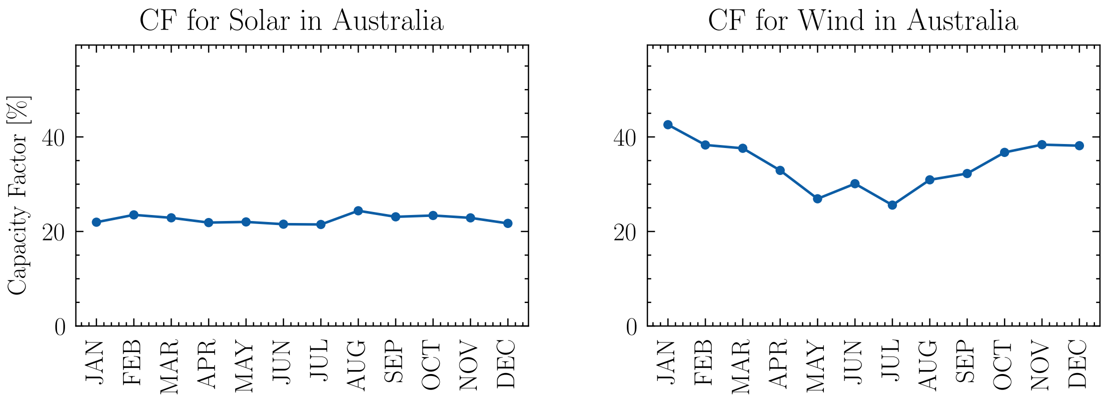

Figure D.1: Monthly capacity factor of solar (left) and wind (right) in Australia.

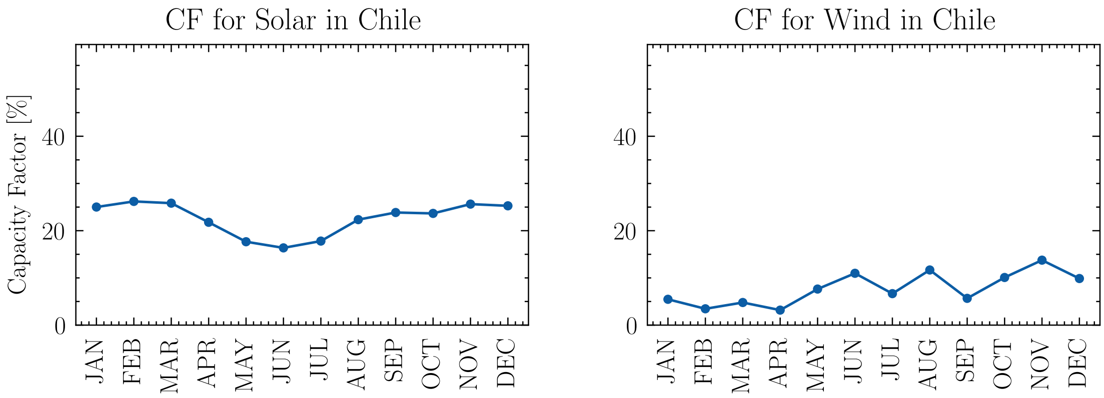

Figure D.2: Monthly capacity factor of solar (left) and wind (right) in Chile.

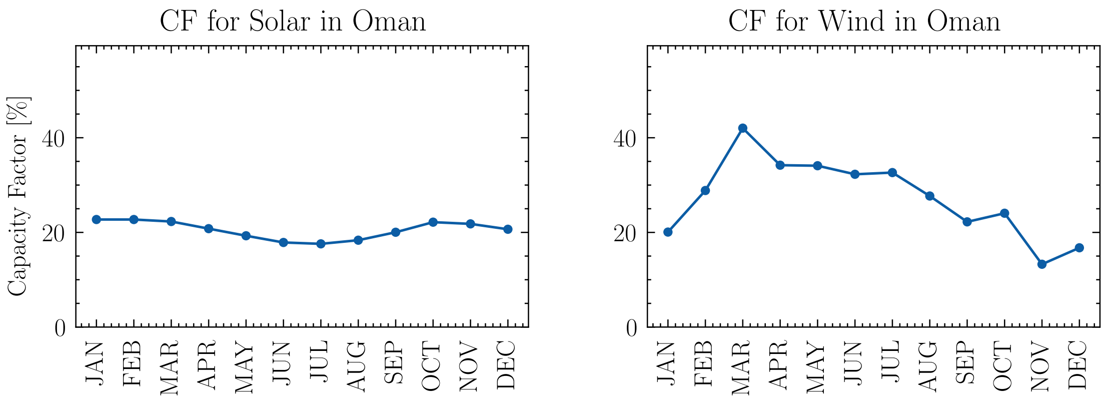

Figure D.3: Monthly capacity factor of solar (left) and wind (right) in Oman.

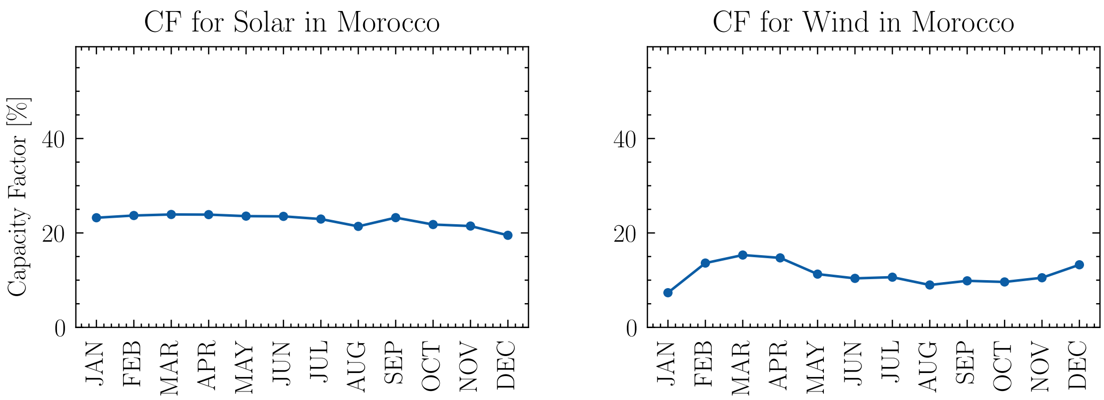

Figure D.4: Monthly capacity factor of solar (left) and wind (right) in Morocco.

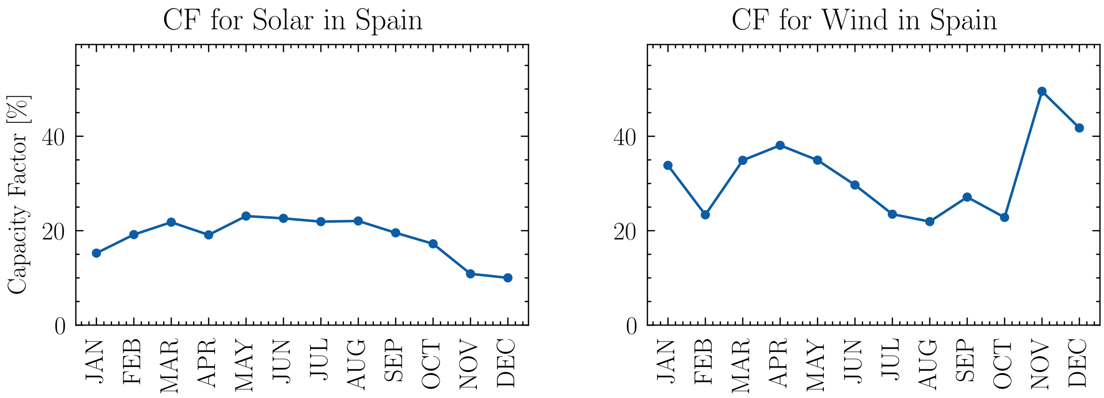

Figure D.5: Monthly capacity factor of solar (left) and wind (right) in Spain.

Appendix E

Additional results

E.1 Monthly variations in the importations for 2030

Base case

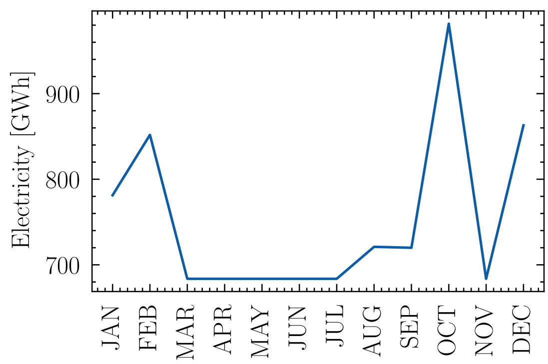

Figure E.1: Monthly variations in wind electricity supply of Australia for the 2030 base case.

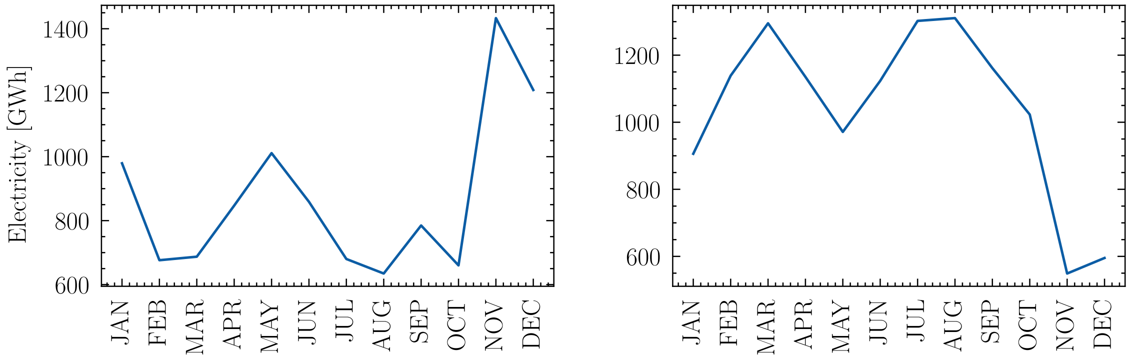

Figure E.2: Monthly variations in wind (left) and solar supply (right) of Spain for the 2030 base case.

Optimistic case

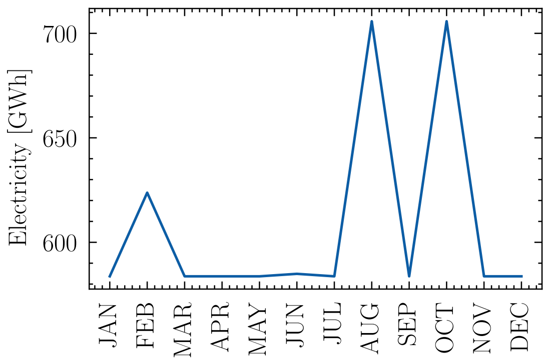

Figure E.3: Monthly variations in wind electricity supply of Australia for the 2030 optimistic case.

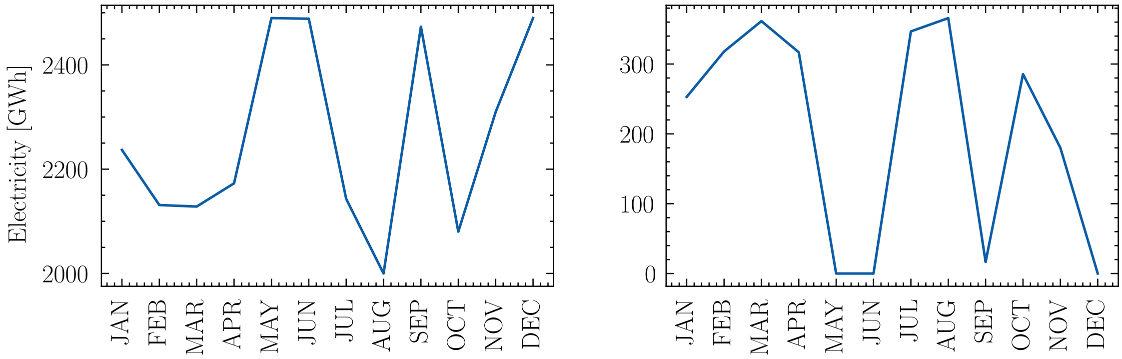

Figure E.4: Monthly variations in wind (left) and solar supply (right) of Spain for the 2030 optimistic case.

E.2 Monthly variations in the importations for 2050

Base case

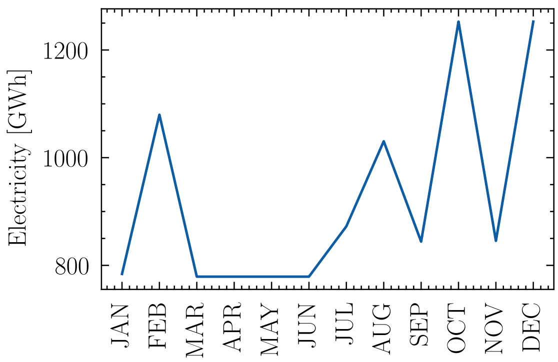

Figure E.5: Monthly variations in wind electricity supply of Australia for the 2050 base case.

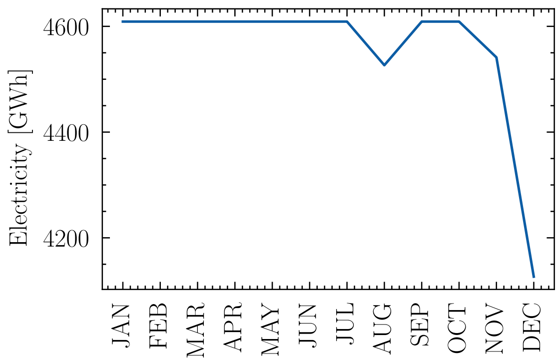

Figure E.6: Monthly variations in solar electricity supply of Morocco for the 2050 base case.

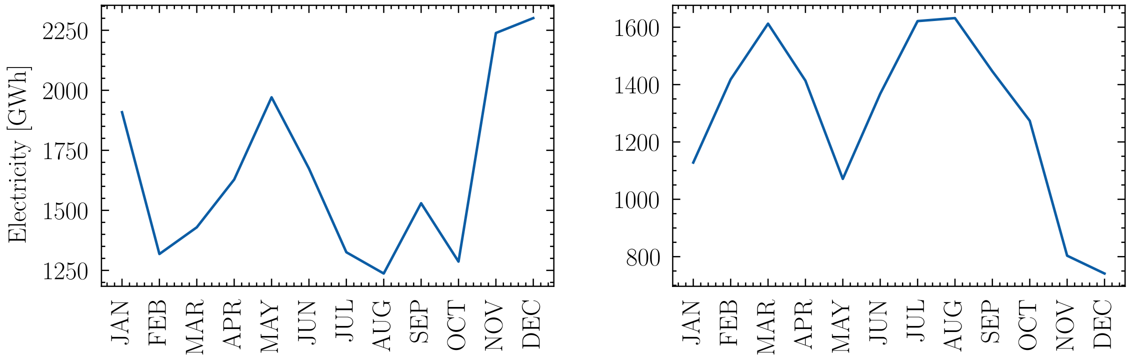

Figure E.7: Monthly variations in wind (left) and solar supply (right) of Spain for the 2050 base case.

Optimistic case

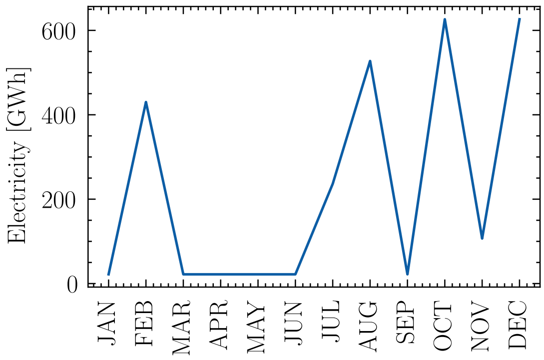

Figure E.8: Monthly variations in wind electricity supply of Australia for the 2050 optimistic case.

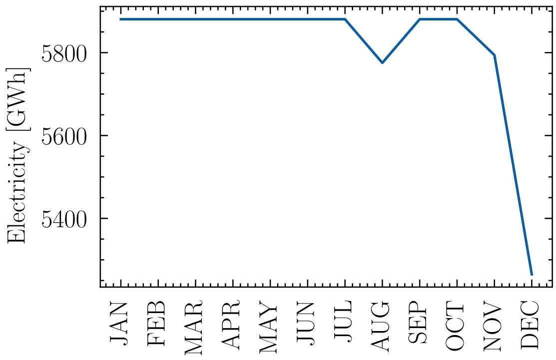

Figure E.9: Monthly variations in solar electricity supply of Morocco for the 2050 optimistic case.

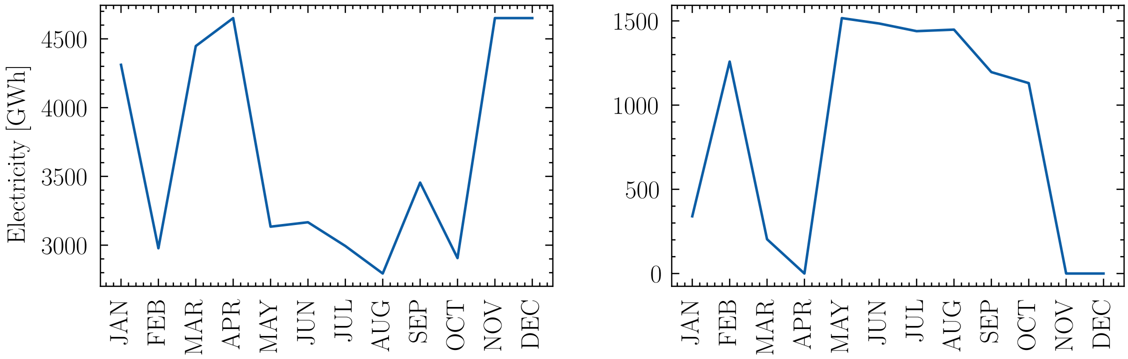

Figure E.10: Monthly variations in wind (left) and solar supply (right) of Spain for the 2050 optimistic case.

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