POLITECNICO
MILANO 1863

SCUOLA DI INGEGNERIA INDUSTRIALE
E DELL'INFORMAZIONE

Hydrogen supply chain integration into the Italian energy context using Hypatia: an energy system modelling framework

TESI DI LAUREA MAGISTRALE IN
ENERGY ENGINEERING-INGEGNERIA ENERGETICA

Author: **Youssef Moustafa Ellakany**

Student ID: 10752411
Advisor: Emanuela Colombo
Co-advisor: Franscesco Cruz Torres, Gianluca Pellecchia
Academic Year: 2022-23

Acknowledgment

I would like to express my sincere gratitude to the individuals and organizations that supported me throughout my research journey. First and foremost, I would like to thank my thesis advisors Prof. Emanuela Colombo, Francesco Cruz Torres and Gianluca Pellecchia for their guidance and support throughout the entire process. Their expertise and encouragement have been invaluable to me.

I am grateful to Politecnico di Milano and the department of energy (SESAM research group) for providing me with the resources, facilities, and opportunities needed to carry out this research.

I would like to extend my thanks to my colleagues and research team members who have contributed to this study in various ways. Their assistance in data collection, analysis, and interpretation has been instrumental in the success of this study.

Finally, I would like to express my heartfelt appreciation to my friends and family members who have supported me throughout this long journey. Their unwavering love, encouragement, and understanding have been a constant source of strength and motivation for me.

Thank you all for your invaluable support and encouragement.

Abstract

The infrastructure of hydrogen poses several challenges and barriers that need to be solved for a smooth transition to a future hydrogen economy. The abundance of technical alternatives for manufacturing, storage, transportation, and end users is mostly to blame for these difficulties. This being the case, it is crucial to comprehend and examine the hydrogen supply chain (HSC) beforehand in order to identify the significant components that may become increasingly critical in achieving the ideal configuration. Italy has set a working strategy to develop a hydrogen economy by 2050 to reduce GHG emissions, increase energy security and create new jobs and opportunities. The strategy expects hydrogen to cover 20% of Italy's final energy demand by 2050.

With this in mind, this work aims at developing an Italian energy integrated model using Hypatia, implementing the emerging processes included in the value chain of hydrogen in the Italian context. The model is set on the solution of a linear optimization problem, pursuing the optimization of the energy production processes through the minimization of the total cost of the supply chain. The developed tool is suitable for analyzing different hydrogen scenarios, returning the dispatched installed capacity for each technology and the required amount of investment. Different production technologies have been considered along with different pathways. In all cases, with production cost above 2 Euro/KgH2, domestic green hydrogen production- excluding policy support- will not be cost-competitive with alternative decarbonized options such as blue hydrogen, especially in the early 2030s with coal gasification being the most economically convenient technology. Moreover, achieving the green hydrogen potential announced in the Italian hydrogen strategy, almost twice the renewable energy capacity needed to be built by 2030.

Keywords: Hydrogen supply chains, Hydrogen scenarios, optimization modelling, Italian vision, hydrogen production technologies.

Contents

Extended Abstract

Introduction

With the implementation of Paris Agreement on November 4, 2016, to reduce carbon emissions, many countries are committed to develop very ambitious plans [1]. These plans include the revolutionization of different sectors, most notably the energy one. As, by decarbonizing the energy sector, other sectors such as industrial, residential and transportation sectors will be decarbonized as well. In fact, over the past two decades, world renewable energy has increased since the 1990s to reach almost 25% of the total world production in 2016, according to the Eurostat database [2].

From a longer-term perspective, the 2050 time-horizon, a full decarbonization would then be required, imposing a much higher REs presence in the energy system. The need to not waste excess energy produced in peak periods imposes the necessity to decouple production from demand. Electrification and battery storage likely will not be enough. Alternatives like hydrogen would play a key role.

In this context the energy system model presented in the paper was developed. The core of this thesis is to develop an energy model in order to assess the role of hydrogen in the Italian energy mix in a long-term scenario. A consistent literature review on the main existing processes related to hydrogen value chain and the most promising ones was conducted. From this perspective, a state of the art of the current hydrogen-related technologies is presented, starting from P2H. Water electrolysis is described in its multiple option: from the mature alkaline electrolyzers (AEC), passing through PEM electrolyzer and solid oxide (SOEC) to the most recent anion exchange membrane ones (AEMEC) a detailed description is reported. Moreover, other production technologies such as Natural Gas (NG) to hydrogen, coal gasification (CG) and biomass gasification (BG) are reported in detail.

Thereafter, different pathways are investigated from Hydrogen to Gas (H2G) with biological methanation to Hydrogen to Power (H2P) using Fuel Cells (FC). The former id reported focusing on Fuel Cell technologies currently available. Several technologies are mentioned, such as Alkaline FC, PEMFC, solid oxide ones, phosphoric acid (PAFC) or molten carbonate based (MCFC) and hydrogen turbines.

Then a literature review for different storage options was done such as compression, liquification and transformation into Liquid Organic Hydrogen Carriers (LOHC).

Lastly, different end-use sectors are investigated trying to determine the future decarbonization options hydrogen can have across several sectors (transport, building and industrial sectors).

Model development

The implemented model is Hypatia: an energy system modelling framework written in the objective oriented Python programming language. Contrary to most of the Python-based open-source energy and power system modelling frameworks that are using Pyomo for solving the optimization problem, Hypatia is based on CVXPY Domain-Specific Language developed by Diamond2016 [71] . Hypatia can optimize both the hourly dispatch and the annual capacity deployments of the energy system. Its final objective is to minimize the total discounted cost of the system by considering all the required cost components in each of its optimization modes. In summary, Hypatia is designed with the following main goals:

- Allow easy interaction with the model code by using excel-based input data
- Formulated to cover both operation and dynamic investment decisions
- Provide the possibility to consider the investment annuities in its planning mode based on the given economic lifetime and interest rate of each technology
- Allow to model various categories of technologies such as supply, conversion, transmission, and storage.
- Able to consider the synergies among different sectors of the energy system including power, heat, transport, clean fuel (Hydrogen) and others.
- Designed to follow both the single-node and multi-node approach at will by the user. Each node in Hypatia can be representative of a broad spectrum of spatial resolutions starting from small-scale applications to the national and continental applications.
- Allow to model the bilateral trade among any pairs of nodes through modelling the inter-regional transmission links for all the represented energy carriers within the Reference Energy System
- Able to adopt arbitrary resolutions in time for each modelling year, allowing to consider the full hourly variability of both demand and supply sides.

- Have a fully transparent and open-source code, flexible to any possible future modification and integration

Several background hypothesis were assumed to define the structure of the energy system. The imposition of a single technology option for each process described in the model was taken in order to keep the system representation as simple as possible and due to computational time increase issue that would derive from multiple technology options. An exception was made for hydrogen storage. Due to its low-performing properties at ambient conditions, H2 requires some transformation. Three possibilities are then compared: physical storage (via compression and liquefaction) and material-based one (switching to LOHC).

Another assumption is made regarding fossil fuels. A limited supply for coal has been applied as Italy does not produce it, all the consumption is imported. Moreover, oil and coal power plants have been banned from electricity production according to the Integrated National Energy and Climate Plan. Regarding natural resources, for solar and wind capacity factors, values are obtained from Renewable. Ninja [25] for 2019 and then a daily average is taken over all the year. Regarding other natural resources such as geothermal energy and hydro, the capacity factor for geothermal plants is taken constant over all the years and equals 0.95. While hydroelectric power plants' capacity factor equals 0.49. These values are taken from SESAM database [78].

Model application

The different analyzed hydrogen energy scenarios investigate the possible hydrogen penetration in the Italian energy context by 2050. Final consumption, supply sectors and annual profiles data for 2050 were estimated by taking advantage of the knowledge that the SESAM research team has developed, comparing with long-term projections, and adjusting with some projections made by the Author. The main aim of these developed scenarios is to evaluate the potential role of hydrogen and its pathways in the energy system pursuing a cost minimization optimization.

With this goal in mind, three different hydrogen energy scenario were designed. The first is the basecase scenario which represents the current situation of final energy demand in Italy with a reference year of 2020. The applied scenario is considered the baseline for all other scenarios. Constructing the basecase scenario, which represents business as usual case, hydrogen is assumed to be used in the industrial sector, giving the fact that there's no plans or strategies for developing a hydrogen economy. This represents the use of hydrogen in chemical processes, ammonia production and synthetic fuels processes. According to this scenario, Hydrogen is produced using the following technologies: SMR plants without CCS, CG + CCS and electrolysis, however, there's a residual capacity of 0.5 GW of SMR plants that already exist in Italy to produce the current demand in 2020.

The second one is set up with the aim to simulate the hydrogen demand in the TFC of energy in Italy according to the Italian National hydrogen strategy and Integrated National Energy and Climate Plan (INECP) [3], [4]. The plan aims to use hydrogen in the national decarbonization process in accordance with INECP, which reflects the broader environmental agenda of the European Union. This results in hydrogen penetration in the final energy demand of 20% by 2050, which is around 6000 Kton of hydrogen across all sectors. The increase of penetration in different sectors from 2030 to 2050 is calculated, for transport (0.19% to 2.3%), industrial (5.1% to 43.5%), residential (2.1% to 20.5%), and service (2% to 18.3%) respectively.

The last one is focused on high hydrogen penetration in the transport sector. As in the national strategy demand scenario, hydrogen penetration is low and according to recent studies and motivation mentioned below, the transport sector is expected to have high penetration by 2050. All other parameters, including technologies, are kept the same. This scenario is based on the EU4 scenario developed by the IEA for four EU countries, including Italy [88]. Hence, according to this scenario, the share of FCEV (thus, of hydrogen) is equal to 2.4% by 2030 (low penetration) and 28.5% by 2050 (high penetration). This scenario was chosen as it allows a quantitative analysis of the demand at two years with a high penetration gap, indicating the available potential for hydrogen in the Italian transport sector.

Based on these energy scenarios, different model runs have been done trying to figure out how the target announced in the Italian hydrogen strategy can be accomplished by 2030 and further estimated visions by 2050. In all scenarios, green hydrogen was not convenient before the late 30s without proper supportive schemes. Therefore, high renewable penetration scenario was established to reach electrical renewable penetration of 0.56 by 2030, which is in line with the INECP. The hydrogen demand in this scenario is the high transport penetration (third one) demand and 100 Euro/tonCO2 as ctax is applied.

Hydrogen production in this scenario is demonstrated in Table 24. In this case, electrolysis starts to produce in 2030 having a total share of 9% with an installed capacity of 5.1 GW. The percentage keeps increasing until it reaches 28% of the total production. In this case, the cost of green hydrogen is 2.2 Euro/KgH2 which is 30% lower than the high transport penetration scenario -ctax 0.1. Moreover, CG + CC is still dominating with a production share of 40% in 2050 while production from SMR + CCS is still relatively higher than green hydrogen, with a 32% share of total production.

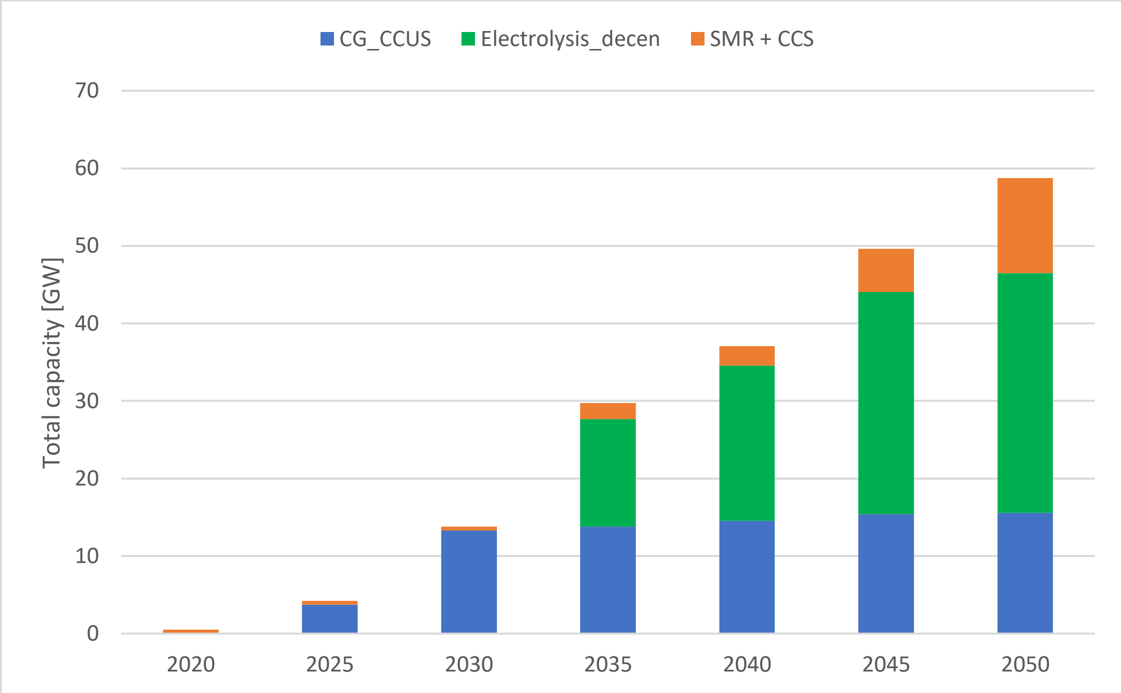

Figure 1: Total hydrogen capacity - high renewable penetration scenario

Technology	2020	2030	2040	2050
CG_CCUS	0%	88%	62%	40%
Electrolysis	0%	9%	27%	28%
SMR + CCS	100%	3%	11%	32%

Table 1: Annual hydrogen production share- High transport penetration demand with high renewable penetration

From primary energy resources perspective, as shown in Figure 49, the RES has increased to reach almost 25% by 2050 compared to 18% in the basecase scenario. This is mainly due to the reduction in consumption of NG and coal in power generation and increasing the power generation from renewable resources such as wind and solar. However, solid fossil fuel supply has increased due to the generation of blue hydrogen using coal gasification technology.

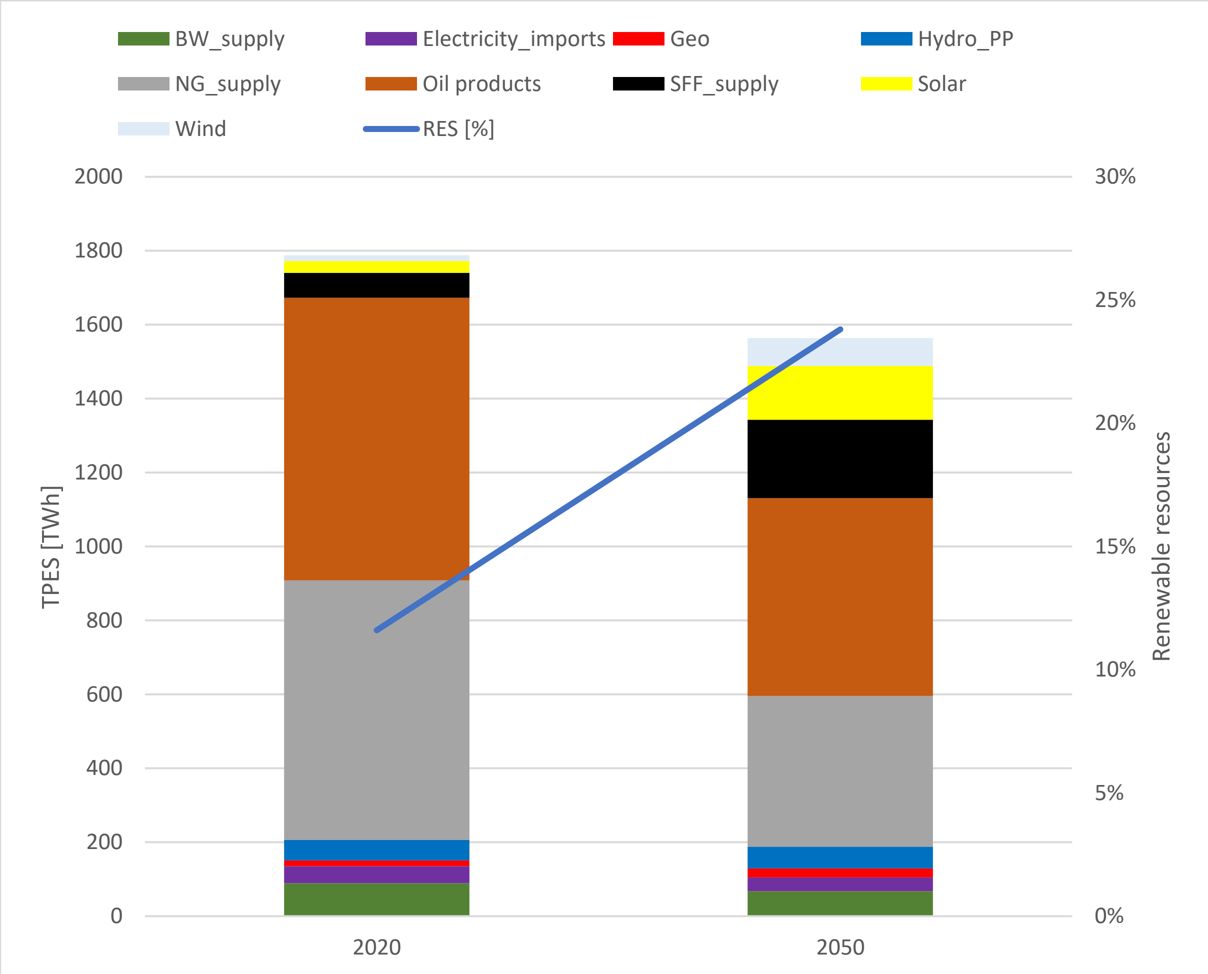

Figure 2: Italian primary energy consumption by source in 2020 and 2050 – High renewable penetration scenario

Conclusion

In this thesis a new energy system model is provided, which is able to analyze a wider and more heterogeneous national energy system, with the addition of the promising technologies related to hydrogen generation and Hydrogen to X pathways. The introduced model was able to simulate the Italian Energy system including the generation and use of electricity, heat, and other commodities adapting current and soon to market technologies.

In addition, a sensitivity analysis is made to gain insights about the possible solutions to boost green hydrogen production. In this analysis, different carbon taxes and adding electrochemical storage to the electric grid have been analyzed. It is noticed that increasing the carbon tax increases the average cost of hydrogen generated. Also, adding electrochemical storage showed in a relative increase in the electrolysis production compared to no storage case, showing that adding the electrochemical storage solves the intermittent characteristics of renewable energy allowing for more installed capacity hence more green hydrogen production.

Moreover, different hydrogen to X pathways have also been investigated. Fuel cell (H2P) showed promising results especially when there was a huge amount of hydrogen demand while biological methanation seemed to be utilized only when there is no storage capacity to store hydrogen indicating that it is better to use NG resources.

In summary, an analysis of the Italian energy system was done using Hypatia to explore the hydrogen potential inside the country. The following findings have been observed:

1. In order to meet the current ambition of the Italian hydrogen strategy (2% of total final consumption by 2030 and 20% by 2050), different technologies could be used to produce hydrogen. The most economically convenient is coal gasification + CCS then comes SMR + CCS.
2. In all cases, domestic green hydrogen production- excluding policy support- will not be cost-competitive with alternative decarbonized options such as blue hydrogen, especially in the early 2030s.
3. With production cost above 2 Euro/KgH2, Green hydrogen without subsidies will be outcompeted by large-scale blue hydrogen projects and CCS-retrofitted steam methane reformers, which can reach production costs of around 2.0 €/kg H2
4. In order to reach the green hydrogen potential announced in Italian hydrogen strategy, almost more than one time and a half renewable energy capacity needed to be built by 2030.
5. Moreover, adding electrical storage capacity to the grid and applying carbon tax helps to push green hydrogen production further.

Chapter 1. Hydrogen processes network

1.1 Introduction

With the implementation of Paris Agreement on November 4, 2016, to reduce carbon emissions, many countries are committed to develop very ambitious plans [1]. These plans include the revolutionization of different sectors, most notably the energy one. As, by decarbonizing the energy sector, other sectors such as industrial, residential and transportation sectors will be decarbonized as well. In fact, over the past two decades, world renewable energy has increased since the 1990s to reach almost 25% of the total world production in 2016, according to the Eurostat database [2].

The International Energy Agency (IEA) [3] noted that in order to achieve Paris agreement targets, with the deeper integration of renewable energy production, flexibility should be introduced in the system. A very promising option for providing this flexibility and solving the intermittency problems of renewables is hydrogen. The integration of hydrogen within the energy supply chain not only can enhance the sustainability and reliability of the energy system, but also perform a significant function in the system's flexibility. The utilization of hydrogen can link different energy sectors and energy transportation and distribution (T&D) networks; thus, it could increase the operational flexibility of future low-carbon energy systems.

Hydrogen is well placed in the energy field. In fact, it can provide good solutions for emissions control and energy security for different regions around the globe, especially the EU. As, hydrogen is a clean fuel to burn with the following characteristics:

- It does not emit CO2.
- It can be produced from a large variety of fossil and renewable resources such as coal and biomass.

Moreover, hydrogen technologies are very suitable for storing the surplus electricity generated (e.g., from solar and wind) on a large scale, covering storage periods from hours to seasons [4],[5]. These technologies can be classified as:

- Power to power: electrical energy is stored in the form of hydrogen by electrolysis and then electrified again using fuel cells.
- Power to gas: electrical energy is transformed into hydrogen by electrolysis and then mixed into natural gas network.
- Power to feedstock: electrical energy is transformed directly into hydrogen and is used as a raw fuel in refining and chemical processes.
- Power to fuel: electrical energy is transformed into hydrogen and is used as a fuel in fuel cell electric vehicles FCEVs in the mobility sector.

Therefore, during the past few years, these technologies have been significantly developed and established in the market. Generally, the barriers that tackle the boost of hydrogen economies is the inefficiency of the present infrastructure [6]. Hence, large investment is needed. Many researchers and policymakers continue to find different solutions to shift from sustainable carbon-based economy to hydrogen based one [5], [7]. In order to realize the aforementioned vision, a strategy is needed to answer the 4Ws questions, when, where, at what sizes and with which technologies [8]. Namely, a strategy is needed to address the temporal, spatial and technological decisions to build hydrogen infrastructure.

In this work, we focus on the introduction of hydrogen into the Italian energy value chain by quantitively finding the most promising and cost-effective pathways for hydrogen processes considering all the stages in the value chain. This will be done through a comprehensive literature review followed by modeling these value chains using Hypatia, an open-source energy system optimization model. This chapter discusses the available technology pathways that could be introduced in the hydrogen supply chain, considering all the stages from feedstock to end-use.

1.2 Hydrogen supply chain (HSC) and process network analysis

Designing the supply chain of hydrogen is a very important and crucial problem according to the supply chain management [9]. Many different steps are involved, each with its own peculiarities. Hence, the concept of supply chain network design is adapted to determine the deployment of hydrogen infrastructure on a regional or national scale or sector scale as well. As an example, the hydrogen supply chain related to the transportation sector is shown in Figure 3 [10].

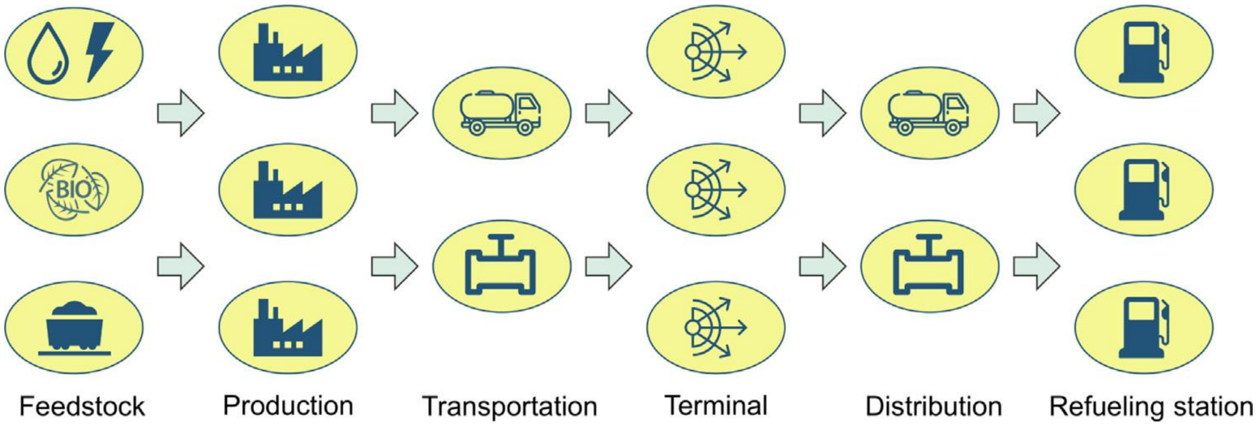

Figure 3: Hydrogen supply chain network (HSCN) in the transportation sector [7].

The first step in the supply chain is the feedstock, and the last consists of refueling stations for end-use. Furthermore, there could be many choices available in each step. For example, in the production section, there are many mature technologies such as electrolysis (using electricity), coal gasification (CG), biomass gasification (BG) and steam methane reforming (SMR). Subsequently, regarding the feedstock, water, biomass, coal, and methane could be used. The determination of such technologies depends on the characteristics of the region, availability of the feedstock and the available infrastructure. Al Mansoori et al. [11] analyzed three different configurations for the supply chain with the same production technology (SMR, Electrolysis and coal gasification) but the major difference is the physical form of the hydrogen generated (gas or liquid). Thus, determining the storage and transportation mode based on that. They considered three different technologies for production: Steam methane reforming, coal gasification and biomass gasification. They have calculated the Capex for liquid hydrogen from SMR plant with a capacity of 480 ton/day to be 535 million dollars and OPEX to be 242 million $/year in the UK. Al Mansoori et al [12] designed a hydrogen supply chain for Germany using the same technologies including CCUS to the coal and steam reforming plants. They found out that using liquid hydrogen is the preferred option with railcars for transportation given its fuel price, flexibility, and availability in Germany.

Anton Ochoa et al. [13] have tried to minimize the cost of the supply chain in Germany up to 2030 and 2050 by studying two cases. One of them uses all the available technology to produce hydrogen such as CG, BG, SMR and electrolysis and the second one, using only “green” hydrogen. Coal gasification was the dominant technology in the first scenario, with 0.3 $/Kg regarding capital and operating cost. Regarding transportation and distribution, it can be done via truck, trains, or pipelines. It will depend on the physical form of hydrogen as well as the storage. This makes each step of the supply chain inherently connected rather than isolated. In the green scenario, hydrogen price was 9.69 and 9.57 $ kg−1 of H2 for 2030 and 2050, respectively, which is not a reasonable price for industry.

1.2.1 Feedstock

As an energy carrier, hydrogen is generated from feedstocks [14]. Biomass, natural gas, coal and water are among the most used feedstocks to generate hydrogen [15],[16],[17]. Recently, there has been an attention towards low carbon hydrogen chains and renewables [18]. Renewable energy allows us to generate a more sustainability-oriented form of hydrogen with no emission and there's no need for carbon capture, utilization, and storage technologies (CCUS). Many researchers modelled the use of renewable energy to produce hydrogen. For instance, Almaraz et al.[19] used four sources (solar, nuclear, wind, hydro-power) to generate electricity which is used to produce hydrogen. Won et al. [20] focused on resources such as biomass, wind and solar to generate green hydrogen. Paolo Gabrielli et al. [21] performed parametric analysis to assess the biomass availability for a Swiss case study. They assumed that biomass is homogenously available in urban areas although limited. Such availability was defined by a fraction of the hydrogen demand that can be met using waste and biomass. The hydrogen production technologies considered in the study are SMR, biomass gasification and electrolysis. However, they assumed that NG, electricity, and water are available in unlimited amounts.

Most of the models presented in literature don't address the feedstock probably; the availability, storage, and transportation of the feedstock, especially, when it comes to water electrolysis and biomass gasification. Only [22] and [20] considered the cost of processing water.

1.2.2 Production Technologies

The current existing method of producing hydrogen is highly emissive. In 2019, hydrogen production – at 95 per cent through steam methane reforming (SMR) and autothermal reforming (ATR) and through coal gasification – caused emissions for about 830 MtCO2 at global level, amounting to 2.5 per cent of global emissions [23]. Currently, increasing the cost of hydrogen production through available channels from a range of 0.5-1.6 US dollars/kgH2 to a range of 2-8.4 US dollars/kgH2 makes it uncompetitive with current alternatives, as shown in Table 1. It would take a very high carbon price for hydrogen to start competing in the end markets at the clean hydrogen production prices projected for 2030 [24]. While lower estimates already see a potential cost-competitiveness at between 100 and 200 euro/tCO2, while 100 euro/tCO2 would be sufficient for blue hydrogen to be cost-competitive with grey hydrogen assuming a 75 percent carbon capture rate, higher estimates would require a carbon price of 300 euro/tCO2 to make green hydrogen more convenient than gas-based hydrogen. However, carbon prices in the 50–60 euro/tCO2 range would be adequate to enable the competitive manufacture of hydrogen-based steel, dispatchable power, and virtually sufficient to generate green ammonia if clean hydrogen production is reduced to 1 US dollar/kgH2, as some estimates anticipate for 2050 [25].

	Classification	Energy feedstock	Process	Waste product/KgH2	Technology readiness level (TRL)	Cost $/KgH2 (33.6 kWhH2)			Input KgH2 (33.6 kWhH2)
						2020	2030	2050	
Emissive hydrogen	Yellow	Grid electricity	Water electrolysis	< 38 kgCO2 depending on power mix	9	N/A	N/A	N/A	50-55 Kwhe & 9.1 l water
	Black	Black coal	Coal gasification	18-20 kgCO2	9	0.95-1.90	N/A	N/A	7.5 kg coal
	Brown	Lignite			9				
	Grey	Natural gas	Steam methane reforming (SMR) / Autothermal reforming (ATR)	6-9 kg CO2	9	1 - 2.4	N/A	N/A	3.8-4.5 m3 gas & 5.7 kWhe & 4.45 l water
Clean hydrogen	Blue		SMR/ATR + carbon capture and storage (CCS)		8	02-May	1.04-3.5	0.74-2.96	

	Turquoise		Methane pyrolysis	3 kg solid carbon	6	N/A	N/A	N/A	5.54 kWh gas & 5 KWhe
	Red	Biomass, waste	(Several processes)	N/A	5	N/A	N/A	N/A	
	Green	RES generated electricity	Water electrolysis	-	6-9 depending on the electrolyzer technology used	2.5-8	1.06-6.42	0.52-4.06	50-55 kWhe & 9.11 water
	Pink/purple	Nuclear generated electricity				N/A	N/A	N/A	
	White	N/A	Byproduct of industrial processes	N/A	N/A	N/A	N/A	N/A	N/A

Table 2: Hydrogen production taxonomy [26],[23],[27],[28].

1.2.2.1 Water splitting

Green hydrogen is produced using renewable resources such as wind, solar and hydro. This can be done using the electricity generated by these resources by means of splitting water process. The inputs to such a process (Eq.1) are electricity and stream of pure water, giving us two outputs: pure stream of hydrogen and oxygen.

$$H_2O_{(l)} + electrcity \;\rightarrow\; H_{2(g)} \;+\; \frac{1}{2}\,O_{2\,(g)} \qquad \Delta\, H^0_{reaction} \;=\; +285.8\;\; \frac{kJ}{mol} \qquad \text{(Eq. 1)}$$

In this section, the state-of-the-art technologies are discussed from techno-economic point of view based on literature review.

Currently, four different types of electrolyzers technologies are available in the market:

- Proton Exchange Membrane Electrolyzer Cell (PEMEC).
- Alkaline Electrolyzer Cell (AEC)
- Solid Oxide Electrolyzer Cell (SOEC)
- Anion Exchange Membrane Electrolyzer Cell (AEMEC).

1.2.2.1.1 Alkaline Electrolyzer Cell (AEC)

Alkaline Electrolyzer Cell is considered a reliable and mature option in the market. An alkaline solution is used as the electrolyte (KOH or NAOH) [23], [26], while, typically, Nickel based metals are used as the electrodes for alkaline water electrolysis. In AEC, an aqueous alkaline solution (KOH or NaOH) is used as an electrolyte. AEC works either atmospherically or under elevated pressure. According to Smolinka et al. [27], pressurized alkaline electrolyzers have a lower efficiency and produce a lower purity product than atmospheric AEC. The foremost advantage of pressurized AEC compared to atmospheric AEC is that it produces compressed hydrogen (either for grid injection or further use) with less additional energy input [28]. This is a result of the fact that the reduction in electric efficiency of the electrolysis with increased pressure is lower than the energy needed to compress the produced hydrogen.

Regarding the lifetime of AEC, it is ranging from 60000 to 90000 hours and it has been commercially available in the industry for the last 100 years [29]. However, Alkaline technology has a lower flexibility and a limit in the operating range: it can go from 10% load to full capacity [26]. Moreover, being a reliable and consolidate technology, it has lower CAPEX and OPEX compared to other technologies such as PEMEC [26].

As a technology, it dominates the market with a 60 % share of global manufacturing capacity, reflecting an advanced maturity stage [22]. In fact, the Technology Readiness level (TRL) for AEC is 9 [23]. By 2030, it is expected to reach 64% of the manufacturing capacity compared to 22% and 4% for PEM and SOEC, respectively [22].

1.2.2.1.2 Proton Exchange Membrane Electrolyzer Cell (PEMEC)

The PEMEC was first brought to the market by General Electric to overcome some of the problems of AEC such as limited operating range in the 1960s [23]. Compared with Alkaline Electrolyzers, they have higher flexibility and better coupling with dynamic systems. Moreover, they have very fast response as it takes around 5 minutes to make a cold start whereas the normal response is within 1 second. On the other hand, for AEC, cold start takes around twice the time [26].

Their operating load range goes from 0 to 160 % of the nominal load of the nominal capacity, hence, gives the ability to overload the system from time to time. Also, they are characterized by a high compressed hydrogen at about, ranging from 30 to 80 bars.

1.2.2.1.3 Solid Oxide Electrolyzer Cell (SOEC)

SOECs are the least developed and most recent technology among water electrolyzers. They are at the demonstration stage; however, some individual companies are trying to bring it to the market. They are characterized by high operating temperature and high electrical efficiency around 81 % as shown in **Error! Reference source not found.**. As they use steam for electrolysis, they need a heat source. Hence, they can be coupled with systems that produce waste heat such as methanation and Fischer-Tropsch synthesis. Other plants such as geothermal, nuclear, and solar can be used to provide the heat source for high temperature electrolysis. Moreover, the CAPEX of this technology is higher compared to AEC and PEMEC, however, they require low-cost materials and ceramics are used as electrolyte. While PEMECs use a great amount of platinum for their catalyst layers.

Furthermore, it has the advantage of being used in a reverse mode, meaning that it can work as a fuel cell converting the hydrogen back into electricity. This could be very beneficial in providing balancing services to the grid in combination with storage facilities. One challenge facing this technology is the required operation at high temperature resulting in higher material degradation.

1.2.2.1.4 Anion Exchange Membrane Cell (AEMC)

When it comes to low temperature electrolyzer cell, there is Anion Exchange Membrane Electrolysis. This technology is still at earlier stage of development with TRL of 6 - the lower among other technologies-, but it is evolving rapidly; Alchemr and Enapter which are two companies for developing of electrolyzers have prototypes at kW scales available [30].

Their structure is similar to PEMEC with a main difference that in the electrolyte ions OH^- are transferred instead of protons H^+. However, they have an advantage that they utilize non-noble metal at the electrodes and non-corrosive electrolyte. These two features enable lower costs and absence of leakage from the cell with the production of high pressure hydrogen [31]. However, the main drawbacks are connected to the membrane degradation issue, which affects durability. Furthermore, efforts on increasing current density and reducing the excessive catalyst loading are investigated by R&D. Table 2 summarizes the main techno-economic parameters of this technology.

Technology		AEC		PEMEC		SOEC		AEMEC	
	Unit	2019	2030	2019	2030	2019	2030	2019	2030
Efficiency (LHV)	%	63 – 70	65 – 71	56 – 60	63–68	74–81	77 – 84	40	
Load range	% of nominal load	10 – 110		0 – 160		20 – 100			
Output pressure	Bar	1-30		30-80		1		30	
OPEX	% of initial CAPEX/year	2%	2%	2%	2%	2%	2%		
CAPEX (total system cost)	USD/kW$_e$	500 – 1400	400 – 850	1100 – 1800	650 – 1500	2800 – 5600	800 – 2800		
Lifetime stack	Operating hours	60000-90000	90000 – 100000	30000-90000	60000-90000	10000 – 30000	40000 - 60000	60000-90000 h	

Maturity level	Technology Readiness level (TRL)	9	9	7	6

Table 3: Techno-economic characteristics of different electrolyzers technologies [20], [21], [22].

1.2.2.2 Natural gas to hydrogen

Nowadays, over 95% of hydrogen production comes from fossil fuels [26]. Generally, there are 3 different ways to generate hydrogen from NG [25]:

- Steam reforming using water and a source of hydrogen.
- Partial oxidation using oxygen in the air.
- Autothermal reforming (ATR).

1.2.2.2.1 Steam Methane Reforming (SMR)

SMR is a process in which natural gas is converted to syngas (mixture of hydrogen and carbon monoxide) in a reformer and then to higher purity hydrogen, it is shifted into a hydrogen-rich mixture by water gas shift reactor. This process comes with CO_2 emissions, roughly 60% from NG oxidization and water gas shift (WGS) which can be captured using carbon capture and storage technologies (CCUS). In total, 90% capture can be achieved in a coupled SMR system with limited energy loss [30].

1.2.2.2.2 Partial Oxidation

Partial oxidation (PO) is a way to convert liquid or gaseous fuel into hydrogen without a catalyst. However, can also be used, with a consequent increase in hydrogen production. It is a mildly exothermic process; hence it can be coupled with an endothermic process (e.g., Steam reforming) to increase efficiency. In general, PO has lower efficiency than SR, but it has the advantage of being able to convert a wider range of raw materials, rather than relying on light hydrocarbon [29].

1.2.2.2.3 Autothermal Reforming

Autothermal reforming is another technology to generate hydrogen in which all the process happens in one reactor, allowing for higher CO2 capture rate than SMR [23].

Also, the capture process has lower cost as the emissions are more concentrated. This means higher capture rates for ATR with lower costs than SMR.

Regarding the cost of hydrogen production using SMR technologies, it depends on various technical and economic factors, gas prices and capital expenditures are the most important [23]. Fuel costs account for around 45% and 75% depending on the region. Adding CCUS technology to SMR increases the CAPEX by 50% on average and around 10% for the fuel. However, in most regions, the cost of hydrogen from NG with CCUS is USD 1.5 – 3/kg H_2 [30].

1.2.2.3 Coal Gasification (CG)

Coal gasification (CG) is widely used to generate hydrogen for production of ammonia and methanol that can be used by the chemical and fertilizer industries, especially in China and Australia. In order to have low-carbon hydrogen production from coal, CCUS technologies are used, but this comes with some challenges : the hydrogen to carbon ratio from coal gasification is 0.1 : 1 while it is 4 : 1 from methane which makes coal as a feedstock with a high level of impurities [32].

The purity of hydrogen required depends on the end-use. The syngas produced from CG can be sufficient to be used for gas turbines, industrial boilers, and refinery processes. If the end-use is fuel cells for example, a second phase (water-gas shift) can be introduced to increase the ratio a bit more.

Regarding the costs of hydrogen generation from CG, CAPEX accounts for 50% of the production cost while fuel accounts for 15-20%. However, the availability of coal plays an important role in determining the viability of the CG hydrogen production projects. Moreover, adding CCUS technology to CG plants to reduce the carbon foot-print increases the CAPEX by 5% and OPEX by 130% [23].

1.2.2.4 Biomass Gasification (BG)

Hydrogen can also be produced in a renewable way from biomass as a feedstock taking into consideration that there is sufficient and sustainable biomass potential. However, the technology is not fully mature, achieving TRL of 6 [33] and there is the problem of tar formation that can poison the catalyst. The cost of hydrogen production from biomass gasification (BG) lies between SMR and electrolysis, but this could change if production is done in a decentralized way [29].

In addition, coupling hydrogen production from biomass and CCUS could be a way to create the so-called negative emissions pathway which may have a role in the future as it gives the possibility to remove CO2 from the atmosphere and generate energy at the same time.

1.3 Hydrogen utilization pathways

Once produced, hydrogen can be destined for different uses. It can be stored as an energy carrier and then reconverted into water, releasing electricity when necessary. It can be used directly as an energy carrier (e.g. transport sector) or for industrial purposes (e.g. steel production).

Otherwise, it can be used as an input for more complex compounds, like synthetic methane or liquid synthetic fuels.

1.3.1 Hydrogen to gas

This route involves the creation of a gaseous energy carrier, primarily synthetic methane, which can significantly accelerate the energy system's conversion. The advantages of producing synthetic methane come from the cost reductions from already-existing infrastructures (e.g., transmission line, storage tanks etc.).

Additionally, the grid's current heat/power systems (such as boilers, gas turbines, etc.) can continue to be used while the research and development of these technologies creates machinery capable of handling input flows with increasing H2 concentration.

CO2 (or CO) and H2 can be used in a chemical reaction to create synthetic methane. The reaction is known as CO2 hydrogenation (Eq.) or CO hydrogenation (Eq.), depending on whether carbon dioxide or monoxide is utilized.

$$CO_{2(g)} + 4H_{2(g)} \rightarrow CH_{4(g)} + 2H_2O_{(g)} \qquad \Delta H^0_{reaction} = -165.1\ \frac{kJ}{mol}$$

$$CO_{(g)} + 3H_{2(g)} \rightarrow CH_{4(g)} + H_2O_{(g)} \qquad \Delta H^0_{reaction} = -206.3\ \frac{kJ}{mol}$$

These reactions go under the name of the methanation process, which will be analyzed in the following sections.

1.3.1.1 Catalytic thermochemical methanation

To date, the main application of the methanation process rely mostly on catalytic thermochemical methanation [23]. The main inputs-outputs are presented Figure 4.

For CO2, the provided input can be also a biogas stream (CH4 and CO2), where carbon dioxide will be the only reactant while methane will behave as an inert [34]. Methanation's exothermic reaction can produce heat through an ORC that is suited for minor power generation, or it can be recovered to maintain reaction operating conditions or meet external heat demands.

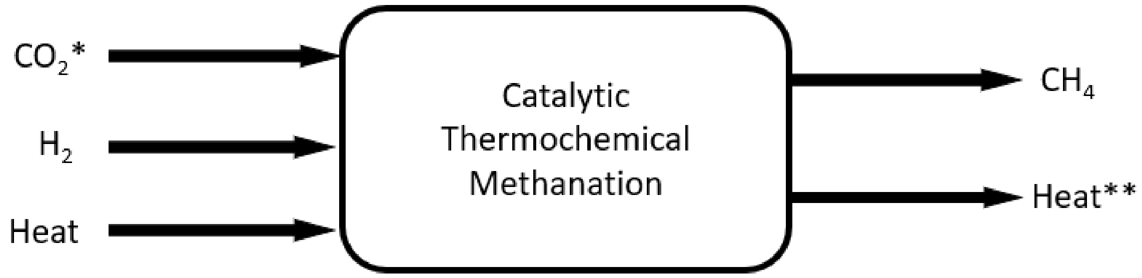

Figure 4 : Scheme of the input and output flows in a catalytic methanation plant.

It is not the only process that can be used; biological methanation can also be used. However, this second solution is still in its early stages of development. More information will be provided in the following Section.

Thermochemical reactors typically operate at temperatures ranging from 200°C to 550°C, with operating pressures ranging from 1 to 100 bar. Several metals, such as Ni, Ru, Rh, and Co, are suitable as catalysts in the process. However, nickel is the best trade-off between activity, good CH4 selectivity, and low material price. The main disadvantage of this catalyst is the high purity requirement for the feed gas in terms of sulphurous compounds[35], [36]. This would require some purification process before the injection in the reactor.

The process is highly exothermic, so there is the possibility to recover some of the heat (i.e., using for steam production in SOECs, for power generation through Organic Rankine Cycle or for district heating) [23].

1.3.1.2 Biological methanation

Biological methanation shown in Figure 5 is another solution for the Hydrogen to Gas, although less developed. There is no metal utilization as catalyst because this function is provided by methanogenic microorganisms [35], [36]. They operate in an anaerobic environment in which they convert the input hydrogen and carbon dioxide into methane [23], [35].

The process runs at ambient pressure at substantially lower temperatures (between 20 and 70 C) than catalytic methanation.

The input feedstock, which is primarily solid biomass, must be processed and gasified prior to the synthesis of methane. This calls for a biogas digester, an intermediary reactor where the organic substrate is hydrolyzed, separated into simple monomers, and then converted into biogas, primarily made up of CH4 and CO2 [35], [36], [37].

This technology has lower overall efficiency compared to the catalytic one. Thus, due to lower rates of CH4 formation, the larger reactors' requirement makes this pathway more suitable for small-sized plants[36].

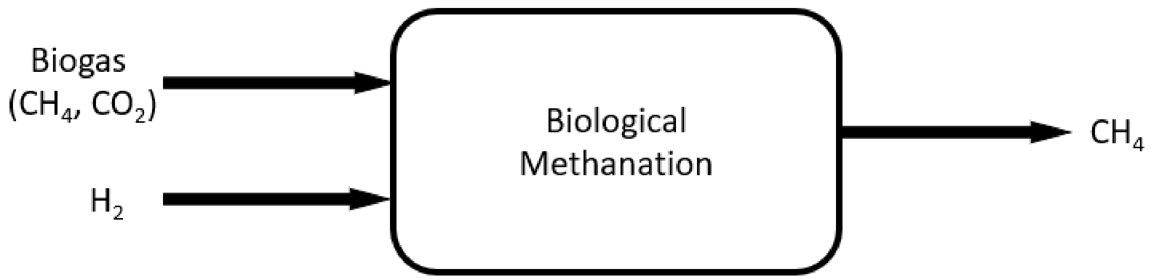

Figure 5: the input and output flows in a biological methanation plant

Biological methanation can occur in two different configurations:

- In this P2G method, hydrogen is delivered directly to the biogas digester through biological methanation in situ. Here, some of the carbon dioxide created by the gasification of biomass is changed into CH4. However, the ideal configuration (elevated T and p) to improve CO2 conversion cannot be adjusted to the digester's operating conditions. As a result, it is challenging to convert all of the CO2. Limited hydrogen conversion occurs in the system as a result of the low solubility of hydrogen in the digestate, resulting in a residual hydrogen concentration of 20% vol in the product gas [35].
  At the output there will be a stream mainly composed of methane, but with a small residue of hydrogen and carbon dioxide.
- Ex situ biological methanation or methanation in a separate reactor; the primary distinction from the prior instance is the presence of a separate methanation reactor, following the biogas digester. Here, a hydrogen stream

and biogas are injected into the reactor, where methanogenic bacteria transform the gases into methane.

In comparison to the In situ design, this configuration enables the setting of conditions that are best for hydrogenotrophic methanogens, increasing the CH_4 content in the output stream [35].

The cost of the second reactor, which was saved in the prior configuration, is the biggest disadvantage.

As was previously demonstrated, the biological and catalytic thermochemical methanation can replace that biogas upgrading facility while also directly reusing the byproduct CO_2. They could be considered as viable options when a new biogas processing facility needs to be constructed.

To inject a stream of pure methane into the gas grid, a typical biogas upgrading plant filters the raw biogas that exits a digester. To meet the technical requirements of the grid, CO_2 and other contaminants (such as water moisture, particulates, ammonia NH_3, or hydrogen sulfide H_2S) must be eliminated [38].

According to a research by the Swiss Federal Office of Energy, it will be possible to convert these upgrading facilities into ones that use direct methanation due to advancements in technology and falling costs [34].

1.3.2 Hydrogen to power

The proposed method for using hydrogen is to convert it back into power using a fuel cell (FC) or a turbine.

In terms of the first solution, the reaction is the opposite of that which takes place in the electrolyte, where the splitting of the water molecule into hydrogen and oxygen uses electricity. The equation shown below gives an overview of how FC technology has been received. Here, a pair of reduction and oxidation reactions combine with an oxidizing agent (usually oxygen) to transform the chemical energy of H_2 back into electrical energy, see Figure 6.

$$H_2 + \frac{1}{2} O_2 \rightarrow\ H_2O + electricity$$

Without any direct emissions, fuel cells generate energy, heat, and water. They have partial load efficiency that is higher than full load efficiency, and they can achieve electric efficiencies of over 60% (LHV-based) [23]. This is a particularly appealing quality, particularly with flexible power systems.

The primary FC technologies for stationary applications are described here. For information on each technology's primary technical specifications, please see **Error! Reference source not found.**.

1.3.2.1 Alkaline Fuel Cell (AFC)

The oldest fuel cell technology is the alkaline fuel cell, which is being developed for space purposes. It is a low temperature FC (60-90C) with the primary benefit of using inexpensive catalyst materials (base metals) [29].

Its input streams are contaminated by carbon dioxide, therefore only pure oxygen may be supplied. Compared to the technologies that are provided below, it is less durable and has a lower output power capacity.

As a result of its aptitude for producing electricity from ammonia, this technology has more recently gained public attention. As alternatives to the present diesel-based off-grid generators, they exhibit fascinating properties when coupled with a cracker to turn ammonia back into hydrogen.

Off-grid ammonia AFCs are replacing current diesel generators in operational trial projects in Kenya and South Africa [23]

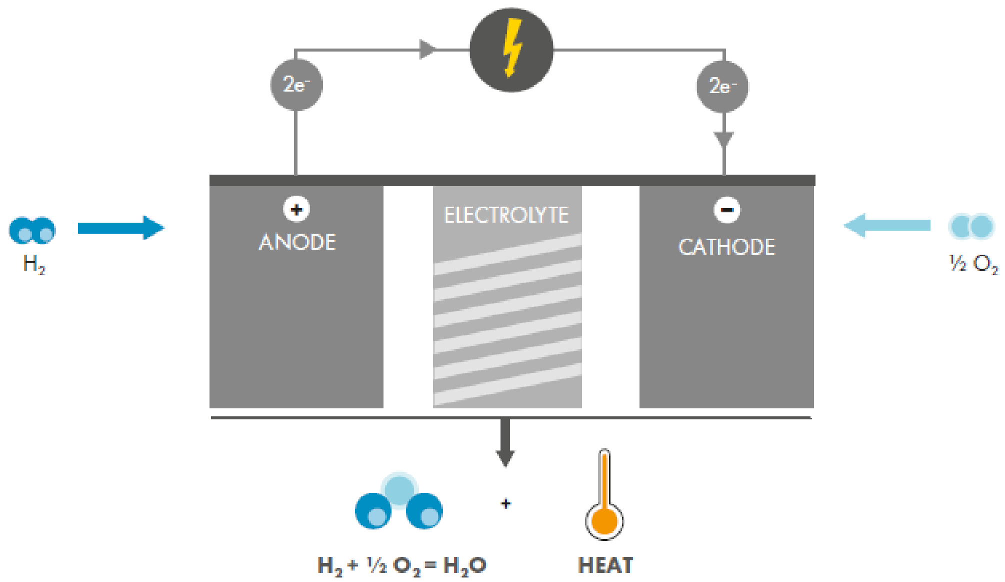

Figure 6: the chemical reactions occurring in a general fuel cell [29].

1.3.2.2 Polymer Electrolyte Membrane Fuel Cell (PEMFC)

PEMFC is a low temperature fuel cell that starts up quickly and operates in the T-range of 80 to 100C. Regarding the PEMEC, platinum is mostly employed as a catalyst, which raises the cost of construction [23], [29].

A stream of pure hydrogen must be provided as input. Although this technology is currently the most widely utilized in the world, interest in the Solid Oxide FCs detailed below is growing [29].

1.3.2.3 Phosphoric Acid Fuel Cell (PAFC)

This technology has power outputs between 100 and 400 kW and operates in the medium temperature range (160 to 220C) [23], [29] .

The PEMFC's ability to produce heat (at roughly 180C), which might be utilized for district heating, is their principal distinction. In spite of the comparatively low electrical efficiency (LHV) of 40%, they would achieve greater overall efficiencies of roughly 80% [23], [29]with heat recovery.

They are less appropriate for small output ranges because of their high material requirements (e.g mobility sector). Instead, they are primarily dispersed as substantial stationary applications [29].

1.3.2.4 Molten Carbonate Fuel Cell (MCFC)

Since MCFCs run at higher temperatures (600–700C), there is no need for an external reformer to convert the hydrocarbon fuel (such as syngas, MeOH), which can be derived directly inside the fuel cell, into H2 [23].

All FC technologies that function at high temperatures are distinguished by this benefit (like the solid oxide FCs presented below). They have a high electrical efficiency (about 55–60%) and the potential to boost overall efficiency (up to 85%) by recovering and using HT waste heat for extra electricity generation [29].Buildings may also use the recovered heat for district heating. For the MW scale, molten carbonate FCs are employed to produce energy.

1.3.2.5 Solid Oxide Fuel Cell (SOFC)

Solid oxide fuel cells, which are currently the second-most significant FC type after PEMFC, exhibit various properties that cause a day by day developing interest in the power generating sector.

They can internally reform hydrocarbon fuels like MCFCs while operating in the high temperature range of 800–1000C [23], [29].

The main disadvantage of working in high-temperature environments is the need for suitable resistant materials and a lengthy startup period.

However, similar to MCFCs, they have excellent electrical efficiency (about 60%) with the ability to collect heat for district heating or a later step in the power generating process [29].

They are used in power generation fields, frequently on a lower scale in the kW range (e.g. micro co-generation, off-grid power supply) but with increasing output capacity size [23].

Error! Reference source not found. below reports the main characteristics of the most diffused and the most promising FC technologies.

1.3.2.6 Hydrogen turbines

A new technology that is ideal for producing electricity on a wider scale is the hydrogen turbine. It has been established that it is technically possible to burn up to 100% hydrogen in a gas turbine (GT).

High temperatures are nevertheless attained in the combustion chamber as a result of its high flammability and flame velocity, with material resistance issues and NOx emissions [23],[39],[40].

A groundbreaking experiment in Japan has completed the first-ever transmission of energy and heat utilizing a gas turbine that is powered exclusively by hydrogen. A district of Kobe city received 1.1 MW of power and 2.8 MW of heat from a 1.1 MW hydrogen GT that was put in a cogeneration system [40].

In order to combat the issue of NOx emissions, an Italian project has successfully created a prototype of a GT burner powered entirely by hydrogen [39].

In terms of gas fuel-based GTs, exhaust gas recirculation is seen to be a potential option to lower nitrogen oxide production and combustion chamber temperature.

Technology	Temperature [°C]	Output capacity	Fuel	Oxidant	Efficiency (LHV H2)	Lifetime	Market development
AEC	60-90	up to 250 kW	H_2	pure O_2	50-60%	5,000 - 8,000	Mature (space applications)
PEMFC	50-90 (LT)	Up to 400 kW	H_2, gas, biogas, syngas, MeOH	O_2	30-60%	60,000 (stationary)	Mature
PAFC	160-220	Up to several 10 MW	H_2, gas, biogas, syngas, MeOH	O_3	30-40%	4,000 - 5,000	Mature
MCFC	600-700	Up to several MW	H_2, gas, biogas, syngas, MeOH	O_4	55-60%	4,000 - 6,000	Early market
SOFC	700-1000	Up to several MW	H_2, gas, biogas, syngas, MeOH	O_5	50-70%	3,000 - 4,000	Mature (volumes rising)

Table 4: different fuel cell technologies characteristics [31].

Another pilot project was carried out in the Italian energy sector in 2010: the Italian energy provider ENEL promoted the construction of a cutting-edge combined cycle hydrogen power plant at Fusina (Venice) [41]. An adjacent coal-fired plant received high-temperature steam from it at a 12 MW output.

The project was completed successfully. The situation was altered in 2018 when the power facility was shut down [42]. Coal gasification and a carbon capture system in the power plant of the nearby Porto Marghera provided the hydrogen supply.

More recently, South Australian government started a pilot project in Port Lincoln. The hydrogen power plant is composed of a 15 MW Alkaline electrolyzer, coupled with a 10 MW pure hydrogen GT and a 5 MW fuel cell [40].

1.4 Storage, transmission, and distribution

1.4.1 Hydrogen storage

Nowadays, hydrogen is mostly stored and delivered in a liquid or compressed way. Globally, most of it is generated and consumed on-site (around 85%) and the other 15% is transported via trucks or pipelines [23]. For hydrogen to play an important role in the future solving the problem of intermittency of renewables, storage options should be used, especially for large-scale operation and the intercontinental hydrogen value chain. Hence, it will accommodate production plant outages and demand fluctuations. However, the type of storage depends on storage duration, volume, the required discharge speed, and geographical availability of different options. Three different levels of storage in the hydrogen supply chain (HSC) can be identified in (Table 5).

Storage level	Main purpose	Equipment or facility	Installation place
Station level	Accommodate daily demand fluctuation	Cascade filling system	Refueling stations
Terminal level	Provide extra capacity in case of facility shutdown	Compressed gas storage /bulk liquid storage	Terminal or production plant
Network level	Accommodate seasonal demand fluctuation	Gaseous hydrogen Geological storage	pipeline network

Table 5: Hydrogen storage levels [10].

Currently, salt caverns, aquifers and depleted oil and natural gas reservoirs are used to store natural gas with significant economies of scale, low operational costs, and high efficiency. They could be all possible and cheap options for long-term hydrogen storage even though hydrogen may be difficult to store due to its lower viscosity, diffusivity and higher compressibility factor compared to other gaseous fuels [43], [44].

Since the 1970s, Salt caverns have been used by the chemical industry. They generally have low risk of contaminating the hydrogen, high efficiency of about 98% and cost less than 0.6/kgH_2 (H_{21},2018, [45], [46]). The United States has the largest salt caverns in operation to store hydrogen. It can store up to 30 days of hydrogen which comes from SMR to supply chemical and petrochemical industries.

There exist demonstration projects and first-of-a kind commercial facilities [22] demonstrating the viability of hydrogen storage in salt caverns. For instance, in Germany in 2021, EWE within the HyCAVmobil research project started leaching a salt cavern with a budget of nearly 10 million EUR. The HyPSTER project (Storengy) in France aims to demonstrate large-scale storage of hydrogen from electrolysis, including fast cycling, with a budget of EUR 13 million and a capacity of 0.1 GWh, with tests planned to start in 2023.

Moreover, depleted gas/oil fields could be used to store hydrogen as they are larger in volume than salt caverns and more widespread. However, there are some challenges that need to be overcome. Because of their porous natural, they operate only with a few cycles per year and are not suitable for large short-term flexibility. Also, they contain containments that would have to be removed before using hydrogen. Water aquifer is among the available underground options to store hydrogen, but it is the least mature one.

These options seem to be very good for long-term hydrogen storage, but further research is needed to evaluate storage tightness that van be compromised by the characteristics of hydrogen, in site bacteria reactions in aquifers and depleted gas fields that may yield hydrogen losses. As shown in

	Salt caverns	Depleted gas field	Aquifer	Lined hard rock cavern
Specific investment	Medium	Low	Low	High
Levelized cost of storage	Low	Medium	Medium	Medium

Cushion gas	25 -35%	45-60%	50-70%	10-20%
Capacity	Medium	Large	Large	Small
Annual cycles	Multiple	Few	Few	Multiple
Geographic availability	Limited	Variable	Variable	Abundant
TRL	10	4	3	5

Table 6, the characteristics of those options are represented with lined hard rock cavern included.

	Salt caverns	**Depleted gas field**	**Aquifer**	**Lined hard rock cavern**
Specific investment	Medium	Low	Low	High
Levelized cost of storage	Low	Medium	Medium	Medium
Cushion gas	25 -35%	45-60%	50-70%	10-20%
Capacity	Medium	Large	Large	Small
Annual cycles	Multiple	Few	Few	Multiple
Geographic availability	Limited	Variable	Variable	Abundant
TRL	10	4	3	5

Table 6: Features of hydrogen underground storage technologies [22].

Although geological storage has the best chances for long-term, large-scale storage, it is significantly less ideal for short-term, smaller-scale storage due to the geographical dispersal, enormous size, and minimum pressure requirements of locations. Tanks offer the best chance of success for these applications.

Here where storage tanks come into the picture, as they are very suitable for such purposes. These tanks, whether they store hydrogen in liquified or gaseous way, have high efficiencies with high discharge rates.

1.4.2 Hydrogen transmission and distribution

Hydrogen could be transported as a compressed or liquified fluid or by incorporating hydrogen into larger molecules, i.e., as a liquid organic hydrogen carrier (LOHC) and transported as a liquid. Liquified hydrogen can be transported using tankers via railways, ships, or roads whereas gaseous hydrogen can be conveyed via railway tube cars, tube trailers or high-pressure pipelines. However, developing this infrastructure is challenging because hydrogen has low energy density (one cubic meter of hydrogen contains a third of the energy of the same volume of natural gas at the same pressure and temperature) and low boiling point (-253 degrees Celsius (°C)). Each single solution has advantages and disadvantages and the cheapest one will depend on geography, scale, distance and end-use. This section will discuss some of these opportunities.

One of the available options is blending hydrogen with natural gas in already existing networks. This would avoid the significant capital costs related to developing new infrastructure for hydrogen transmission. There are around 3 million kilometers of natural gas network around the world and 400 billion cubic meter of underground storage [23]. If some of these networks were used for hydrogen transportation, that would give a huge boost for hydrogen economy. However, some challenges related to how much hydrogen could be injected into the NG grid need to be faced. Determining this percentage will depend on the least tolerant component of the grid and what the end-use is, as indicated in Figure 7. Overall, blending hydrogen with natural gas will increase the costs sightly by around 0.3 USD/kgH_2 to 0.4 USD/kgH_2, on top of the costs of the hydrogen production[47].

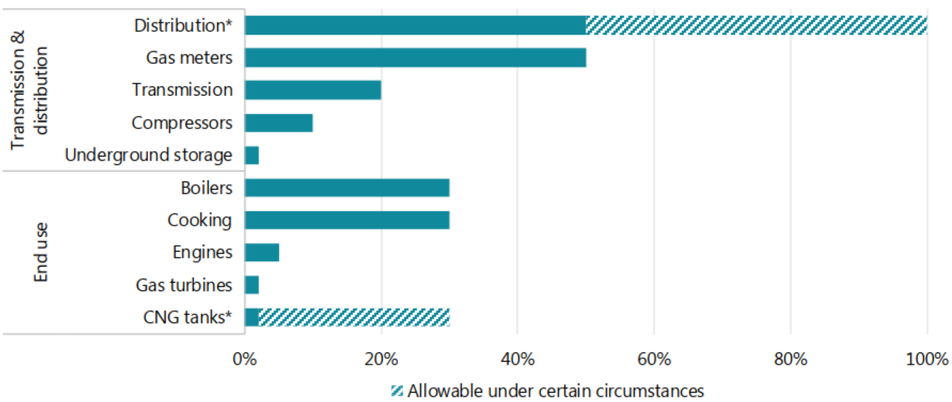

Figure 7: Tolerance of selected existing elements of the natural gas network to hydrogen blend by volume [20].

Repurposing gas networks

Another option is repurposing existing gas networks to 100 % hydrogen, but the practical experience is very limited. This alternative could be realized by repurposing natural gas pipelines that became redundant due to the decline in natural gas demand to minimize stranded assets. There is only one example of 12 km pipeline in Netherland which transports around 4 kt H_2/year that is a by-product [30]. Moreover, the European Hydrogen Backbone, covering 28 countries in EU, represents a pledge of establishing a dedicated hydrogen network by 2030 to connect local supply and demand and progressively connecting EU and neighboring regions [48]. By 2030, a 28 000 km network of low hydrogen supply could be established to connect ports, regions, and emerging hydrogen clusters[1]. By 2040, the network could be extended to reach 53000 km of pipelines of which 40% are new pipeline and 60% are repurposed natural gas network.

Many planned projects have been established for repurposing natural gas networks in countries such Germany, Italy, and United Kingdom. For instance, In Italy, Snam has stated the compatibility of its existing natural gas network to accommodate 100% hydrogen, 70% of it with no or limited pressure drop. By 2030, they are intending to invest EUR 3 billion to connect Sicily with North-Italy through 2700 km of pipelines [49].

Alternative options (Ammonia and LOHC)

While compressed or liquified hydrogen can be economically feasible solutions for certain sectors such as mobility, they are not the best solution for other sectors due to low energy density for compressed hydrogen and the reduction of energy content and boil-off losses for liquid hydrogen. Using other alternatives such as ammonia and liquid organic hydrogen carriers (LOHC) could offer certain advantages over compressed and liquified hydrogen. Converting hydrogen to ammonia can provide the added advantages of storage and transportation compared to liquid hydrogen. However, this process requires from 7% to 18% of the energy contained in hydrogen, depending on the location and capacity of the system [50],[51]. Around the same amount of energy is required to reconvert ammonia to pure-hydrogen [52]. Nevertheless, ammonia contains 1.7 times more hydrogen than liquid hydrogen and liquifies at -33.34 °C, as shown in Table 7.

---

[1] Hydrogen cluster is a network of hydrogen suppliers and could include RE production, potential users, and the necessary infrastructure to connect both two.

However, in order to use ammonia as a hydrogen carrier, the round-trip efficiency must be considered evaluating also the ammonia cracking losses. S. Giddy et. al [52] performed an analysis for different ammonia utilization routes and calculated the round-trip efficiency. The best-case scenario for residential applications, SOFC and PEMFC produce round trip efficiency (RTE) of 50% (CHP) and 39% (CHP), respectively. Regarding the automotive sector, IC engines and PEMFC produce the best RTE of 21% and 19%, respectively. Considering the cost, the production of ammonia is more expensive than hydrogen itself due to the additional process and capital requirement for production. Moreover, the cost of ammonia will be determined by the cost of hydrogen, for example, if hydrogen was produced from CG, SMR, or electrolysis. Nevertheless, if hydrogen needs to be transported, the additional cost makes ammonia cheaper than hydrogen by 0.88 \$/kg-H_2 [50].

Another alternative is liquid organic hydrogen carriers (LOHC) which can be used for long distances H_2 delivery. They are liquids or low melting solids that can be reversibly hydrogenated and dehydrogenated at high temperature with the presence of a catalyst. Clear benefits of the LOHC are compatibility with the existing infrastructure, release of high purity hydrogen and storing hydrogen without losses even in the long-term or when transported overseas as they can be transported as liquids without the need for cooling. Using LOHC will result in reduction in the final cost incurred by the transporter and final user. However, just like ammonia, the process needs an energy between 35% and 40% of the hydrogen itself [53]. Moreover, they could be reused again requiring further cost reduction.

There are a wide range of LOHCs, most of the current projects and research are focused on toluene ($C_6H_5CH_3$) which, when loaded with hydrogen transforms into methylcyclohexane (MCH) (CH3C6H11) that can be used for storing and transporting hydrogen. It has been favored by the industrial and research communities as it is relatively low-cost option and the high boiling point as shown in Table 7. Almost 22 Mt of toluene is currently annually produced which can carry 1.4 MtH_2 and costs around 400-900 USD per tonne [23].

Key characteristics	Liquified hydrogen	Ammonia	LOHC (MCH)
Melting point (°C)	-259.16	-77.73	-126.3
Boiling point (°C)	-252.87	-33.34	101
Volumetric energy density (Wh/L)	8.49	12.92-14.4	5.66

Volumetric H2 content (kgH_2/m3)	70.8	107.7-120	47.1
Supply chain integration	Medium/high[2]	High	Medium
Transport	Ship: Low Pipeline: High Truck: High	Ship: High Pipeline: High Truck: High	Ship: High Pipeline: High Truck: High
Gravimetric energy density (MJ/kg)	120	21.18-22.5	7.35
Gravimetric H2 content (wt.%)	100	17.65	6.1
Conversion and reconversion[3] energy required	Current: 25–35% Potential: 18%	Conversion: 7–18% Reconversion: < 20%	Current: 35–40% Potential: 25%
Technology improvements and scale-up needs	Production plant efficiency; boil-off management	Integration with flexible electrolyzers; improved conversion efficiency; H2 purification	Utilization of conversion heat; reconversion efficiency
Maturity level	9	11	11

Table 7: Comparison between different potential hydrogen carriers [23],[51], [54].

Total cost of delivering and storing

The total cost of hydrogen delivery should consider all the stages included in the supply chain as with different carriers and routes, there are different conversion, transmission distribution and storage costs. Moreover, it will vary according to the existing infrastructure available in the importing and exporting countries, modes of transportation, distance and end-use. According to IEA [23], for inland transmission below 3500 km, using hydrogen gas pipelines is cheaper option, while above this distance, ammonia would be cheaper. Regarding overseas transport using ships,

[2] High: commercial and proven; Medium: demonstrated prototype; Low: under-development or validated.

[3] Calculated as a percentage of the LHV of hydrogen, these value are for H_2 that can be used in fuel cells.

ammonia and LOHCs are the best options. Comparing using pipelines or ships, below 1500 km pipeline is the cheaper option. Above this, transporting ammonia and LOHC by ships become the cheaper available option, see Figure 8.

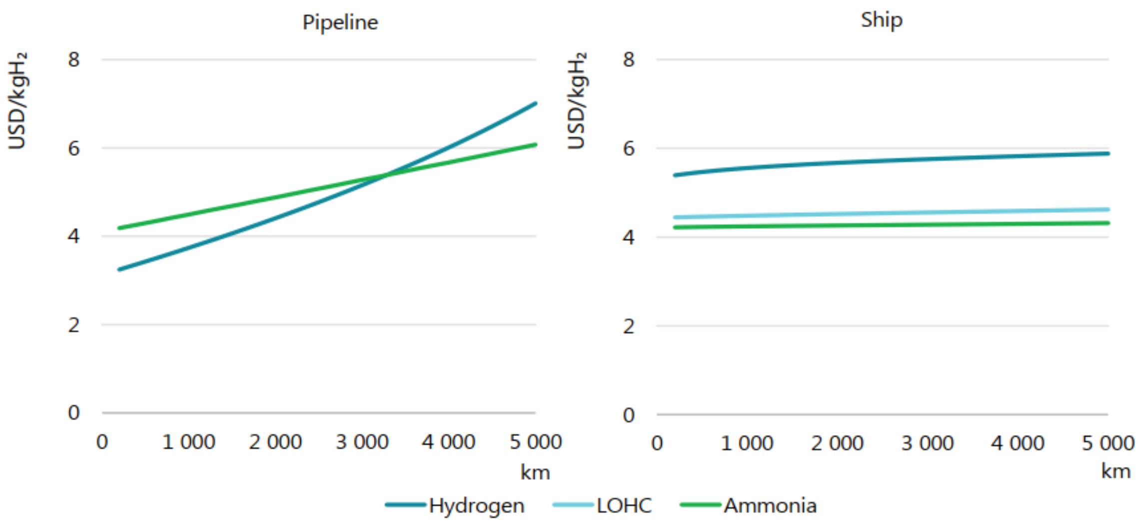

Figure 8: Delivery cost to the industrial sector by pipeline and ships in 2030 [23].

Also, depending on the country situation, domestic production of low-carbon hydrogen could be generally cheaper than importing it. This happens because the additional cost of transportation will be higher than the production costs from RES and the cost of CCUS. However, some countries with limited cap of CO2 emissions may go for low carbon hydrogen import as a way to diversify energy resources. For example, for European countries, importing hydrogen produced in North Africa, the cheapest option would be to use ammonia or LOHC. The selection between decentralized and centralized conversion will depend on the distribution distance. In 2030, the estimated cost is to be around 7.5 – 9 USD/ kgH_2 [23].

1.5 End-use

Transport

Using hydrogen in transport can offer a green alternative to fossil fuels such as refined oil products and natural gas in different sectors: road, rail, naval transport, and aviation. Hence, hydrogen demand in road transportation experienced a surge of about 60% since 2020. Most of this consumption is from trucks and buses because of their high annual mileage and relatively heavy weight to the stock of fuel cell electric vehicles (FCEV). The number of heavy-duty commercial vehicles using hydrogen increased over 60-fold since 2020, achieving 45% of the total hydrogen demand in the transport sector [24].

Moreover, FCEVs increased to over 59 .000 by the end of June 2022, with 15% increase since the end of-2021. This expansion mainly comes from cars consumption, which represents around 85% of the total FC stock. Most of hydrogen car demand occurs in Korea, US, China, and Japan. Consequently, the infrastructure for refueling stations increased in the last two years reaching more than 700 stations in operation by the end of 2021, reaching 975 by June 2022, with China (+185) and Korea (+118) witnessing the largest increase. Worldwide, the ratio of FCEVs to refueling stations is declining with time due to the fast deployment of refueling stations reaching 60 FCEVs per station.

As for Europe, the development of rail passenger lines powered by hydrogen is taking off in France, Netherlands, Sweden, and Austria [25]. In Germany, delivered by Alstom, the first hydrogen fuel cell train fleet started operation in August 2022 [23]. Moreover, Italy and France have ordered 6 and 12 trains, respectively [30]. This shows the great potential of hydrogen in decarbonizing non-road transport sector.

Industry

Currently, the global uses for hydrogen are concentrated in the industry sector where 34 Mt of hydrogen is used to produce ammonia, 15 Mt for methanol and 5Mt for direct reduction of iron (DRI) [28]. Theoretically, all this hydrogen is produced from fossil fuels such as coal and natural gas, resulting in 7% of the industrial CO_2 emissions in 2021[30]. Giving the current announced policies, the hydrogen demand in industry is expected to increase by 11Mt by 2030 compared to 2021 levels [25].

Around 34Mt of hydrogen are needed for the production of ammonia where one ton of ammonia needs 180 Kg of H_2 and results in around 2.2 tonne of CO_2 emissions. Considering climate ambitions of many countries, the need for low-emissions hydrogen for the production of ammonia is necessary. Two technologies have been identified that can achieve substantial reduction of CO2 for ammonia production: electrolysis and the use of CCUS [55]. To date, around 1.3 Mt of low-emission hydrogen production is planned by 2030, when considering early-stage projects which are currently under-development, this number increases to 2.9 Mt.

Looking at the second hydrogen industrial application (methanol), hydrogen demand equals 15 Mt in 2021. All such demand is met with hydrogen obtained from fossil fuels. As for ammonia, methanol production emits nearly the same amount of CO2 emission as with coal-based production and using electrolysis and CCUS could help reduce these emissions. There are also some projects to decarbonize methanol production reaching a total volume of 0.23 Mt H2 by 2030, however, the number is still relatively low.

Buildings

hydrogen consumption in the building sector is limited, although large scale demonstration projects, such as ENE- FARM program in Japan, are underway. The reasons why hydrogen is not widely used in this sector include high costs, safety regulations and the existing natural gas infrastructure already serving final users[25].

Hydrogen can be used in the building sector for heat supply by blending hydrogen in the existing natural gas network. The advantage of this solution is that it has low cost and is compatible with most infrastructure and equipment. Currently, the blending ratios are around 5-20%, GRHYD project in France and HyDeploy in United Kingdom projects are a representatives of this solution [30]. Another potential solution is the use of 100% hydrogen for supply heat for building, providing a full decarbonization of the gas network. In terms of cost, this solution seems attractive for large complexes, commercial buildings and for district energy networks. Fuel cells and co-generation energy storage capacity could be used in such cases to meet cooling, heating and electricity demands, taking advantage of low electricity prices[23].

In the longer term, the use of hydrogen in residential buildings will depend on hydrogen price and technology cost developments. Specifically, hydrogen price needs to be in the range of USD 1.5–3.0/kgH_2 in heating markets to compete with natural gas boilers [23].

Electricity generation

Hydrogen has a great potential to be used in the power generation sector as technologies that can use hydrogen as a fuel are commercially available now. For instance, some designs of ICE, gas turbines and fuel cells can technically operate on hydrogen-rich gases or pure hydrogen. However, such generation accounts for around 0.2 % of total electricity generation [30].

Several technologies can be used to produce electricity from hydrogen, fuel cells are used to generate electricity and heat using hydrogen with an electrical efficiency of over 50-60% [30]. The stationary fuel cell capacity was around 2.5 GW in 2021, however, only 90 MW use hydrogen as a fuel and the rest use natural gas. Gas turbines can also be used for power generation from hydrogen. Within state-of-the-art gas turbines, hydrogen can be mixed with other gases such as natural gas with typical values ranging from 30%-60% by volume [28]. Many new natural gas-fired power projects are considering the co-firing hydrogen or the full utilization of hydrogen, for instance, Germany. Moreover, many projects have been announced or under-development that could use hydrogen or ammonia in combined cycle gas turbine with a capacity of 3500 MW by 2030. 26% of these projects are in North America, 33% in Europe and 40% in the Asia Pacific region [23].

The cost of electricity generation from hydrogen and ammonia is likely to remain high until 2030. A coal power plant in Japan that co-fire 60% of low emission ammonia has a 30% increase in the generation cost above the energy market value [56]. This value could come down to 15% during peak load conditions, taking advantage of the wholesale electricity markets that allow higher prices during peak load times. Having the current trends, hydrogen demand for the electricity generation sector is expected to remain quite low with a demand of 0.3 Mt of hydrogen in the period of 2030[48].

Chapter 2. Model development

The aim of this chapter is to give an overview of the Italian hydrogen supply chain and future hydrogen deployment scenarios. It presents and summarizes the current and expected hydrogen supply chain in Italy, underlying the development of the sector and strategic actions needed to allow faster hydrogen penetration. Afterwards, it continues with explaining the methods and the framework used to implement these scenarios using Hypatia, an energy system modelling framework.

2.1 Italian hydrogen situation

Italy has a strategic position to locate itself in all the sectors across the hydrogen supply chain with its large operators and companies in the national context. Large lead markets, infrastructure abundance, access to natural gas and clean electricity, and a favorable geographical position gives Italy a great advantage in being a corridor to export and transport green hydrogen.

Italy is an export-oriented economy with a sizeable manufacturing base. Italian hydrogen production in 2016 was 520,000 t/year, as shown in Table 1. This number became 480,000 t/year in 2019 which equals 19 TWh per year of which about 8500 t/year are sold in cylinders, liquid form and in suitable pipes[57].

The current use of hydrogen entirely goes for the production of ammonia and for hydrocracking in the refining industry [58]. Most of this production comes from routes currently considered grey or blue hydrogen if carbon capture and storage technology is used, as mentioned previously. Moreover, this already established market for grey hydrogen is well placed to kickstart clean hydrogen production.

Hydrogen production in Italy is made up of large operators which in the short term, through SMR, can produce renewable hydrogen from biomethane or low carbon content hydrogen from methane (SMR with carbon capture systems, for the production of blue hydrogen) and by having leading companies in low and high temperature electrolysis technologies (for the generation of "green hydrogen", when powered by renewable sources). In addition, the industrial system features leading international companies in the production of advanced components, such as electrodes and components for high-tech auxiliary systems.

Italy produces just 3% of European ammonia production capacity, which suggests a smaller market than other EU countries [58]. However, one should consider the location benefits of integrating the refineries in Sicily with hydrogen production, as Sicily is a region abundant with solar energy potential and well connected with gas coming from North Africa. Switch the current use of Italian refineries to green hydrogen would require additional 23-27.6 TWh/yr of renewable electricity, which is about one quarter of Italy's RES bases electricity production in 2019 [59].

Hydrogen Demand	2001	2006	2011	2016
Oil refinery	328,000	392,000	360,000	424,000
Chemical industry	48,000	48,000	48,000	48,000
Other	48,000	48,000	40,000	48,000
Total	424,000	488,000	448,000	520,000

Table 8: Current hydrogen production and involved industries in tons.

The steel sector in Italy deserves attention as well. Italy is the 11th crude steel producer at a global level and the second one after Germany in EU. The production of crude steel in 2019 was 23.2 Mt which represents around 15% of EU production [60]. In Taranto, the direct use of hydrogen (H-BF) in the primary steel making using blast furnace base oxygen furnace could partially reduce emissions, however, the conversion to direct reduction of iron could permit to 90-100 % emissions reduction by using clean hydrogen as the only reactant (H-DRI/EAF route) instead of natural gas [61]–[63].

Hydrogen could also make it into other industrial routes as a fuel replacing nature gas for high temperatures industrial heating process such as glass, ceramic, cement, and paper sectors. However, use of hydrogen as a decarbonizing path against electrification or carbon capture and storage may not deemed promising [64].

For Italy to adapt [65] a hydrogen based economy, a dedicated infrastructure is required, which includes pipelines, different storage options such as tanks and underground bulk for short term storage or geological formation like salt caverns, depleted gas fields or aquifer structures for seasonal long term storage. In this respect, Italian industrial actors have mentioned the probability and benefits of leveraging on Italy's gas infrastructure to support the ambition of becoming a big regional hub for Europe [9].

The 32,700 km long gas network in Italy is linked to other foreign networks. Gas Transmission System Operator (TSO) Snam of Italy claims that connectivity with North Africa in particular might bring down supply costs by 10% to 15% in comparison to domestic output[66]. This abundance of gas infrastructure in Italy perfectly fits into the European Hydrogen Backbone, a pan-European industrial vision for the hydrogen transmission across Europe [48]. The backbone would expand from 6,800 km by 2030 to 23,000 km by 2040, comprising new pipelines stretches (25 percent) and both retrofitted and repurposed gas infrastructure (75 percent). According to the two Italian companies, Snam's acquisition of 49.9% of the Tunisian and offshore portion of Transmed from owner Eni is intended to support "possible initiatives in the development of a hydrogen value chain from North Africa [48]. 98 percent of the Italian gas infrastructure, which is larger than Germany and at the same level as Spain and France, would be prepared for hydrogen shipment based solely on pipe materials (96 per cent)[67], [68].

For this scenario to become reality, full readiness is required meaning the readiness of all components of the backbone grid (valves, connections, metering equipment's compressors , which represent 24% in Europe according to the distribution system operators [69]) for which a sizeable investment is warranted. Still, the cost of repurposing is estimated to be around one third of the cost of building new hydrogen pipelines, thus having an existing network is a major advantage [70].

2.2 Modeling framework

In this section, the pillars of the implemented model will be presented, starting from its framework, why it is developed, mathematical formulation and its logic structure.

Hypatia is an energy system modelling framework written in the objective oriented Python programming language. Contrary to most of the Python-based open-source energy and power system modelling frameworks that are using Pyomo for solving the optimization problem, Hypatia is based on CVXPY Domain-Specific Language developed by Diamond2016 [71] . Hypatia can optimize both the hourly dispatch and the annual capacity deployments of the energy system. Its final objective is to minimize the total discounted cost of the system by considering all the required cost components in each of its optimization modes. In summary, Hypatia is designed with the following main goals:

- Allow easy interaction with the model code by using excel-based input data
- Formulated to cover both operation and dynamic investment decisions
- Provide the possibility to consider the investment annuities in its planning mode based on the given economic lifetime and interest rate of each technology
- Allow to model various categories of technologies such as supply, conversion, transmission, and storage.
- Able to consider the synergies among different sectors of the energy system including power, heat, transport, clean fuel (Hydrogen) and others.
- Designed to follow both the single-node and multi-node approach at will by the user. Each node in Hypatia can be representative of a broad spectrum of spatial resolutions starting from small-scale applications to the national and continental applications.
- Allow to model the bilateral trade among any pairs of nodes through modelling the inter-regional transmission links for all the represented energy carriers within the Reference Energy System
- Able to adopt arbitrary resolutions in time for each modelling year, allowing to consider the full hourly variability of both demand and supply sides.
- Have a fully transparent and open-source code, flexible to any possible future modification and integration

Hypatia is inspired by the other existing energy system optimization models particularly OSeMOSYS by Howells, 2011,[72] Calliope by Pfenninger-Pickering, 2018 [73] and TIMES by Loulou,2005 [74]. It is designed to complete the path of these frameworks by addressing the main challenges of the modern energy system modelling frameworks that are shortly explained in the following:

Dynamic annual investments on the energy system: With the aim of exploring the possible evolution of the energy systems in the transition pathways, the energy modeling frameworks need to cover both the operation and planning modes by simultaneously delivering the required dynamic annual capacity expansions and full hourly dispatch of different technologies within the energy systems.

However, most of the existing models with high temporal resolution are falling short of delivering all the required annual investments in the long-term horizons and just follow a snapshot approach for estimating the required new capacities to be installed for the future growths in the final demand.

Resolution in time: On the other hand, most of the planning models are not computationally able to include fine temporal resolutions down to hourly timesteps within each modelling year of the time horizon. Therefore, they may deliver inaccurate results due to missing the full variability of both demand and supply sides of the energy system.

Resolution in space: The concept of spatial resolution contains not only the ability of representing multiple regions in different dimensions but also the possibility to model the interconnections among various regions by modelling the inter-regional transmission links.

Sector coupling: The interactions and synergies among different sectors of the energy system must be considered in the energy modelling frameworks by following a comprehensive technology definition similar to all the above-mentioned models.

Transparency: The concept of transparency and openness has manifold aspects. The open science approach for an energy model is not only about publishing the governing structures and equations but also following several criteria such as:

- Convenient access to source code, data, and assumptions
- Providing understandable input data structure not only for the experts but also for any potential user
- Clear and modular core code
- Flexible source code to any possible future modification and integration

2.2.1 Mathematical formulation

The model generator is structured to solve a linear optimization problem, using Linear Programming (LP). This method allows to achieve the best outcome in a mathematical problem represented by linear relationships. The goal is to optimize a linear objective function, whose examples typically are profit maximization or lowest cost configuration, given some linear constraints.

The problem to solve is an optimization problem wherein the total objective function is a linear function, which has the form in the planning mode. The objective function equation of the planning mode is the sum of all the regional costs in addition to the inter-regional transmission link costs discounted to the reference year.

Total Objective function

$$\min: Eq_{obj} = \sum_{Reg} Reg_{obj}(reg) + Exchange\_link\_obj \qquad \forall reg \in regions$$

Regional objective function

$$Reg_{obj(reg)} = \sum_{year}(1 + Discount\_rate(year, reg))^{-year} \times \sum_{tech}[InvCost(reg, year, tech) + FixCost(reg, tech, year) + DecomCost(reg, tech, year) + VarCost(reg, tech, year) + Fixtas(reg, tech, year) + InvTax(reg, tech, year) - InvSub(reg, tech, year) - FixSub(reg, tech, year) + CO2Cost(reg, tech, year) - InvSalvafe(reg, tech, year)] \quad \forall reg \in regions$$

Trades Objective Function

$$\begin{aligned} Exchange\_links\_obj &= \sum_{year}(1 + Discount_{rate}(year))^{-year} \\ &\times \sum_{link}[FixCost\_link(link) + VarCost\_link(link) + FixTax\_link(link) \\ &- FixSub\_link(link)] \qquad \forall link \in links \end{aligned}$$

Costs

calculating the components of the objective function including the investment, fixed and variable operation and maintenance and decommissioning costs followed by the related taxes considered for each unit of investment or fixed cost of the technologies. Carbon taxes are also included to be applied for the carbon-intensive technologies. Alongside the related costs of technologies, some revenues are considered in the objective function with a negative sign.

These revenues are including the salvage values on some of the investments where the operational lifetime of the technology lasts longer than the end of the modelling time horizon and subsidies that are applied to some technologies based on the national policies. The Hypatia model considers the economic lifetime of the technologies in the investment cost calculation. Therefore, each required investment in a specific year “y” is divided into a stream of annuities during several years (from “y+1” to “y+EndLIFE”) which is determined by the technology-specific economic lifetime, depreciation rate and time value of money.

Investment cost

The cost required for the new installed capacity of the technologies.

$\forall reg \in regions, \forall tech \in technologies, \forall year \in years$:

$$\boldsymbol{Inv\_present}(reg, tech, year) = \boldsymbol{NewCapacity}(reg, tech, year) \times INV(reg, tech, year)$$

$$Depreciation(reg, tech) = \frac{r(1+r)^n}{(1+r)^n - 1} \quad where{:}\, n = Economic\_lifetime(reg, tech) \quad r = Interest\_rate(reg, tech)$$

$$\boldsymbol{Annuity}(reg, tech, year) = Depreciation(reg, tech) \times \boldsymbol{Inv\_present}(reg, tech, year)$$

$$\boldsymbol{InvCost}(reg, tech, year) = \sum_{year_k = year+1}^{year+Economic_{lifetime}+1} (1 + Discount_{rate})^{year - year_k} \times \boldsymbol{annuity}(reg, tech, year_k)$$

Investment Salvage Value

The revenues calculated at the end of the time horizon for the unused period of the investments whose technical lifetime exceeds the modelling horizon.

Fixed Cost

The fixed annual operation and maintenance cost is based on the total installed capacity of each technology.

$$\boldsymbol{FixCost}(reg, tech, year) = \boldsymbol{TotalCapacity}(reg, tech, year) \times F\_OM(reg, tech, year)$$

Taxes & Subsidies

Taxes and incentives calculated based on the total investment and fixed cost of each technology.

$$\forall reg \in regions, \forall tech \in technologies, \forall year \in years:$$

$$InvTax(reg, tech, year) = NewCapacity(reg, tech, year) \times Investment\_tax(reg, tech, year) \times INV(reg, tech, year)$$

$$InvSub(reg, tech, year) = NewCapacity(reg, tech, year) \times Investment\_sub(reg, tech, year) \times INV(reg, tech, year)$$

$$FixTax(reg, tech, year) = TotalCapacity(reg, tech, year) \times Fix\_tax(reg, tech, year) \times F\_OM(reg, tech, year)$$

$$FixSub(reg, tech, year) = TotalCapacity(reg, tech, year) \times Fix\_sub(reg, tech, year) \times F\_OM(reg, tech, year)$$

Decommissioning Cost

Cost of dismantling the new capacities installed in the vintage years of the modelling horizon.

$$DecomCost(reg, tech, year) = DecomCap(reg, tech, year) \times Decom\_cost(reg, tech, year)$$

Variable Cost

Annual variable operation and maintenance costs including the cost of consumed fuels.

$$VarCost(reg, tech, year) = Production_{annual(reg,tech,year)} \times V_{OM(reg,tech,year)} \quad \forall reg \in region, \forall tech \in technologies, \forall year \in years$$

Carbon Tax

The tax is dedicated to the amount of CO2 emitted by each technology.

$$CO2Cost(reg, tech, year) = Production\_annual(reg, tech, year) \times Specific\_emission(reg, tech, year) \times Carbon\_tax(reg, tech, year)$$

Capacity

Accumulated New Installed Capacity

$$Accumulated\_NewCapacity(reg, tech, year) = \sum_{Vintage\_year} NewCapacity(reg, tech, vintage\_year)$$

Total Installed Capacity

$$TotalCapacity(reg, tech, year) = Accumulated\_NewCapacity(reg, tech, year) + Residual\_capacity(reg, tech, year)$$

Decommissioned Capacity

Calculates the annual decommissioning capacities based on the previously installed new capacities in the vintage years of the horizon.

$$DecomCapacity(reg, tech, year) = \sum_{vintage\_year} NewCapacity(reg, tech, vintage\_year)$$

Emission

Calculates the annual CO2 emission based on the annual production of each technology and the exogenous specific emission given by the user per unit of output activity.

$$CO2_{equivalent(reg,tech,year)} = Production\_annual(reg, tech, year) \times Specific\_emssion(reg, tech, year)$$

Constraints

Energy balance

Guarantees the balance between the supply and demand sides of the energy system.

$$\sum_{tech \nexists\ tech\_Demand} Production(reg, tech, year, ts) + \sum_{REG} Import(reg, tech, REG, year, ts) \geq \sum_{Tech \nexists tech_{Demand} \& tech\_Supply} Use(reg, carr, tech, year, ts) + \sum_{REG} Exports(reg, REG, Carr, year, ts) + \sum_{tech \nexists tech\_Demand} Demand(reg, carr, tech, year, ts)$$

$$Production(reg, carr, tech, year, ts) = Production\_total(reg, tech, year, ts) \times carrier\_ratio\_output(reg, carr, tech, year, ts)$$

$$Use(reg, carr, tech, year, ts) = Use_{total(reg,tech,year,ts)} \times carrier\_ratio\_input(reg, carr, tech, year, ts)$$

Trade balance

Ensures that the amounts of imports and exports among any pair of regions are completely balanced.

$$Imports(reg, carr, REG, year, ts) = Exports(REG, carr, reg, year, ts)$$

Resource & Technology Availability

Ensures that the production of each technology does not exceed its available activity based both the technology capacity factor and resource capacity factor.

$$\sum_{Carr} Production(reg, carr, tech, year, ts) \leq TotalCapacity(reg, tech, year) \times Resource\_capacity\_factor(reg, tech, year, ts) \times Annual\_production\_per\_unitcapacity(reg, tech) \times Timeslice\_fraction(ts)$$

$$\sum_{carr}\sum_{ts} Production(reg, carr, tech, year, ts)$$
$$\leq Capacity\_factor\_tech$$
$$\times \sum_{ts}[TotalCaapcity(reg, tech, year)$$
$$\times Resource\_capacity\_factor(reg, tech, year, ts)$$
$$\times Annual\_Production\_per\_unitcapacity(reg, tech)$$
$$\times Timeslice\_fraction(ts)]$$

Capacity

Maximum & Minimum Regional Total Capacity

Maximum and minimum allowed annual total installed capacity for each technology in each region based on the defined scenario.

$$TotalCapacity(reg, tech, year) \leq Max\_totalcap(reg, tech, year)$$
$$TotalCapacity(reg, tech, year) \geq Min\_totalcap(reg, tech, year)$$

Maximum & Minimum Regional New Capacity

Maximum and minimum allowed annual aggregated total installed capacity for each technology over all the regions based on the defined scenario.

$$NewCapacity(reg, tech, year) \leq Max\_newcap(reg, tech, year)$$
$$NewCapacity(reg, tech, year) \geq Min\_newcap(reg, tech, year)$$

Maximum & Minimum Overall Total Capacity

Maximum and minimum allowed annual aggregated new installed capacity for each technology over all the regions based on the defined scenario.

$$\sum_{reg} TotalCapacity(reg, tech, year) \leq Max\_totalcap\_global(tech, year)$$
$$\sum_{reg} TotalCapacity(reg, tech, year) \geq Min\_totalcap\_global(tech, year)$$

Maximum & Minimum Overall New Capacity

Maximum and minimum allowed annual aggregated new installed capacity for each technology over all the regions based on the defined scenario.

$$\sum_{reg} NewCapacity(reg, tech, year) \leq Max\_newcap\_global(tech, year)$$

$$\sum_{reg} NewCapacity(reg, tech, year) \geq Min\_newcap\_global(tech, year)$$

Activity

Maximum & Minimum Regional Production

Maximum and minimum allowed production of each technology in each region based on the defined scenario.

$$Production\_annual(reg, tech, year) \leq Max\_production(reg, tech, year)$$

$$Production_{annual(reg,tech,year)} \geq \ Min\_production(reg, tech, year)$$

Maximum & Minimum Overall Production

Maximum and minimum aggregated production of each technology over all the regions based on the defined scenario.

$$\sum_{reg} Production_{annual(reg,tech,year)} \leq Max\_production\_global(tech, year)$$

$$\sum_{reg} Production\_annual(reg, tech, year) \geq Min\_production\_global(tech, year)$$

Output to Input Activity Ratio

Ensures the relationship between the production and consumption of each technology based on the given efficiency (output/input activity ratio)

$$Production(reg, tech, year, ts) = Output\_input\_act\_ratio(reg, tech, year) \times Use(reg, tech, year, ts)$$

CO2 Equivalent Emissions

Regional Emission cap

Ensures that the annual amount of CO2 emissions emitted in each region does not exceed the given maximum allowed annual carbon emissions.

$$CO2_{equivalent(reg,tech,year)} \leq Emission\_\ cap\_annual(reg, year)$$

Overall Emission cap

Ensures that the aggregated annual amount of CO2 emitted over all the regions does not exceed the maximum allowed annual values by the user.

$$\sum_{reg}\sum_{tech} CO2\_equivalent(reg, tech, year) \leq Global\_emission\_cap\_annual(year)$$

2.2.2 Hypatia logic structure

Once the mathematical formulation of the framework has been defined, the next step is to introduce the logical components that constitute the model. This becomes relevant to explain the logical behavior behind the reference energy system. In the following section, the main concepts of the model will be presented.

Technology categorization

Hypatia follows the same technology classification as Calliope as shown in Table 2.

Technology Category	Description
Supply	Supplies an energy carrier to the system without consuming any other carriers
Demand	Consumes and sinks an energy carrier from the energy system
Transmission	Transmits an energy carrier locally from a supply point to a demand point
Conversion	Converts an energy carrier to another
Conversion plus	Converts one/multiple energy carrier to one/multiple other carriers
Storage	Stores and energy carrier and discharge it when it is required

Table 9: The technology categorization in Hypatia.

All the technologies in a Hypatia model can have only one carrier input and one carrier output except the technologies within the Conversion-plus category which can have multiple carrier inputs and outputs.

Carrier types

Besides the technology classifications, Hypatia also considers different kinds of energy carriers as shown in Table 3.

Carrier Type	Description
Resource	The energy resource extracted from the nature (by a supply technology) that are not still processed such as raw oil
Intermediate	An energy carrier that can be consumed by **non-Demand** technologies
Demand	An energy carrier that can be consumed by **Demand** technologies

Table 10: Different carrier types in a Hypatia model

The Reference Energy System in a Hypatia model should always start from Supply technologies (such as resource extraction technologies) and end with Demand technologies.

2.3 Scheme of reference energy system description (SRES)

Once the specific commodities and the processes are presented in their different categories, the SRES representation can be introduced. SRES, whose acronyms mean Scheme of the Reference Energy System, is a way to represent the interconnections and the links between different technologies and different sectors. Through its structure, becomes more intuitive the representation of the energy system implemented in the model.

For the definition of what technologies had to be implemented in the SRES, it was necessary to define and estimate what demand they had to supply. A process starting from the bottom, the end-user was thus required to firstly answer the question "what demands do exist?", followed by the consequent "how these demands can be supplied?".

The first logical step was to identify the considered type of demands and clarify which consumer they should supply. Basically, the whole Italian economy is divided into six sectors which represents in total the total final consumption of the country. Also, there are three kinds of demand classes: power demand, thermal one and pure energy carrier one.

While the first two describe the necessary electricity and heat demand, the latter represents all those final products that can be used to produce further heat or power (e.g., hydrogen, Natural gas, …. etc.).

The implemented sectors' demands are industrial sector demand, transport sector demand, service sector demand, residential sector demand, primary sector demand and export demand. For computational time and scheme simplicity, aggregate demands are considered inside each sector. Nevertheless, each sector's demand is met through different energy carriers. As such, each sector has its own electricity demand, heat demand and those final energy carrier demand.

Once the final uses are defined, it is possible to focus on the segment of the energy supply chain, which means to represent the processes needed to supply these demands. The Scheme of Reference Energy System (SRES) presents many technologies that can be categorized according to the desired end products. There are power plants, combined heat and power plants, transmission and distribution networks, refinery, and hydrogen production plants.

The leftmost segment of the SRES is the final segment, and it displays the primary supply or imported commodities as raw materials that make up the feedstock for the aforementioned heat- and power-generation methods.

The logic of the scheme is to represent all relevant flows that characterize a specific process transformation. Starting from left to right of the scheme, it is possible to notice the pathway of an energy carrier covers to reach the end-user at its final form.

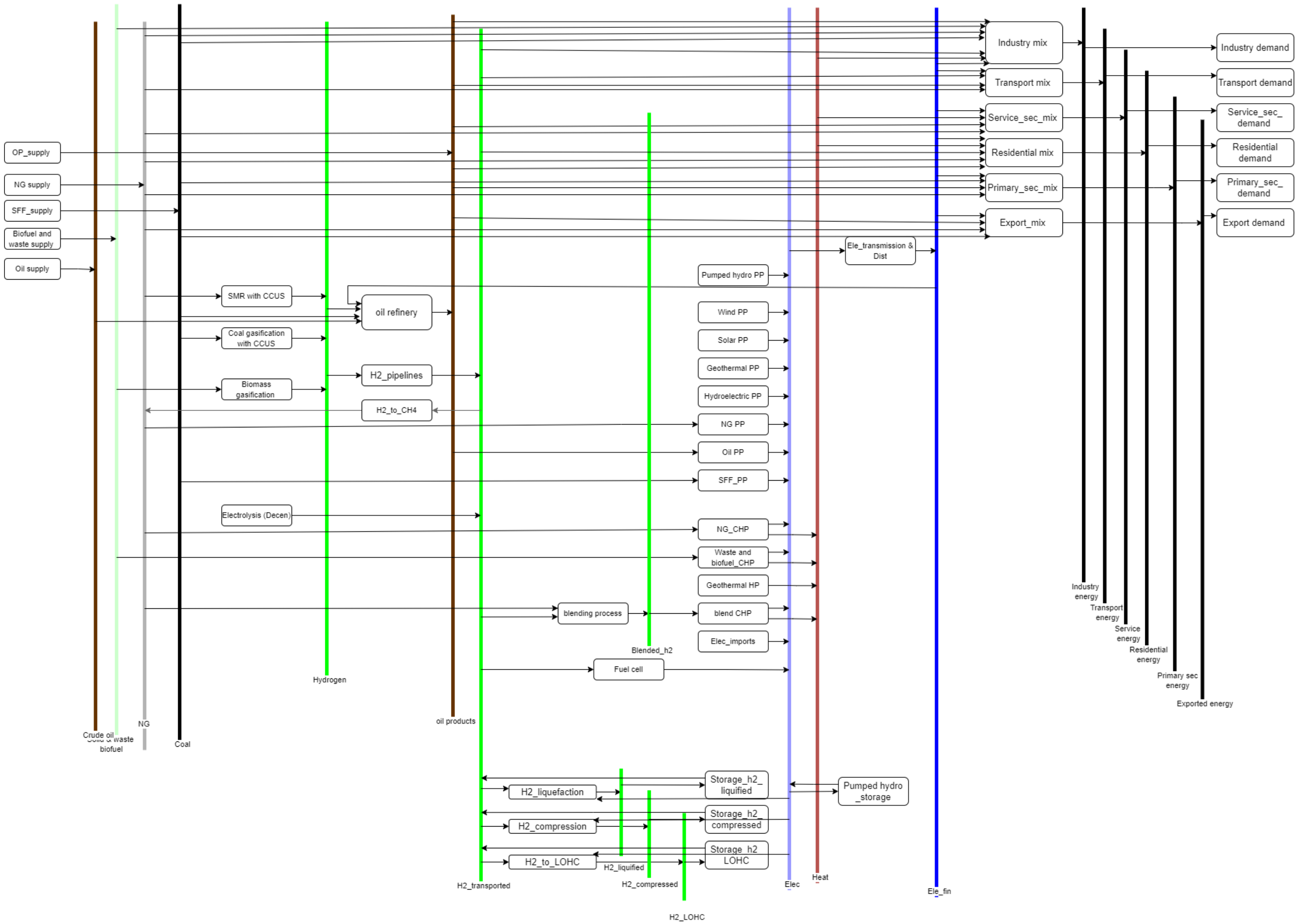

Figure 9: Scheme of Reference Energy System

2.3.1 Processes involved in the hydrogen supply chain

Addressing the hydrogen supply chain in the SRES, it is currently produced via water electrolysis, steam methane reforming, coal gasification and biomass gasification. In reality, different electrolyzer technologies are used to produce hydrogen. However, in the model a single electrolyzer technology is considered: proton exchange membrane electrolyzer. As they are supposed to become more diffused in the future market, mainly thanks to their flexibility and high efficiency, mentioned in Chapter 1. Hydrogen processes network

Moreover, a distinction between centralized and decentralized production of hydrogen is introduced in the model by using small capacity electrolyzer for decentralized production. This decentralized production of hydrogen is meant to be produced and used on-site.

Considering hydrogen to power, which is the inverse process of water electrolysis using fuel cells, electricity production utilizing hydrogen is modulated using single technology also. Again, several FC technologies are already in the market but again several projections suggest a dominant role of Proton Exchange Membrane Fuel Cells shared with Solid Oxide Fuel Cells [23], [29].

Final hydrogen bus can be destined to pure energy carrier demand or can be used as input for other conversion process such as blending process or other synthetic fuels. Furthermore, multiple storage options are considered in order to strengthen hydrogen production during the overload given by renewables, with a consequent benefit for the grid stability. Three storage technologies are considered: compressed hydrogen gas, liquified hydrogen storage and the use of liquid organic materials.

2.4 Model assumptions

Several background hypotheses are required before introducing the major assumptions for the definition of the researched scenarios.

2.4.1 Assumption of single technology option for each process

The definition of the technology number taken into account for each process is the first major principle that guides the model's structure. The logical ground of the model is to keep the system representation as simple as possible. More complex structures will require a considerable increase in computational power and optimization issue.

For this reason, just one solution was considered in all processes where there are many technologies. The decision between fuel cells and water electrolysis technologies could serve as an illustration. The major technologies are discussed in Chapter 1, and the major technological characteristics are included in Tables 2 and 3. The two markets offer a wide variety of solutions, each with its own set of operational requirements. However, determining the market share of each technology would have been challenging if the model had been examined as a single aggregated node.

Due to its great degree of versatility and the expanding market penetration, PEMEC was the technology of choice for electrolyzers at that time [21]. The same factors led to the decision to utilize PEMFC as the technology for Hydrogen to Power (H2P), as discussed in Section 2.4.4.

Multiple technology options for each process may be enabled by future implementations that may call for various considerations, such as the multi-node solution.

2.4.2 Assumption on costs

Hypatia’s framework allows to calculate total system cost discounted to the reference year in the planning mode. As such, it allows to solve the optimization problem by considering investment costs, fixed cost, and variables costs, returning the optimized installed capacity of the studied technologies.

Investment costs for these new technologies are difficult to predict, they depend on many factor (political, geographical) and they will decrease over time. For this reason, investment costs for each technology are taken from the literature as well as fixed cost which is related to the cost of labor and employee’s wages. Regarding the variable costs, they are only assigned to the commodities. They are considered as the price necessary to supply a unit of the specific energy carrier such as NG, solid fossil fuels and oil products, typical GWh from the well to the conversion technology.

Moreover, the interest rate is taken as constant for all technologies and equals 10% according to the literature review done in Chapter 1.

The model returns the optimal generating mix to reduce resource use (e.g., fossil NG, biomass) and total system cost. It compares the resources available and their associated costs to determine the technology's ability to produce the necessary amount of energy for each hourly time-step (e.g., hydrogen use in FC compared with gas grid in GT power plant).

Policymakers may find the findings useful in making decisions by using them to determine which technologies need further research and development.

2.4.3 Assumption on multiple hydrogen storage options

For the hydrogen storage options, some assumptions need to be taken into account. In chapter 1, different storage options are discussed on different levels and the affirmed and most promising ones are represented.

While other energy carriers present relatively low storage problems (physical and of economic nature), hydrogen has non-performing characteristics in ambient conditions. For these reasons, different storage solutions are investigated. As mentioned before, three storage technologies are considered:

- Hydrogen compression storage.
- Hydrogen liquification storage.
- Liquid organic hydrogen carriers.

As nowadays hydrogen is mostly stored and delivered in a liquid or compressed way. Moreover, compressed hydrogen represents an interesting trade-off suitable for the transport sector. Space requirements in private FCEVs pushed the development of high compressed H2 tanks (at 700 bar for small vehicles and 350 bar for heavy trucks). Hydrogen Refueling Stations (HRS) should then supply the energy carrier at the same operating conditions. In the model, hydrogen is assumed to be stored in caverns with a storage pressure of 60 – 150 bar [75].

The liquefaction process is the focus of the second solution. Although it comes at a higher energy cost, this technique offers the advantage of increasing volumetric energy density. Liquid hydrogen is assumed to be stored in insulated tanks.

The last solution is the hydrogenation of organic material using chemicals. The fundamental benefit of LOHC technology is that it permits chemically bonded hydrogen storage under ambient conditions. Therefore, no high-pressure or extremely well-insulated tank is needed. Additionally, the technology can expand on the current fossil fuel infrastructure, such as by using tanker ships, rail trucks, road tankers, and tank farms [76].

Various substances have previously been looked into for their potential as LOHC compounds. The LOHC system dibenzyltoluene (H0-DBT)/perhydro dibenzyltoluene (H18-DBT) is demonstrated by Brückner et al. to be extremely promising for a number of reasons. Although the reaction enthalpy of H18-DBT (65 kJ/mol = 8.9 kWh/kgH2) and the dehydrogenation temperature of H18-DBT are relatively high (>260 °C), its storage density of up to 6.2 weight-percent of hydrogen in comparison to the total weight of the carrier, ease of handling (no "dangerous goods" complications), thermal robustness, and high cycle stability offer important advantages [77].

Moreover, Due to its widespread use as an industrial heat transfer fluid (e.g., under the trade name Marlotherm SH), H0-DBT is readily available. This study assumes a LOHC system based on the H0-DBT/H18-DBT pair in light of these benefits. It is assumed to be stored in underground tanks.

Each of the three options for hydrogen storage is defined as the required one to store the entire H2 production for 1000 consecutive hours (approximately 40 days). In total, the 3 contributions together allow for 120 days of production with no consumption of hydrogen.

2.4.4 Assumption on hydrogen to power (H2P)

This industry exemplifies the utilization of hydrogen to generate electrical power again. A description of the many options is illustrated in Chapter 1. But in the existing model, only one conversion option is taken into account. Technology utilizing fuel cells is currently widely available, with substantial differences between each type.

According to literature reviews, PEMFC technology has a wide market share and competes with solid oxide fuel cells. The model assumes that the former is the sole route accessible for H2P because of this. Future solutions, such hydrogen turbines, could be researched further and included in the model. The decision driver to not include them in the model was influenced by the zero-dimension characteristic (0-D) of the model itself.

2.4.5 Assumption on availability of natural resources

One of the inputs of the model is the availability of natural resources such as wind and solar. The parameter inside the code responsible for that is called “capacity factor resource”. For solar and wind capacity factors, values are obtained from Renewable. Ninja [25] for 2019 and then a daily average is taken over all the year. Figure 10 represents these values as the average daily capacity factors over all the year. These values are taken as constant from 2020-2050.

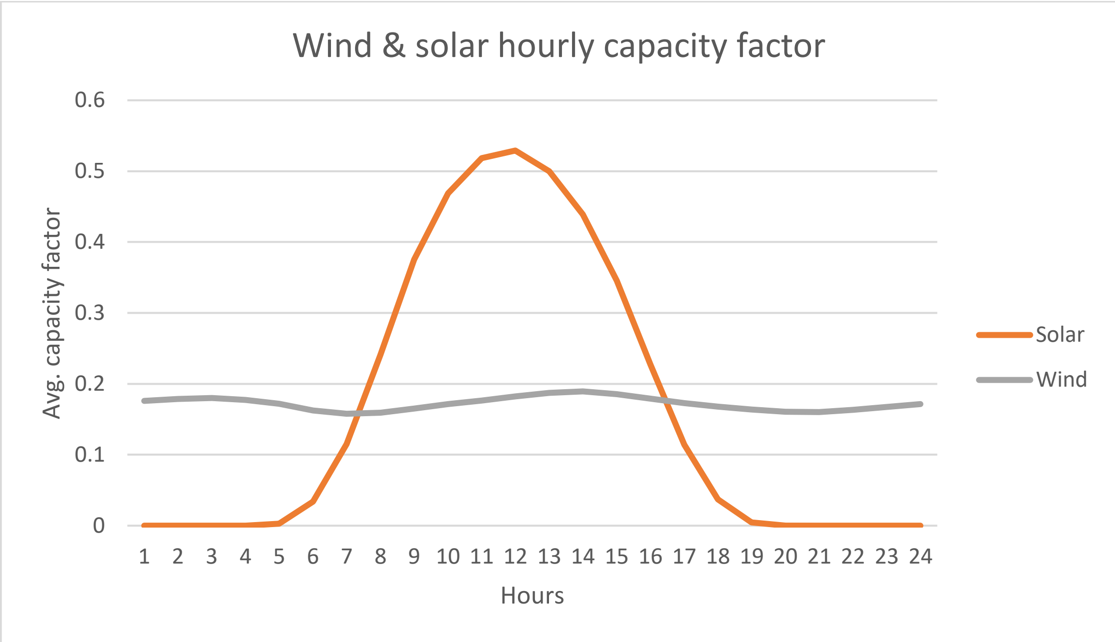

Figure 10: Wind and solar average capacity factors.

Regarding other natural resources such as geothermal energy and hydro, the capacity factor for geothermal plants is taken constant over all the years and equals 0.95. While hydroelectric power plants' capacity factor equals 0.49. These values are taken from SESAM database [78].

2.4.6 Technological data assumptions

After introducing the main background hypothesis, it is necessary to analyze the implemented technologies for the different hydrogen production technologies, and hydrogen – to – X pathways.

2.4.6.1 Main technical data assumed in hydrogen production

Regarding the hydrogen production technologies, water electrolysis, coal gasification, steam methane reforming and biomass gasification are the represented production technologies in the model. As introduced in the background hypothesis, for computational issues, there is the necessity to choose a single technology option for a specific process. As such, only PEM electrolyzer is chosen to represent the P2H pathway.

Technology	H_2 efficiency [LHV]	Investment cost [Euro/GW]	Fixed cost [Euro/GW]	lifetime [year/hour]	Specific direct emission [$kgCO_{2eq}$/GWh]	Availability
Steam methane reforming (SMR) - baseline	0.79	460,726,055.55	13,821,781.67	30	300000	0.92
SMR + CCS	0.71	1,013,144,520.20	50,657,226.01	30	30888	0.92
Coal Gasification + CCS	0.56	1,379,914,156.56	68,995,707.83	30	491700	0.92
Biomass Gasification + CCS	0.50	3,238,666,449.47	161,933,322.47	30	456900	0.93
PEM electrolyzer	0.76	1,743,287,777.77	87,164,388.89	40000	-	1

Table 11: Main technical parameters for hydrogen production technologies (2020) [79],[23],[33].

In Table 11, the main technical parameters for each of these technologies are represented. These technical parameters are not constant over the years but changing (mostly, decreasing), full data is available in Appendix A. Therefore, the table only represents the values for the starting year 2020.

Moreover, the efficiency term represents the unit of H2 obtained per one unit of input, whatever the input energy carrier is (electricity, NG, coal, biomass), on a LHV basis.

2.4.6.2 Main technical data assumed in hydrogen to gas

The two processes described in chapter 1 are biological methanation and catalytic methanation. However, only catalytic methanation is implemented in the model for simplification. Moreover, the process seems more suitable for average plants sizes [29].

The resulting CH4 can be used to substitute natural gas in different end uses. Also, it is important to notice that in the model there is no storage for carbon dioxide and the technology will keep using the available CO2 until it is finished. Table 12 represents the main technical parameters for hydrogen to gas technologies.

Process	**Overall efficiency**	**CO_2 used [Kg/MWh$_{Ch4}$]**	**Output heat [MWh/MWh$_{Ch4}$]**
Catalytic methanation	0.78	200	0.245
Biological methanation	0.72	-	-

Table 12:Main technical parameters assumptions for methane synthesis processes [36].

2.4.6.3 Main technical data assumed in hydrogen to power (H2P)

Another possibility to utilize hydrogen is to be reconverted back to power using fuel cells. Different fuel cells technologies are available in the market, however as mentioned before only one technology is used which is PEMFC. As shown in Table 13Table 12, the efficiency of PEMFC is lower than Alkaline FC in the year 2020 however, with time passes by the efficiency increases to reach 0.57 in 2050 which is higher than alkaline one [28]. Further consideration can be done to see how the diffuse of alkaline FC technology will impact the price of hydrogen.

Technology	**H_2 efficiency [LHV]**	**Investment cost [Euro/GW]**	**Fixed cost [Euro/GW]**	**lifetime [year/hour]**

PEM FC	0.47	2,093,077,338.37	104,653,866.92	60000
Alkaline FC	0.5	549,022,449.49	27,451,122.47	7000

Table 13: Main technical parameters for hydrogen to power (2020)

2.4.6.4 Main technical data assumed in hydrogen storage

Hydrogen has non-performing characteristics in ambient conditions, with very low volumetric energy densities compared to different gaseous fuels. For that reason, three storage options are considered with their specific preprocesses: hydrogen compression, hydrogen liquification and liquid organic hydrogen carrier.

The storage processes have two steps: a conversion module which is the hydrogen transformer to the storage required state (e.g., pressure required) and the physical storage itself. These conversion modules are mass-based throughput capacity. For compressed hydrogen, the compressor size is able to produce 5473 GWh of compressed hydrogen at 150 bar per year. This capacity size assumes that hydrogen storage can be done for 40 days of consecutive production with no consumption. The electricity demand is calculated and is 4.4 kWh/kgH2. Main technical parameters for all the conversion modules are represented in Table 14. Overall efficiency considers the losses too.

According to the 2008 Nexant Report, liquefaction plant efficiency increases as plant capacity rises [30]. Particularly, the IdealHy-study asserted an energy demand of 6.78 kWh/kg for a plant with a daily capacity of 50 tons of hydrogen [31]. However, for simplicity, this number was taken as constant. The total electricity demand of the liquification module is 7.84 kWh/kg H2. This demand represents the whole conversion module demand as it combines the liquefaction process itself, pumping the liquid hydrogen and evaporating it again to inject in into the grid. The annual capacity of the conversion module is 41455.74907 GWh of liquid hydrogen.

The hydrogenation and dehydrogenation and LOHC pumping are combined in the conversion module of H2_to_LOHC. The process has the same annual productivity as the liquification module, but has lower overall efficiency. The electricity demand for all the conversion module is 0.9 kWh/kgH2 and for simplicity, the heat demand in the hydrogenation and dehydrogenation process are not considered.

Process	**Inputs [GWh / GWh $_{tot\_in}$]**			**lifetime**

	Electricity	**Hydrogen**	**Overall efficiency**	**losses [%]**	
H2_compression	0.12	0.88	0.88	0.005	15
H2_liquification	0.18	0.82	0.80	0.0165	20
H2_to_LOHC	0.02	0.98	0.69	0.040	20

Table 14: Main technical parameters for hydrogen storage transformation processes [31],[30],[32],[33],[23].

For the physical storage module, compressed hydrogen is stored in caverns with a storage pressure between 60 – 150 bar., while liquid hydrogen and LOHC are stored in tanks. All storage options have the same capacity that allows the storage for 1000 hours of production with no consumption. Moreover, the charge and discharge efficiency include the leakage and boil off losses. All assumptions are reported in Table 14.

Storage	**Storage capacity [GWh]**	**Capacity loss [%]**	**Charge efficiency [%]**	**Discharge efficiency [%]**	**lifetime**
Liquified Hydrogen Storage	4930.0625	0.0003	0.99	0.99	25
Compressed Hydrogen Storage	4930.0625	0.00	0.98	0.98	50
LOHC storage	4930.0625	0.00	0.99	0.99	25

Table 15:Main technical parameters for hydrogen storage options [22],[34],[35], [21].

2.4.7 Assumption on residual capacity installed

One of the inputs to the model is the already installed capacities of technologies. They are entered through a parameter called "Residual capacity". As such, the residual capacity for already existing power plants in Italy at the reference year 2020. Furthermore, these plants have to be decommissioned after their expected lifetime. Therefore, each type of plant has its own yearly decommission rate, as shown in Table 9.

	Residual capacity [GW]	Decommission rate [GW/year]
Geo_PP	0.869	-0.043
Solar_PV_PP	21.65	-0.866
Wind_PP	10.8706	-0.544
Hydro_PP	12.88636364	-0.430
Pump_hydro_PP	6.013636364	-0.200
Geo_HP	0.6	-0.030
SFF_PP	7.167	-0.287
Oil_PP	2.4472	-0.098
NG_PP	30.845	-1.234
Oil_refinery	114.5183916	-4.581
NG_CHP_P	13.442	-0.672
BW_CHP_P	3.6178	-0.181

Table 16: Residual capacity and yearly decommission rate for several plants.

Chapter 3. Model application

The aim of the thesis is to provide a model that can assess the introduction of hydrogen into the Italian Energy System in a long-term scenario. For such a reason, the tested time horizon is set to be 2050. This chapter introduces the proposed scenarios for hydrogen demand, data used for different technologies and the obtained results.

3.1 Hydrogen energy scenarios design

In this section, a comprehensive analysis of the hydrogen scenarios as a final energy carrier in Italy's energy mix is presented, exploring possible utilization of hydrogen in different sectors such as transport, industry and building sectors. Three scenarios are developed to explore and compare different penetrations of hydrogen across the national context. The tested time horizon for each scenario is 2050, indicating long-term vision of hydrogen deployment in the Italian energy system. Figure 11 demonstrates the implemented scenarios that are used to study different analysis.

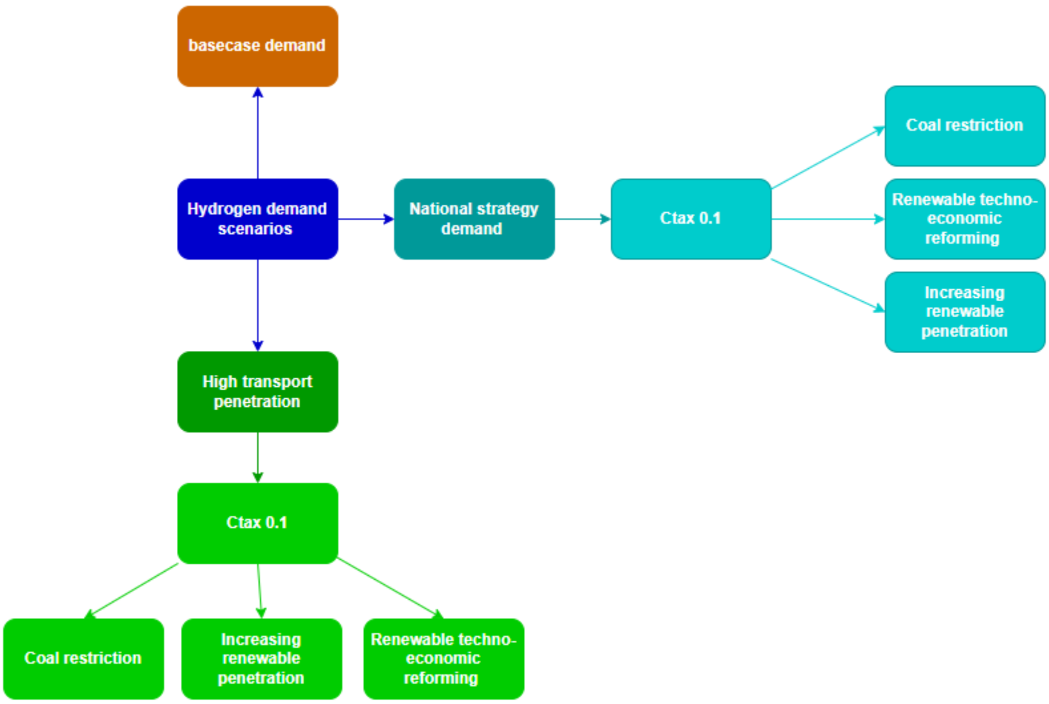

Figure 11: Different implemented scenarios scheme.

3.1.1 Basecase hydrogen scenario

Scenario definition:

The first scenario developed is the basecase scenario which represents the current situation of final energy demand in Italy with a reference year of 2020. The applied scenario is considered the baseline for all other scenarios. Constructing the basecase scenario, which represents business as usual case, hydrogen is assumed to be used in the industrial sector, giving the fact that there's no plans or strategies for developing a hydrogen economy. This represents the use of hydrogen in chemical processes, ammonia production and synthetic fuels processes. According to this scenario, Hydrogen is produced using the following technologies: SMR plants without CCS, CG + CCS and electrolysis, however, there's a residual capacity of 0.5 GW of SMR plants that already exist in Italy to produce the current demand in 2020.

Moreover, the electricity production from fossil fuels such as oil and coal are restricted so that there are no new installed capacities for those kinds of plants. Regarding renewable energy resources such as wind, solar and hydro, a maximum new capacity limit per year is applied as mentioned in Table 18 however, a minimum total capacity limit is also applied to ensure that certain percentage of renewable energy is present every year.

Regarding storage technologies, in the basecase scenarios, the only available storage technology is the pumped hydro storage for electrical storage. No hydrogen storage technologies are implemented in this case.

Scenario demand profile:

The whole country's final energy demand is divided into six final disaggregated end-use (consumption) national sectors, without getting into further details as to how it is used inside each sector or how efficient the utilization process is. As such, the focus of thesis is to address the role of hydrogen as a final energy carrier.

The national end-use energy demand is divided into 6 major sectors that contribute to the final energy consumption: the export, primary sector, transport sector, industrial, residential, and service sectors. Each of these sectors consumes several energy carriers. Table 17 presents a general scheme for each sector and possible carrier utilization. The aforementioned sectorial representation was based on the European Reference Scenario 2020 (REF2020) and Ricerca Sistema Energetico (RSE) [1], [2]. This general scheme is applied for the basecase scenario and all further ones.

Energy carrier (form) \ Sectors	Export sector	Primary sector	Transport sector	Industry sector	Residential sector	Services sector
Electricity	✓	✓	✓	✓	✓	✓
Biofuel_waste	✓	✗	✗	✓	✓	✓
Oil_products	✓	✓	✓	✓	✓	✓
Solid_fossil_fuels	✓	✓	✗	✓	✗	✗
Natural gas	✓	✓	✓	✓	✓	✓
Heat	✗	✓	✗	✓	✓	✓
Hydrogen	✗	✗	✓	✓	✓	✓

Table 17: General scheme for all possible energy carriers (forms) used in each sector

The total final energy consumption for each year was taken from the Reference Scenario 2020 (REF2020) and kept constant across all scenarios. For each sector, the values are taken from the same database, and they change across years except for the export sector, which is constant from 2020 onwards as there are no proper estimates available. The primary sector is considered the energy branch consumption in REF2020 database. Figure 12 shows the total final consumption (TFC) in GWh that is used in all the final demand scenarios. Also, Figure 13 shows the percentage that each sector consumes for 2020, 2030, 2040 and 2050. These values are assumed to be constant for all scenarios. Instead, the shares in energy carriers ’consumption in each sector change over the years, characterizing each scenario and differentiating it from all the others. Accordingly, certain scenarios exhibit a switch from the consumption of fossil fuels to more sustainable ones in each sector.

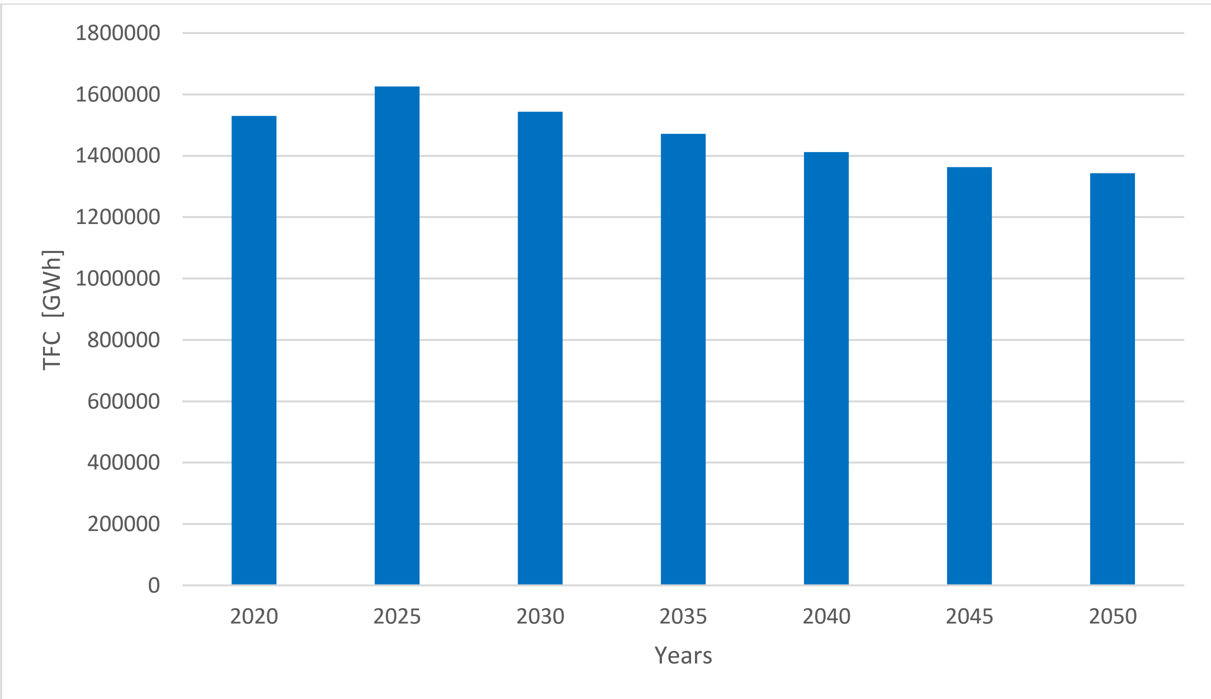

Figure 12: Total final consumption in Italy (2020-2050) [1].

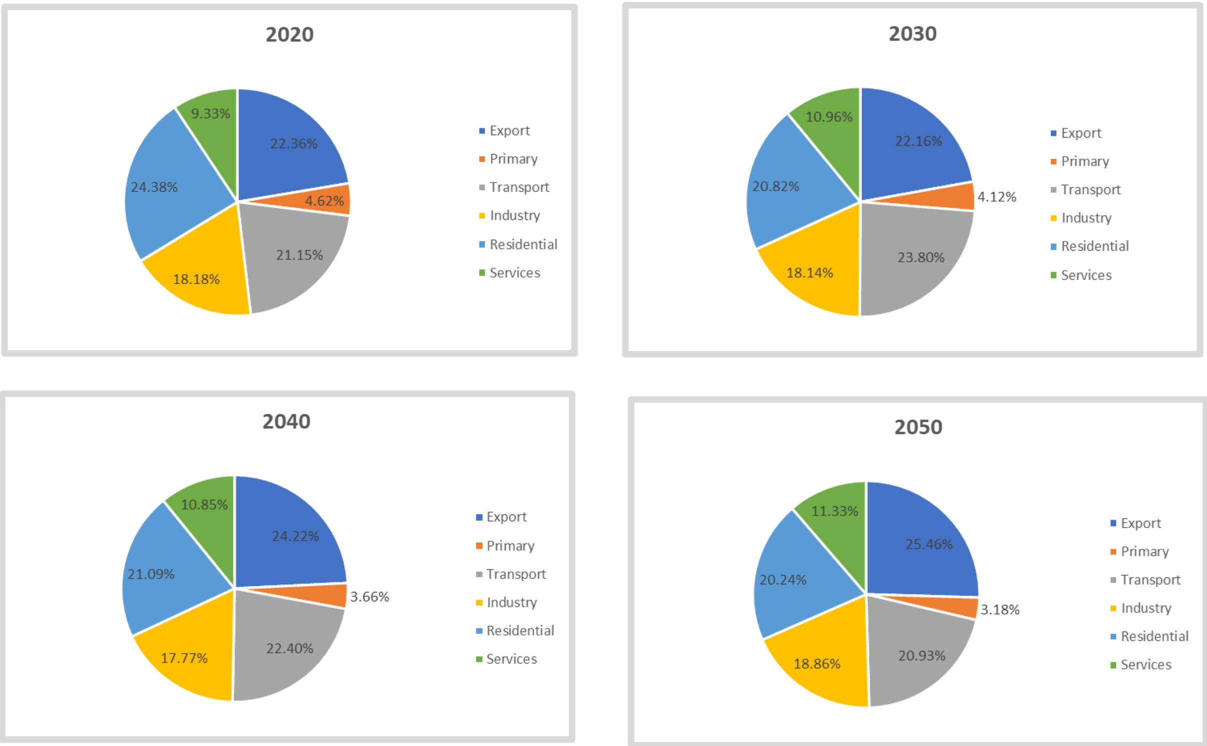

Figure 13: Sectors' shares in the national TFC over the years

Constructing the basecase scenario, which represents business as usual case, hydrogen is only used in the industrial sector. This represents the use of hydrogen in chemical processes, ammonia production and synthetic fuels processes. The energy carrier's ratio used in each sector is taken from RSE data [2]. Referring to the basecase scenario, these ratios are kept constant across all the years (2020-2050) for all sectors excluding the industrial one. Moreover, the hydrogen consumption in the industrial sector is taken according to REF2020. It is forecasted that hydrogen consumption in the industrial energy mix will increase to each 0.08% and 2.15% in 2030 and 2050, respectively, as shown in Figure 14.

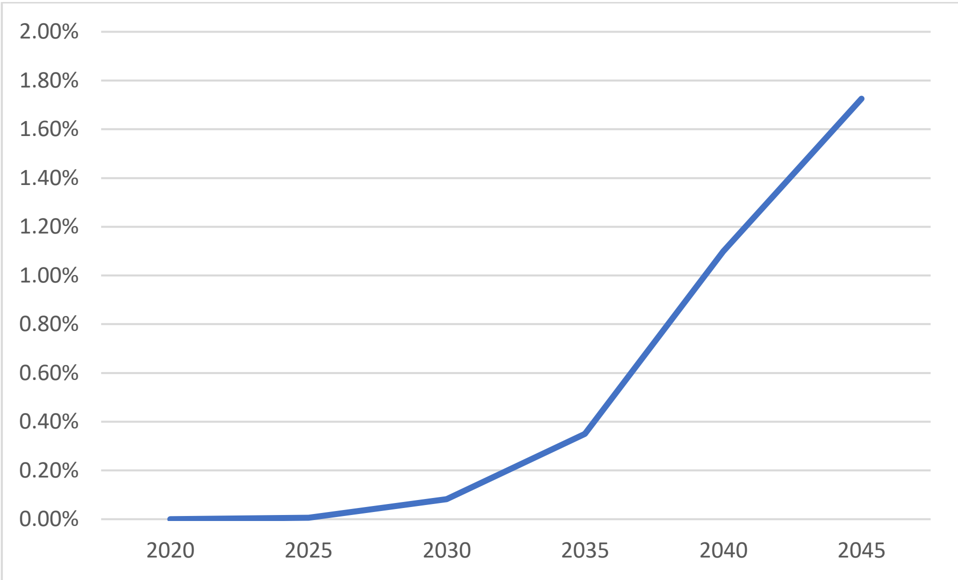

Figure 14: Hydrogen penetration in the industrial sector

For the remaining sectors, the energy carriers' ratios were kept constant over the years, representing business as a usual case with no strategies or ambitions to switch to a more sustainable and less emitting fuel mix. The carrier ratios percentages are shown in Figure 15, Figure 16 and Figure 17 for residential, service and transport sector, respectively. In the transport sector, we can see the domination of oil products representing 93.11% of the total transport energy mix, while in the residential sector, natural gas has 51.93% of the total residential energy mix. This opens the door for hydrogen as an energy carrier to substitute these fuels for more sustainable and less overall emissions related to each sectors.

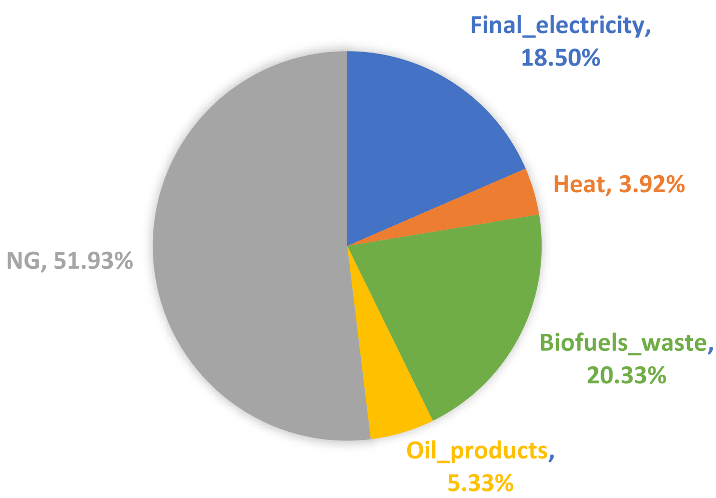

Figure 15: Residential sector energy mix by energy carrier.

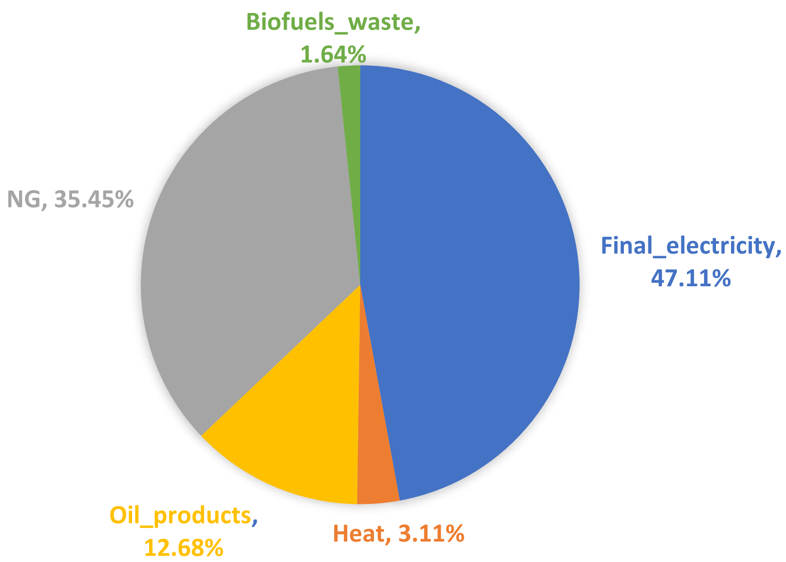

Figure 16: Service sector energy mix by energy carrier.

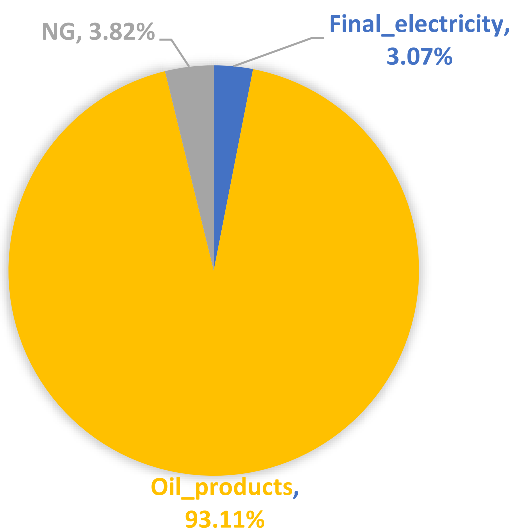

Figure 17: Transport sector energy mix by energy carrier.

3.1.2 Italian Hydrogen Strategy scenario

Scenario definition:

In the national hydrogen strategy scenario, the demand of hydrogen is forecasted according to the Italian Hydrogen strategy. This indicates hydrogen penetration in all the economic sectors. In this scenario, all the same restrictions applied in the basecase are kept with adding more technologies that could utilize hydrogen. These technologies are Fuel cell, blending hydrogen in the gas grid and biological methanation.

Also, all the available hydrogen storage technologies are presented in the model. These technologies are compressed hydrogen storage, liquified hydrogen storage and LOHC storage. According to this scenario, in line with Italian hydrogen strategy, only certain hydrogen chains are possible. They are blue and green hydrogen. There is no grey hydrogen production as in the basecase, resulting in an increasing cost in the SMR due to the retrofitting with CCS section.

Scenario demand profile:

The second scenario is set up with the aim to simulate the hydrogen demand in the TFC of energy in Italy according to the Italian National hydrogen strategy and Integrated National Energy and Climate Plan (INECP) [3], [4]. The plan aims to use hydrogen in the national decarbonization process in accordance with INECP, which reflects the broader environmental agenda of the European Union.

The plan aims to increase the current hydrogen penetration in the final energy consumption from 1%, which represents around 480,000 ton to reach 2% in 2030. However, the only target mentioned for the sectors is the transport sector. The INECP, in particular, predicts that approximately 1% of the Renewables target for transport will be obtained from hydrogen which is equivalent to approximately to 21,132 tons of green hydrogen [80].

According to the Italian National Hydrogen Strategy, hydrogen can be used to decarbonize the hard-to-abate sectors characterized by high energy intensity and the lack of scalable electrification solutions. Two of these sectors are the petroleum, and refining sectors, where hydrogen is already used as a feedstock both in the ammonia, methanol, and synthetic fuel production. In Italy, the primary steel industry has an important role, having in operation one of the biggest integrated steel plants in Europe. Today, production is based on a blast-furnace (BF) in which the iron ore is smelted into iron by using coke as reducing agent. The molted iron is then converted into steel in the Basic Oxygen Furnaces (BOF).

There are two promising routes to decarbonize steel production: applying CCS to the existing BF-BOF steel plant or avoiding CO2 emissions through the use of hydrogen. In the second case, the BF-BOF steel plant should be dismantled and substituted with direct reduced iron (DRI) plant. The DRI is a commercial process in which natural gas is used as a reducing agent. However, in the long term, H2 from electrolysis could be used instead of natural gas with the same function. The DRI-H2 process is still in the R&D phase, but there are interesting pilot plants in construction in Europe[81], [82].

Moreover, the heavy transport sector represents a great opportunity for hydrogen utilization as fuel. To date there are already strong interests and consistent investments in development hydrogen technology for automotive applications [30]. Asiatic motor companies have already placed on the market some light vehicles fueled by hydrogen. For example, China aims for more than 1 million FCEV in service compared with just 1,500 by 2030 while Japan wants to have 800,000 FCVs sold by that time from around 3,400 currently. However, the current main limits of this technology spread are economically based.

Indeed, fuel cell stacks and compact on-board hydrogen storage tanks still present very high production costs, which makes light FCEVs not competitive with current fossil-based or hybrid alternatives yet [83] . The main criticism for light vehicles is the space available for fuel storage. Range requirements and limits in space for the H2 tank impose compressing the gaseous fuel up to 700 bar [84]. This requires using very expensive metal alloys to guarantee safety parameters of the car and respect space limits.

A different situation occurs with heavy trucks and buses. They offer higher space availability for the on-board tank, enabling lower pressure levels and ensuring longer ranges. Common pressure value is 350 bar. To date only few hundreds of hydrogen fueled buses and trucks are in operation at a global level, mainly thanks to some pilot projects [85],[23].

In the building sector, with particular reference to residential and commercial heating, hydrogen can also contribute to decarbonization, as a competitor to heat pumps and other low-carbon technologies to replace methane and petroleum products. In fact, in terms of TCO, hydrogen boilers can be a valid alternative to heat pumps and biomethane heating to contribute to a complete decarbonization of the sector. Their diffusion will require a progressive conversion of the existing gas network to hydrogen, both in terms of transmission and distribution; this will allow consumers to use hydrogen boilers to take advantage of their greater flexibility than heat pumps, thanks to a smaller footprint and less fluctuation in efficiency. Hydrogen boilers can therefore be a good alternative to methane ones where the installation of heat pumps is not technically possible or does not offer an efficiency that justifies the initial investment. However, hydrogen demand depends on renovation rates, the relative shares of biomethane and hydrogen, and the mix of heating technologies [86]

Taking these considerations and the Italian National Hydrogen Strategy estimates into account and interpolating the data to obtain the remaining years' hydrogen demand, a hydrogen demand scenario is estimated using the following hypotheses:

- Hydrogen will be utilized as final energy carrier in industrial, transport, residential and service sectors according to the Italian National Hydrogen strategy, however, the strategy does not say how much hydrogen is used inside each sector except for transport sector. It mentions that by 2030, hydrogen penetration should be 1% of TFC and it can go up to 20% by 2050. Hence, these values were taken.

- Having the target for the transport sector (1% of renewable target mentioned in INEPC in 2030 comes from low emission fuels) which is around 30 kth2/year and the percentage of total hydrogen in the final energy consumption (2% in 2030) mentioned in the Italian hydrogen strategy. These numbers were interpolated and forecasting until 2050, hydrogen penetration in the transport sector is forecasted, Figure 18. According to this scenario, hydrogen will substitute oil products, presenting the replacement of means of transportation that uses fossil fuel derived products.
- According to The fit for 55 Package, 55% of hydrogen total final consumption is assumed to be used in the industry sector [87], the hydrogen will be used to decarbonize hard to abate sector, especially steel sector using DRI technology. Hence, it will substitute natural gas, solid fossil fuels and oil products in the energy mix, resulting in phase-out of coal and oil products by 2050.
- In the building sector, 30% of the hydrogen total final consumption is assumed to be used by the residential sector while the remaining 15 % is used by the service sector. These values (30% and 15%) are assigned according to the ratios of TFC of each sector in 2020, as approximately the TFC of the residential sector is twice the service one. In this case, hydrogen will be utilized using different technologies, especially to decarbonize heating and cooling sector using hydrogen fired boilers or hybrid heat pumps. Hence, it will substitute natural gas as well as oil products, resulting in a phase-out of oil products by 2050 in the residential sector. Moreover, the substitution rate of oil products in the service sector is the same as the residential sector.
- Export and primary sectors' energy carrier ratios are kept the same as the basecase scenario.

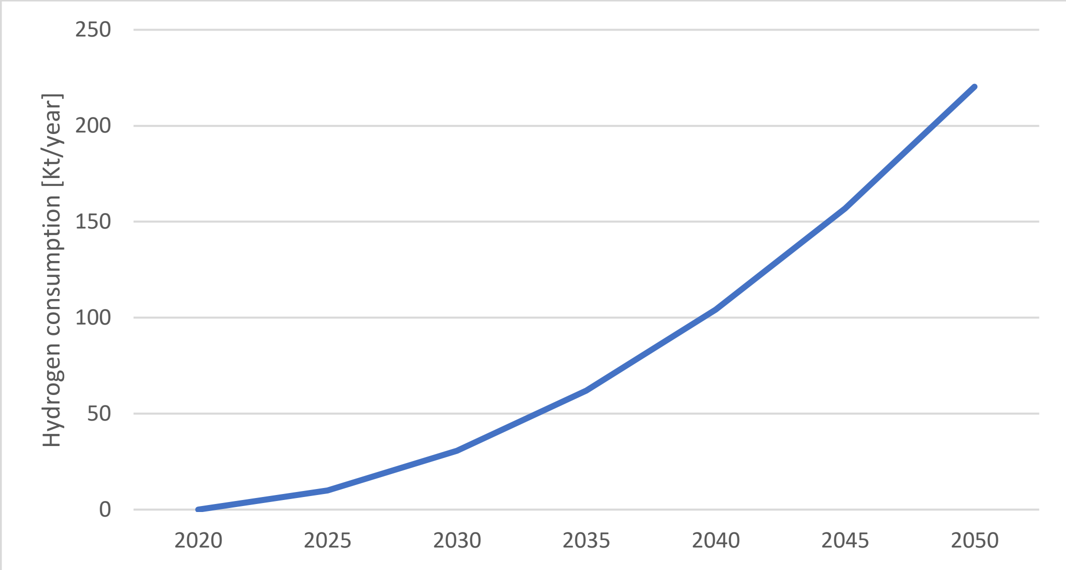

Figure 18: hydrogen penetration in the transport sector.

This results in hydrogen penetration in the final energy demand of 20% by 2050, which is around 6000 Kton of hydrogen across all sectors. The penetration for transport, industrial, residential, and service sectors is 0.19%, 5.1%, 2.1% and 2%, respectively, in 2030 while in 2050, these values increase to 2.3%, 43.5%, 20.5% and 18.3%, respectively.

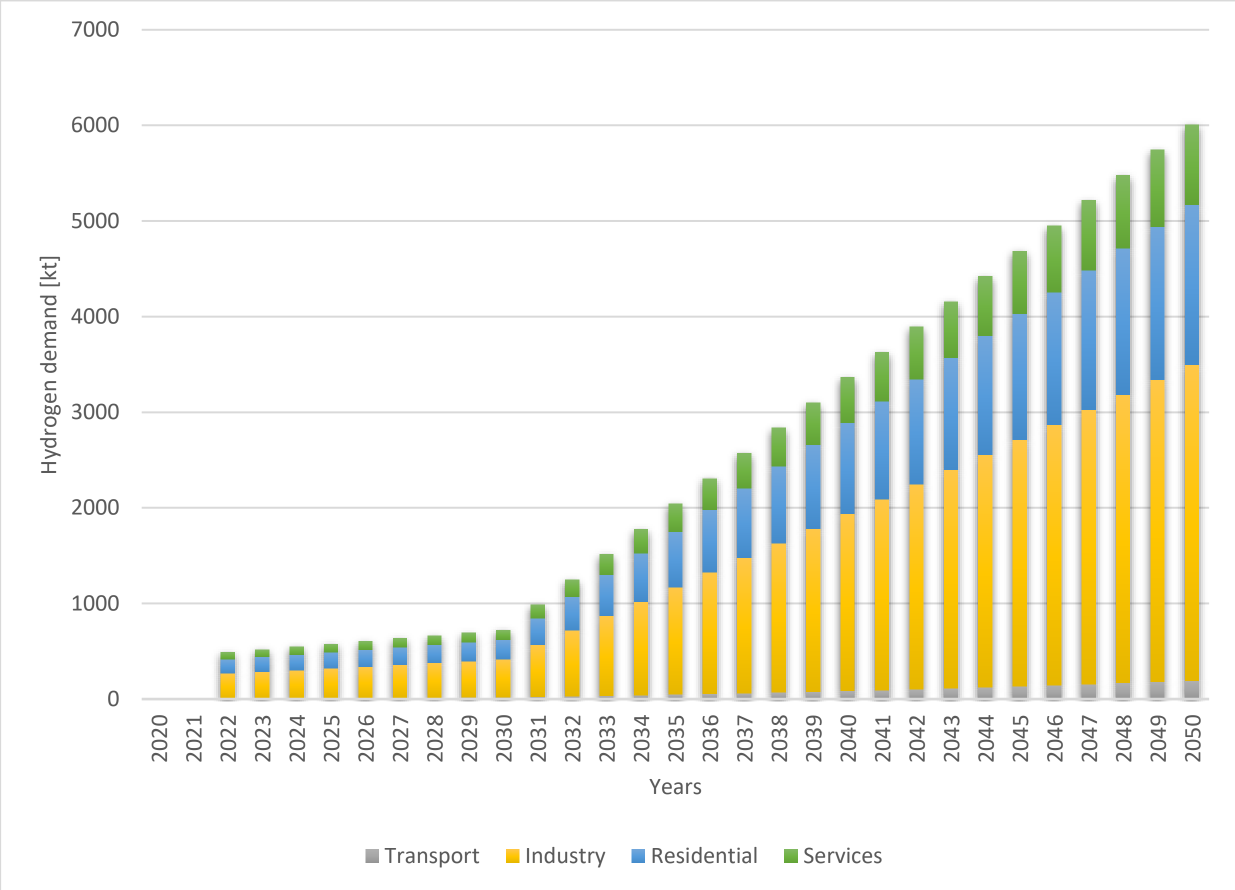

Figure 19: Hydrogen sectorial demand (Italian national strategy)

3.1.3 High penetration for transport scenario

Scenario definition:

This scenario is focused on high hydrogen penetration in the transport sector. As in the national strategy demand scenario, hydrogen penetration is low and according to recent studies and motivation mentioned below, the transport sector is expected to have high penetration by 2050. All other parameters, including technologies, are kept the same.

In the national demand scenario, the hydrogen penetration in the transport sector was relatively low compared to the adaption potential of the Italian transport market. For example, heavy trucks and buses account for 30% of the final energy demand in the transport sector in Italy [58], a comparable level to other European countries with high hydrogen ambitions. On the other hand, for the railway transport, there's around 4,763 km of rail network in Italy are still served by diesel trains with domestic actors already working on their conversion to hydrogen [57]. Taking these motivation into consideration, the scenario is set up with the same final demand as in the Italian Hydrogen strategy scenario but with more hydrogen penetration in transport sector. The demand related to industrial, residential, service, primary and export sectors are kept unchanged.

Scenario demand profile:

This scenario is based on the EU4 scenario developed by the IEA for four EU countries, including Italy [88]. The EU4 scenario focuses on different aspects however, only the numbers related to hydrogen penetration in the transport sector were chosen. Hence, according to this scenario, the share of FCEV (thus, of hydrogen) is equal to 2.4% by 2030 (low penetration) and 28.5% by 2050 (high penetration). This scenario was chosen as it allows a quantitative analysis of the demand at two years with a high penetration gap. Moreover, recent reports matched these numbers (2.4 by 2030 and 28.5% by 2050) from EU4, where the hydrogen council estimated a penetration of 25% in passenger cars in 2050 [89], indicating the available potential for hydrogen in the transport sector. A more recent outlook has adjusted this value down, to account for 14% in the transport sector in 2050 [7]. However, the implication on the mobility sector is still unclear, with the shift of priority for road transport in recent policies to public transport and heavy carbonized vehicles [90].

In this scenario, oil derived products such as gasoline and diesel that are used by light vehicles and heavy weight transport are substituted by hydrogen, have a decrease rate equals to hydrogen increase rate, as this will help to decarbonize the transport sector. This results in achieving a percentage of oil products in the energy mix has dropped from 93.11% in 2020 to 63.27% in 2050, as shown in Figure 20.

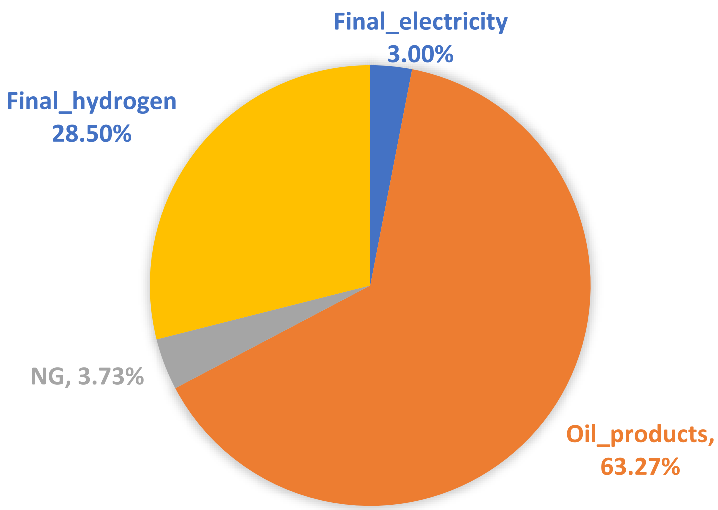

Figure 20: Transport energy mix 2050 (Third scenario)

3.2 Demand hourly profiling for the various energy carrier

Once the annual demand for all the possible carriers for each sectors has been defined according to each available scenario, the following step is to define their hourly profile during the year.

All carrier types were assumed to have the same hourly profile as the electricity demand profile in Italy. The data were collected using Terna website for the last 365 days then averaged to obtain an average hourly profile for the whole year. This assumption is taken for simplicity of representation as specifying more than one demand curve related to each carrier requires high computational power. Moreover, the hourly profile demand of hydrogen is very hard to anticipate with the limited information available.

After that, the profile was normalized so that can be used for each year's demand. Figure 21 shows the implemented hourly profile demand in the model.

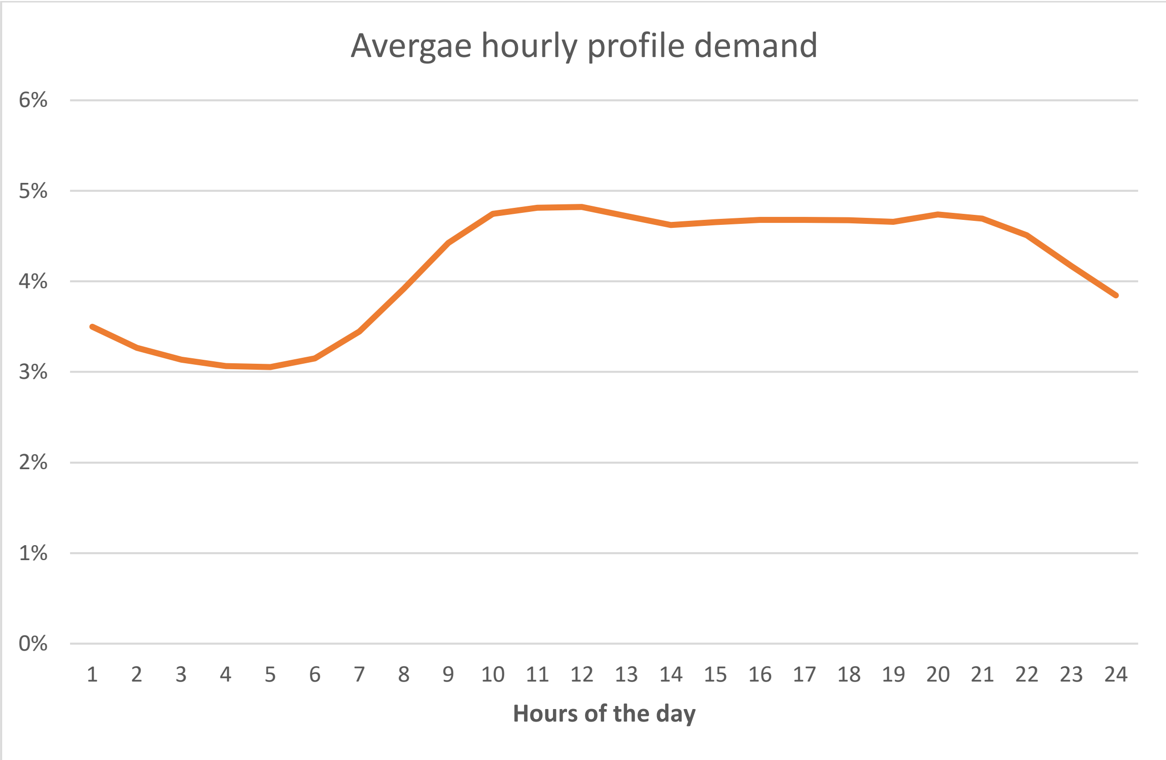

Figure 21:Average hourly profile load curve

3.3 Input data description

In this section, the main input data will be presented, starting from the available primary resources and their price over the modeling period to the main techno-economic parameters for each implemented technology.

3.3.1 Available resources

One the of the required input data for the model is the available resource which in Hypatia framework represents a raw energy carrier (primary energy) comes from imports of fossil fuels such as natural gas and coal. This also includes the available natural resources such as wind, solar and hydro.

Starting from the fossil fuels resources, the available sources are solid fossil fuels which represent coal, natural gas, oil products and crude oil. Each of these resources comes with a price which varies over the years. Moreover, the annual maximum availability is unlimited expect for coal as the study is focused on Italy. All the coal consumption in Italy is imported from outside without any domestic production. Hence, maximum annual production is assumed to be 10% of the OECD EU total supply in 2020 which corresponds to 580 GWh of coal.

Regarding the price of each commodity, it changes overtime according to the forecasting done by SESAM research group [78]. Starting from fossil fuel commodities, such as coal and natural gas, both prices are increasing over the modeling period, as shown in Figure 22 and Figure 23. The forecasting method is running average over the whole modeling period which is up to 2050. The historical data for both commodities were obtained from Natural gas EU Dutch TTF spot market price [91] and Rotterdam Coal Futures spot price [92].

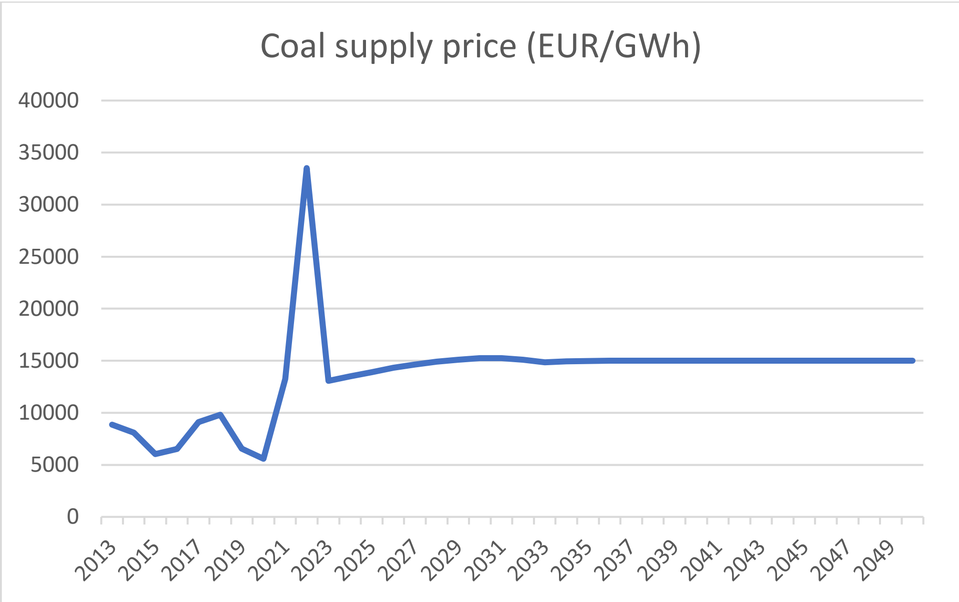

Figure 22: Coal supply price over the modeling period.

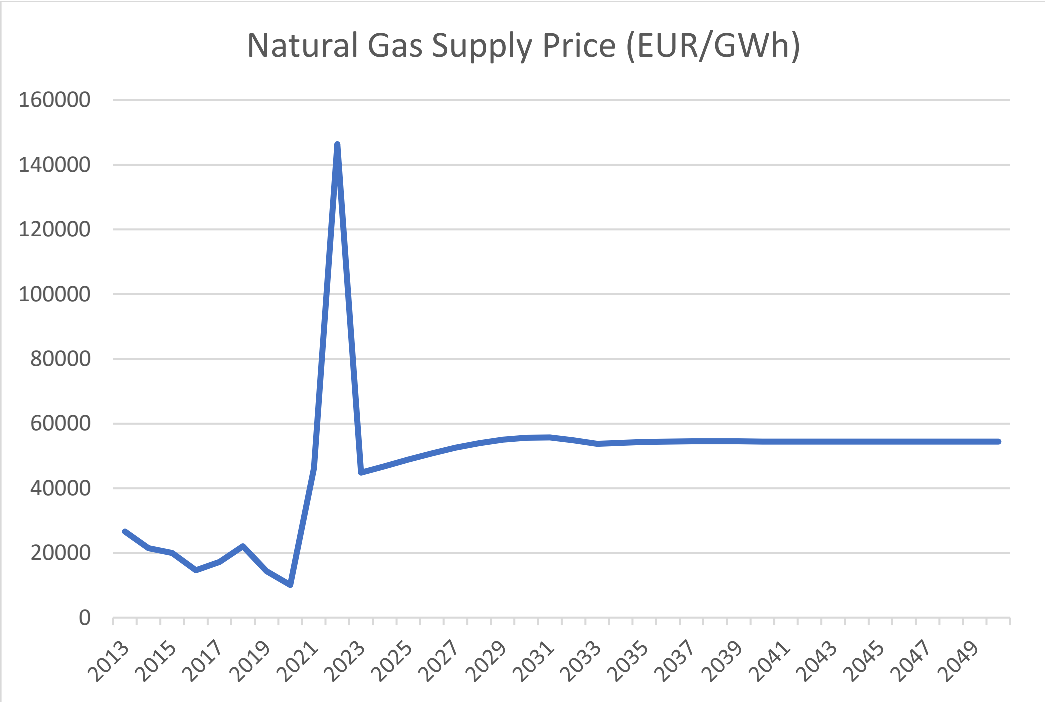

Figure 23: Natural gas supply price over the modeling period.

Regarding oil products import for Italy, the historical data were obtained from Weekly Oil Bulletin website [93] and using running average method as well, prices over the modeling period were forecasted, as shown in Figure 24.

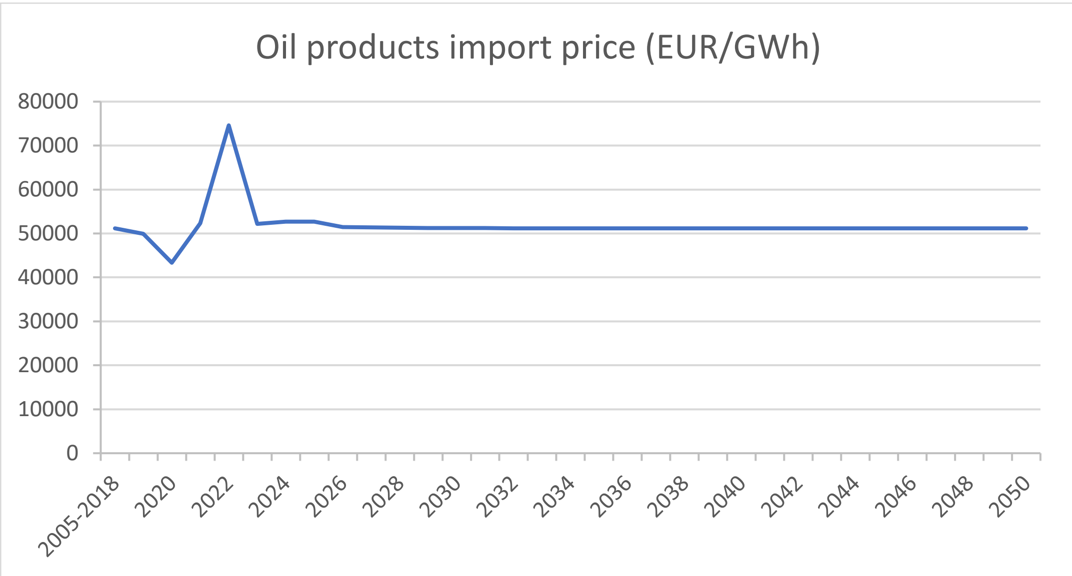

Figure 24: Oil products import price over the modeling period.

Crude oil prices were also obtained using Registration of Crude Oil Imports and Deliveries in the European Union database [94] and forecasted over the modeling period as shown in Figure 25.

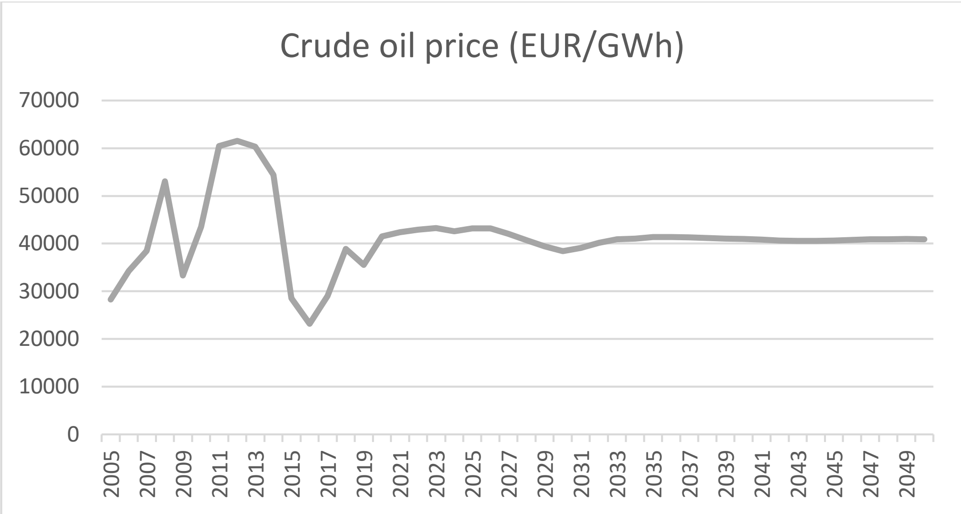

Figure 25: Crude oil price over the modeling period.

Regarding primary renewable resources such as hydro, biowaste and geothermal, here below are the main assumptions reported. Hydroelectric, which in the model is divided into two technologies which are the pumped hydro power plants and hydroelectric power plants (run of river), had been already exploited at its maximum. It is unlikely to expect a consistent increase in its capacity. Same consideration can be made for geothermal heat and power generation. For biowaste supply, it is considered available all year long and will be consumed as needed with a price of 140491.8 Euro/GWh [78].

3.3.2 Technical parameters of implemented technologies

The first class of data that the model requires is the main technical parameters for the implemented technologies.

The first data that needed to be inserted is the cost data related to each technology such as investment cost, fixed cost, and variable cost.

Table A 1 listed in appendix A shows the investment cost per GW for each technology. The investment cost for each technology decreases with time indicating a learning rate for each one. These data were obtained from SESAM database [79]. The fixed cost of each technology is mainly represented as a percentage of the investment cost, while the variable cost is zero as mentioned before. This is due to the assumption of assigning the variable cost to the commodity price.

The second data that the model requires is the technical parameters such as efficiency, minimum capacity factor, maximum capacity factor and availability. Table A 2 listed in appendix A demonstrates the efficiency of different technologies. Some of the well-known technologies in the market have an increasing efficiency indicating a learning curve such as electrolyzer (PEM), CG + CCS and fuel cells [78]. Table 18 demonstrates the technical features of several technologies.

Technology	Min capacity factor	Max capacity factor	Availability	Max new capacity [GW/year]
Electrolyzer (PEM)	0.067	1	1	1.00E+10
CG + CCUS	0.1667	1	0.92	1.00E+10
BG + CCUS	0.1818	1	0.93	1.00E+10
SMR + CCUS	0.1818	1	0.92	1.00E+10
Fuel cell (PEM)	0.067	1	1	0.5
NG PP	0.1	1	0.92	1.00E+10
Oil PP	0.1	1	0.92	0
NG_CHP_PP	0.1	1	0.9125	1.00E+10
BW_CHP_PP	0.1	1	0.93	0.2
Blend_CHP	0.1	1	0.9125	1.00E+10
Geo_PP	0.8	1	0.95	0.1
Hydro_PP	0.34	1	1	0.5
Solar PV	1	1	1	5
Wind PP	1	1	1	2

Table 18: Main technical parameters for several technology.

Regarding the emission data, the emissions originated from each end-use sector are calculated considering all the energy carriers consumed by the sector and the relative emission factors of such carriers [95]. Specifically, the emission generated per unit of energy consumed by an end use sector (i.e., emission factor of the end use sector) is calculated as a weighted average of the emission factors of all the energy carriers consumed by that sector, weighted with the carrier ratios of such carriers in that sector (i.e., the share of that carrier in the total energy consumption of that sector. Knowing the energy carriers' ratios for each end-use sector, it was possible to obtain the avoided emissions, based on the demand scenario design mentioned in Hydrogen energy scenarios design. Table 19 shows the emission factor energy carriers implemented in the model. For example, oil products' emission factor is calculated by summing up gasoline, gas oil and LPG test data emission factor.

Carrier	Oil products	Solid fossil fuels	Biofuel waste	NG
Emission factors (tonCO2/TJ)	70.85933333	100.1263333	88.8815	57.632
Emission factors (kgCO2/GWh)	254889.6882	360166.6667	319717.6259	207309.4

Table 19: Emission factors for available energy carrier carriers [95],[78].

Some considerations on the hydrogen storage technologies are presented below.

The available storage capacities were generally obtained by assuming 3 days of storage as mentioned previously in Section 2.4.3. However, due to the high cost of investment for storage technologies, the model does not induce any storage capacity. So, unlimited storage residual capacity for each kind of storage and the code will decide which one to use based on the lowest cost.

3.4 Results

In the section, the main results of different scenarios analysis are presented. Starting from the basecase results, focusing on the power generation and consumption allocation is presented, followed by a detailed analysis on hydrogen production and utilization.

Lastly, some consideration regarding Hydrogen to X are presented.

3.4.1 Basecase scenario (BAU)

In the basecase scenario, electricity generation is presented in Figure 26. Oil and solid fossil fuels are phased out after 2043 as there is no new additional capacity for those kind of plants. Moreover, NG production is also decreasing with time indicating the already established decarbonization targets of Italy.

Hydro-electric generation has a constant trend across the years with full exploitation of the potential in Italy, as well as geothermal energy.

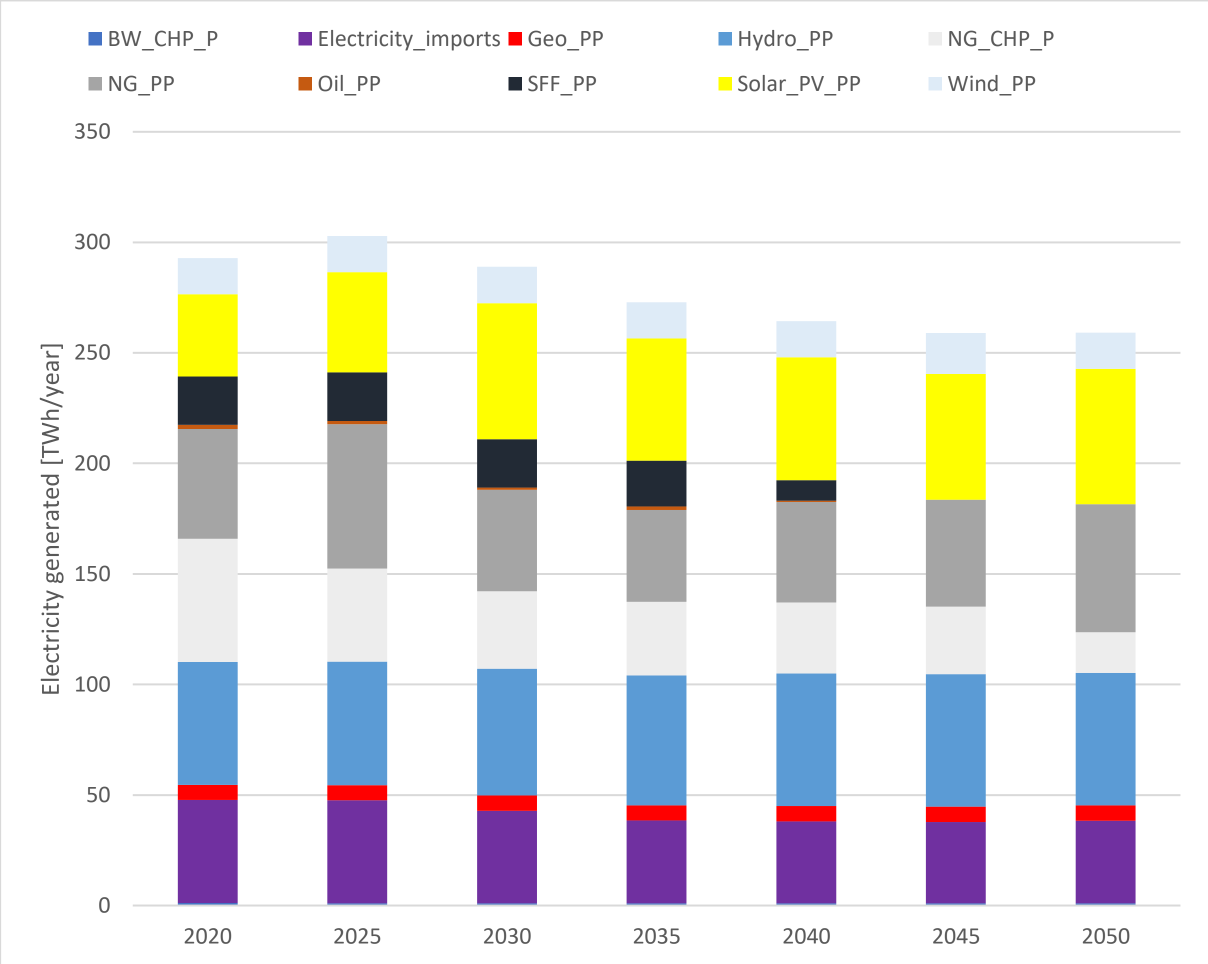

Figure 26: Electricity production in the basecase scenario

Electricity from wind generation has almost a constant trend over the years as well as constant capacity, as demonstrated by Figure 26 and Figure 27. The phase-out of coal and oil products in electricity generation is replaced by NG power plants and solar PV power plants, however, the increase in solar energy is not only noticeable after the phase-out but even before starting from 2026. Electricity from imports decreases with time as new capacities are installed and it becomes more convenient to self-produce than buying electricity at a price of 55.20 EURO/MWh. Although, there is almost 3 GW of BW-CHP power plants available to produce, production is very limited.

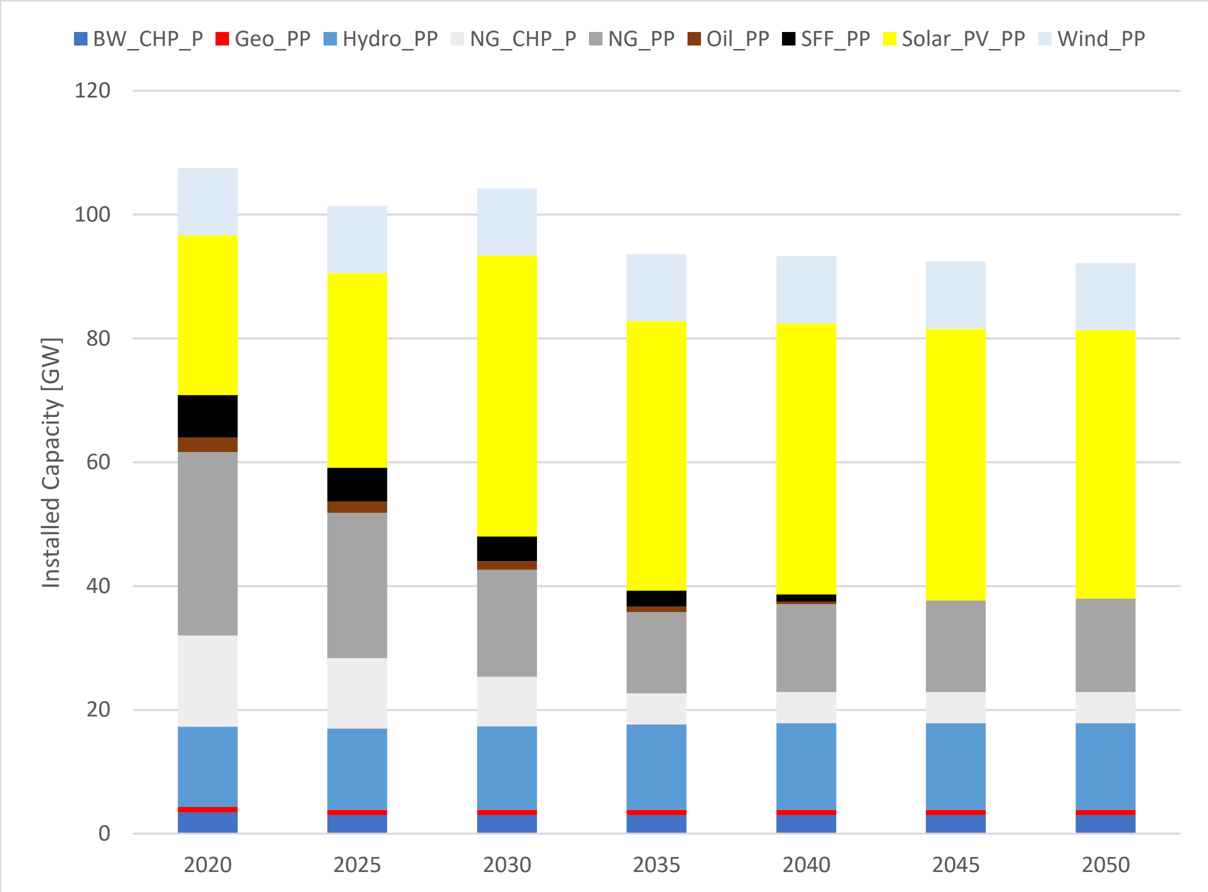

Figure 27 :Electric installed capacity in the basecase scenario

Technology	2020	2030	2040	2050
Electricity_imports	13%	13%	13%	14%
Geo_PP	2%	2%	2%	3%
Hydro_PP	16%	18%	21%	22%
NG_CHP_P	33%	17%	9%	9%
NG_PP	14%	16%	21%	23%
Oil_PP	1%	0%	0%	0%
SFF_PP	6%	7%	3%	0%
Solar_PV_PP	10%	21%	23%	23%
Wind_PP	5%	5%	6%	6%

Table 20: Electricity production share - basecase scenario.

Looking at

Technology	2020	2030	2040	2050
Electricity_imports	13%	13%	13%	14%
Geo_PP	2%	2%	2%	3%

Hydro_PP	16%	18%	21%	22%
NG_CHP_P	33%	17%	9%	9%
NG_PP	14%	16%	21%	23%
Oil_PP	1%	0%	0%	0%
SFF_PP	6%	7%	3%	0%
Solar_PV_PP	10%	21%	23%	23%
Wind_PP	5%	5%	6%	6%

Table 20, the shares of each production technologies are demonstrated over the whole modeling period. The production from renewable energy is almost 40% over the whole modeling period, showing that if Italy continues with the current applied strategy, it will reach an electric penetration of 56% in 2050. However, NG still has a large share of production.

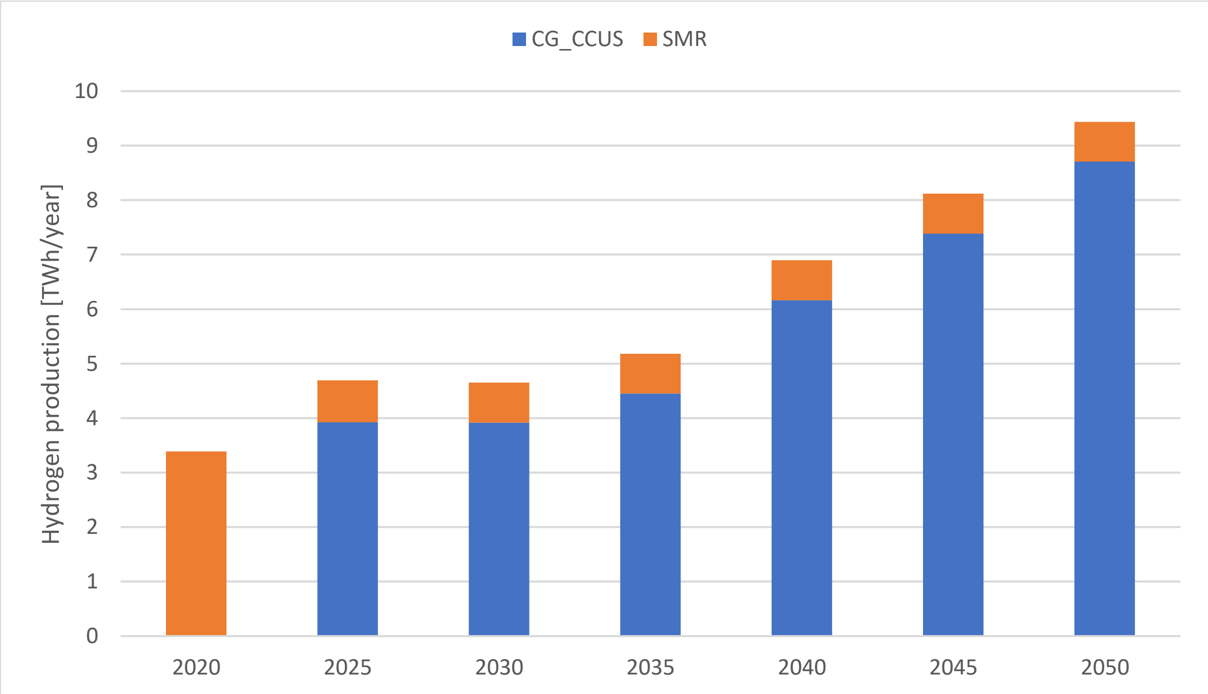

Figure 28: Hydrogen production in the basecase scenario

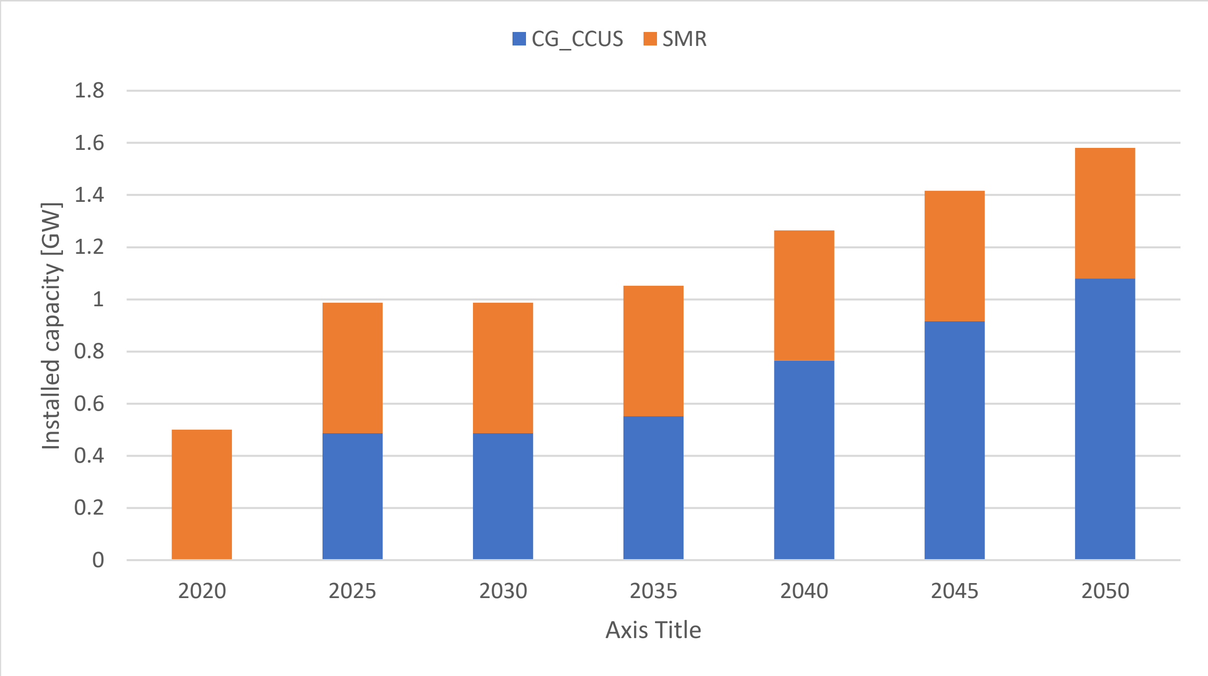

Figure 29: Hydrogen installed capacity in the basecase scenario

The hydrogen production in the basecase is mainly composed of two technologies SMR without CCS (grey hydrogen) and CG + CCS (blue hydrogen). The production in the first year totally comes from SMR production, however after that CG dominates the production. SMR works with its minimum capacity factor and the rest of the production is met by CG technology as shown in Figure 28. Moreover, the capacity of SMR is kept at 0.5 GW without installing new capacities. All the new capacities are installed for CG + CCS technology as it is more convenient for the production, as shown in Figure 29. This shows that coal gasification technology is much cheaper and more convenient to produce hydrogen than SMR.

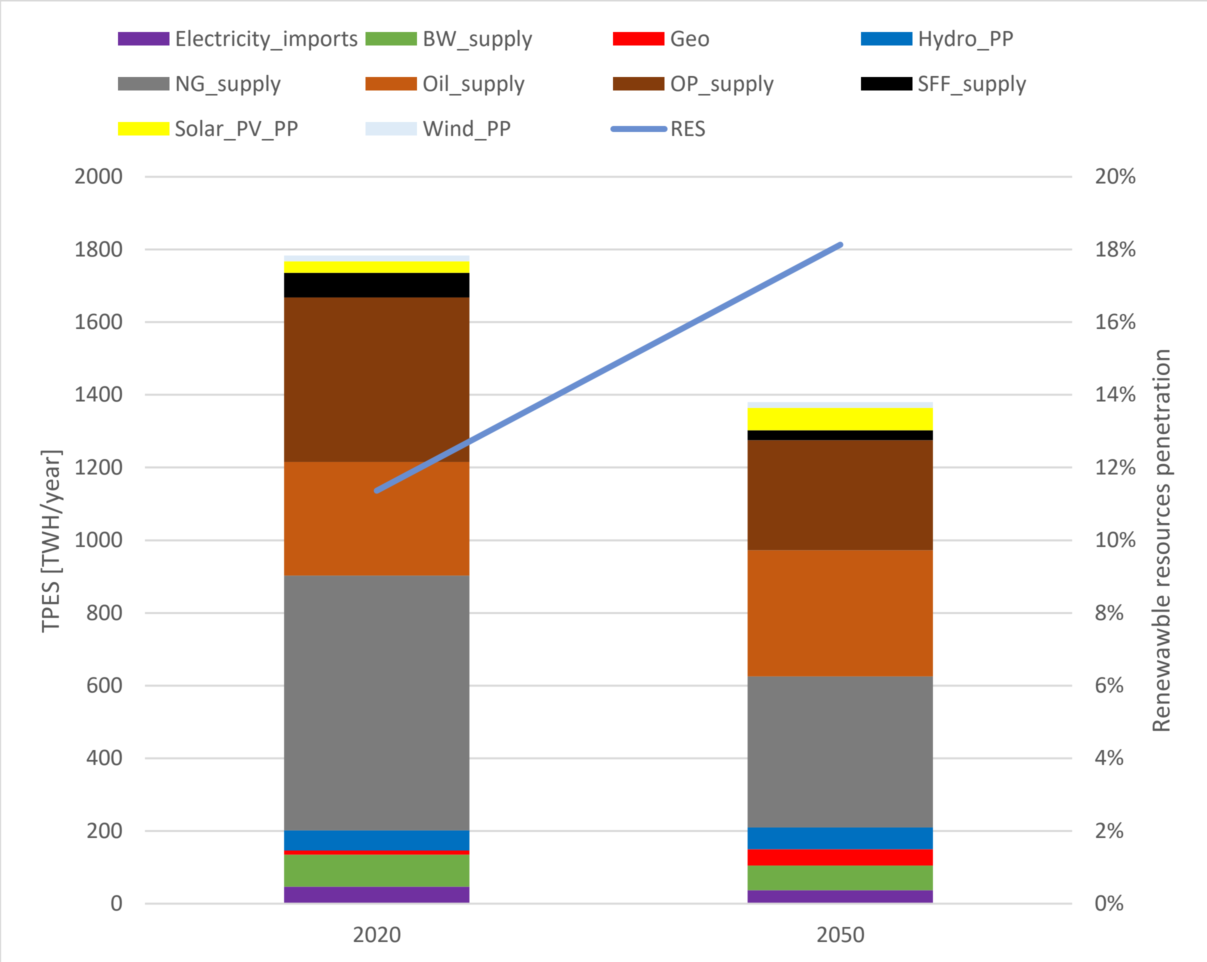

Figure 30: Italian primary energy consumption by source in 2020 and 2050 – basecase scenario

From primary energy consumption, the total consumption decreases as shown in Figure 30, with increasing RES to reach 18% by 2050. This increase in renewable penetration comes from an increase in production from solar and geothermal energy with decrease in NG, solid fossil fuels and oil consumption.

3.4.2 National hydrogen strategy scenario

In this scenario, hydrogen demand is forecasted according to the Italian Hydrogen Strategy which means high penetration across different sectors as mention in Section 3.1.2. Moreover, hydrogen is produced from three different technologies: SMR + CCS, CG + CCS, electrolysis. Moreover, NG power plants are retrofitted with CCS units.

Compared to the basecase, this scenario has more renewable electric penetration as NG electricity production keeps decreasing until it reaches 21% in 2050, showing an

8% decrease compared to the basecase. This decrease in NG power plants production is substituted with increased production from renewable energy sources, especially wind, as shown in Figure 31.

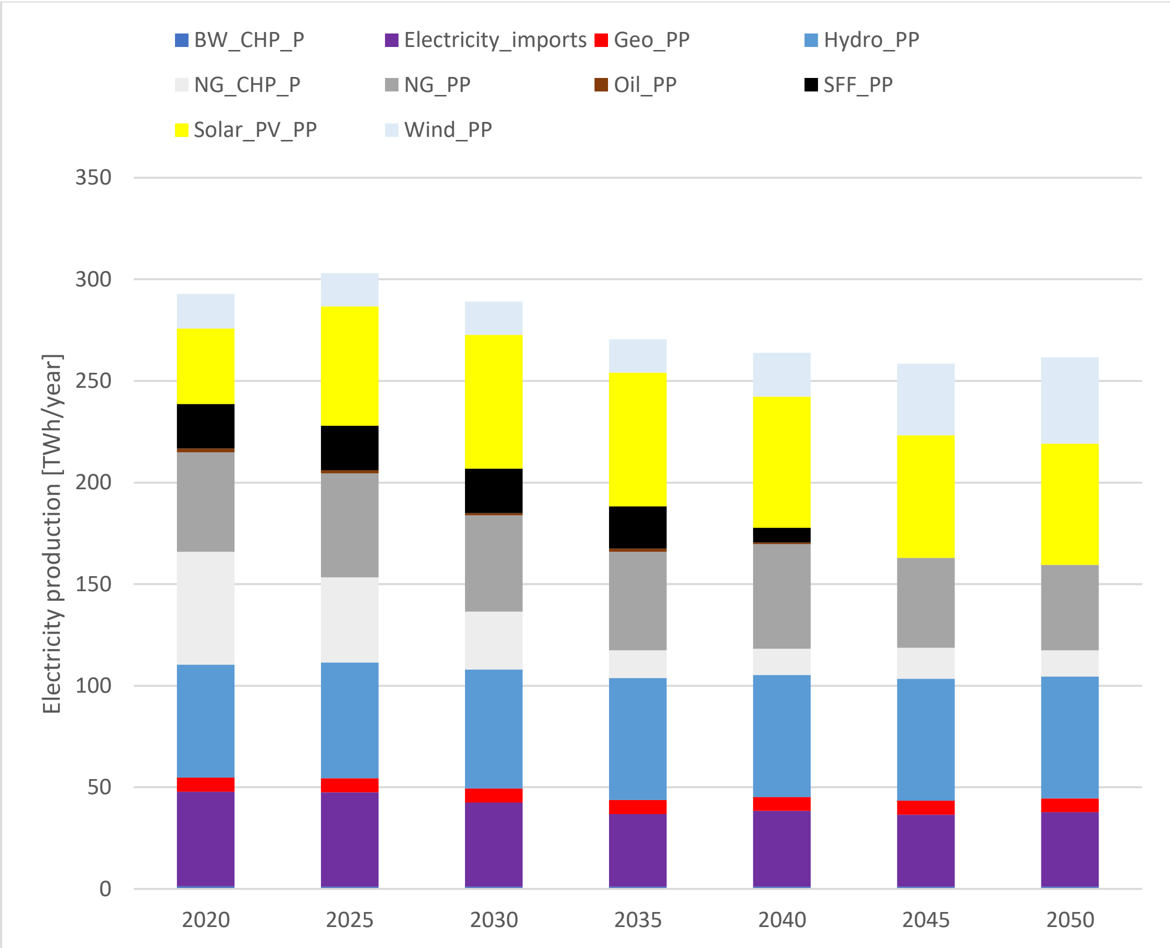

Figure 31: Electricity production in the National hydrogen strategy.

Figure 32 shows a huge increase in wind installed capacity, especially after 2046. This contributes to a 10% increase in production from wind power plants compared to the basecase by 2050. This is mainly due to the increase the electricity generation related to electrolysis consumption as the production of green hydrogen starts from 2046. Also, due to retrofitting NG power plants with CCS, their cost increases, so there's no more new installation as the basecase and wind power plants replaces them.

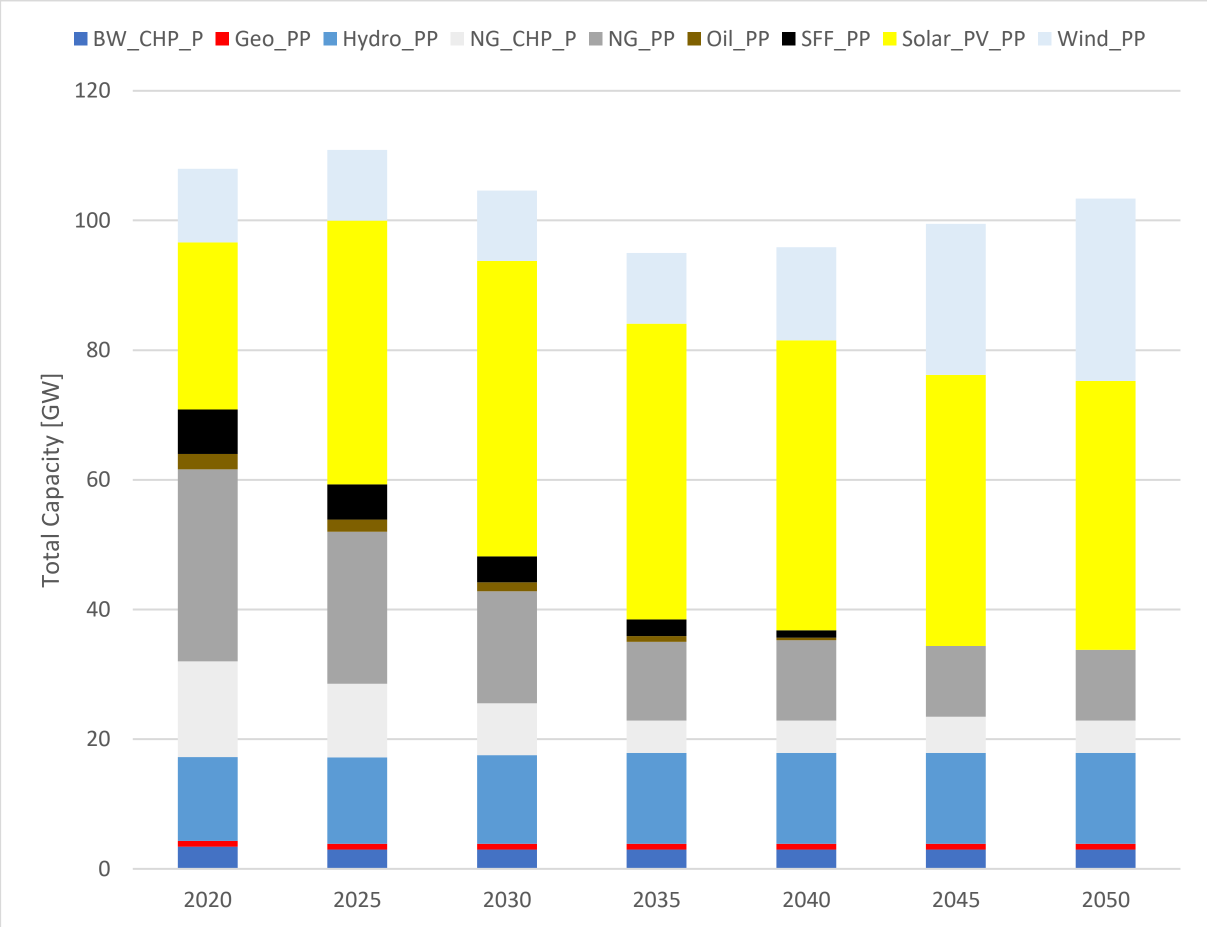

Figure 32: Electric installed capacity - National hydrogen strategy scenario

Technology	2020	2030	2040	2050
Electricity_imports	16%	14%	14%	14%
Geo_PP	2%	2%	3%	3%
Hydro_PP	19%	20%	23%	23%
NG_CHP_P	19%	10%	5%	5%
NG_PP	17%	16%	19%	16%
Oil_PP	1%	0%	0%	0%
SFF_PP	7%	8%	3%	0%
Solar_PV_PP	13%	23%	24%	23%
Wind_PP	6%	6%	8%	16%

Table 21: Electricity production share - National hydrogen strategy scenario.

Hydrogen production in the national strategy scenario follows almost the same trend as the baseline however, with increasing demand, SMR + CCS technology starts at 2040 to reach 4% of the total production, as shown in Figure 33 and Figure 34. This percentage keeps increasing until it reaches 40% in 2050.

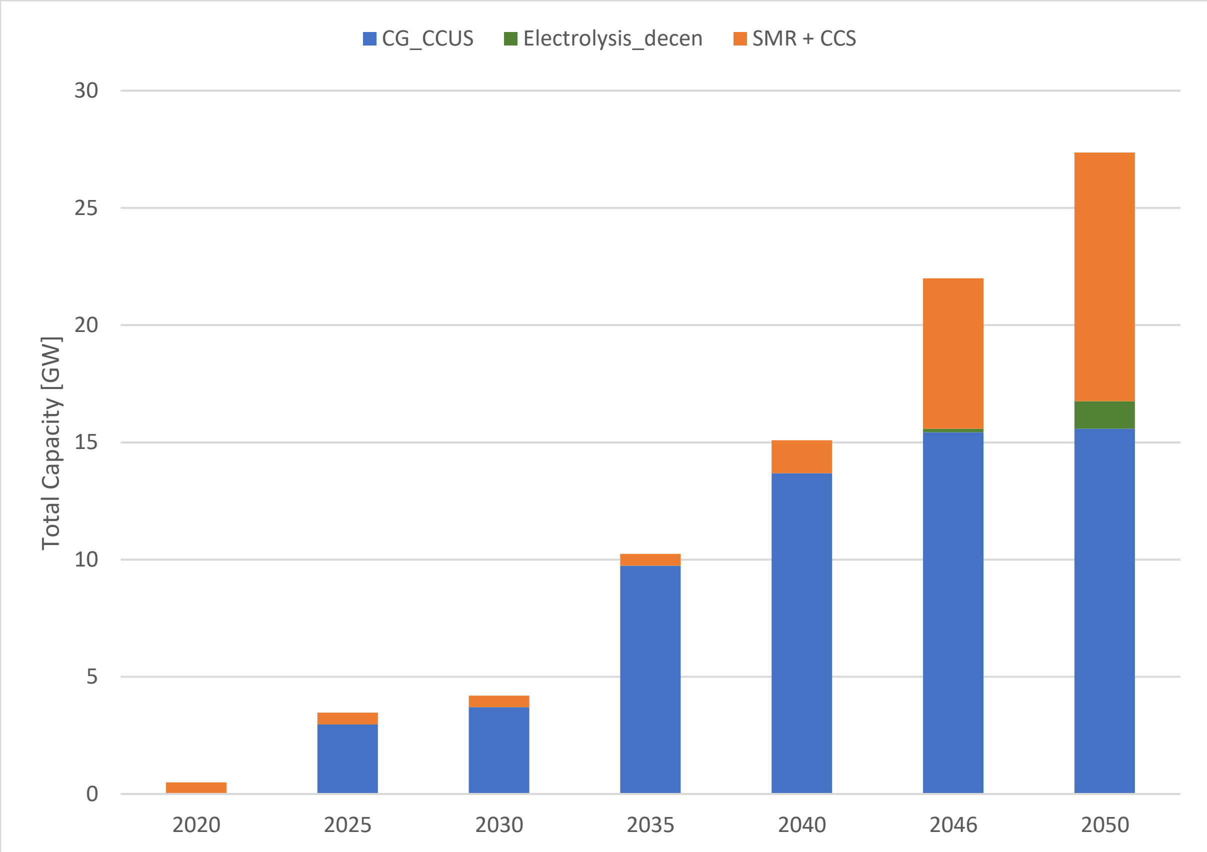

Figure 33: Total installed hydrogen capacity - National hydrogen strategy scenario

Electrolyzer starts to produce in 2046 with an increasing production share summing up to reach 1.5% in 2050 with a total capacity of 1.17 GW. In 2046, CG + CCS technology reaches its maximum limit of solid fossil fuel supply, hence gives room for electrolyzer to be competitive with also an increasing cost of NG.

Increasing the hydrogen demand with adding restriction on CG technology made SMR +CCS and electrolyzer produce more compared to the basecase, however, green hydrogen from electrolyzer comes into the picture in the late 40s.

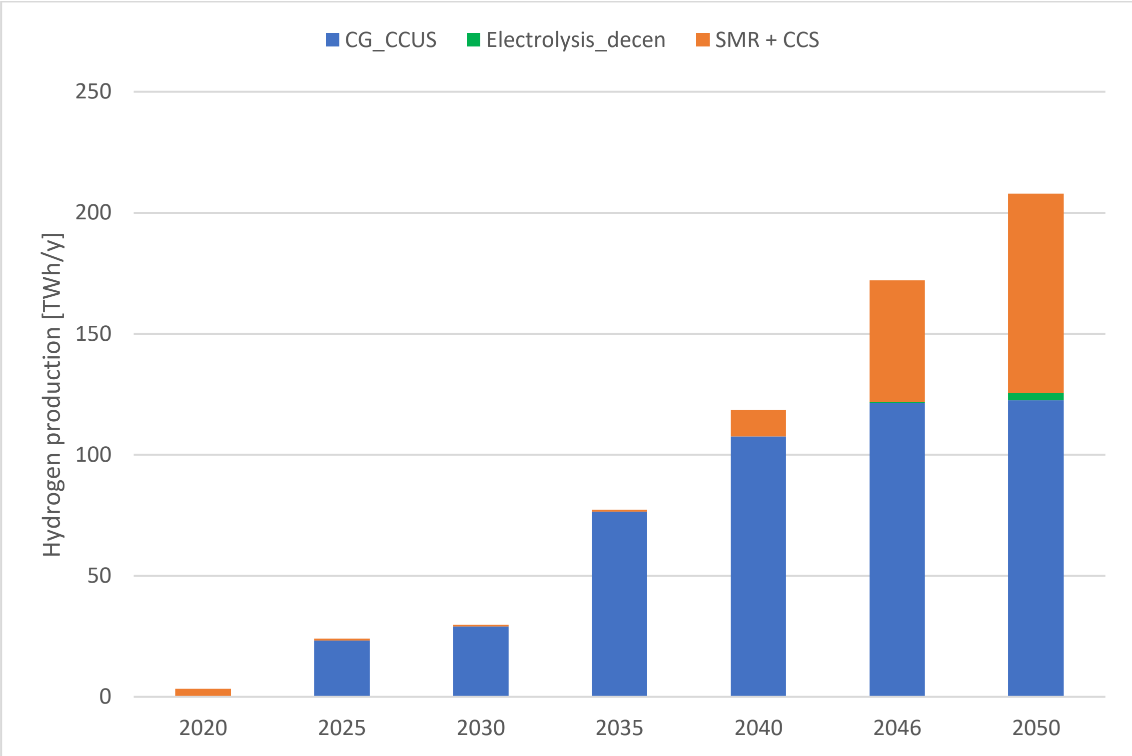

Figure 34: Hydrogen production - National hydrogen strategy scenario.

3.4.3 High transport penetration scenario

In the high transport penetration scenario where there is more hydrogen demand in the transport sector, the electricity generation has no big difference than the national hydrogen strategy scenario. The major difference here is that there is more generation from solar energy hence more capacity installed along the years as shown in Figure 35 and Figure 36.

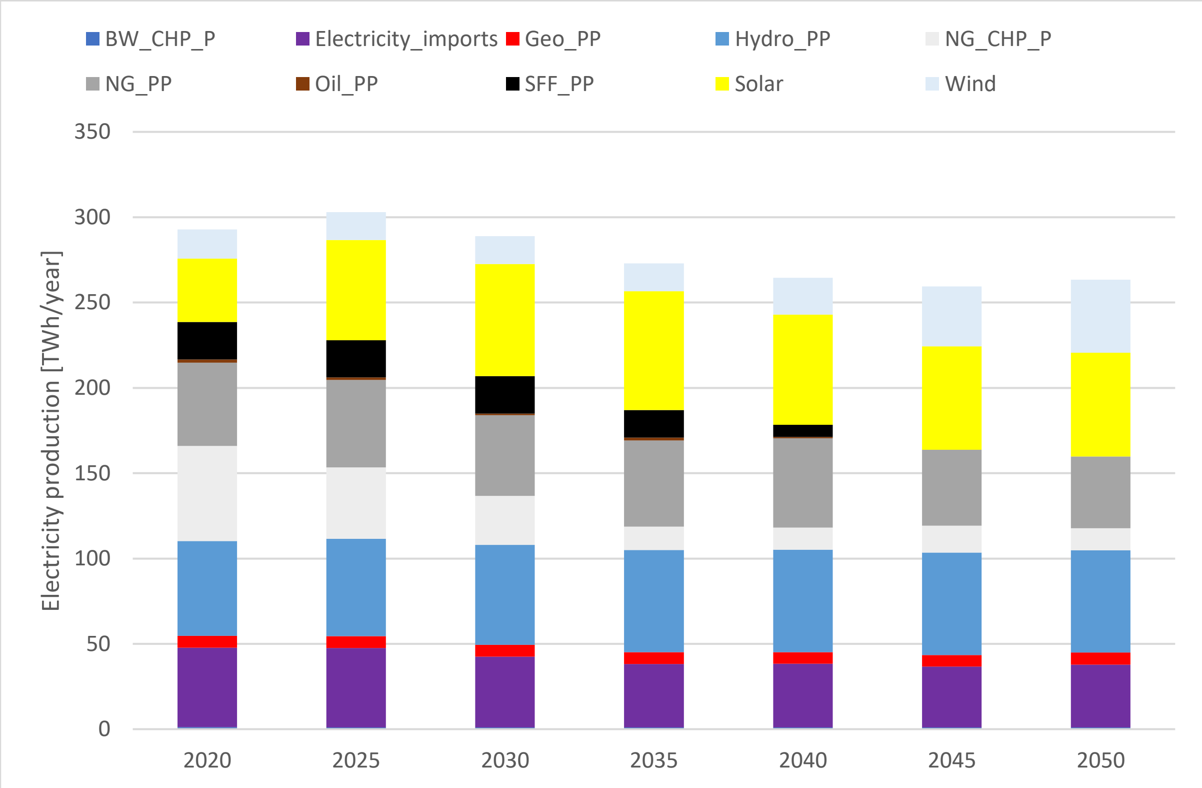

Figure 35: Electricity production - high transport penetration scenario.

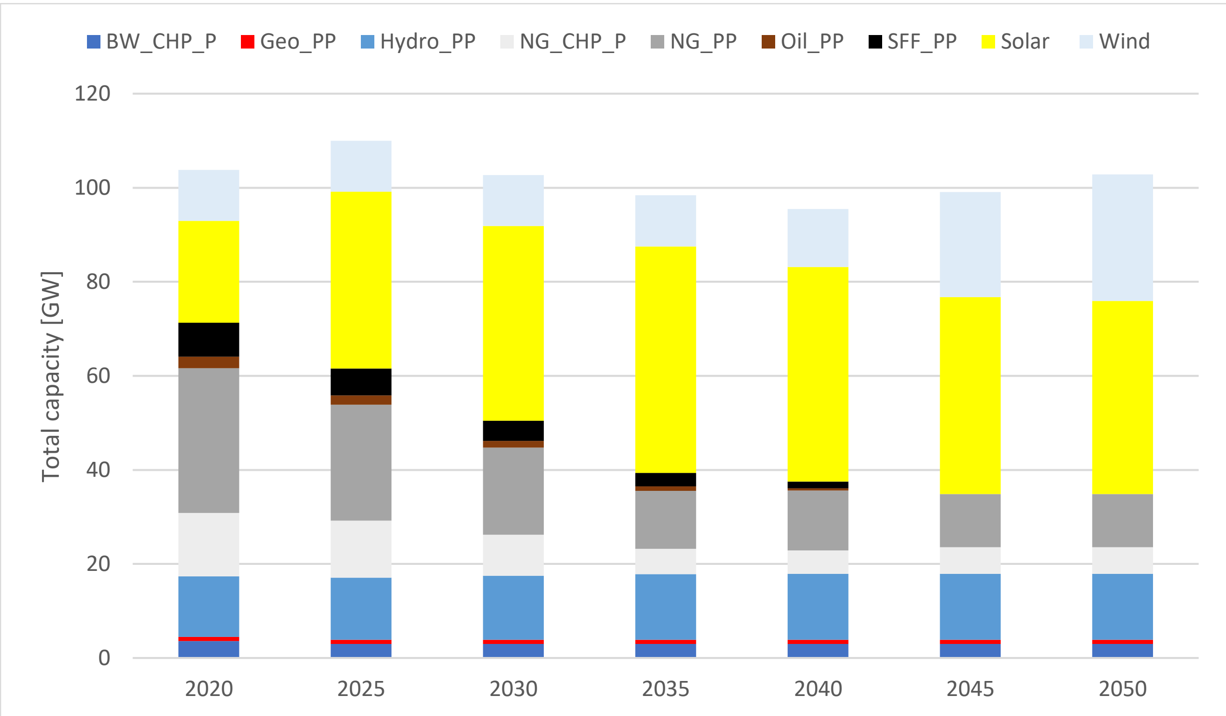

Figure 36: Total electric capacity - high transport penetration scenario

Figure 37 and Figure 38 demonstrate the hydrogen production and total installed capacity for high transport penetration scenario. In the scenario, the electrolyzer started working in 2043, 3 years before the one related to the national strategy. This is mainly due to the restriction on the production from CG + CCS. As the maximum limit for production from CG + CCS has been reached earlier, we can also notice an increase in the installed capacity for SMR + CCS technology summing up to 20 GW by 2050.

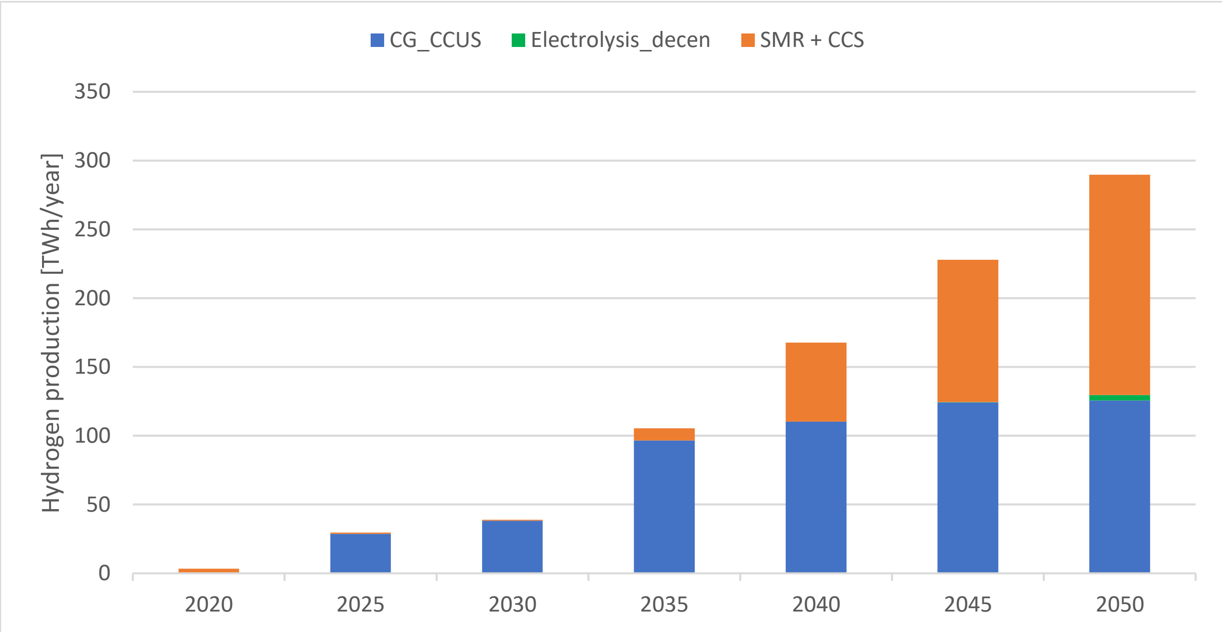

Figure 37: Hydrogen production - high transport penetration scenario.

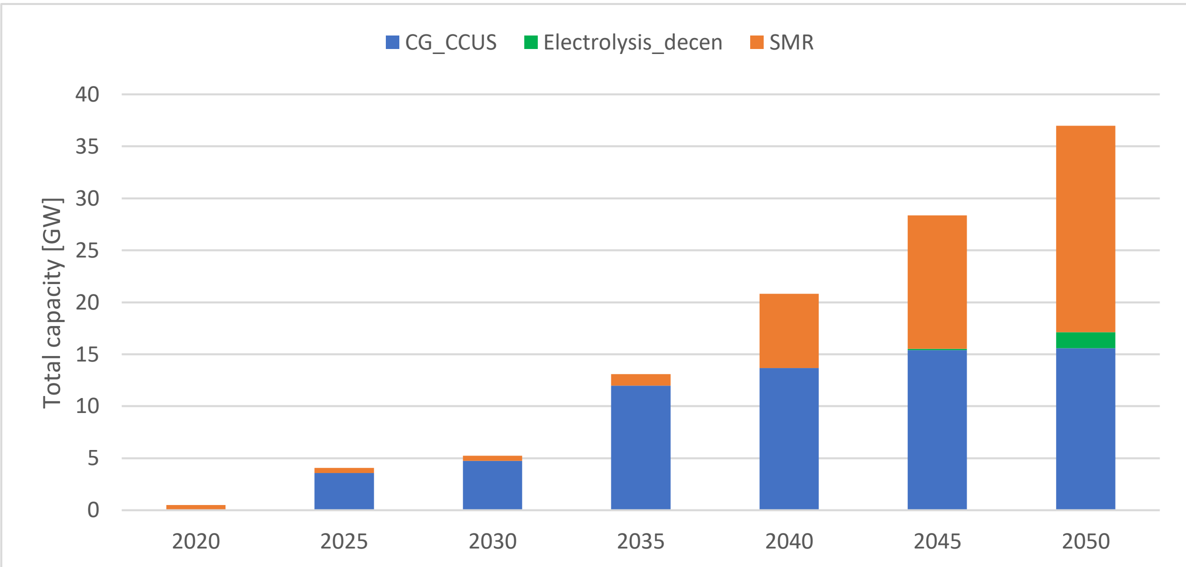

Figure 38: Total hydrogen capacity - high transport penetration scenario.

The production from SMR + CCS reached around 55 % in 2050 as shown in Table 22 while the production from electrolyzer almost has the same percentage of national strategy scenario. However, the total installed capacity has increased by 37%.

Technology	2020	2030	2040	2050
SMR + CCS	100%	2%	34%	55.24%
CG + CCS	0%	98%	66%	43.37%
Electrolyzer	0%	0%	0%	1.5%

Table 22: Hydrogen production share - high transport penetration scenario.

3.4.4 Effect of different carbon tax

To study the effect of implementing different carbon tax scenarios on the production of hydrogen, especially when using coal as a source of production. Four different values for carbon tax (50,100,150 and 200 Euro/tonCO2) were applied to the mentioned above scenarios.

Figure 39 illustrates the blue hydrogen costs of production by 2030 for SMR + CCS and CG + CCS with carbon capture rate of 90%. As expected, by increasing the carbon tax from 50 Euro/tonCO2 to 200 Euro/tonCO2, the cost of blue hydrogen increases. However, the relative increase in blue hydrogen that comes from CG + CCS is higher than the one that comes from SMR + CCS at the same carbon tax. This is due to the higher emission related to coal consumption.

Moving from low production (low demand) to high production (high demand), the effect is very huge on the production of SMR + CCS technology. As there is a reduction in hydrogen cost related to increasing the dispatchability (capacity factor) as well as the total installed capacity of SMR + CCS. This effect on production from CG + CCS is almost zero as the production and total installed capacity in both cases are the same, indicating that blue hydrogen from coal gasification is the least cost pathway to produce hydrogen.

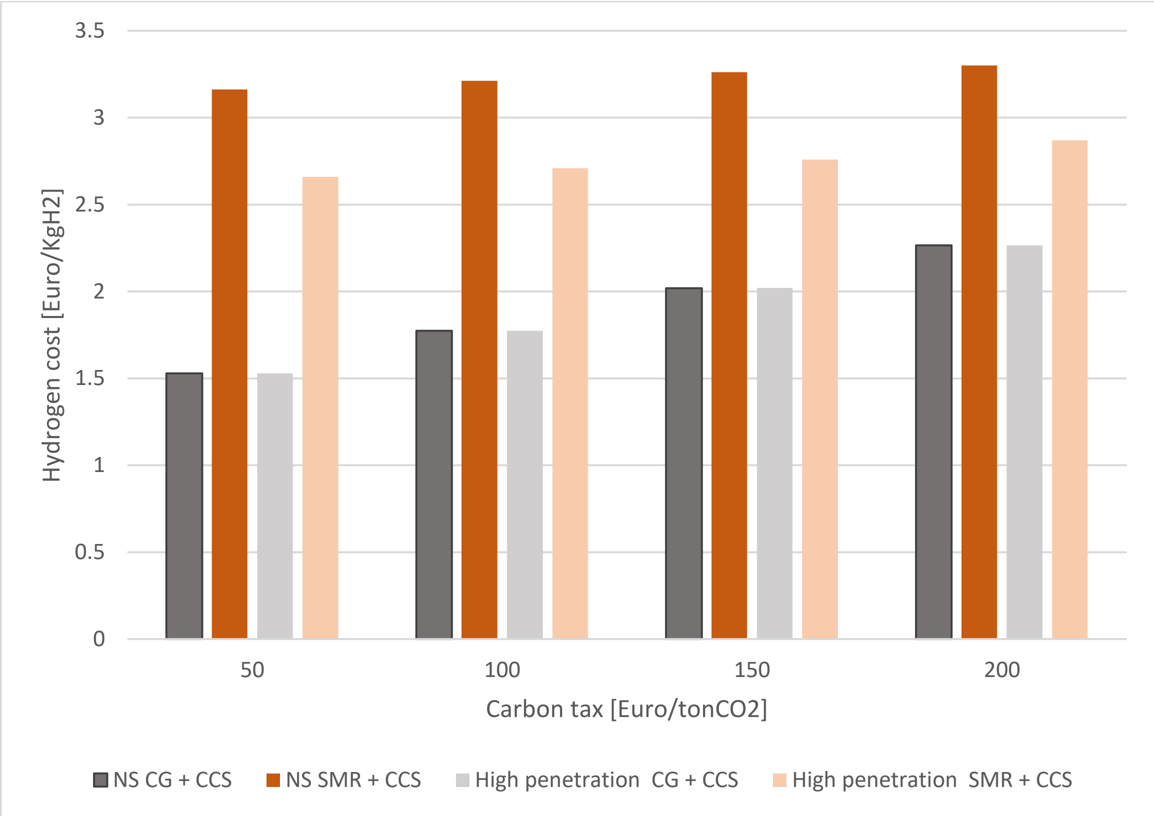

Figure 39: Hydrogen production cost by 2030 for SMR+CCS and CG + CCS

Figure 40 and Figure 41 show the comparison between the average cost of green hydrogen and the overall hydrogen generated inside the grid with low demand and high demand for different carbon tax. By increasing carbon tax prices, the average cost of hydrogen which is composed of blue hydrogen generated (SMR + CCS and CG + CCS) and green hydrogen generated from electrolysis is increasing. Mainly, this is because most of the hydrogen generated inside the grid is blue hydrogen. However, the average cost for green hydrogen decreases with increasing carbon tax due to increased production as production started in 2040 compared to 2046 and 2043, in national strategy scenario and high transport penetration scenario, respectively.

Interestingly, moving from low demand scenario to high demand scenario, the average cost of injected hydrogen into the grid is 0.03 Euro/kgH2 less, while the cost of green hydrogen increases by almost 0.05 Euro/kgH2. This can be explained by increasing the total capacity of electrolyzer which puts a cost to be amortized by the plants. Moreover, in order to match the cost of green hydrogen with the cost of injected grid hydrogen, carbon tax has to be increased by increasing the hydrogen demand as shown in the figure below.

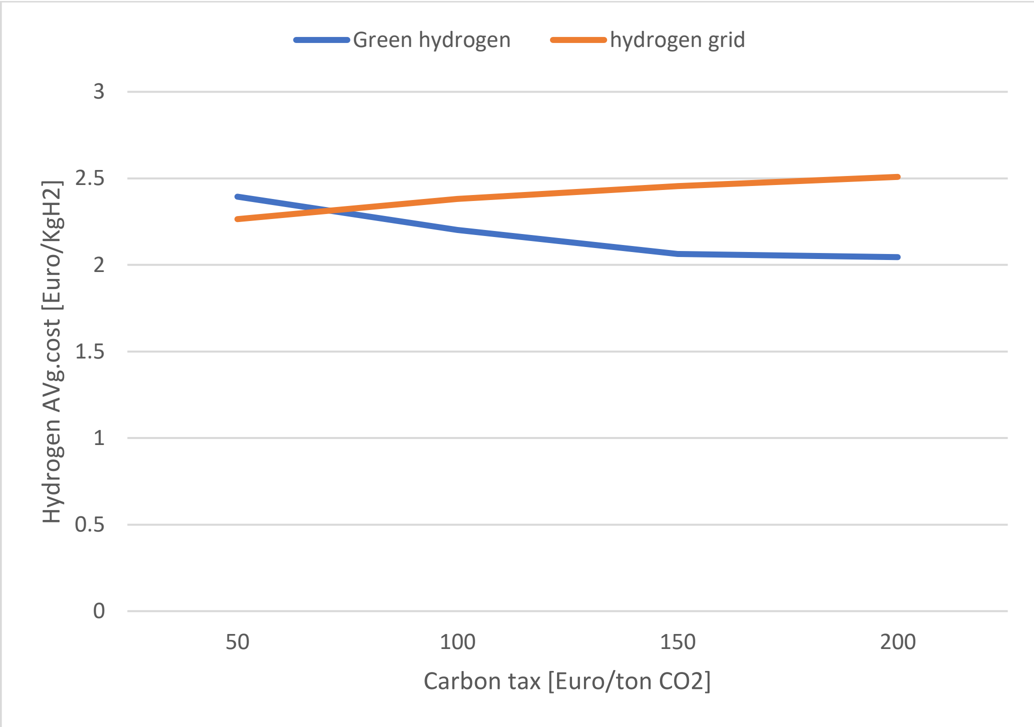

Figure 40: Average cost of hydrogen with different carbon tax - national hydrogen strategy scenario.

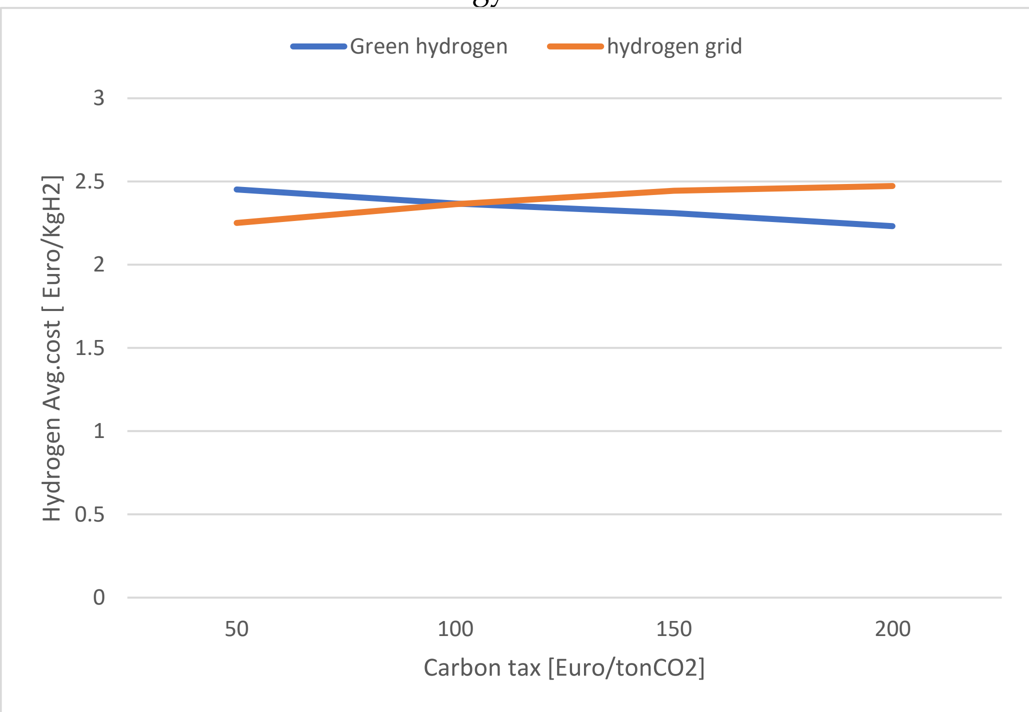

Figure 41: Average cost of hydrogen with different carbon tax – high transport penetration scenario.

3.4.5 Effect of adding chemical energy storage

One of the possibility that should be explored is adding different storage technologies such as electrochemical storage to the electric grid and it is also considered as one of the major objective in the Integrated National Energy and Climate Plan in Italy.

According to the INECP, 4 GW of electrochemical storage are installed by 2030 in the model. This will help to keep over-generation to a minimum and provide security and flexibility in the grid.

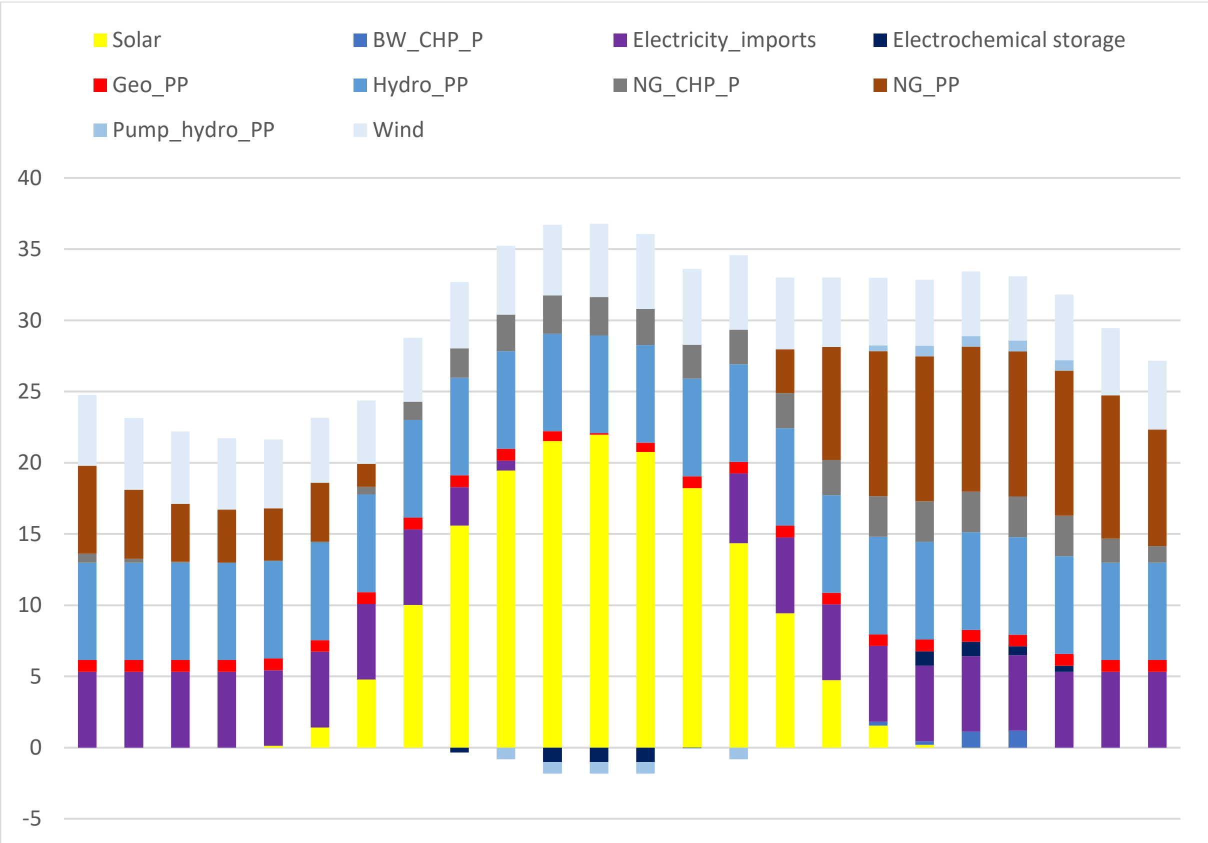

Figure 42: Daily power generation curve - high transport penetration scenario-ctax0.1

The daily power generation curve shown in Figure 42 demonstrates the average electricity daily generation over the year. It is noticeable that when solar PV plants are generating the electricity imports are almost reduced and reach zero at midday.

The generation from NG power plants is mostly concentrated during the early hours in the mornings and late hours in the night as there is no more generation from solar PV plants. Moreover, the pumped-hydro storage as well as electrochemical storage charge during the midday due to excess electricity generation and discharge it during the night. Adding the storage allows the model to install more solar PV plants and this has an increasing effect on the production of electrolysis as shown in Figure 43.

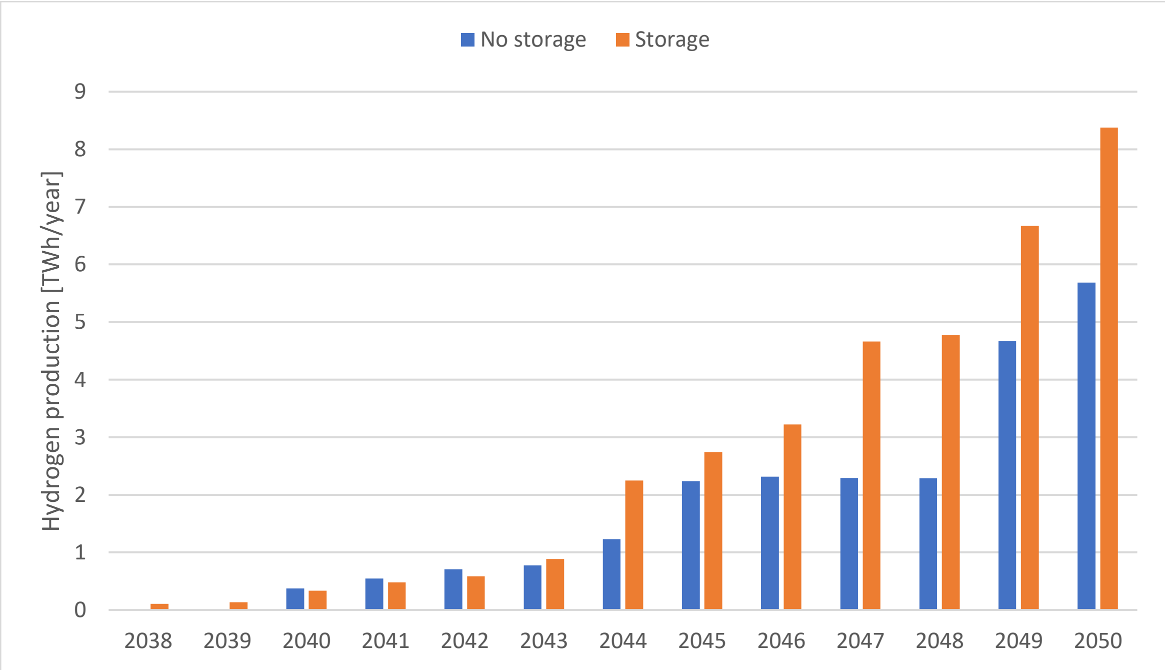

Figure 43: Effect of adding electrochemical storage on green hydrogen production - High transport penetration- ctax0.1

Figure 43 shows the effect of adding electrochemical storage on the production of green hydrogen. It is noticeable that adding electrochemical storage has a big effect on green hydrogen production. The effect is not noticeable until 2044 when there is a huge increase in renewable installed capacities. Adding electrochemical storage helps to stabilize the grid and allows the over-generation in the model by adding more renewable capacity which is used by the electrolyzer to produce green hydrogen. Also, Hypatia does not allow renewable curtailment hence adding the storage had a big impact on the installed capacity summing up to reach 3 GW compared to 1.5 GW in case of no storage.

Regarding hydrogen storage options, a detailed process was applied in order to explore three different options (compressed hydrogen, liquified hydrogen and LOHC). During the first runs of the model, the model did not return any storage options as they were too expensive to be installed and the code usually uses the excess hydrogen generation into the methanation process to decrease NG supply and has domestic production. Therefore, an equal storage capacity was assumed for the three options of storage and code decides which one is more convenient to be used. The code emerges a preference for compressed hydrogen at 350 bar as shown in Figure 44. The long period of storage excludes the H2 liquefaction, where boil-off issue determines a loss rate that does not justify its utilization. LOHC seems promising especially for long distance transportation using ships, but it still has high energy consumption during the transformation process back to hydrogen. Moreover, if their cost is considered, their presence is unfavored.

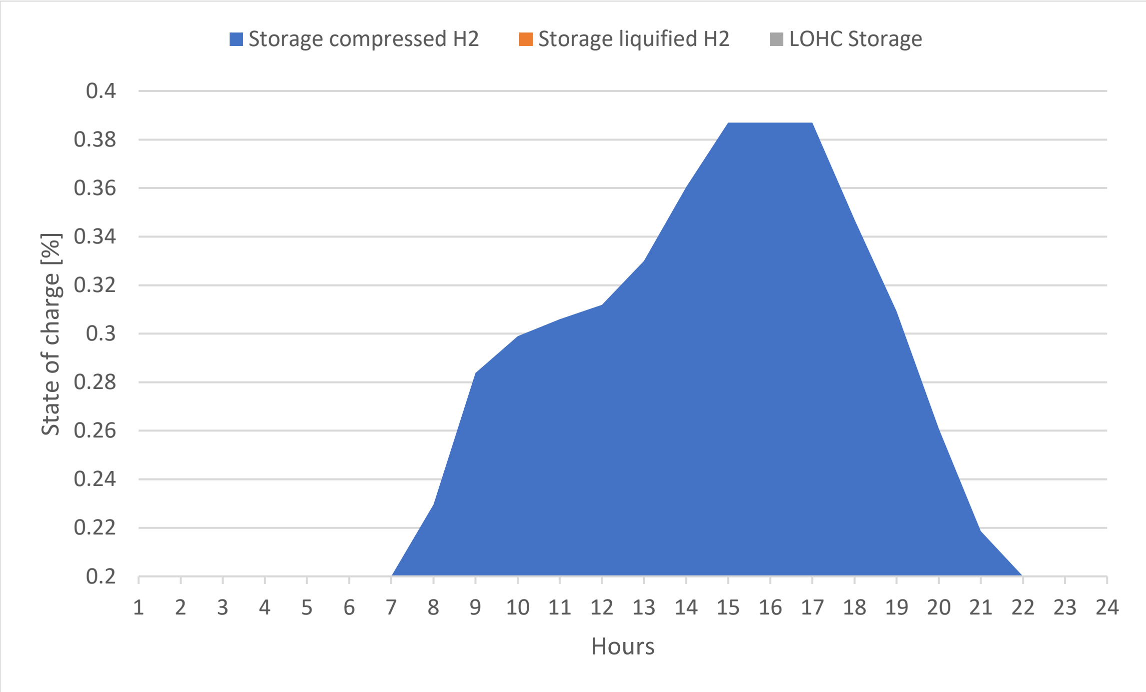

Figure 44: Storage of hydrogen - high transport penetration scenario – ctax0.1

3.4.6 Coal restriction scenario

There are different and various ways to generate hydrogen, one of them is coal gasification with carbon capture units. However, Italy does not produce coal anymore and all the production is imported. Therefore, this scenario is established to explore the dynamics if blue hydrogen only comes from natural gas and biomass gasification.

The results showed that green hydrogen starts to be competitive in 2038 which is a bit earlier than the high transport penetration scenario however, SMR + CCS dominates the production as it is cheaper to produce. Green hydrogen production in 2050 accounted for 5.7 TWh/year (2%) compared to 282 TWh/year from SMR + CCS, Figure 45.

Therefore, without proper policy support schemes such as innovation fund or investment tax credit, green hydrogen is not the most economical way to produce hydrogen

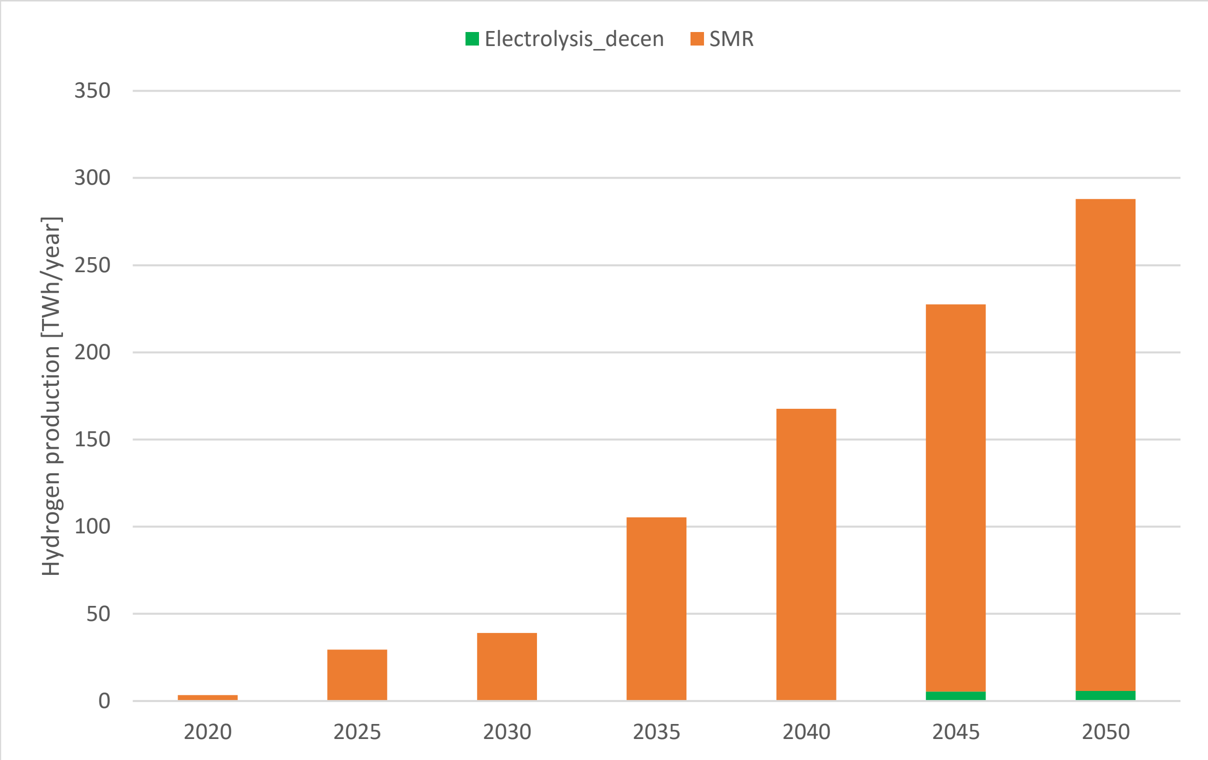

Figure 45: hydrogen production - high transport penetration scenario- no CG

3.4.7 High renewable penetration scenario

As mentioned before, green hydrogen was not convenient before the late 30s without proper supportive schemes. Therefore, this scenario was established to reach electrical renewable penetration of 0.56 by 2030, which is in line with the INECP. The hydrogen demand in this scenario is the high transport penetration demand and 100 Euro/tonCO2 as ctax is applied.

By forcing higher electrical penetration, these reduces the enduring costs going further in time for electrolysis production hence supporting green hydrogen production.

Figure 46 illustrates the electricity generation in this scenario. It can be noticed that there is a huge increase in the electricity generated from RES to reach 0.55 by 2030, matching the targets for INECP. The number keeps getting higher until it reaches 0.78 in 2050. Most of the generation comes from solar PV, Wind and hydroelectric plants. Moreover, Blend CHP which is injecting hydrogen into the NG grid with 10% by volume starts to produce substituting CHP by 2030 and increases with time. NG power plants as well as coal and oil are showing a phaseout trend towards 2050 as they are substitute with RES.

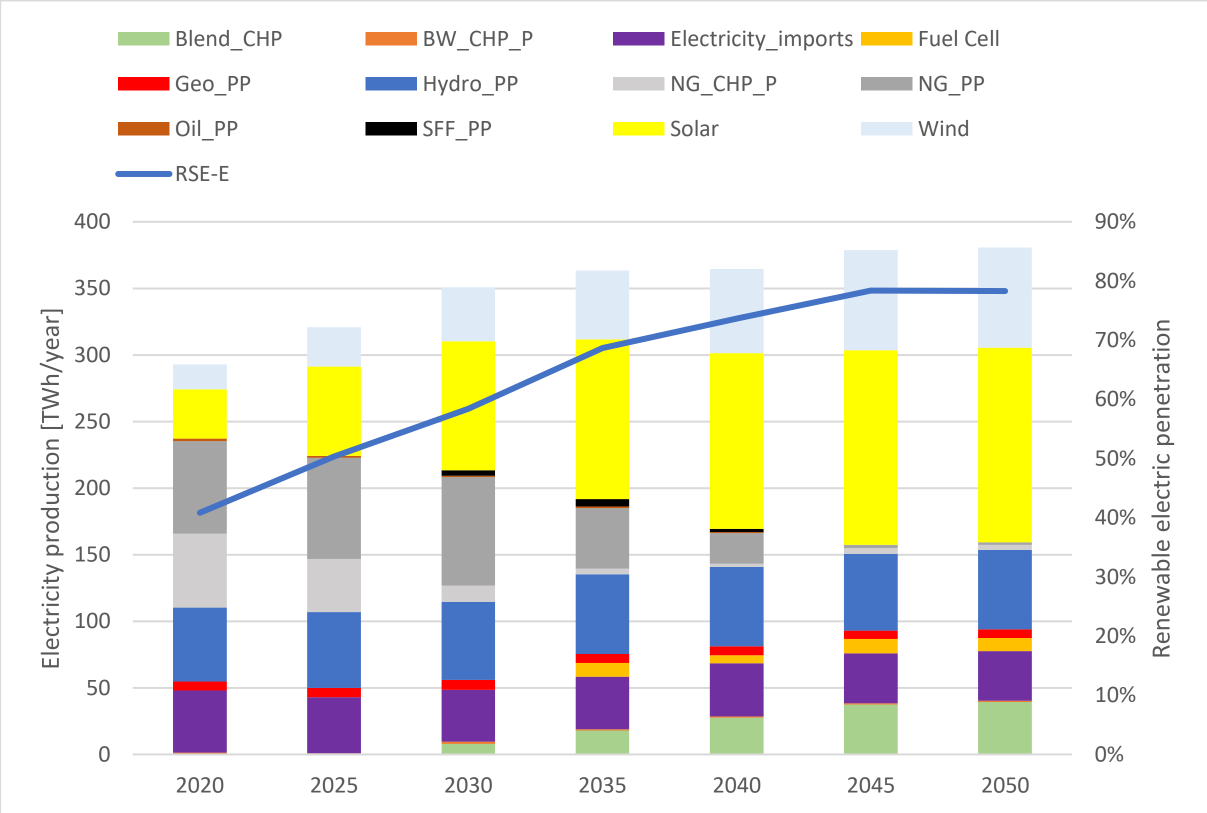

Figure 46: electricity generation - High transport penetration demand with high renewable penetration

Compared to previous scenarios, electricity production is increasing from year to year. This is due to the electricity consumption related to electrolysis as well as compression to store the hydrogen.

Table 23 shows the shares of electricity production in 2050. It can be seen that hydrogen electric, wind and solar power plants have almost 54% of the total production while the gas grid which is composed of the total gas injected including the blending gas is around 12%. Fuel cells have 3% share of the total production in 2050 indicating that by increasing hydrogen production FC is considered as a feasible option to generate electricity.

Source	Annual power generation [TWh/year]	Share on total
Hydroelectric	59.52650602	16%
Electricity imports	37.25106284	10%
Wind	75.33837215	20%
PV	145.9075354	38%

H2P (fuel cell)	9.807167687	3%
Geothermal	6.564018768	2%
Coal & oil	0	0%
Gas (NG & blend)	45.25826141	12%
Waste	1.0264968	0.27%
Total	**380.6794211**	

Table 23: Annual power generation from different sources (2050)

Hydrogen production in this scenario is demonstrated in Figure 47 and Table 24. In this case, electrolysis starts to produce in 2030 having a total share of 9% with an installed capacity of 5.1 GW. The percentage keeps increasing until it reaches 28% of the total production. In this case, the cost of green hydrogen is 2.2 Euro/KgH2 which is 30% lower than the high transport penetration scenario -ctax 0.1. Moreover, CG + CC is still dominating with a production share of 40% in 2050 while production from SMR + CCS is still relatively higher than green hydrogen, with a 32% share of total production.

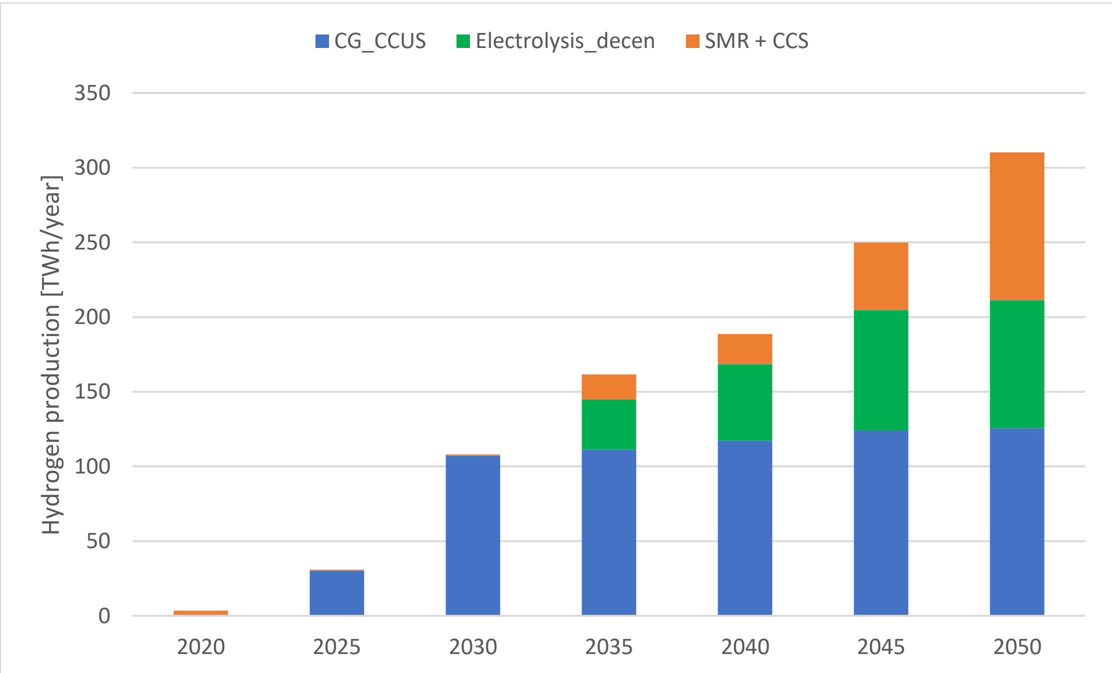

Figure 47: hydrogen generation - High transport penetration demand with high renewable penetration

Technology	2020	2030	2040	2050

CG_CCUS	0%	88%	62%	40%
Electrolysis	0%	9%	27%	28%
SMR + CCS	100%	3%	11%	32%

Table 24: Annual hydrogen production share- High transport penetration demand with high renewable penetration

The total installed capacity for hydrogen production is illustrated in Figure 48. The total installed capacity for electrolysis has an increasing trend towards 2050. It reaches almost 50% of the total installed capacity, however, the overall production share is 28%. This is because electrolysis works only when there's power generation from renewable sources hence has a limited period to work. This matching between renewable energy generation and electrolysis production ensures that the hydrogen produced is 100% green hydrogen and it is one of the new requirements stated by the new European directive.

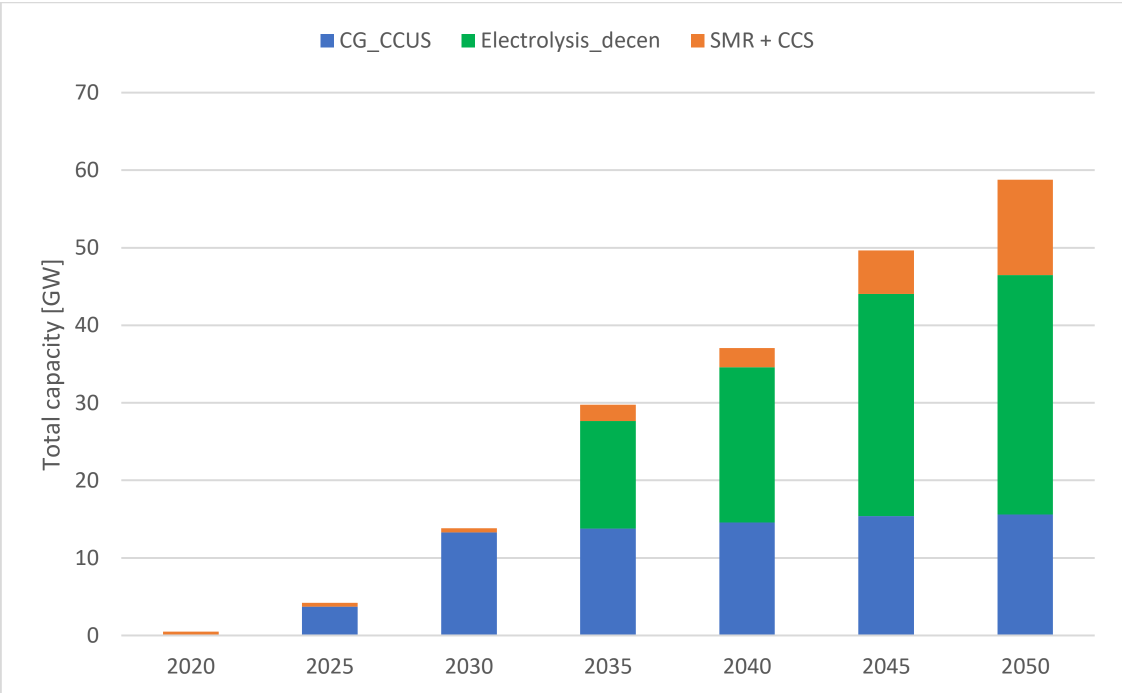

Figure 48: Total hydrogen capacity - high renewable penetration scenario

From primary energy resources perspective, as shown in Figure 49, the RES has increased to reach almost 25% by 2050 compared to 18% in the basecase scenario. This is mainly due to the reduction in consumption of NG and coal in power generation and increasing the power generation from renewable resources such as wind and solar. However, solid fossil fuel supply has increased due to the generation of blue hydrogen using coal gasification technology.

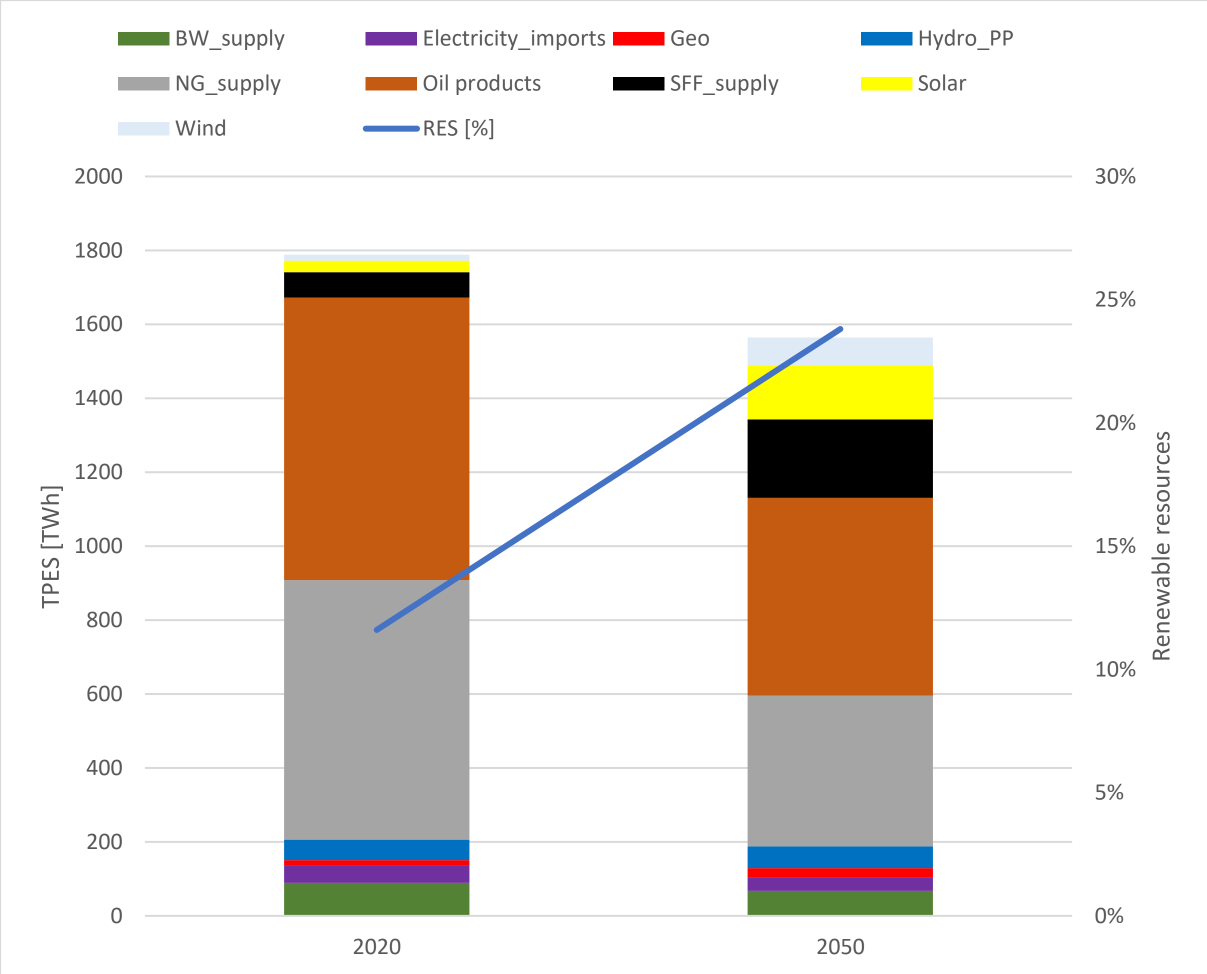

Figure 49: Italian primary energy consumption by source in 2020 and 2050 – High renewable penetration scenario

3.4.8 Hydrogen to X results

Once the overall production of hydrogen and electricity has been analyzed, it is useful to focus on the different pathways available for hydrogen. Regardless of the final hydrogen demand, which is distributed across different end-use sectors, there are two pathways that uses hydrogen; hydrogen to power using fuel cells and hydrogen to gas by using biological methanation.

Regarding hydrogen to gas pathway, this behavior has been noticed. If there is an available storage capacity, it is preferable to store the hydrogen instead of turning it to synthetic natural gas. In the high renewable penetration scenario, biological methanation starts to produce in 2030, the year in which electrolysis starts to produce too. The share of synthetic natural gas injected into the gas grid reached its maximum of 8% in 2038 and after that kept decreasing until it reached zero in 2040.

The second path of hydrogen to power is represented by introducing Fuel cell. The production is also increasing from 2032 in an increasing trend until it reached 3% of the total power generation as shown in Table 23.

Last word on hydrogen storage utilization. The scenarios setup had the main hypothesis to allow very large amounts of storage capacity for all hydrogen forms. Especially for hydrogen, the results seem to prefer the H2 compression at 350 bar instead of its conversion to LOHC or liquefaction. The latter can be excluded due to its loss rate (e.g., boil-off issue), that weakens this solution for long seasonal storage.

Chapter 4. Conclusions

In this thesis a new energy system model is provided, which is able to analyze a wider and more heterogeneous national energy system, with the addition of the promising technologies related to hydrogen generation and Hydrogen to X pathways.

Here below the aspects of work are summarized. The main considerations from the model application are then summarized, concluding by pointing out the possible future developments to further enhance the analysis and reduce current uncertainties.

The introduced model was able to simulate the Italian Energy system including the generation and use of electricity, heat, and other commodities adapting current and soon to market technologies.

After a literature review of the main technologies related to hydrogen and H2-based pathways, the most promising processes were selected. With implemented additional pathways, the model version developed in this work enables us to provide information on a wider and more heterogeneous national energy system, assessing the role that hydrogen-based technologies could have in a 2050 scenario in the Italian energy system.

In all scenarios, most of the generated hydrogen comes from blue technologies such as steam methane reforming retrofitted with carbon capture and storage unit and coal gasification technology with carbon capture and storage unit. However, coal gasification technology is the most dominate in all scenarios indicating that it is the most economically convenient technology.

In all cases, domestic production of green hydrogen will not be cost-competitive with alternative decarbonized options such as blue hydrogen, especially in the early 2030s. Without policy support, green hydrogen is difficult to compete in the market with blue hydrogen resources up to early 40s. Moreover, in order to achieve the current ambitions stated in the Italian Hydrogen strategy (5GW of electrolysis capacity by 2030), almost twice the renewable installed capacity is needed.

Regarding storage technologies, due to the high capital costs the model does not induce any installed capacity. Hence, with the assumption of very large amounts of storage capacities, it emerges a preference for hydrogen compression at 150 bar. The long period storage excludes liquified hydrogen as storage, where boil-off issue determines a loss rate that does not justify its utilization. While LOHC seems promising especially for overseas transportation, it still has high energy consumption during hydrogenation and dehydrogenation. Moreover, if their cost is considered, their presence is unfavored.

In addition, a sensitivity analysis is made to gain insights about the possible solutions to boost green hydrogen production. One of the sensitivity analysis is done on carbon tax. By applying different carbon taxes (50,100,150,200 Euro/tCO_2), it is noticed that increasing the carbon tax increases the average cost of hydrogen generated. The relative increase in blue hydrogen that comes from CG + CCS is higher than the one that comes from SMR + CCS at the same carbon tax. Also, moving from low production (low demand) to high production (high demand), a huge reduction in the cost of hydrogen produced by SMR + CCS while on CG + CCS is almost negligible. Most importantly, by increasing the demand, carbon tax has also to be increased to reach the breakeven point where cost of green hydrogen equals cost of blue hydrogen. Another sensitivity analysis is done to figure out the effect of adding chemical energy storage to the electrical green on the production of electrolysis. It resulted in a relative increase in the electrolysis production compared to no storage case, showing that adding the electrochemical storage solves the intermittent characteristics of renewable energy allowing for more installed capacity hence more green hydrogen production.

Different hydrogen to X pathways has also been investigated. Fuel cell (H2P) showed promising results especially when there was a huge amount of hydrogen demand while biological methanation seemed to be utilized only when there is no storage capacity to store hydrogen indicating that it is better to use NG resources.

In summary, an analysis of the Italian energy system was done using Hypatia to explore the hydrogen potential inside the country. The following findings have been observed:

1. In order to meet the current ambition of the Italian hydrogen strategy (2% of total final consumption by 2030 and 20% by 2050), different technologies could be used to produce hydrogen. The most economically convenient is coal gasification + CCS then comes SMR + CCS.
2. In all cases, domestic green hydrogen production- excluding policy support- will not be cost-competitive with alternative decarbonized options such as blue hydrogen, especially in the early 2030s.
3. With production cost above 2 Euro/KgH2, Green hydrogen without subsidies will be outcompeted by large-scale blue hydrogen projects and CCS-retrofitted steam methane reformers, which can reach production costs of around 2.0 €/kg H2
4. In order to reach the green hydrogen potential announced in Italian hydrogen strategy, almost more than one time and a half renewable energy capacity needed to be built by 2030.

5. Moreover, adding electrical storage capacity to the grid and applying carbon tax helps to push green hydrogen production further.

Acronyms

IEA	International Energy Agency
FCEV	Fuel Cell Electric Vehicle
HSC	Hydrogen supply chain
HSCN	Hydrogen supply chain network
EU	European Union
CG	Coal Gasification
BG	Biomass Gasification
SMR	Steam Methane Reforming
CCUS	Carbon Capture, Utilization, and Storage
NG	Natural gas
ATR	Autothermal Reforming
CCS	Carbon Capture and Storage
PEMEC	Proton Exchange Membrane Electrolyzer Cell
AEC	Alkaline Electrolyzer Cell
SOEC	Solid Oxide Electrolyzer Cell
AEMEC	Anion Exchange Membrane Electrolyzer Cell
TRL	Technology Readiness Level
LHV	Low Heating Value
WGS	Water Gas Shift
PO	Partial Oxidation

SR	Steam Reforming
ORC	Organic Rankine Cycle
P2G	Power to Gas
FC	Fuel Cell
AFC	Alkaline Fuel Cell
PEMFC	Polymer Electrolyte Membrane Fuel Cell
PAFC	Phosphoric Acid Fuel Cell
MCFC	Molten Carbonate Fuel Cell
HT	High Temperature
GT	Gas Turbine
LOHC	Liquid Organic Hydrogen Carrier
CHP	Combined Heat and Power
RTE	Round Trip Efficieny
DRI	Direct Reduction of Iron
ICE	Internal Combustion Engine
RES	Renewable Energy Resources
TSO	Transimission System Operator
SRES	Scheme of Reference Energy System
HRS	Hydrogen Refueling Station
P2H	Power to Hydrogen
REF2020	European Reference Scenario 2020
RSE	Ricerca Sistema Energetico

TFC	Total Final Consumption
INECP	Integrated National Energy and Climate Plan
BF	Blast-Furnace
BOF	Basic Oxygen Furnaces
TCO	Total Cost of Ownership
LPG	Liquefied Petroleum Gas
GHG	Greenhouse Gas
BAU	Business as Usual
BW	Bio-waste

Bibliography

[1] M. Nachmany and E. Mangan, “Policy brief: Aligning national and international climate targets,” *Policy briefs*, no. October, p. 8, 2018.

[2] Eurostat, “No Title,” *Statistics (Ber).*, 2020, [Online]. Available: Statistics

[3] Iea, *{IEA WIND ENERGY - Report 2009}*. 2009.

[4] B. De colvenaer and C. Castel, “The fuel cells and hydrogen joint undertaking (FCH JU) in Europe,” *Int. J. Low-Carbon Technol.*, vol. 7, no. 1, pp. 5–9, 2012, doi: 10.1093/ijlct/ctr035.

[5] “Technology Roadmap,” *Encycl. Prod. Manuf. Manag.*, pp. 781–782, 2006, doi: 10.1007/1-4020-0612-8_961.

[6] *WATER ELECTROLYSIS AND HYDROGEN 2 0 2 2*. 1831. doi: 10.2760/7606.

[7] “FCH JU. Hydrogen Roadmap Europe; FCH JU: Bruxelles, Belgium, 2019”.

[8] Z. Lin, C. W. Chen, J. Ogden, and Y. Fan, “The least-cost hydrogen for Southern California,” *Int. J. Hydrogen Energy*, vol. 33, no. 12, pp. 3009–3014, 2008, doi: 10.1016/j.ijhydene.2008.01.039.

[9] K. Govindan, M. Fattahi, and E. Keyvanshokooh, “Supply chain network design under uncertainty: A comprehensive review and future research directions,” *Eur. J. Oper. Res.*, vol. 263, no. 1, pp. 108–141, 2017, doi: 10.1016/j.ejor.2017.04.009.

[10] L. Li, H. Manier, and M. A. Manier, “Hydrogen supply chain network design: An optimization-oriented review,” *Renew. Sustain. Energy Rev.*, vol. 103, no. January, pp. 342–360, 2019, doi: 10.1016/j.rser.2018.12.060.

[11] A. Almansoori and N. Shah, “Design and operation of a future hydrogen supply chain: Snapshot model,” *Chem. Eng. Res. Des.*, vol. 84, no. 6 A, pp. 423–438, 2006, doi: 10.1205/cherd.05193.

[12] A. Almansoori and A. Betancourt-Torcat, "Design of optimization model for a hydrogen supply chain under emission constraints - A case study of Germany," *Energy*, vol. 111, pp. 414–429, 2016, doi: 10.1016/j.energy.2016.05.123.

[13] A. Ochoa Bique and E. Zondervan, "An outlook towards hydrogen supply chain networks in 2050 — Design of novel fuel infrastructures in Germany," *Chem. Eng. Res. Des.*, vol. 134, pp. 90–103, 2018, doi: 10.1016/j.cherd.2018.03.037.

[14] J. Ren, A. Manzardo, S. Toniolo, and A. Scipioni, "Sustainability of hydrogen supply chain. Part I: Identification of critical criteria and cause-effect analysis for enhancing the sustainability using DEMATEL," *Int. J. Hydrogen Energy*, vol. 38, no. 33, pp. 14159–14171, 2013, doi: 10.1016/j.ijhydene.2013.08.126.

[15] A. Almansoori and N. Shah, "Design and operation of a stochastic hydrogen supply chain network under demand uncertainty," *Int. J. Hydrogen Energy*, vol. 37, no. 5, pp. 3965–3977, 2012, doi: 10.1016/j.ijhydene.2011.11.091.

[16] J. Kim and I. Moon, "Strategic design of hydrogen infrastructure considering cost and safety using multiobjective optimization," *Int. J. Hydrogen Energy*, vol. 33, no. 21, pp. 5887–5896, 2008, doi: 10.1016/j.ijhydene.2008.07.028.

[17] P. Fragiacomo and M. Genovese, "Technical-economic analysis of a hydrogen production facility for power-to-gas and hydrogen mobility under different renewable sources in Southern Italy," *Energy Convers. Manag.*, vol. 223, no. August, p. 113332, 2020, doi: 10.1016/j.enconman.2020.113332.

[18] T. Abbasi and S. A. Abbasi, "'Renewable' hydrogen: Prospects and challenges," *Renew. Sustain. Energy Rev.*, vol. 15, no. 6, pp. 3034–3040, 2011, doi: 10.1016/j.rser.2011.02.026.

[19] S. Domenech and E. Monso, "ScienceDirect Hydrogen supply chain optimization for n e es region , deployment scenarios in the Midi-Pyr e France," vol. 9, 2014, doi: 10.1016/j.ijhydene.2014.05.165.

[20] W. Won, H. Kwon, J. H. Han, and J. Kim, "Design and operation of renewable energy sources based hydrogen supply system: Technology integration and optimization," *Renew. Energy*, vol. 103, pp. 226–238, Apr. 2017, doi: 10.1016/J.RENENE.2016.11.038.

[21] P. Gabrielli, F. Charbonnier, A. Guidolin, and M. Mazzotti, "Enabling low-carbon hydrogen supply chains through use of biomass and carbon capture and storage: A Swiss case study," *Appl. Energy*, vol. 275, no. November 2019, p. 115245, 2020, doi: 10.1016/j.apenergy.2020.115245.

[22] G. S. Ogumerem, C. Kim, I. Kesisoglou, N. A. Diangelakis, and E. N. Pistikopoulos, "A multi-objective optimization for the design and operation of a

hydrogen network for transportation fuel," *Chem. Eng. Res. Des.*, vol. 131, pp. 279–292, 2018, doi: 10.1016/j.cherd.2017.12.032.

[23] International Energy Agency, "The Future of Hydrogen: Seizing today's opportunities," *IEA Publ.*, no. June, p. 203, 2019.

[24] "Making renewable hydrogen Making renew - able hydrogen".

[25] "Hydrogen Economy Outlook," 2020.

[26] I. Renewable and E. Agency, *"Hydrogen from renewable power: Technology outlook for the energy transition (2018)", IRENA, available at https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power [Accessed : 29-Nov.-2019]*, no. September. 2018. [Online]. Available: www.irena.org

[27] T. F. I. Smolinka, M. (Fraunhofer I. Günther, and J. (Fcbat) Garche, "Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien," *NOW-Studie*, vol. 2010, p. 53, 2011.

[28] R. Bhandari, C. A. Trudewind, and P. Zapp, "Life cycle assessment of hydrogen production via electrolysis - A review," *J. Clean. Prod.*, vol. 85, pp. 151–163, 2014, doi: 10.1016/j.jclepro.2013.07.048.

[29] J. Adolf *et al.*, "Energy of the Future. Sustainable Mobility through Fuel Cells and H2. Shell Deutschland Oil GmbH," p. 37, 2017, [Online]. Available: https://epub.wupperinst.org/frontdoor/deliver/index/docId/6786/file/6786_Hydrogen_Study.pdf

[30] I. E. A. International and E. Agency, "Global Hydrogen Review," 2022.

[31] I. Vincent and D. Bessarabov, "Low cost hydrogen production by anion exchange membrane electrolysis : A review," *Renew. Sustain. Energy Rev.*, vol. 81, no. August 2016, pp. 1690–1704, 2018, doi: 10.1016/j.rser.2017.05.258.

[32] N. Muradov, "Low to near-zero CO2 production of hydrogen from fossil fuels: Status and perspectives," *Int. J. Hydrogen Energy*, vol. 42, no. 20, pp. 14058–14088, 2017, doi: 10.1016/j.ijhydene.2017.04.101.

[33] F. Cells, "Technology Roadmap".

[34] T. Villigen and C.- Bern, "Direct Methanation of Biogas".

[35] A. Lövenich *et al.*, "The Future Cost of Electricity-Based Synthetic Fuels".

[36] J. Lefebvre *et al.*, "Renewable Power-to-Gas : A technological and economic review," vol. 85, 2016, doi: 10.1016/j.renene.2015.07.066.

[37] B. Lecker, L. Illi, A. Lemmer, and H. Oechsner, "Biological hydrogen

methanation – A Review," *Bioresour. Technol.*, no. August, 2017, doi: 10.1016/j.biortech.2017.08.176.

[38] T. Data and R. Fuels, "Page 1 | 335 - Technology Data for Renewable Fuels," pp. 1–335.

[39] A. Cappelletti, F. Martelli, and V. S. Marta, "ScienceDirect Investigation of a pure hydrogen fueled gas turbine burner," *Int. J. Hydrogen Energy*, vol. 42, no. 15, pp. 10513–10523, 2017, doi: 10.1016/j.ijhydene.2017.02.104.

[40] C. Munnings, D. Palfreyman, and P. Hartley, "National Hydrogen Roadmap".

[41] "Enel Inaugurates World's First Hydrogen-Fueled Power Plant", [Online]. Available: https://www.powermag.com/enel-inaugurates-worlds-first-hydrogen-fueled-power-plant/#:~:text=Italy%27s Enel on Monday inaugurated,electricity as well as heat.

[42] "Chiusa la centrale a idrogeno", [Online]. Available: https://nuovavenezia.gelocal.it/venezia/cronaca/2018/01/20/news/chiusa-la-centrale-a-idrogeno-1.16377980

[43] J. Simon, A. M. Ferriz, and L. C. Correas, "HyUnder - Hydrogen underground storage at large scale: Case study Spain," *Energy Procedia*, vol. 73, pp. 136–144, 2015, doi: 10.1016/j.egypro.2015.07.661.

[44] O. Kruck and F. Crotogino, "' Assessment of the potential , the actors and relevant business cases for large scale and seasonal storage of renewable electricity by hydrogen underground storage in Europe ' Overview on all Known Underground Storage Technologies for Hydrogen," *KBB Undergr. Technol. GmbH*, vol. Overview o, no. 4, pp. 53,70,74-76, 2013, [Online]. Available: http://hyunder.eu/wp-content/uploads/2016/01/D3.1_Overview-of-all-known-underground-storage-technologies.pdf

[45] F. Crotogino, S. Donadei, U. Bünger, and H. Landinger, "Large-Scale Hydrogen Underground Storage for Securing Future Energy Supplies," *18th World Hydrog. Energy Conf. 2010 - WHEC 2010 Parallel Sess. B. 4 Storage Syst. / Policy Perspect. Initiat. Co-operations*, vol. 78, no. January, p. 10, 2010, [Online]. Available: https://core.ac.uk/download/pdf/34994534.pdf

[46] A. S. Lord, P. H. Kobos, and D. J. Borns, "Geologic storage of hydrogen: Scaling up to meet city transportation demands," *Int. J. Hydrogen Energy*, vol. 39, no. 28, pp. 15570–15582, 2014, doi: 10.1016/j.ijhydene.2014.07.121.

[47] R. Berger, "Development of Business Cases for Fuel Cells and Hydrogen Applications for Regions and Cities," *Navig. Complex.*, p. 149, 2017, [Online]. Available: https://www.fch.europa.eu/sites/default/files/FCH

Docs/171121_FCH2JU_Application-Package_WG5_P2H_Hydrogen into gas grid %28ID 2910558%29 %28ID 2911642%29.pdf

[48] A. Wang, K. Van der Leun, D. Peters, and M. Buseman, "European Hydrogen Backbone," no. July, p. 24, 2020, [Online]. Available: https://transparency.entsog.eu/

[49] "Snam 2030 vision and 2021-2025 plan Snam has reshaped its business over the last six years," no. November, 2021.

[50] J. R. Bartels, M. B. Pate, R. M. Nelson, and G. Kim, "No Title," 2008.

[51] P. T. Aakko-saksa, C. Cook, J. Kiviaho, and T. Repo, "Liquid organic hydrogen carriers for transportation and storing of renewable energy – Review and discussion," *J. Power Sources*, vol. 396, no. February, pp. 803–823, 2018, doi: 10.1016/j.jpowsour.2018.04.011.

[52] S. Giddey, S. P. S. Badwal, C. Munnings, and M. Dolan, "Ammonia as a Renewable Energy Transportation Media," pp. 10231–10239, 2017, doi: 10.1021/acssuschemeng.7b02219.

[53] C. Wulf and P. Zapp, "Assessment of system variations for hydrogen transport by liquid organic hydrogen carriers," *Int. J. Hydrogen Energy*, vol. 43, no. 26, pp. 11884–11895, 2018, doi: 10.1016/j.ijhydene.2018.01.198.

[54] A. Patonia, R. Poudineh, and A. Hove, "Global trade of hydrogen : what is the best way to transfer hydrogen over long distances ?," no. December 2021, 2022.

[55] "Ammonia Technology Roadmap," *Ammon. Technol. Roadmap*, 2021, doi: 10.1787/f6daa4a0-en.

[56] I. E. Agency, "The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector".

[57] I. Hydrogen, "Italian Hydrogen and Fuel Cell Association POSITION PAPER H2IT".

[58] M. Giuli, *Italy in the International Hydrogen Economy*.

[59] B.P. Statistical Review 2020, "Stratistical Review of World Energy," *Stat. Rev. World Energy*, vol. 67, pp. 1–56, 2020, [Online]. Available: bp.com/statisticalreview

[60] "World Steel Association website: Annual Steel Data (Total Production of Crude Steel)".

[61] D. Covering, *European steel in figures 2022*. 2022.

[62] A. Barzaghi and S. Italia, "Outlook for the Italian Steel Industry".

[63] T. Eprs and E. Parliamentary, *Carbon-free steel production*, no. April. 2021.

[64] "Matthias Schimmel et al., Making Hydrogen Cost-Competitive, cit".

[65] "The European House - Ambrosetti, H2 Italy 2050, cit".

[66] "Luca Franza, Clean Molecules across the Mediterranean, Rome, Istituto Affari Internazionali, April 2021, https://www.iai.it/en/node/13116".

[67] "Snam, Snam 2030 Vision and 2021-2025 Plan, 29 November 2021, https://www.snam.it/en/ Investor_Relations/Strategy/2021-2025_strategic_plan; Stefano Mauro, 'Le reti gas esistenti sono pronte al trasporto dell'idrogeno', in RiEnergia, 27 April 2021, https://".

[68] "American Society of Mechanical Engineers (ASME), B31.12 Hydrogen Piping and Pipelines, 2019, https://www.asme.org/codes-standards/find-codes-standards/b31-12-hydrogen-piping-pipelines".

[69] "Ready4H2, Europe's Local Hydrogen Network. Part 1: Local Gas Networks Are Getting Ready to Convert, https://www.ready4h2.com/projects-3".

[70] "ACER, Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure, cit".

[71] "Diamond, S., & Boyd, S. (2016). CVXPY: A Python-embedded modeling language for convex optimization. The Journal of Machine Learning Research, 17(1), 2909-2913".

[72] "Howells, M., Rogner, H., Strachan, N., Heaps, C., Huntington, H., Kypreos, S., … & Roehrl, A. (2011). OSeMOSYS: the open source energy modeling system: an introduction to its ethos, structure and development. Energy Policy, 39(10), 5850-5870".

[73] "Pfenninger, S., & Pickering, B. (2018). Calliope: a multi-scale energy systems modelling framework. Journal of Open Source Software, 3(29), 825".

[74] "Loulou, R., Remme, U., Kanudia, A., Lehtila, A., & Goldstein, G. (2005). Documentation for the times model part ii. Energy Technology Systems Analysis Programme".

[75] M. Reuß, T. Grube, M. Robinius, P. Preuster, P. Wasserscheid, and D. Stolten, "Seasonal storage and alternative carriers: A flexible hydrogen supply chain model," *Appl. Energy*, vol. 200, pp. 290–302, 2017, doi: 10.1016/j.apenergy.2017.05.050.

[76] D. Teichmann, W. Arlt, and P. Wasserscheid, "Liquid Organic Hydrogen Carriers as an efficient vector for the transport and storage of renewable energy,"

Int. J. Hydrogen Energy, vol. 37, no. 23, pp. 18118–18132, 2012, doi: 10.1016/j.ijhydene.2012.08.066.

[77] "ChemSusChem - 2013 - Br ckner - Evaluation of Industrially Applied Heat-Transfer Fluids as Liquid Organic Hydrogen Carrier.pdf."

[78] "SESAM Polimi", [Online]. Available: https://sesam.polimi.it/

[79] "SESAM database", [Online]. Available: https://publications.jrc.ec.europa.eu/repository/handle/JRC92496

[80] "Massimo Beccarello Project Manager : Andrea Andreuzzi".

[81] "HYBRIT: The world's first fossil-free steel ready for delivery", [Online]. Available: https://group.vattenfall.com/press-and-media/pressreleases/2021/hybrit-the-worlds-first-fossil-free-steel-ready-for-delivery

[82] "'Our low-emissions innovation portfolio covers all possible technology pathways,' Available at https:// corporate.arcelormittal.com/ sustainability/ our-low-emissions-innovation-portfolio-covers-all-possible-technology-pathways".

[83] P. M. Santarelli, I. S. Gillet, and D. Torre, "POLITECNICO DI TORINO Master of Science in Energy and Nuclear Master ' s Degree Thesis TCO calculation of hydrogen light duty vehicles and forecast up to," 2022.

[84] "Roadmap on hydrogen standardisation," no. March, pp. 1–121, 2023.

[85] "D. Gielen, E. Taibi, and R. Miranda, 'Hydrogen: A renewable energy perspective.' International Renewable Energy Agency (IRENA), 2019".

[86] A. Wang *et al.*, "Analysing Future Demand, Supply, and Transport of Hydrogen," *EUuropean Hydrog. Backbone*, no. June, p. 70, 2021, [Online]. Available: https://transparency.entsog.eu/

[87] "The Fit for 55 Package: Key Points for Green Hydrogen and PtX", [Online]. Available: https://ptx-hub.org/the-fit-for-55-package-key-points-for-green-hydrogen-and-ptx/

[88] A. Lahnaoui, C. Wulf, and D. Dalmazzone, "Optimization of hydrogen cost and transport technology in france and germany for various production and demand scenarios," *Energies*, vol. 14, no. 3, 2021, doi: 10.3390/en14030744.

[89] "Hydrogen Council. Hydrogen Scaling Up, a Sustainable Pathway for the Global Energy Transition; Hydrogen Council: Brussels, Belgium, 2017.".

[90] "ean Comission. COM(2020) 301, A Hydrogen Strategy for a Climate-Neutral Europe; European Comission: Brussels, Bel_gium, 2020".

[91] "Natural gas EU Dutch TTF spot market price", [Online]. Available: https://tradingeconomics.com/commodity/eu-natural-gas

[92] "Rotterdam Coal Futures spot price", [Online]. Available: https://www.indexmundi.com/commodities/glossary/rotterdam-coal

[93] "Weekly Oil Bulletin", [Online]. Available: https://energy.ec.europa.eu/data-and-analysis/weekly-oil-bulletin_en#price-developments

[94] "Registration of Crude Oil Imports and Deliveries in the European Union", [Online]. Available: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fenergy.ec.europa.eu%2Fsystem%2Ffiles%2F2020-05%2F5_crude_oil_imports_history_0.xlsx&wdOrigin=BROWSELINK

[95] *Italian Greenhouse Gas Inventory 1990-2019, National Inventory Report 2021*.

Appendix A

Table A 1: Investment cost for implemented technologies (Euro/GW)

Year	Geothermal PP	Solar PV	Wind PP	Hydro PP	Pumped hydro PP
2020	10,954,471,708.51	862,365,850.75	1,455,242,373.14	3,546,553,462.76	296,438,261.20
2021	10,844,265,755.71	845,118,533.74	1,449,852,586.58	3,547,820,089.00	296,438,261.20
2022	10,734,059,802.91	827,871,216.72	1,444,462,800.01	3,549,086,715.23	296,438,261.20
2023	10,623,853,850.11	810,623,899.71	1,439,073,013.44	3,550,353,341.47	296,438,261.20
2024	10,513,647,897.30	793,376,582.69	1,433,683,226.88	3,551,619,967.71	296,438,261.20
2025	10,403,441,944.50	776,129,265.68	1,428,293,440.31	3,552,886,593.94	296,438,261.20
2026	10,293,235,991.70	758,881,948.66	1,422,903,653.74	3,554,153,220.18	296,438,261.20
2027	10,183,030,038.90	741,634,631.65	1,417,513,867.17	3,555,419,846.42	296,438,261.20

2028	10,072,824,086.10	724,387,314.63	1,412,124,080.61	3,556,686,472.65	296,438,261.20
2029	9,962,618,133.30	707,139,997.62	1,406,734,294.04	3,557,953,098.89	296,438,261.20
2030	9,852,412,180.49	689,892,680.60	1,401,344,507.47	3,559,219,725.13	296,438,261.20
2031	9,753,226,822.97	683,424,936.72	1,390,564,934.34	3,559,219,725.13	296,438,261.20
2032	9,654,041,465.45	676,957,192.84	1,379,785,361.20	3,559,219,725.13	296,438,261.20
2033	9,554,856,107.93	670,489,448.96	1,369,005,788.07	3,559,219,725.13	296,438,261.20
2034	9,455,670,750.41	664,021,705.08	1,358,226,214.94	3,559,219,725.13	296,438,261.20
2035	9,356,485,392.88	657,553,961.20	1,347,446,641.80	3,559,219,725.13	296,438,261.20
2036	9,257,300,035.36	651,086,217.32	1,336,667,068.67	3,559,219,725.13	296,438,261.20
2037	9,158,114,677.84	644,618,473.44	1,325,887,495.53	3,559,219,725.13	296,438,261.20
2038	9,058,929,320.32	638,150,729.56	1,315,107,922.40	3,559,219,725.13	296,438,261.20
2039	8,959,743,962.80	631,682,985.68	1,304,328,349.26	3,559,219,725.13	296,438,261.20
2040	8,860,558,605.28	625,215,241.80	1,293,548,776.13	3,559,219,725.13	296,438,261.20
2041	8,770,189,723.98	618,747,497.91	1,282,769,202.99	3,559,219,725.13	296,438,261.20
2042	8,679,820,842.68	612,279,754.03	1,271,989,629.86	3,559,219,725.13	296,438,261.20
2043	8,589,451,961.38	605,812,010.15	1,261,210,056.73	3,559,219,725.13	296,438,261.20
2044	8,499,083,080.09	599,344,266.27	1,250,430,483.59	3,559,219,725.13	296,438,261.20
2045	8,408,714,198.79	592,876,522.39	1,239,650,910.46	3,559,219,725.13	296,438,261.20
2046	8,318,345,317.49	586,408,778.51	1,228,871,337.32	3,559,219,725.13	296,438,261.20
2047	8,227,976,436.19	579,941,034.63	1,218,091,764.19	3,559,219,725.13	296,438,261.20
2048	8,137,607,554.90	573,473,290.75	1,207,312,191.05	3,559,219,725.13	296,438,261.20
2049	8,047,238,673.60	567,005,546.87	1,196,532,617.92	3,559,219,725.13	296,438,261.20
2050	7,956,869,792.30	560,537,802.99	1,185,753,044.78	3,559,219,725.13	296,438,261.20

Year	SMR + CCS	Electrolysis (PEM)	CG + CCS	BG + CCS	H2 to CH4
2020	1,013,144,520.20	1,743,287,777.77	1,379,914,156.56	3,238,666,449.47	182,710,000.00
2021	975,222,351.00	1,641,407,323.22	1,357,840,058.07	3,034,339,537.86	182,710,000.00
2022	937,300,181.81	1,539,526,868.68	1,335,765,959.59	2,830,012,626.24	182,710,000.00
2023	899,378,012.62	1,437,646,414.13	1,313,691,861.10	2,625,685,714.63	182,710,000.00
2024	861,455,843.43	1,335,765,959.59	1,291,617,762.62	2,421,358,803.01	182,710,000.00
2025	823,533,674.24	1,233,885,505.04	1,269,543,664.13	2,217,031,891.40	182,710,000.00
2026	785,611,505.05	1,132,005,050.50	1,247,469,565.65	2,012,704,979.78	182,710,000.00
2027	747,689,335.85	1,030,124,595.95	1,225,395,467.16	1,808,378,068.17	182,710,000.00
2028	709,767,166.66	928,244,141.41	1,203,321,368.68	1,604,051,156.56	182,710,000.00
2029	671,844,997.47	826,363,686.86	1,181,247,270.19	1,399,724,244.94	182,710,000.00
2030	633,922,828.28	724,483,232.32	1,159,173,171.71	1,195,397,333.33	182,710,000.00
2031	632,564,422.22	717,238,400.00	1,156,456,359.59	1,192,227,719.18	182,710,000.00
2032	631,206,016.16	709,993,567.67	1,153,739,547.47	1,189,058,105.04	182,710,000.00
2033	629,847,610.10	702,748,735.35	1,151,022,735.35	1,185,888,490.90	182,710,000.00
2034	628,489,204.04	695,503,903.03	1,148,305,923.22	1,182,718,876.76	182,710,000.00
2035	627,130,797.98	688,259,070.70	1,145,589,111.10	1,179,549,262.62	182,710,000.00
2036	625,772,391.92	681,014,238.38	1,142,872,298.98	1,176,379,648.48	182,710,000.00
2037	624,413,985.85	673,769,406.06	1,140,155,486.86	1,173,210,034.34	182,710,000.00
2038	623,055,579.79	666,524,573.73	1,137,438,674.74	1,170,040,420.19	182,710,000.00
2039	621,697,173.73	659,279,741.41	1,134,721,862.62	1,166,870,806.05	182,710,000.00
2040	620,338,767.67	652,034,909.09	1,132,005,050.50	1,163,701,191.91	182,710,000.00
2041	618,980,361.61	644,790,076.76	1,129,288,238.38	1,160,531,577.77	182,710,000.00

2042	617,621,955.55	637,545,244.44	1,126,571,426.26	1,157,361,963.63	182,710,000.00
2043	616,263,549.49	630,300,412.12	1,123,854,614.13	1,154,192,349.49	182,710,000.00
2044	614,905,143.43	623,055,579.79	1,121,137,802.01	1,151,022,735.35	182,710,000.00
2045	613,546,737.37	615,810,747.47	1,118,420,989.89	1,147,853,121.20	182,710,000.00
2046	612,188,331.31	608,565,915.15	1,115,704,177.77	1,144,683,507.06	182,710,000.00
2047	610,829,925.25	601,321,082.82	1,112,987,365.65	1,141,513,892.92	182,710,000.00
2048	609,471,519.19	594,076,250.50	1,110,270,553.53	1,138,344,278.78	182,710,000.00
2049	608,113,113.13	586,831,418.18	1,107,553,741.41	1,135,174,664.64	182,710,000.00
2050	606,754,707.07	579,586,585.85	1,104,836,929.29	1,132,005,050.50	182,710,000.00

Year	Geothermal HP	Fuel cell (PEM)	Coal PP	Oil PP	NG PP + CCS
2020	3,665,054,865.70	2,093,077,338.37	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2021	3,643,495,719.43	1,958,934,739.89	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2022	3,621,936,573.16	1,824,792,141.40	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2023	3,600,377,426.89	1,690,649,542.92	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2024	3,578,818,280.62	1,556,506,944.43	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2025	3,557,259,134.35	1,422,364,345.95	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2026	3,535,699,988.09	1,288,221,747.47	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2027	3,514,140,841.82	1,154,079,148.98	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2028	3,492,581,695.55	1,019,936,550.50	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2029	3,471,022,549.28	885,793,952.01	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2030	3,449,463,403.01	751,651,353.53	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2031	3,428,982,214.05	743,953,719.19	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16

2032	3,408,501,025.10	736,256,084.84	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2033	3,388,019,836.14	728,558,450.50	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2034	3,367,538,647.19	720,860,816.16	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2035	3,347,057,458.23	713,163,181.81	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2036	3,326,576,269.28	705,465,547.47	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2037	3,306,095,080.32	697,767,913.13	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2038	3,285,613,891.37	690,070,278.78	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2039	3,265,132,702.41	682,372,644.44	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2040	3,244,651,513.46	674,675,010.10	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2041	3,225,248,281.81	666,977,375.75	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2042	3,205,845,050.17	659,279,741.41	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2043	3,186,441,818.53	651,582,107.07	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2044	3,167,038,586.89	643,884,472.72	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2045	3,147,635,355.25	636,186,838.38	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2046	3,128,232,123.60	628,489,204.04	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2047	3,108,828,891.96	620,791,569.69	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2048	3,089,425,660.32	613,093,935.35	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2049	3,070,022,428.68	605,396,301.01	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16
2050	3,050,619,197.04	597,698,666.66	1,724,731,701.51	1,463,292,400.12	1,616,935,970.16

Table A 2: Tech efficiency for each technology

Year	SMR + CCS	Electrolysis (PEM)	CG + CCS	BG + CCS	H2 to CH4
2020	0.709375	0.76375	0.56375	0.5	0.78
2021	0.71125	0.769375	0.564375	0.5	0.78
2022	0.713125	0.775	0.565	0.5	0.78
2023	0.715	0.780625	0.565625	0.5	0.78
2024	0.716875	0.78625	0.56625	0.5	0.78
2025	0.71875	0.791875	0.566875	0.5	0.78
2026	0.720625	0.7975	0.5675	0.5	0.78
2027	0.7225	0.803125	0.568125	0.5	0.78
2028	0.724375	0.80875	0.56875	0.5	0.78
2029	0.72625	0.814375	0.569375	0.5	0.78
2030	0.728125	0.82	0.57	0.5	0.78
2031	0.73	0.822	0.5715	0.5015	0.78
2032	0.732	0.824	0.573	0.503	0.78
2033	0.734	0.826	0.5745	0.5045	0.78
2034	0.736	0.828	0.576	0.506	0.78
2035	0.738	0.83	0.5775	0.5075	0.78
2036	0.74	0.832	0.579	0.509	0.78
2037	0.742	0.834	0.5805	0.5105	0.78
2038	0.744	0.836	0.582	0.512	0.78
2039	0.746	0.838	0.5835	0.5135	0.78
2040	0.748	0.84	0.585	0.515	0.78
2041	0.75	0.842	0.5865	0.5165	0.78
2042	0.752	0.844	0.588	0.518	0.78
2043	0.754	0.846	0.5895	0.5195	0.78
2044	0.756	0.848	0.591	0.521	0.78
2045	0.758	0.85	0.5925	0.5225	0.78
2046	0.76	0.852	0.594	0.524	0.78
2047	0.762	0.854	0.5955	0.5255	0.78
2048	0.764	0.856	0.597	0.527	0.78
2049	0.766	0.858	0.5985	0.5285	0.78
2050	0.768	0.86	0.6	0.53	0.78

Year	Hydro PP	Fuel cell	Coal PP	Oil PP	NG PP
2020	0.92	0.47125	0.46	0.4305556	0.52
2021	0.92	0.478125	0.462	0.4305556	0.523

2022	0.92	0.485	0.464	0.4305556	0.526
2023	0.92	0.491875	0.466	0.4305556	0.529
2024	0.92	0.49875	0.468	0.4305556	0.532
2025	0.92	0.505625	0.47	0.4305556	0.535
2026	0.92	0.5125	0.472	0.4305556	0.538
2027	0.92	0.519375	0.474	0.4305556	0.541
2028	0.92	0.52625	0.476	0.4305556	0.544
2029	0.92	0.533125	0.478	0.4305556	0.547
2030	0.92	0.54	0.48	0.4305556	0.55
2031	0.92	0.5415	0.48	0.4305556	0.55
2032	0.92	0.543	0.48	0.4305556	0.55
2033	0.92	0.5445	0.48	0.4305556	0.55
2034	0.92	0.546	0.48	0.4305556	0.55
2035	0.92	0.5475	0.48	0.4305556	0.55
2036	0.92	0.549	0.48	0.4305556	0.55
2037	0.92	0.5505	0.48	0.4305556	0.55
2038	0.92	0.552	0.48	0.4305556	0.55
2039	0.92	0.5535	0.48	0.4305556	0.55
2040	0.92	0.555	0.48	0.4305556	0.55
2041	0.92	0.5565	0.48	0.4305556	0.55
2042	0.92	0.558	0.48	0.4305556	0.55
2043	0.92	0.5595	0.48	0.4305556	0.55
2044	0.92	0.561	0.48	0.4305556	0.55
2045	0.92	0.5625	0.48	0.4305556	0.55
2046	0.92	0.564	0.48	0.4305556	0.55
2047	0.92	0.5655	0.48	0.4305556	0.55
2048	0.92	0.567	0.48	0.4305556	0.55
2049	0.92	0.5685	0.48	0.4305556	0.55
2050	0.92	0.57	0.48	0.4305556	0.55

List of Figures

List of Tables