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Power-to-Hydrogen-to-Power

A case study from a single farm to a Renewable Energy Community

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Introduction

The agricultural sector, a pillar of the Italian economy, is currently undergoing a dual transition. On one side, there is the food transition, which is driving the evolution towards more sustainable production systems, in line with the European "Farm to Fork" strategy, whose primary objectives are to reduce the climate footprint of agricultural activities, halve the use of pesticides and combat the dispersion of nutrients (such as nitrogen and phosphorus) into the environment. On the other hand, this path is meshed with the energy transition, which encourages the adoption of renewable technologies, such as anaerobic digesters, photovoltaic or wind power plants. In this scenario, farmers evolve from mere consumers of fossil fuels to prosumers (producers-consumers), reducing their historical dependence on diesel for mechanisation and natural gas for thermal processes. This transformation not only reduces the sector's contribution to national emissions but also mitigates its economic vulnerability to energy price volatility on global markets [1].

The imperative of decarbonisation, established in European objectives (such as the RED II Directive) and national objectives (PNIEC), requires the rural sector to radically revise its consumption models. In this context, agriculture is no longer just a consumer but a potential decentralised producer of renewable energy, thanks to the growing spread of photovoltaic and, in the future, agrivoltaics systems, as highlighted in several recent studies [2].

The increase in production from non-programmable renewable sources (such as solar) raises the issue of energy surpluses and grid stability. Excess energy must be managed, either through electrochemical storage systems (batteries) for short periods or through long-term solutions.

It is in this scenario, the Power-to-Gas (P2G) technology emerges, which uses surplus renewable electricity to produce green hydrogen through electrolysis process [3]. Hydrogen is a strategic vector capable of offering seasonal energy storage, managing imbalances between summer photovoltaic (PV) energy production and winter consumption, but also decarbonising agricultural (and non-agricultural) activities known as "hard-to-abate", such as the refuelling of heavy machinery (tractors) or the supply of heat.

The main objective of this thesis concerns the analysis of the potential of hydrogen as a new energy carrier for agriculture, describing its different types, the so-called "hydrogen colours", with a focus on the electrolysis process for the production of green hydrogen, the most suitable storage methods for agricultural use (such as compression at 350 bar), and its possible use to produce electricity and heat.

To this end, the Italian and European legislative context has been examined, with particular attention to incentive mechanisms, such as decrees concerning renewable energy sources (RES) and the NRRP, which play a crucial role in promoting the adoption of these technologies. This thesis examines the configurations of Renewable Energy Communities (RECs) and the widespread self-consumption, which, supported by a constantly evolving regulatory framework, represent an innovative solution for promoting the production and sharing of clean energy, mainly because they allow the agricultural communities involved to obtain incentives and funding for new projects related to the renewable energy sources.

Starting from this concept, the thesis examines a specific application project: the technical-economic analysis of a Power-to-Gas system, but more specifically, Power-to-Hydrogen-to-Power (P2H2P), for the self-sufficiency of a farm. The final goal, however, is to demonstrate how, despite an unsustainable economic result in the case of a single farm (see CHAPTER 4), the establishment of an agricultural Renewable Energy Community can solve the problem of sustainability. This work therefore aims to size the technical and management architecture of the proposed REC, verifying its sustainability through the evaluation of CAPEX, OPEX and the final calculation of the Levelised Cost Of Hydrogen (LCOH), demonstrating how economies of scale and regulatory incentives are fundamental in making green hydrogen a key solution for the energy transition of the Italian agricultural sector, contributing to environmental, economic and social benefits.

Chapter 1: Renewable technologies in the agricultural context

It is well known that the agricultural sector requires large amounts of energy to enable farmers and breeders to cultivate their land and feed their animals. In fact, its energy management is traditionally characterised by high consumption, divided between electricity for irrigation and facilities, thermal energy for drying or heating and, above all, the utilization of fossil fuels for heavy mechanisation (tractors and machinery). Consequently, although the massive use of conventional fuels (mainly diesel) for mechanisation and heating is an environmental constraint, it also represents an opportunity for possible decarbonisation measures.

The need to decarbonise the primary sector and stabilise operating costs in the face of fossil fuel market instability, is driving farms towards self-production of energy. In this scenario, the adoption of renewable energy systems (RES), with particular reference to the evolution represented by agrivoltaics, is now the most accredited solution for distributed generation of energy. However, the success of this paradigm depends on the management of production peaks and the intermittent nature of solar energy; critical issues that make the use of innovative and low environmental impact storage technologies indispensable [2].

Therefore, the real challenge lies in defining technical and economic schemes capable of electrifying even the most energy-intensive mechanical processes, allowing the definitive abandonment of diesel as a fuel, and the achievement of a completely carbon-free production chain [4].

Next, we will take a detailed look at the three main RES used in agriculture: photovoltaic, wind and bioenergy.

1.1 Photovoltaics in agriculture

Photovoltaics (PV) is one of the main renewable technologies used globally, and research and development into it began around two centuries ago, while its practical application took place in 1954, at Bell Laboratories in the USA, thanks to scientists Gerald Pearson, Daryl Chapin and Calvin Fuller, who created the first efficient silicon (Si) solar cell [5].

In Italy, on the other hand, the first photovoltaic panels were installed in 1979 at Passo dei Mandrioli. Then, thanks to the first incentives in 1992, the use of photovoltaics spread throughout the country, leading solar energy to become one of the main sources of renewable production in Italy [6], [7]. Furthermore, over the last fifteen years, photovoltaic energy production in Italy has grown exponentially, from around 1,900 GWh in 2010 to an estimated almost 36,000 GWh in 2024:

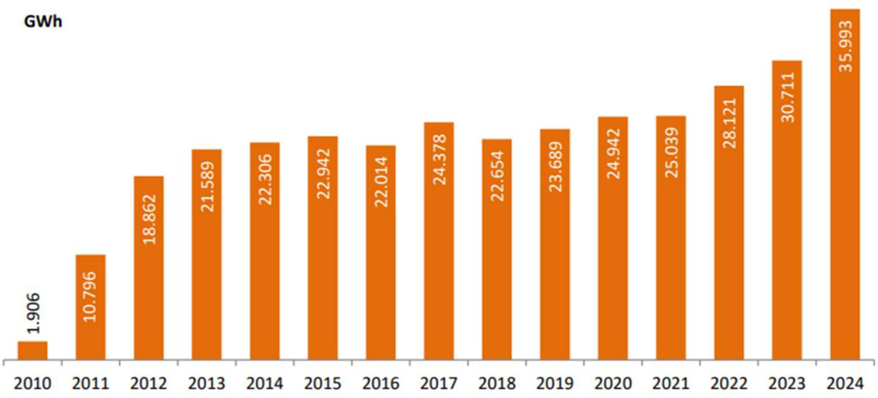


Figure 1: annual and monthly production of photovoltaic plants in Italy [8].

Analysing the distribution of gross production by sector of use, we can see that the civil/residential sector contributes for the 26%, while the agricultural sector accounts for around 8%; the remainder, approximately 66%, is attributable to the industrial and tertiary sectors [8].

In Italy, polycrystalline (approximately 72.5%) and monocrystalline (21.5%) photovoltaic panels are used, with the remaining panels using thin-film technology [9]. From a design perspective, there are also two types of photovoltaic systems; there are "grid-connected" systems, which are widely used because being connected to the grid provides additional security for continuous energy use (especially when the renewable system is unable to produce enough energy during periods of peak consumption) and the electricity produced by the system can also be fed directly into the grid (e.g. in situations where there is a surplus of energy produced); "off-grid systems" instead are less common because, as they are not connected to the public electricity grid, they must necessarily adopt energy storage systems, such as batteries.

The success of PV is justified by several intrinsic advantages, many of which are crucial in the decentralised agricultural context. First of all, solar energy can be used virtually anywhere, with the Sun providing an average power of 1370 W/m^2 on the Earth's surface; furthermore, photovoltaics is now a proven technology and does not require too much maintenance over the years; finally, in recent years, the possibilities for recycling materials have increased, enabling circular economy models to be achieved. These characteristics make PV the basic technology for renewable energy production within farms and future Renewable Energy Communities.

1.1.1 Agrivoltaics

The evolution of photovoltaics in rural areas has led to the development of agrivoltaics systems, an innovative approach that aims to integrate agricultural activities with solar energy production on the same land. The fundamental concept behind these systems is the optimisation of land use, thus maximising the benefits of both agriculture and clean energy generation.

Agrivoltaics systems are distinguished by several key aspects:

- Dual use of land: they allow the simultaneous use of land for growing crops and installing solar panels; this makes it possible to efficiently address the limitation of resources that the land offers.

- Increased soil productivity: the partial shade provided by the panels can have positive effects on certain crops, reducing water evaporation and, in some cases, improving crop yields. Elevated structures can also protect delicate crops from extreme weather conditions, such as excessive sunlight or hail (see Figure 2).

- Income diversification: agrivoltaics provides farmers with two sources of income: one linked to the sale of agricultural products and the other linked to energy production, which can obviously be used directly by the farm, but can also be sold to the grid [2].

Figure 2: example of agrivoltaics architecture with photovoltaic panels suspended above horticultural crops [2].

The adoption of these solutions promotes environmental sustainability by reducing the carbon footprint of agriculture and contributing to renewable energy targets. Although the potential is considerable, the design of agrivoltaics systems presents specific challenges, including the selection of appropriate crops under shading conditions and the optimisation of design to ensure the best exposure to light.

That said, agrivoltaics represents a fundamental approach to promoting sustainable agriculture and a crucial part of the renewable energy production strategy, especially for large-scale farms, which have a greater impact on energy and resource consumption [10].

1.2 Wind power in agriculture

In the context of Renewable Energy Sources in agriculture, wind energy is a fundamental element for diversifying the production mix and overcoming the intrinsic limitations of systems based solely on solar energy. Unlike large wind farms, which are associated with industrial or offshore contexts (built far from sea and ocean coasts), vast rural areas offer an ideal environment for the installation of small and medium-sized systems (mini-wind and micro-wind).

This design choice is highly strategic for farm self-sufficiency. Wind power guarantees energy production that complements photovoltaics; in fact, while solar power peaks during the day and in the summer months, wind energy is often more abundant at night and in the winter season. This temporal complementarity is essential to achieve optimal energy production efficiency for the farm, which can be used by various machines linked to the Power-to-Gas plant, such as, for example, the electrolyser [11].

The adoption of small wind turbines (typically with power ratings between 1 kW and 200 kW) is supported by technical and economic feasibility analyses, which assess their efficiency in contexts with optimal wind regimes. Specific studies on the feasibility of mini wind turbines, focused on the analysis of the Annual Energy Production (AEP) and Capacity Factor (CF) of 1 to 5 kW turbines, demonstrate their ability to make a significant contribution to self-consumption and energy decentralisation; in fact, these turbines, being able to operate at very low wind speeds (1-4 m/s), potentially produce energy throughout the year, almost continuously [12].

These wind configurations are therefore often used in conjunction with photovoltaics, thus forming hybrid systems that maximise the production of available renewable energy, reducing in this way the need to draw from the grid.

However, often happens that technologies such as wind power may be unpopular with local communities, as they have a significant impact on the landscape and noise levels. In addition, technical aspects must be considered during the design phase to avoid turbulence (which damages the blades) and shading, in order to maximise efficiency.

Despite these considerations, wind power systems contribute directly to reducing fossil fuel consumption on farms and, together with photovoltaics, represent the primary source of clean energy needed to power the green hydrogen cycle.

1.3 Bioenergy in agriculture

When it comes to bioenergy, agriculture is perhaps the best sector for the production and use of these technologies, as even a small to medium-sized farm can generate a large amount of organic and livestock waste throughout the year. Unlike solar and wind power, which are intermittent sources, bioenergy is derived from the conversion of organic matter (biomass) into thermal or electrical energy, offering a programmable source that is available almost continuously, making it crucial for the stability and energy self-sufficiency of farms.

The main forms of bioenergy used in agriculture are:

- Biogas: a gaseous fuel produced through anaerobic digestion, a biological process in which bacteria present in organic waste decompose the organic matter itself (livestock waste, crop residues such as corn silage, manure) in the absence of oxygen, i.e. under anaerobic conditions. Biogas is mainly composed of methane (CH_4) and carbon dioxide (CO_2). It is used to power cogeneration (CHP) engines that simultaneously produce electricity and heat, the latter being essential for heating warehouses or production cycles [13].
- Biomethane: this is the evolution of biogas. Through the upgrading (biogas purification) process, the CO_2 component is separated, bringing the gas to a methane concentration of over

97%. This makes it compatible with national natural gas network standards and usable as a biofuel, such as compressed biomethane (Bio-CNG) for cars and liquefied biomethane (Bio-LNG), used mainly as fuel for heavy goods vehicles and maritime transport.

- Solid biofuels: derived from wood residues, pruning, or dedicated crops (such as wood chips), they are mainly used for heat production (thermal biomass) through dedicated boilers, essential for drying and heating processes on the farm.

CHAPTER 2: Power-to-Gas and hydrogen

Power-to-Gas (P2G) technology originated from the need to balance the grid and exploit excess energy produced by renewable energy systems (mentioned in the previous chapter). In fact, P2G serves to exploit energy surpluses (Power) from renewable sources (especially photovoltaic and wind power) that would otherwise be wasted, to generate hydrogen (Gas) through a process called "water electrolysis".

During electrolysis, electrical energy is used to separate the two hydrogen atoms (H_2) from the oxygen atom (O) present in the water molecule (H_2O), thus releasing large quantities of hydrogen, which is captured and stored (see **EQ.1**). The hydrogen produced in this way is called "green hydrogen" and is currently the cleanest type of hydrogen:

$$2H_2O + electrical\ energy = 2H_2 + O_2 \quad \textbf{EQ.1}$$

Hydrogen produced via P2G is not only a form of storage, but also a versatile energy carrier offering two main end uses:

- Power-to-Hydrogen-to-Power: this pathway, which will be the central focus of this thesis, involves the storage of compressed hydrogen (e.g. at 350 bar) and its subsequent use in fuel cells; these convert the chemical energy of H_2 back into electricity and heat (cogeneration) at times of low production from renewable sources, or when the company requires more energy than usual. This cycle would theoretically guarantee energy self-sufficiency and system resilience [14].
- Hydrogen as a raw material (Power-to-X): it concerns the direct use of hydrogen or its derivatives. In the agricultural context, H_2 can be used as a zero-emission fuel for heavy-duty mobility (tractors and machinery) or as a fuel for boilers and generators to replace natural gas or diesel. In addition, hydrogen can act as a precursor for the synthesis of other chemicals, such as ammonia (Power-to-Ammonia technology), which can be used to produce low-emission fertilisers, paving the way for complete decarbonisation of the agri-food supply chain [4].

2.1 Hydrogen: characteristics and uses

Hydrogen (H_2) is the most abundant element in the universe. However, on Earth, it is not found in its free form, but is bound to other elements, mainly oxygen in water or carbon in hydrocarbons, such as methane (CH_4).

2.1.1 Nature and production of hydrogen

Hydrogen is an energy carrier (like electricity) that must be produced by consuming energy, and is different from fossil fuels, which are primary sources of energy (they can often generate energy in their pure form). As it is often bound to other natural elements, in order to be used as a zero-emission fuel, hydrogen must be freed from its bond with oxygen (through water electrolysis) or extracted from hydrocarbons (hydrogen reforming).

Although it is the simplest element, the processes for producing it in its pure form are complex; in fact, these processes, which require a lot of energy, involve significant losses and are associated with high costs and, in the case of extraction from fossil fuels, cause carbon emissions and therefore air pollution.

2.1.2 Energy density and storage challenges

One of the main critical issues with hydrogen is its low volumetric energy density compared to other fuels (0.0179 MJ/l), but at the same time, it has the highest gravimetric energy density (34 kcal/g) [2]. However, its low volumetric density makes hydrogen difficult to store and transport, reducing its practicality for uses not directly connected to the grid (such as aviation or navigation).

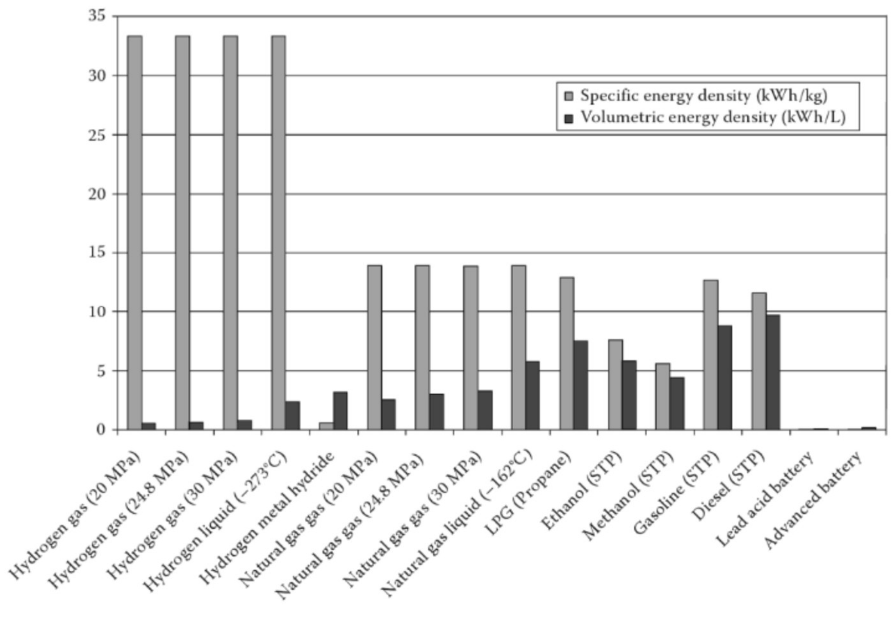


Figure 3: comparison between specific energy density (kWh/kg) and volumetric energy density (kWh/l) for different energy carriers and some storage systems [3].

The partial solution is to condense hydrogen into liquid form, thereby drastically reducing its volume. However, its liquefaction point is extremely low (-253°C), which requires a significant amount of energy for the cooling process alone. Even in liquid form, its energy density would not reach that of comparable fossil fuels, such as petrol or diesel (see Figure 3) [2], [3].

2.1.3 Transport and derivatives

To overcome density and transport issues, hydrogen can be managed in various forms:

- Compressed gas and pipelines: the transport of large volumes of hydrogen over long distances is mainly managed through dedicated or repurposed pipelines. These infrastructures must be designed to withstand high operating pressures (generally between 60 and 100 bar) and to counteract the degrading effect of hydrogen on metallic materials. The main phenomenon to be prevented is “hydrogen embrittlement”: in this process, hydrogen atoms penetrate the crystalline structure of steel, diffusing inside it and causing a drastic loss of ductility, thus degrading its mechanical characteristics [15].
- Derivative products: hydrogen can be converted into derivative products, which have higher volumetric energy densities but also greater flexibility, such as ammonia (NH_3); it can be stored and transported by ship, or by truck and pipeline, in liquid form at moderate pressures, or in cryogenic tanks at approximately -33°C and 1 bar pressure. Unfortunately, the synthesis of hydrogen into ammonia, and its subsequent dehydrogenation, involve significant energy consumption.
  Another derivative product is methanol (CH_3OH), which is formed by reacting hydrogen with carbon dioxide (CO_2) and is very useful because it is in a liquid state at ambient temperature and pressure, making it easier to handle and transport (by ship, cistern or tank).

2.1.4 Combustion properties and safety

Hydrogen in its gaseous state can be used as a fuel, even under normal atmospheric pressure and temperature conditions (0°C and 1 atm). However, it has some significant differences compared to natural gas:

- Ignition and flammability: hydrogen ignites with very low energy and has a wide flammability range, meaning it can burn in mixtures with air ranging from 4% to 75%, while methane, for example, can only burn in the 5-15% range [16]:

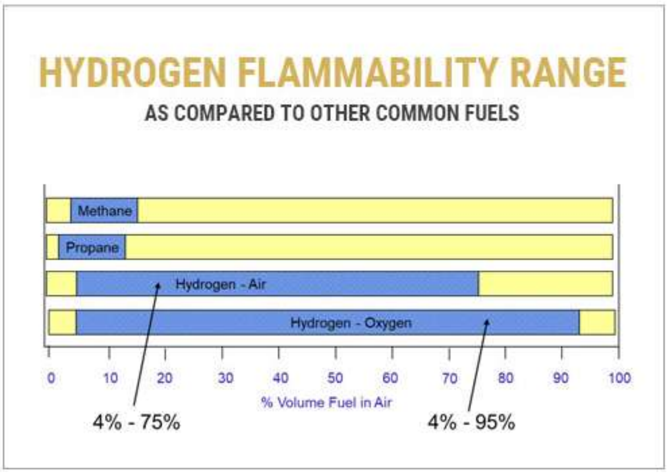


Figure 4: comparison of flammability ranges in air (% by volume) for different gaseous fuels [16].

- Dispersion: its dispersion behaviour differs from other gases due to the small size of its atoms, and this can lead to losses during storage in a gaseous state.

- Detection: being colourless, odourless and tasteless, it requires specific sensors or odorization techniques for detection; in addition, additives are needed to produce a flame that is visible during combustion [2].

2.1.5 Strategic role in decarbonisation

As mentioned above, hydrogen can be used strategically as a vector for energy storage, to be then reused for electricity production (P2H2P technology); however, given the low overall efficiency of this technology, which is around 30-35% (see CHAPTER 4-5), hydrogen is not very competitive for short-term storage, given that, compared to battery storage systems, used for example in photovoltaic systems, the efficiency of the latter can reach values of up to 90%. Therefore, the use of direct electrification remains the priority, where technically feasible.

However, hydrogen becomes indispensable for so-called "hard-to-abate" sectors (such as the steel industry, aviation and fertiliser production), where direct electrification is not applicable due to the high temperatures required and when specific chemical reagents are needed. In these sectors, which are responsible for significant CO_2 emissions, hydrogen can be used in two main ways: as a storage vector, to manage seasonal energy surpluses or stabilise the corporate/national electricity grid, using P2H2P technology, or as a direct substitute for fossil fuels, acting both directly as a fuel and as a raw material in thermochemical processes, enabling the decarbonisation of supply chains otherwise bound to the use of coal and natural gas [2], [17].

A prime example for hard-to-abate sectors is the steel industry, which in recent years has begun to use a process called Direct Reduced Iron (DRI), in which coal (coke), usually used to heat and chemically reduce iron (**EQ.2**), is replaced by hydrogen, which is also capable of removing oxygen from iron ore (**EQ.3**), generating water vapour as the only by-product instead of carbon dioxide, thus decarbonising steel production at its source:

$$Fe_2O_3 + 3CO \rightarrow 2Fe + CO_2 \quad \textbf{EQ.2}$$

$$Fe_2O_3 + 3H_2 = 2Fe + 3H_2O \quad \textbf{EQ.3}$$

2.2 Hydrogen colours

Hydrogen is classified using a colour coding system, which indicates the production method, the raw material used and, in particular, the carbon footprint. This distinction is fundamental for assessing its sustainability:

	Idrogeno MARRONE	Idrogeno GRIGIO	Idrogeno BLU	Idrogeno VERDE
Processo	Gassificazione	Steam reforming	Steam reforming o gassificazione con CCUS	Elettrolisi
Fonte energetica	Carbone	Gas metano	Gas metano Carbone	Energia elettrica rinnovabile
Carbon footprint	18-20 tCO_2/tH_2	9-10 tCO_2/tH_2	da 1 a > 6 tCO_2/tH_2	0 tCO_2/tH_2

Figure 5: classification of hydrogen based on the energy source and carbon intensity of the production process. In recent years, new colours have been devised to represent hydrogen, linked to how it is produced and its associated environmental impact, but the four colours shown in the image represent the main production methods [2].

Brown hydrogen: obtained from coal through gasification, a process that begins with the partial oxidation (POX) of coal in a gasifier, producing a synthesis gas containing H_2, CO and CO_2 (**EQ.4**). Water vapour is then added, which promotes the "water gas shift reaction" (**EQ.5**), thus converting excess CO into CO_2, increasing the hydrogen yield:

$$C + \frac{1}{2}O_2 \rightarrow CO \quad \textbf{EQ.4}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \quad \textbf{EQ.5}$$

Grey hydrogen: currently dominant in global production, it is derived from natural gas, mainly through a process called "Steam Methane Reforming" (SMR). In this process, desulphurised methane (CH_4) is fed into a reactor with water vapour. Here, the first reaction (**EQ.6**) takes place, followed by the reaction in **EQ.5**. Afterwards, the resulting gas is cooled and finally the hydrogen is extracted by pressure swing adsorption (PSA). The final reaction is **EQ.7**:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \quad \textbf{EQ.6}$$

$$CH_4 + H_2O \rightarrow CO_2 + 4H_2 \quad \textbf{EQ.7}$$

Blue hydrogen: this is produced by adding Carbon Capture and Storage (CCS) technologies to fossil fuel-based processes, such as SMR or gasification. This solution reduces greenhouse gas emissions, although current CCS systems have limited capture efficiency (usually between 85% and 95%), and therefore cannot eliminate the climate impact of CO_2 emissions. Currently, only 0.5% of global hydrogen production uses this technology.

Although SMR is currently the most economical option, cost projections for 2050 indicate an increase in its LCOH. This increase will be driven both by the volatility of natural gas prices (used as a raw material and process fuel) and by the likely rise in carbon costs, linked to government carbon taxes and the European Emission Trading System (ETS), which will weigh on residual emissions not captured by the CCS system [14].

Green hydrogen: this is the only carbon-neutral option available, as mentioned above, through water electrolysis using energy from renewable sources. Although the basic reaction is unique, there are four main electrolysis technologies: Alkaline (AEL), Proton Exchange Membrane (PEM), Solid Oxide (SOEC) and Anion Exchange Membrane (AEM). A typical electrolysis plant is a modular system that includes a water purification unit (necessary for proper operation, especially for PEM), a generation stack (i.e. the central component of the electrolyser), a heat removal system and gas purification/drying units. Downstream of the process, a compressor and storage system are often added for the pure hydrogen that has been produced.

Unfortunately, today 95% of the hydrogen produced is grey, while only 0.1% is green hydrogen. Thanks to European environmental policies and rising coal prices, industrial sectors are moving towards decarbonisation, seeking to reduce the production of brown and grey hydrogen and increase the creation of blue and green hydrogen [2].

2.3 Various types of electrolysers

We will now describe the most used types of electrolysers for the production of green hydrogen and then try to understand which of these could be used for the farm that is the subject of the case study in CHAPTER 4.

	Alkaline	PEM	AEM	Solid Oxide
Operating temperature	70-90 °C	50-80 °C	40-60 °C	700-850 °C
Operating pressure	1-30 bar	< 70 bar	< 35 bar	1 bar
Electrolyte	Potassium hydroxide (KOH) 5-7 $molL^{-1}$	PFSA membranes	DVB polymer support with KOH or NaHCO3 1$molL^{-1}$	Yttria-stabilized Zirconia (YSZ)
Separator	ZrO_2 stabilized with PPS mesh	Solid electrolyte (above)	Solid electrolyte (above)	Solid electrolyte (above)
Electrode / catalyst (oxygen side)	Nickel coated perforated stainless steel	Iridium oxide	High surface area Nickel or NiFeCo alloys	Perovskite-type (*e.g.* LSCF, LSM)
Electrode / catalyst (hydrogen side)	Nickel coated perforated stainless steel	Platinum nanoparticles on carbon black	High surface area nickel	Ni/YSZ
Porous transport layer anode	Nickel mesh (not always present)	Platinum coated sintered porous titanium	Nickel foam	Coarse Nickel-mesh or foam
Porous transport layer cathode	Nickel mesh	Sintered porous titanium or carbon cloth	Nickel foam or carbon Cloth	None
Bipolar plate anode	Nickel-coated stainless steel	Platinum-coated titanium	Nickel-coated stainless steel	None
Bipolar plate cathode	Nickel-coated stainless steel	Gold-coated titanium	Nickel-coated Stainless steel	Cobalt-coated stainless steel
Frames and sealing	PSU, PTFE, EPDM	PTFE, PSU, ETFE	PTFE, Silicon	Ceramic glass

Table 1: comparison of the main technical and construction characteristics of electrolysis technologies (alkaline, PEM, AEM and solid oxide) [18].

2.3.1 Alkaline Electrolyser AEL

Alkaline electrolysis is the technology that most closely approximates the “general” concept of water electrolysis; in fact, an alkaline electrolyser comprises in its operating scheme: two electrodes (a cathode and an anode), both made of steel coated with a layer of nickel (Ni); the alkaline electrolyte, i.e. an alkaline aqueous solution (containing potassium hydroxide, KOH); a membrane, or diaphragm, (in this case made of zirconium oxide ZrO_2), and, of course, electrical energy to power the whole system. These are the oldest type of industrial electrolysers and have been in use for many years.

As can be seen in Figure 6, from right to left, during electrolysis, a redox reaction of water takes place, where the external electricity creates a potential difference between the two electrodes, and consequently the cathode, having a negative charge, attracts the hydrogen atoms (positive) present in the water molecule, releasing hydroxyl ions (OH^-), which pass through the membrane and reach the anode, which, having a positive charge, attracts them. The output of the reaction is therefore hydrogen and oxygen gas:

$$Cathode: 2H_2O + 2e^- \rightarrow H_2 + 2OH^- \quad \textbf{EQ.8}$$

$$Anode: 4OH^- \rightarrow O_2 + 2H_2O + 4e^- \quad \textbf{EQ.9}$$

Alkaline electrolysis is advantageous because it does not require rare metals, has good efficiency (55-65%), is resistant to contaminants present in water, has a long operating life (up to approximately 80,000 hours) and has the highest level of technological maturity among electrolysers (TRL 9).

However, it has some disadvantages, such as high operating temperatures (up to 100°C), and limited operating pressures, as if these are too high, they can promote crossover phenomena between gases, i.e. the diaphragm cannot retain gases such as oxygen and hydrogen outside, risking them reacting with each other. Finally, the most serious disadvantage is the slow reaction to energy load fluctuations, typical of renewable technologies [18].

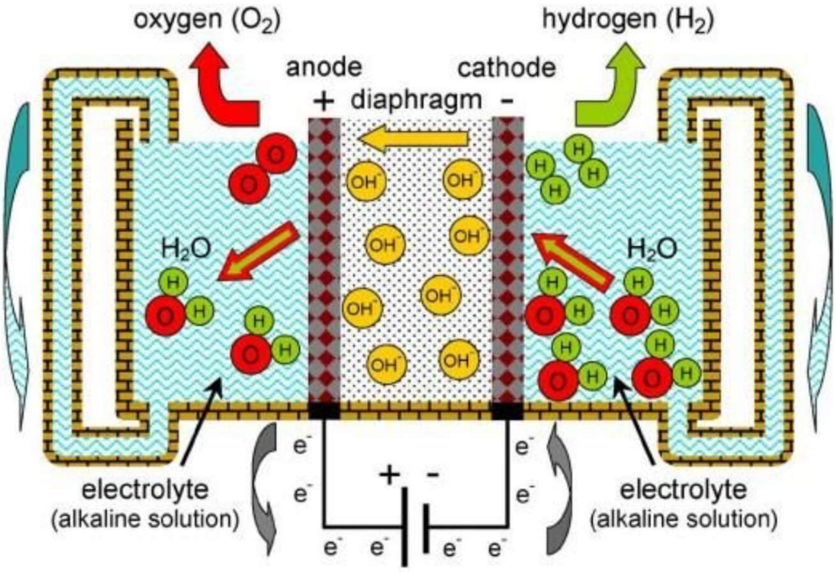


Figure 6: operating diagram of an alkaline electrolytic cell (AEL) with a porous diaphragm [5].

2.3.2 Solid Oxide Electrolysis Cell SOEC

These electrolysers operate at high temperatures, generally between 700 and 800°C; these high temperatures facilitate reaction kinetics, as they allow both electrical energy and heat to be exploited, thus increasing overall efficiency.

Also, for this electrolyser, the electrodes are nickel-based, as many are resistant to high temperatures.

An interesting advantage of SOECs is that they have the potential for reversibility, as they can operate as fuel cells (see section 2.6) to convert hydrogen back into electricity when necessary. They also allow the co-electrolysis of CO_2 and H_2O to produce syngas (synthetic gas), which is a fundamental basic element for the chemical industry. However, as it does not produce hydrogen as an output, but methane, it can no longer be considered a "green technology".

Despite their high theoretical efficiency, SOEC technology is currently less mature than AEL, which affects initial costs. Furthermore, they have a slow start-up phase and are therefore not very suitable for energy load fluctuations [18]:

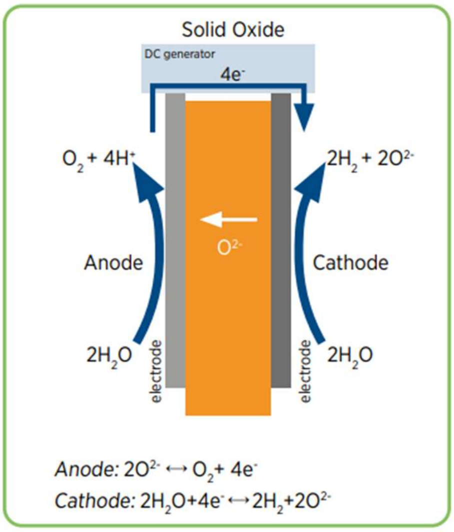


Figure 7: operating scheme of a solid oxide electrolytic cell (SOEC) [18].

2.3.3 Proton Exchange Membrane PEM

Proton Exchange Membrane electrolysis represents the cutting edge of technology in the field of green hydrogen, overcoming many of the limitations of alkaline technology, as it uses a solid polymer membrane, typically made from a perfluorosulfonic acid (PFSA) polymer, such as Nafion, instead of an aqueous alkaline electrolyte. This membrane performs crucial functions, such as conducting protons between electrodes, physically separating the gases produced and providing electrical insulation between the electrodes. In addition, the solid membrane allows the system to operate at high pressures despite its reduced thickness, minimising resistive losses. Thanks to its structure, it has a low hydrogen crossover rate, which guarantees compressed hydrogen with a very high degree of purity (99.999%) at the outlet [19].

As for the electrodes, the anode is usually made of iridium (Ir) or ruthenium (Rn), while the cathode is usually made of platinum (Pt). In this case, looking at Figure 8, from right to left, the water molecules first react with the anode, producing positive hydrogen ions, which then travel towards the cathode through the polymer membrane:

$$Anode: H_2O \rightarrow \frac{1}{2}O_2 + 2H^+ + 2e^- \quad \textbf{EQ.10}$$

$$Cathode: 2H^+ + 2e^- \rightarrow 2H_2 \quad \textbf{EQ.11}$$

Furthermore, inserted between the cells are bipolar plates, which are essential for connecting the cells in series, but also for physically isolating them, preventing the hydrogen from adjacent cells from mixing.

One of its main advantages lies in its ability to operate at high current densities; this translates into potentially reduced operating costs, especially in systems coupled with dynamic energy sources such as solar and wind power, where peaks in energy input would otherwise be wasted.

In addition, it has high efficiency (60-70%) and a high level of technological maturity (TRL 8).

On the other hand, it is very sensitive to water purity, which must therefore be pre-treated; it also has a shorter operating life than other electrolysers and has a high initial investment cost [5].

Despite these disadvantages, the PEM electrolyser has exceptional operational flexibility: it can operate not only under highly dynamic conditions, but also with very wide partial loads and under overload conditions, and these characteristics make it the most efficient and technically appropriate choice for Power-to-Gas (P2G) projects, where energy fluctuations are always present:

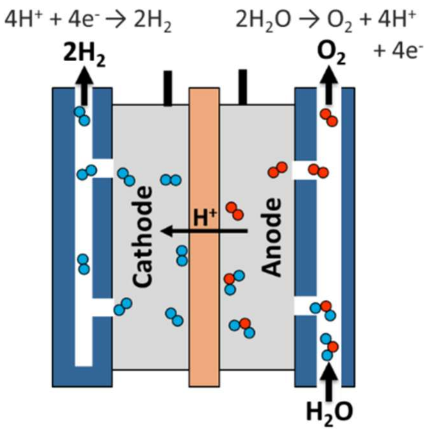


Figure 8: ion transport mechanism in a PEM electrolytic cell [5].

2.3.4 Anion Exchange Membrane AEM

AEM is a recently emerging technology that is a hybrid between AEL and PEM, seeking to combine the advantages of both. In fact, AEM has a solid membrane made of divinylbenzene (DVB), that is used in to improve the mechanical and chemical stability of the polymer in alkaline environments, limiting swelling and increasing operational life; it also acts as an electrolyte (as in PEM), but unlike PEM, it does not require the use of precious materials, such as platinum or iridium, for the electrodes.

Despite its potential, AEM is still a developing technology, with a limited number of companies marketing it and limited distribution. The main challenges hindering its full maturity are issues concerning its stability; in fact, the AEM membrane still has chemical and mechanical stability problems, leading to highly variable service life profiles. Furthermore, performance is not yet optimal, as the conductivity of the membrane is still rather low and it still requires a supporting electrolyte, such as KOH.

On the other hand, AEM can operate at temperatures of 60-70°C, with partial loads (like PEM), and can operate at high pressures and with good hydrogen purity.

Although AEMs promise to offer efficient electrolysis at lower costs, their current limited implementation is indicative of a technology that still needs further research and development to overcome challenges related to stability and efficiency [2], [5]:

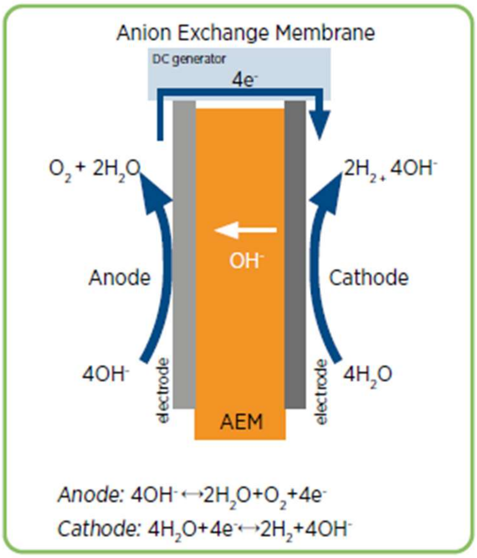


Figure 9: components and ion flows in an anion exchange membrane (AEM) electrolyser [18].

2.4 Hydrogen compression

After describing the main methods of hydrogen production, it is now appropriate to analyse the available compression technologies required to enable its storage under suitable conditions.

Hydrogen compression is a particularly suitable solution for small-scale storage systems, especially when storage times are relatively short, as is typically the case in experimental and demonstration plants [20].

Among the various technological solutions available today, mechanical compressors are one of the most widely used options. These devices work by directly converting mechanical energy into pressure energy through the reciprocating motion of a piston, which progressively compresses the gas, reducing its volume and causing a consequent increase in pressure.

2.4.1 Diaphragm compressors

The main technical feature about diaphragm compressors regards the fact that the piston never comes into contact with the hydrogen, because the hydraulic fluid (typically oil) and the diaphragm are interposed between the two, even though there are diaphragm compressors known as "oil-free". The reciprocating motion of the piston is therefore transferred to the process fluid, which acts on the elastic diaphragm, which compresses the hydrogen (see Figure 10).

The diaphragm compressor also has an oil management and regulation system, which limits excessive oil build-up. during compression, the discharge valve opens, which can create a very high pressure gradient between the diaphragm and the oil; as a result, a pressure limiter is activated, allowing part of the oil to be discharged, thus restoring the pressure balance:

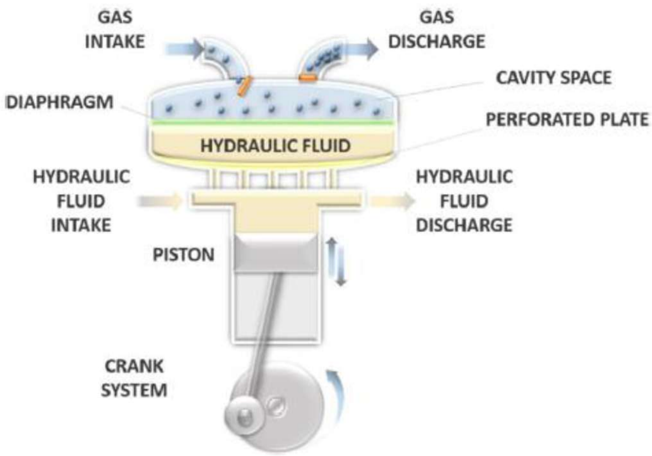


Figure 10: diagram of a hydraulically operated diaphragm compressor [3].

There is consequently a separate circuit that regulates oil pressure, but offers other advantages, such as reducing mechanical stress on the diaphragm (the most important component), extending its operating life and also allowing it to absorb part of the compression heat, preventing the hydrogen from overheating.

A further significant advantage of diaphragm compressors is the possibility of treating hydrogen in a completely closed circuit, eliminating the risk of leaks (i.e. unwanted gas escape). This aspect is particularly important from a safety point of view, as hydrogen leaks are one of the main risks associated with the use of conventional mechanical compressors [3].

Diaphragm compressors are a particularly efficient solution for hydrogen compression, thanks to their ability to guarantee high flow rates with low power consumption and reduced thermal cooling requirements and offers high levels of volumetric efficiency. These characteristics make them particularly suitable for hydrogen-related applications, especially when gas purity and operational safety are priorities.

Despite these benefits, their main limitation is their generally shorter service life, due to the cyclic mechanical stress to which the diaphragm is subjected. However, this critical issue can be mitigated through careful design, aimed at ensuring optimal fluid flow within the chambers and reducing local stresses [21].

2.4.2 Reciprocating compressors

Reciprocating compressors are widely used in industrial applications, as they require high pressure levels, generally above 3MPa, reaching at maximum 25 MPa, making them suitable for moderate flow rates and high-pressure operations. In fact, these machines can reach power levels of around 11.2 MW, allowing flow rates of up to approximately 900 kg/h [22].

The technical functionality of a single-stage reciprocating compressor is based on a piston-cylinder system, coupled with two automatic valves, one for suction and one for delivery. The piston is driven by a rotating crankshaft, connected to the piston and the valves. The rotation of the shaft causes the piston to rise and, consequently, the gas inlet and outlet valves to open and close, regulating the compression cycle:

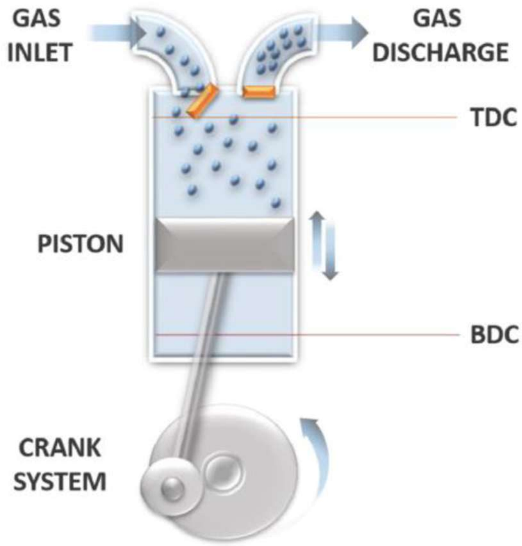


Figure 11: representation of a reciprocating piston compressor with a connecting rod-crank system [3].

Despite their high level of technological maturity and operational reliability, the use of reciprocating compressors for hydrogen compression presents several critical issues. Firstly, the fact that the gas can encounter the piston, and the presence of numerous moving mechanical parts during use, greatly increases component wear and tear. As a result, friction can also occur, generating heat and making it more difficult to cool the gas. Furthermore, the reciprocating motion of the piston can induce periodic pressure variations within the compression chamber, and these fluctuations manifest themselves in the form of vibrations and noise which, under the most severe operating conditions, can generate potentially dangerous situations, including explosive risks. Added to these problems is the possibility of hydrogen contamination in the presence of lubrication systems, as well as degradation or embrittlement of materials exposed to the gas, aspects that require careful design and targeted selection of the materials used [23], [24].

Overall, reciprocating compressors are a well-established and versatile technology, capable of operating over a wide range of flow rates and achieving high operating pressures. However, compared to other compression solutions, they are more complex in terms of construction and management, especially in applications where gas purity, noise reduction and ease of operation are priority requirements.

2.4.3 Linear compressors

This technology is based on the use of electromagnetic forces to generate the reciprocating motion of the piston, eliminating the need for traditional mechanical motion transmission systems and thus reducing friction.

The operating principle exploits the magnetic repulsion between a magnet attached to the piston and a magnetic field generated by the passage of electric current inside a coil. The reversal of the current causes the magnetic field to reverse, inducing the piston to move in the opposite direction. A fundamental component is the spring, connected to the piston, which facilitates the return and thrust of the piston during compression (figure 12). This system is based on mechanical resonance, i.e. in a condition where the frequency of the electromagnetic force applied to the piston coincides with the natural frequency of the mass-spring system, to promote the best possible compression efficiency. However, synchronisation is a complex element to achieve, as it depends on the mass of the piston, the stiffness of the spring and the elastic effect of the gas in the compression chamber. The electromagnetic system also ensures that the compressor does not make too much noise or vibrate, so as not to generate excess heat. The only drawback is that this is a complex system, which therefore requires dedicated control systems to analyse and regulate the compression process in order to achieve the best possible efficiency [21]:

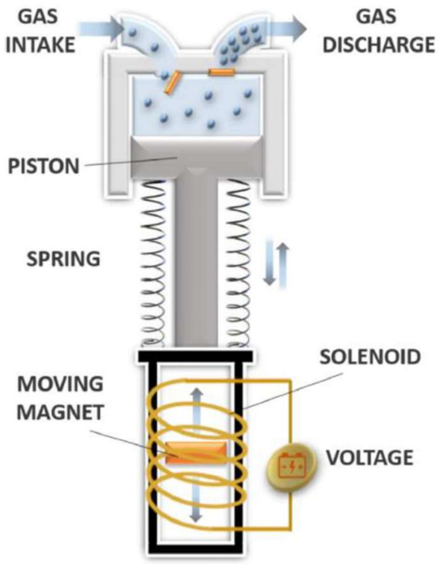


Figure 12: diagram of a linear compressor with electromagnetic drive via solenoid [3].

Overall, linear compressors enable extremely quiet operation and offer significant advantages in terms of reliability and operating comfort; however, their application in the hydrogen sector requires careful design of control systems and thorough evaluation of operating conditions.

2.5 Types of hydrogen storage

Now that we have looked at the various types of mechanical compressors, it is time to analyse the main hydrogen storage techniques that could potentially be used.

2.5.1 Storage of hydrogen in gaseous form

Hydrogen-based energy storage is a promising solution for integrating renewable energy sources and long-term energy storage, particularly for excess or intermittent energy in water electrolysis [25].

The simplest and most economical way to store hydrogen is in its gaseous state, which is mainly achieved by compressing the gas to pressures ranging from 200 to 350 bar. Hydrogen is stored in cylinders or containers suitable for high-pressure storage, which can be located either above ground or underground.

The main advantages of this solution are the simplicity of the plant and the relatively low costs, especially when compared to other more advanced storage technologies. However, the most significant limitation of gaseous storage is its low energy density per unit volume, which requires the use of large tanks. As a result, gaseous storage systems require significant space and lose some of the advantage associated with the low specific weight of hydrogen: the weight of the tank accounts for over 90% of the total weight of the storage system.

For example, a tank that can hold up to 3,000 litres of hydrogen can weigh up to 900 kg, while the hydrogen contained within it will weigh much less. In fact, considering the density of hydrogen to be approximately 25 kg/m^3, and converting the storable litres into m^3, we get:

$$Hydrogen\,mass = density * volume = 25\frac{kg}{m^3} * 3m^3 = 75kg \quad \textbf{EQ.12}$$

Consequently, hydrogen compressed at such pressures cannot be used as fuel for vehicles, as it would have too much impact on the vehicle weight. In fact, in order to be used for mobility, hydrogen must be compressed to pressures of around 700 bar, thus allowing hydrogen storage densities high enough to compete with other types of fuel to be achieved.

Another critical aspect is the energy consumption associated with the compression process, which is one of the main cost items of the entire storage system. To ensure adequate performance, it is necessary to concentrate large quantities of gas in small volumes, making it necessary to find a compromise between the energy required for compression and the volumetric energy density that can be achieved. Furthermore, at the atomic level, hydrogen can interact with the metallic materials that make up the tanks and components of the compression system, and this interaction can give rise to metal embrittlement, which can lead to design and operational criticalities that are not easy to resolve.

In recent years, however, significant progress has been made thanks to the development of tanks with metal or thermoplastic structures reinforced with high-performance fibres, such as carbon or glass fibres; these tanks weigh up to three or four times less than traditional cylinders and partially mitigate the limitations described above.

In addition to storage in tanks, an emerging solution for large-scale applications is underground hydrogen storage, which involves the use of geological formations such as salt caverns, depleted oil and gas fields, and confined aquifers. In the case of salt caverns, these are created by "solution mining", pumping water into the salt layers to dissolve the salt and create storage volumes. Depleted gas and oil reserves are very efficient at storing gas for long periods of time and therefore represent a particularly promising solution for the future [26].

2.5.2 Storage of hydrogen in liquid form

Storing hydrogen in liquid form allows for a significantly higher volumetric energy density than in gaseous form. Therefore, for the same tank volume, the amount of energy that can be stored is significantly greater. However, this solution presents significant technological and energy-related challenges, mainly related to the very low liquefaction temperature of hydrogen, which is approximately −253°C. In fact, specialised insulated tanks or containers are used to maintain these cryogenic temperatures and reduce heat transfer. Liquid hydrogen tanks and transport containers are made safer and more functional by using advanced composite materials such as carbon fibre reinforced polymers (CFRP), which provide structural reinforcement and insulation.

Hydrogen liquefaction processes require complex systems based on a combination of compressors, heat exchangers, expansion engines and laminating valves, designed to achieve the necessary thermodynamic conditions. The simplest and historically most widespread liquefaction cycle is the Linde-Hampson cycle, or Joule-Thomson expansion cycle, generally supplemented by an auxiliary gas pre-cooling phase. In this process, the hydrogen is first compressed, then cooled in a heat exchanger and finally expanded through a throttle valve, exploiting the Joule-Thomson effect, which allows it to reach a liquid state (Figure 13, left).

Unlike many other gases, hydrogen at ambient temperature tends to heat up during Joule-Thomson expansion. To avoid this behaviour, it must first be cooled to a temperature below its Joule-Thomson inversion point, which is approximately -71°C, thus allowing cooling by expansion until liquefaction:

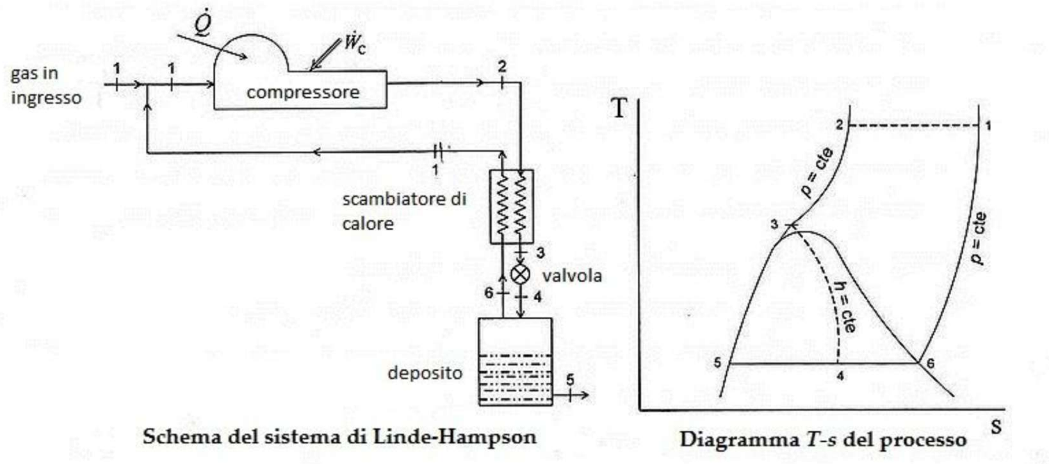


Figure 13: diagram of the liquefaction plant based on the Linde-Hampson cycle (left) and relative T-s diagram (temperature and entropy) of the process (right). Starting from point (1), the inlet gas is compressed, thus increasing the initial pressure (2), and then passes through the heat exchanger (3), which lowers its temperature by transferring heat to the cold return flow; the gas then passes through the isenthalpic laminating valve (the enthalpy remains constant), further reducing the pressure; in the (T-s) diagram, point (4) is located within the saturation bell, in which the hydrogen is in both liquid and gaseous phases; consequently, the gaseous phase is recirculated (4-6) in the heat exchanger to cool it down, restarting the process, while the liquid phase (5) is collected in the tank [14].

From a geometric point of view, liquid hydrogen tanks are often spherical in shape, as spherical geometry has the smallest heat exchange surface area per unit volume, thus minimising heat exchange with the outside. However, in practical applications, cylindrical tanks are frequently used, as they are preferred for their greater simplicity of construction and lower costs. In any case, the inevitable heat losses and the need to maintain extremely low temperatures require the use of advanced materials and complex technologies, which increase the weight and cost of the storage system.

The operating costs of cryogenic storage are high, mainly due to the electricity consumption required for the compression and liquefaction processes. Added to these aspects are significant safety issues related to the management, distribution and supply of liquid hydrogen, which limit its application to specific contexts and mainly on an industrial scale [14].

2.5.3 Use of metal hydrides

Hydrogen can bond with specific metals and metal alloys, forming what are known as metal hydrides. Storage through the formation of metal hydrides is also known as "solid storage" and compared to gaseous and liquid storage, allows for greater energy efficiency and safety by storing hydrogen within solid materials through chemical bonds or physical adsorption [26]. In fact, metal hydrides are solids that are generated by the diffusion of hydrogen into the crystal lattice of the metal, where it occupies the interatomic spaces.

The storage process consists of two phases: hydrogenation (absorption) and dehydrogenation (release). The first occurs at relatively low pressures, which, however, saturate 90% of the metal alloy. To be completely saturated, higher pressures are required, but this requires an adequate cooling system, since, being an exothermic process, it releases heat, which can compromise the efficiency of the system and, to solve this issue, an adequate cooling system is used. Dehydrogenation, on the other hand, requires heat, and in fact there are two types of metal alloys: high temperature (150-300°C) and low temperature (20-90°C). The storage operations usually take place in tanks containing metallic materials in powder form; the alloys used are obtained by combining materials such as iron (Fe), aluminium (Al), magnesium (Mg), or lanthanum (La) with compounds (such as nickel, vanadium (V), titanium (Ti), chromium (Cr), or rare earths) capable of absorbing hydrogen.

The optimal operating conditions of temperature and pressure depend heavily on the chemical composition of the metal hydride used. Furthermore, in order to not have too much long operating times, the material must have a high heat exchange surface area, capable of facilitating effective temperature control during both phases.

The use of low operating pressures gives this technology significant advantages in terms of safety and reduced compression costs. In fact, in the event of an accident involving tank rupture, the drop in pressure causes the compound to cool, automatically stopping the gas leak.

The main disadvantage of this type of storage is the overall weight of the systems and the generally high costs, which limit large-scale commercial use. The total cost is strongly influenced by the cost of the hydride itself, which is penalised by limited production and the absence of economies of scale. Furthermore, any growth in demand for these alloys, resulting in a shortage of available materials, could lead to significant increases in their costs [14].

2.5.4 Use of chemical hydrides

The most used chemical hydrides are methanol (CH_3OH), ammonia and methylcyclohexane ($CH_3C_6H_{11}$). These elements are interesting for the hydrogen storage, that can usually have a period that exceeds 100 days, because they remain in liquid state at ambient temperature and pressure.

Ammonia has a high energy density and is relatively easy to liquefy; however, in most applications, its use is less efficient than liquid hydrogen, mainly due to the high energy consumption required for both synthesis and decomposition processes [27]. Furthermore, ammonia and methanol are generally classified as "open cycle" hydrogen carriers, as the release of hydrogen involves the formation of end products that cannot be directly converted back into the original carrier.

Although these solutions are technically valid, they have further limitations related to the toxicity of the substances involved and the need for energy-intensive processes, factors that reduce their suitability for applications dedicated exclusively to hydrogen storage, favouring instead their use in other application contexts in the supply chain.

The system based on the reaction between hydrogen and toluene, which leads to the formation of methylcyclohexane, is completely reversible, so is "closed cycle". This feature makes this solution particularly interesting for hydrogen storage, as both toluene (C_7H_8) and methylcyclohexane are widely known compounds, easily transportable and characterised by a relatively high level of safety [14]. They are therefore configured as liquid organic hydrogen carriers (LOHC), which are very suitable for closed cycle (i.e. recyclable) and seasonal storage systems.

2.6 Fuel cells

We have reached the last paragraph regarding the technologies we will use during the case study in CHAPTER 4. Now, the topic that will be discussed concerns fuel cells, which are electrochemical devices that directly converts the chemical energy of various types of substances, such as hydrogen, methanol, phosphoric acid and molten carbonates into direct current electrical energy, through the redox reaction, without the intermediation of a thermal cycle, typical of internal combustion engines [28]. This feature allows high electrical efficiency, which can reach up to 75%, and covers a wide range of powers applications.

Fuel cells can be seen as similar to electrochemical batteries in terms of how they work, as they directly convert chemical energy into electrical energy; unlike batteries, however, fuel cells do not contain the reagent, which runs out after use, preventing further electricity production, but are able to supply energy continuously as long as they are fed with fuel and oxidizer, requiring, however, a high degree of fuel purity, particularly in the case of hydrogen [14]. Furthermore, hydrogen is one of the most widely used elements in fuel cells, thanks to its favourable environmental characteristics: its use allows for virtually zero greenhouse gas emissions at the local level, producing only water and low-temperature heat as by-products.

There are different types of fuel cells, which are mainly distinguished by the nature of the electrolyte used, the operating temperature range, and the relevant application sectors. Based on these criteria, fuel cells can be classified into five main categories: alkaline fuel cells (AFC), phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC), solid oxide fuel cells (SOFC), and proton exchange membrane fuel cells (PEM). Alkaline cells, despite being one of the first solutions used in operational applications, have seen a gradual decline in their use over time due to limitations related to materials and costs. Phosphoric acid cells, on the other hand, are widely used in cogeneration systems, while in the mobility sector, PEM fuel cells have established themselves as the reference technology, thanks to their high power density and fast start-up times.

In recent years, research and development on fuel cells has grown significantly, expanding the range of possible applications. These range from logistics and industrial handling, such as hydrogen-powered forklifts, to energy storage systems, fuel cell electric vehicles (FCEVs), and grid-scale power generation support. In particular, in the transport sector, which in 2021 accounted for around 29% of total greenhouse gas emissions, fuel cells are a promising technological alternative to traditional solutions. Studies conducted by the US Department of Energy and Argonne National Laboratory have shown that the adoption of FCEVs could reduce greenhouse gas emissions by up to 50% compared to gasoline-powered vehicles [29].

In summary, fuel cells can currently be used mainly in three sectors: transportation, stationary installations, and portable applications. In the future, they will be able to power more vehicles and supply energy to industrial plants, but the main problem, as with many innovative technologies, is that they are still expensive compared to traditional technologies. However, rapid technological progress and growing attention to decarbonization suggest that these technologies will play an increasingly important role in the future energy system [30].

2.6.1 Stationary fuel cells

Stationary fuel cells are used to support various electricity grid functions, such as improving system resilience, managing peak loads and regulating frequency. As Distributed Energy Resources (DER), stationary fuel cells, thanks to their programmability, long autonomy and integration with grid-forming inverters, can act as true distributed power plants, improving the stability, reliability and flexibility of modern grids dominated by intermittent renewable sources. Fuel cell-based power plants also represent a promising solution for electricity generation, thanks to their high degree of controllability and rapid response. Such plants can be used to compensate for fluctuations in production from non-programmable renewable sources, such as photovoltaics and wind power, helping to bridge power gaps and improve system reliability [14], [31].

In general, stationary fuel cell applications include systems installed in fixed locations, operating as primary generators, backup systems or combined heat and power (CHP) plants. The main advantages of these solutions include reduced carbon emissions and high fuel conversion efficiency. Currently, some of the leading manufacturers of large-scale fuel cells, with power ratings above 100 kW, are based in the United States, while Japan and Europe are particularly active in the development and adoption of small-scale systems, generally below 100 kW, for residential and commercial applications. In the United States, these systems are mainly used as backup solutions for telecommunications infrastructure and public utilities [32], [33].

Small-scale fuel cells have demonstrated high application versatility in the construction sector as well. For example, the Japanese company Miura, in collaboration with Ceres Power, has developed a 4.2 kW fuel cell CHP system for commercial buildings. Similarly, Ceres Power participated in a project with Doosan Fuel Cell, in South Korea, to develop SOFC systems with power ratings between 5 and 20 kW, for commercial applications. These examples highlight the potential of fuel cells as a technology to support distributed generation in buildings and local networks.

A particularly relevant case in the field of stationary applications is the Ene-Farm system, a micro-cogeneration solution based on fuel cells, with electrical power ranging from 0.3 to 1 kW, developed by companies such as Panasonic and Toshiba. Japan is currently the country with the highest penetration of micro-CHP systems of this type. Ene-Farm is designed for residential use and enables the combined production of electricity and heat for domestic use. At the end of 2018, approximately 300,000 Ene-Farm units had been installed, reflecting the growing interest in this technology as a means of reducing energy consumption and improving the resilience of residential infrastructure [32], [34].

2.6.2 General architecture of fuel cells

A fuel cell has a very similar structure to an electrolyser; in fact, the process that takes place is practically the reverse of electrolysis, mainly because electrolysis, as we have seen, requires electrical energy to create hydrogen, while fuel cells use hydrogen to generate electricity.

Fuel cells typically consist of two flat electrodes, the anode and the cathode, which are electrically conductive and have a porous structure, necessary for the passage of reactant gases; they are separated by an electrolyte, which can be liquid or solid and allows the selective transport of ions, while preventing that of electrons. In fact, in the electrochemical cell, the hydrogen, which is fed to the anode, passes through its porous state, reaching the electrolyte, with which (thanks to the help of a catalyst such as platinum) it dissociates the hydrogen molecule into H^+ ions and electrons. These electrons, are unable to pass through the electrolyte, so they are forced to flow through the external electrical circuit, thus generating a useful electric current:

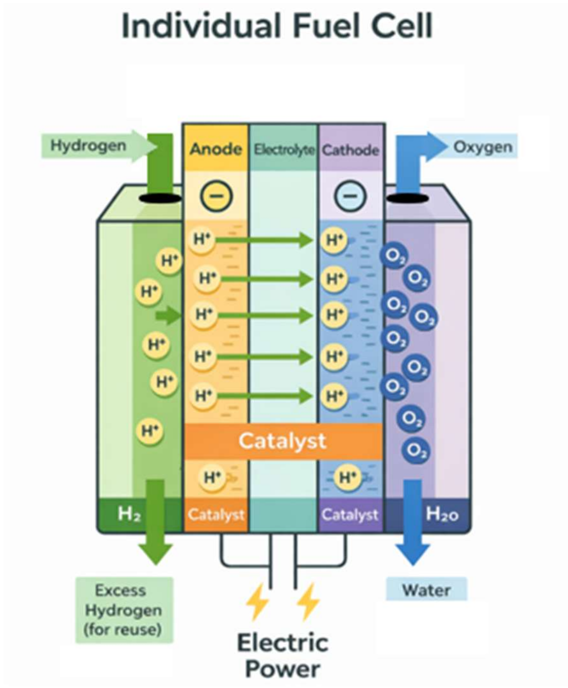


Figure 14: functional diagram of a single fuel cell for electricity generation.

The protons produced by the anode flow towards the cathode, passing through the electrolyte, and encounter oxygen molecules (O_2), used as an oxidising agent, which then meet hydrogen, producing H_2O and heat as output:

$$Anode\ reaction: 2H_2 \rightarrow 4H^+ + 4e^- \quad \textbf{EQ.13}$$

$$Cathode\ reaction: O_2 + 4H^+ + 4e^- \rightarrow 2H_2O \quad \textbf{EQ.14}$$

The use of platinum serve to lower the activation energy required for electrochemical reactions to occur. The electrochemical circuit of the fuel cell is closed internally, thanks to the presence of the electrolyte. Under nominal operating conditions, a single cell (Figure 14) can supply a voltage of around 0.7 V, with current density values generally between 300 and 800 mA/cm². Since the electrical voltage obtainable from a single cell is relatively low, several cells are connected electrically in series via bipolar plates, forming a “fuel cell stack”. Several stacks in turn can be integrated into modules, in order to create generators capable of meeting the power requirements of the reference application.

A complete fuel cell system is not limited to the electrochemical module alone but includes a series of auxiliary subsystems. Upstream of the electrochemical section, there is generally a fuel treatment system, often based on a reformer, whose task is to produce hydrogen from alternative fuels. Downstream of the stack, the direct current electricity generated is converted into alternating current by an inverter and then adapted to the required voltage and frequency levels by a transformer. The plant is finally completed by reagent supply systems, devices for the management and possible recovery of the heat produced (particularly relevant in cogeneration applications) and a supervision and control system, essential for the correct functioning of the plant, safety management and the monitoring of any abnormal conditions or faults [14], [31]. The main types of fuel cells will be analysed in the following paragraphs.

2.6.3 Phosphoric Acid Fuel Cell (PAFC)

Phosphoric acid fuel cells use work in the same way of the general fuel cells: hydrogen is oxidized at the anode, while oxygen is reduced at the cathode with the formation of water. Their main characteristic, however, is linked to their electrolyte, that is a liquid solution of water and phosphoric acid (H_3PO_4), that is contained in a porous medium consisting of Teflon and silicon carbide (SiC), with a thickness of a few tenths of a millimetre. This element is very useful because it is thermally and chemically stable and tolerant to the presence of CO_2 and CO, which may be present in the gases produced by reforming processes (therefore not "green").

PAFCs operate at medium-high temperatures, ranging from 150 to 200°C, and can achieve electrical efficiencies of 36-45%, but with the possibility of heat recovery in cogeneration, they achieve overall efficiencies of 85%.

From a construction point of view, the electrodes are generally made of porous graphite-based material, while platinum is used as a catalyst to promote electrochemical reactions. However, PAFCs require larger amounts of platinum, making them particularly expensive to manufacture:

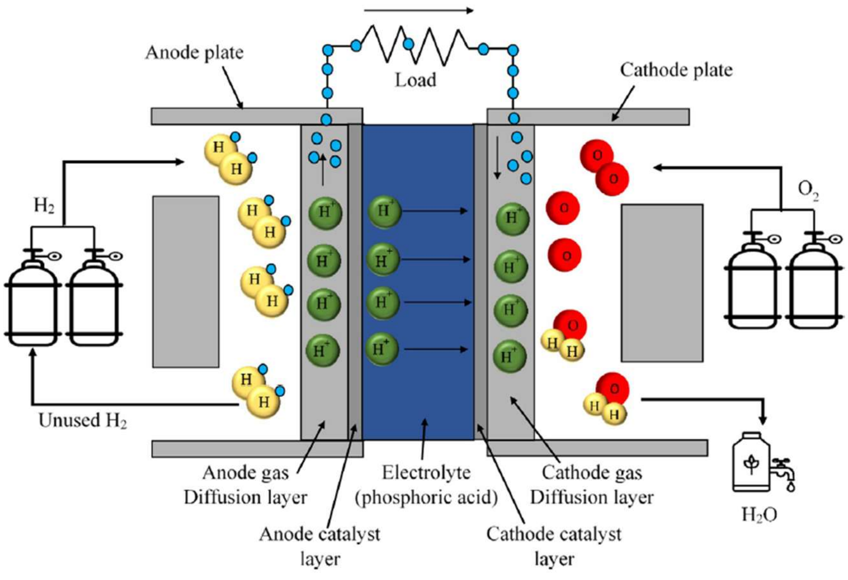


Figure 15: operating diagram of a phosphoric acid fuel cell (PAFC) [29].

Compared to other fuel cell technologies, PAFCs have a lower power density, making them larger and heavier for the same power output; as for the power of individual stacks, they can vary from 5 to 400kW.

This type of fuel cell has a long start-up time, which limits its use in dynamic applications and makes it unsuitable for the variable energy production of renewable sources. Another limitation is related to phosphoric acid, which crystallizes at temperatures below 42°C, that is an irreversible process, leading to the uselessness of the cell. On the other hand, an electrode cooling system is also required, as the electrolyte could evaporate at excessively high temperatures.

Based on these characteristics, PAFCs are particularly suitable for stationary and distributed generation applications, especially in cogeneration plants. Over time, they have also found use in specific areas such as landfills, water treatment plants, food industries, and contexts where a highly reliable and continuous power supply is required. Phosphoric acid fuel cells are one of the most mature technologies from a technical and economic point of view; however, their commercial diffusion remains limited mainly due to high production costs [14], [35], [36]

2.6.4 Molten Carbonate Fuel Cell (MCFC)

MCFCs belong to the category of high-temperature cells, as their operating temperature ranges between 600 and 700°C. This characteristic allows them to work with gases such as CO_2 and CO; in fact, the high temperatures allow internal fuel reforming, enabling the direct conversion of hydrocarbons into hydrogen, without the need for an external reformer, and this lead to a possible use of fuels such as gas, biogas and LPG.

The electrolyte that makes up the cell is a liquid mixture of lithium carbonate (Li_2CO_3), sodium (Na_2CO_3), and potassium (K_2CO_3), which is retained in a porous lithium aluminate ($LiAlO_2$) matrix. Under these operating conditions, the electrolyte allows the transport of carbonate ions (CO_3^{2-}), which are the ionic species responsible for electrical conduction within the cell:

$$Anode\ reaction: H_2 + CO_3^{2-} \rightarrow H_2O + CO_2 + 2e^- \quad \textbf{EQ.15}$$

$$Cathode\ reaction: \frac{1}{2}O_2 + CO_2 + 2e^- \rightarrow CO_3^{2-} \quad \textbf{EQ.16}$$

MCFC electrodes are relatively inexpensive because they are made of nickel and chromium, plus a small percentage of lithium.

As mentioned above, the electrochemical reactions take place in the presence of carbon dioxide, which is necessary for the cathodic reaction, as it contributes to the formation of CO_3^{2-} ions that migrate through the electrolyte from the cathode to the anode (see Figure 16). In this sense, MCFCs represent one of the rare cases in which carbon dioxide is used within the electrochemical cycle for energy production, rather than simply being a by-product:

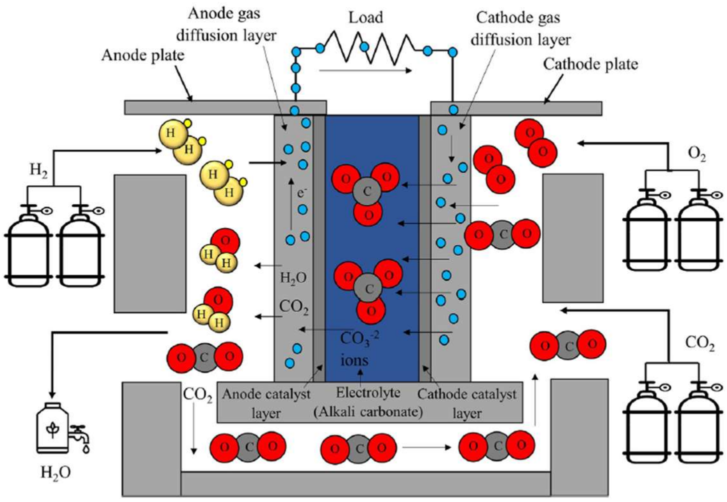


Figure 16: diagram of a molten carbonate fuel cell (MCFC) [29].

In addition, the heat produced during operation can be effectively recovered for cogeneration applications, such as the production of high-pressure steam, which is widely used in industrial and commercial settings.

On the other hand, the use of high temperatures can corrode and degrade the various components of the fuel cell over time, and start-up times are long, so this technology cannot be used in scenarios with frequent load variations.

Due to their operating characteristics, molten carbonate fuel cells are particularly suitable for stationary applications that require continuous operation and substantially constant power. Such applications include distributed power generation, industrial plants, and electrical utility infrastructure. Commercially available solutions currently feature modules with typical power ratings of around 300 kW, while stacks can be configured to achieve total power ratings in the order of several megawatts, up to approximately 3 MW. MCFCs are also suitable for integration with biomass gasification systems and, in recent years, have been the subject of growing interest for innovative applications, such as those related to marine propulsion [14], [35], [36].

2.6.5 Polymer Electrolyte Membrane Fuel Cell (PEMFC)

This type of cell, also known as Proton Exchange Membrane Fuel Cells or Solid Polymer Fuel Cells (SPFC), belongs to the low-temperature cell family. They use a solid proton-conducting membrane, Nafion, as an electrolyte. This membrane is semi-permeable: it allows H^+ ions to pass through while ensuring electrical insulation between the anode and cathode and uses oxygen from the air as an oxidizing agent. The electrochemical reactions are catalysed by noble metals, typically platinum, deposited on porous electrodes that allow the diffusion of reactant gases to the active zones. The electrodes form a “three-phase interface”, where the reactant gas, the catalyst, and the Nafion come into contact. The overall operation of the PEMFC requires only hydrogen, air, and water, which is the main by-product of the reaction; in fact, the reactions that take place in the cell are the same as those in a generic fuel cell (**EQ.13-14**).

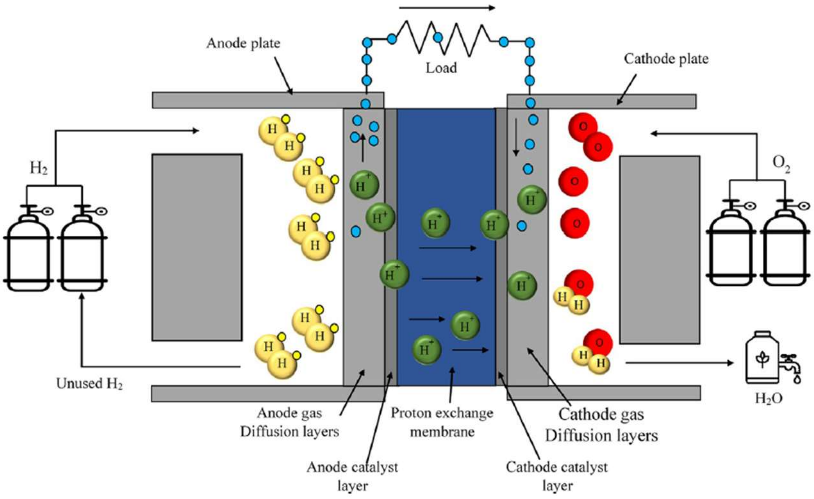


Figure 17: architecture of a proton exchange membrane fuel cell (PEMFC) [29].

PEMFCs operate at relatively low temperatures, generally between 85 and 105°C. This feature offers numerous advantages, including fast start-up times, reduced component corrosion, and lower mechanical and thermal stress on the system, qualities that MCFCs, for example, do not possess due to their high temperatures. The power ratings of commercially available stacks range from less than 1 kW to 100 kW, although cells with a power rating of around 10 kW are currently being produced, meaning that they have not yet reached a power level suitable for industrial use.

One of the central aspects of PEMFC technology is water management; in fact, the proton conductivity of Nafion is highly dependent on its degree of hydration: in low humidity conditions, the membrane has low ionic conductivity, while this increases significantly with water content. On the other hand, if hydration is excessive, there is a risk of "electrode flooding," in which the pores become clogged, and the diffusion of reactants decreases. Furthermore, at temperatures of around 80-90°C, Nefion dehydration can occur. On the other hand, the higher the temperature, the higher the reaction rate and the lower the carbon monoxide poisoning.

For this reason, managing the water balance is one of the main operational challenges of PEMFCs; solutions adopted so far include humidification of the feed gases, direct hydration of the membrane, or the use of self-humidifying membranes, obtained by adding materials such as SiO2 or TiO2 to Nafion [14].

From a performance standpoint, PEMFCs have an electrical efficiency of 60% when hydrogen is used directly, while this drops to 40% when reformed fuels are used, with the advantage of extremely low or zero local emissions and a very limited number of moving parts [36].

The main critical issues with PEMFCs mainly concern the high cost of catalysts, which are made of noble metals, and their sensitivity to carbon monoxide, which means that the hydrogen used must be of high purity.

Despite the critical issues highlighted, PEMFCs currently represent one of the most advanced and promising technologies for applications in the transport and distributed power generation sectors. This is mainly due to their high-power density, considerable operational flexibility, and ease of integration into modular architectures. At the same time, research and development are focusing on reducing the use of noble metals, increasing the useful life of membranes, and lowering overall system costs, with the aim of making PEMFCs increasingly competitive within the context of hydrogen-based energy technologies [34], [37].

2.6.6 Alkaline Fuel Cell (AFC)

Alkaline fuel cells are one of the first fuel cell technologies developed and belong to the category of low-temperature cells, typically operating in a range between 60 and 120°C. Unlike PEMFCs, AFCs use an alkaline solution as an electrolyte, generally potassium hydroxide (KOH) or sodium hydroxide (NaOH) in aqueous solution, or, in more recent versions, an alkaline polymer membrane. In this type of cell, the mobile ion is not the H^+ proton, but the OH^- hydroxide ion, which migrates from the cathode to the anode through the electrolyte. As can be seen, the architecture and operation of the AFC is very similar to that of the AEL alkaline electrolyser. In fact, as mentioned above, these two technologies are similar in structure, but the process is practically the reverse.

The electrodes are generally made of nickel or graphite, while the catalysts used may include silver, platinum, gold (Au) or palladium (Pd). At the anode, hydrogen is oxidised, while at the cathode oxygen is reduced, and electrons flow through the external circuit, producing electricity with an efficiency of up to 60%:

$$Anode\ reaction: 2H_2 + 4OH^- \rightarrow 4H_2O + 4e^- \quad \textbf{EQ.17}$$

$$Cathode\ reaction: O_2 + 2H_2O + 4e^- \rightarrow 4OH^- \quad \textbf{EQ.18}$$

AFCs, like PEMFCs typically have stack sizes ranging from 1 kW to 100 kW.

One of the main limitations of this technology is its extreme sensitivity to the presence of carbon dioxide (CO_2) in both the fuel and the feed air. CO_2 reacts with the alkaline electrolyte to form carbonates, which reduce the concentration of OH^- ions, which are essential for the cell to function and quickly compromise its performance:

$$CO_2 + 2OH^- \rightarrow CO_3^{2-} + H_2O \quad \textbf{EQ.19}$$

Consequently, pure hydrogen and oxygen are needed to power the fuel cell. These can be obtained through purification systems, such as scrubbers, for example, which, however, would lead to a possible increase in the cost of the system:

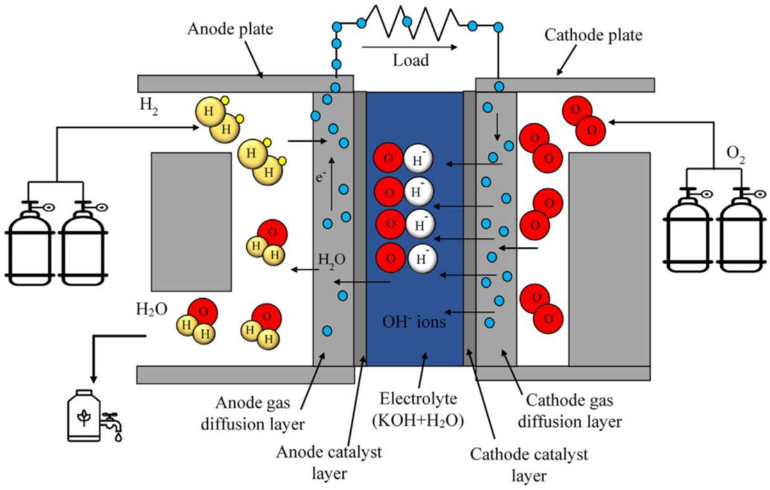


Figure 18: reaction mechanism in an alkaline fuel cell (AFC) [29].

Nowadays, AFCs are used for niche applications (aerospace, military fields), despite being a mature technology, precisely because of their main drawback of requiring extremely pure reagents. Furthermore, due to high costs and durability issues, AFCs have been progressively abandoned for stationary generation and mass mobility applications in favour of more flexible technologies (such as PEMFCs), which are now better suited to modern hydrogen-based energy systems [14], [35], [36].

2.6.7 Solid Oxide Fuel Cell (SOFC)

SOFCs belong to the category of high-temperature cells (such as MCFC) and use a solid ceramic material as electrolyte, typically yttria-stabilised zirconia (YSZ). This electrolyte allows oxygen ions to be exchanged at high temperatures, generally between 800 and 1000°C, but which are likely to fall by around 200°C in the future, thanks to research.

As with MCFCs, high temperatures offer numerous advantages, such as internal reforming processes and the possibility of operating with molecules such as CO and even sulphur (S). Furthermore, the solid-state electrolyte means that the cell has no evaporation or dehydration problems and, as with MCFCs, the high temperatures make the use of catalysts unnecessary.

From a materials perspective, SOFCs require components capable of ensuring high chemical and mechanical stability at high temperatures. The anode is generally made of a cermet (a combination of ceramic and metal) based on nickel and zirconium oxide, while the cathode is made of lanthanum manganite ($LaMnO_3$) doped with strontium (LSM).

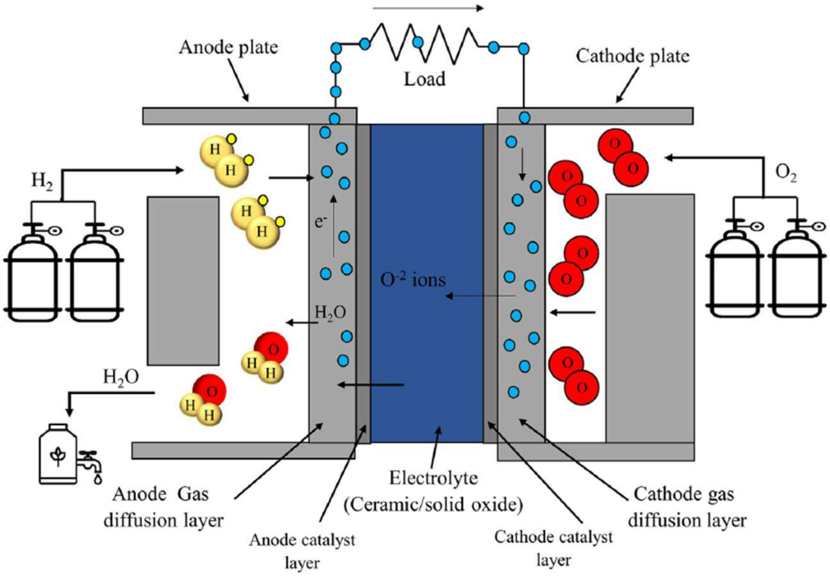


Figure 19: ion transport in a solid oxide fuel cell (SOFC) [29].

The electrochemical reactions differ from those of low-temperature cells: at the cathode, molecular oxygen is reduced to O^{2-} ions, which migrate through the solid electrolyte towards the anode, where they react with the fuel to produce electrons and heat:

$$Anode\ reaction: H_2 + O^{2-} \rightarrow H_2O + 2e^- \quad \textbf{EQ.20}$$

$$Cathode\ reaction: \frac{1}{2}O_2 + 2e^- \rightarrow O^{2-} \quad \textbf{EQ.21}$$

High temperatures, as we have already seen, lead to long start-up times and also to poor adaptability to dynamic applications, while they are particularly suitable for stationary and continuous applications, useful for industrial plants and power stations. Currently, the commercial diffusion of solid oxide fuel cells is still limited, mainly due to the significant technological complexities and high costs associated with ceramic materials and interconnection systems.

Nevertheless, the high efficiencies that can be achieved, the considerable flexibility in the use of fuels and the favourable integration with heat recovery systems make SOFCs one of the most promising solutions for the future development of energy systems based on hydrogen [14], [31], [34].

The following table summarises the five fuel cells we have analysed, highlighting their efficiencies and main advantages and disadvantages:

Fuel Cell Type	Common Electrolyte	Operating Temperature	Typical Stack Size	Electrical Efficiency (LHV)	Applications	Advantages	Challenges
Polymer Electrolyte Membrane (PEM)	Perfluorosulfonic acid	<120°C	<1 kW - 100 kW	60% direct H_2;[i] 40% reformed fuel[ii]	• Backup power • Portable power • Distributed generation • Transportation • Specialty vehicles	• Solid electrolyte reduces corrosion & electrolyte management problems • Low temperature • Quick start-up and load following	• Expensive catalysts • Sensitive to fuel impurities
Alkaline (AFC)	Aqueous potassium hydroxide soaked in a porous matrix, or alkaline polymer membrane	<100°C	1 - 100 kW	60%[iii]	• Military • Space • Backup power • Transportation	• Wider range of stable materials allows lower cost components • Low temperature • Quick start-up	• Sensitive to CO_2 in fuel and air • Electrolyte management (aqueous) • Electrolyte conductivity (polymer)
Phosphoric Acid (PAFC)	Phosphoric acid soaked in a porous matrix or imbibed in a polymer membrane	150 - 200°C	5 - 400 kW, 100 kW module (liquid PAFC); <10 kW (polymer membrane)	40%[iv]	• Distributed generation	• Suitable for CHP • Increased tolerance to fuel impurities	• Expensive catalysts • Long start-up time • Sulfur sensitivity
Molten Carbonate (MCFC)	Molten lithium, sodium, and/or potassium carbonates, soaked in a porous matrix	600 - 700°C	300 kW - 3 MW, 300 kW module	50%[v]	• Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Suitable for CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Low power density
Solid Oxide (SOFC)	Yttria stabilized zirconia	500 - 1000°C	1 kW - 2 MW	60%[vi]	• Auxiliary power • Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Solid electrolyte • Suitable for CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Limited number of shutdowns

Table 2: performance parameters, useful life and stages of development of the various fuel cell technologies [36].

CHAPTER 3: Energy transition and regulations for renewable energy communities (RECs)

The transition to an energy system based on green hydrogen and Renewable Energy Sources (RES) must first and foremost follow an appropriate regulatory and legislative framework. The feasibility of complex projects such as the Power-to-Gas system in agriculture is not only determined by the efficiency of the electrolyser or storage capacity but is intrinsically linked to the incentive mechanisms that support the high investment cost (CAPEX, see CHAPTER 4).

With the "Clean Energy for All Europeans" package, adopted in 2016, Europe is strengthening its drive towards renewables in support of the energy transition. The package includes Directive (EU) 2018/2001 (RED II), which introduces a harmonised regulatory framework for the deployment of renewables, setting quantitative targets for 2030 and regulating, among other aspects, self-consumption and energy cooperation mechanisms between Member States, which are key elements for the development of Renewable Energy Communities.

In 2019, the European Green Deal was reached, perhaps the most important agreement for the energy transition, as it aims to make Europe the first climate-neutral continent by 2050. To make this happen, the "Fit for 55" package was introduced, committing the EU to reducing net greenhouse gas emissions by at least 55% by 2030 compared to 1990 levels [38]**.** To keep pace with these new targets, Italy adopted the Integrated National Energy and Climate Plan (PNIEC) in 2020.

Subsequently, in response to the energy crisis triggered by Russia's invasion of Ukraine, in 2022 the European Commission presented the REPowerEU plan, aimed at ensuring energy security and independence, as many Member States were (and still are) dependent on gas sources from Russia. This event prompted Member States to boost sustainable energy through their respective National Recovery and Resilience Plans (NRRPs) [39].

Once again, Italy has had to align itself with European targets by adopting the FER 2 and FER X support schemes, which aim to incentivise production capacity from clean energy sources. The former promotes the production of electricity from renewable energy plants, with the aim of achieving a capacity of 4.6 GW by 31 December 2028 (see paragraph 3.1.5), while FER X aims to make renewable sources competitive in the coming years.

Overall, the regulatory framework outlined in recent years, is intended to provide significant economic support to offset the high investment costs associated with new renewable technologies, such as hydrogen-based Power-to-Gas systems. These measures encourage the development and dissemination of widespread self-consumption models, particularly in the agricultural sector, helping to improve economic sustainability and strengthen the energy self-sufficiency of businesses [5].

3.1 European Green Deal

In 2019, the EU promoted the Green Deal as a political strategy to combat global warming and promote energy, climate and economic transition, with the aim of achieving climate neutrality by 2050, in line with the commitments made under the Paris Climate Agreement [40].

In 2021, the EU launched the European Climate Law, which legally enshrines climate neutrality by 2050 and a cut in emissions of at least 55% by 2030 compared to 1990 levels. This goal implies a profound reconfiguration of energy and industrial systems, pushing towards a growing use of renewable sources, more efficient energy use and a gradual abandonment of fossil fuels [41].

In the energy sector, the Green Deal sets out three fundamental pillars for the transition to a clean system:

- ensuring a secure and affordable energy supply;
- developing a fully integrated and digitalised European energy market;
- increasing energy efficiency by improving the performance of the manufacturing and residential sectors and promoting large-scale electricity generation from renewable sources [42].

In addition to setting binding targets and establishing a regulatory framework, the European Green Deal provides tools to support climate and energy policies. In particular, initiatives such as the European Emissions Trading System (ETS), the Social Climate Fund and the Just Transition Fund are designed to encourage investment in clean technologies and the development of modern energy infrastructure, promoting a fair transition to a low-carbon system [43].

In summary, the European Green Deal provides the theoretical basis for building a more economically and socially sustainable Europe, focusing on the use of new technologies, particularly those specifically dedicated to the use of renewable energy, linked to energy efficiency and the promotion of energy communities and renewable hydrogen.

3.1.1 RED II

The Renewable Energy Directive II is the main regulatory instrument for promoting renewable energy in the European Union. It is part of the “Clean Energy for All Europeans” legislative package and aims to guide Member States towards a wider use of renewable sources in the energy mix by 2030 [44]. Specifically, with this directive, the EU aims to achieve 32% of energy produced from renewable sources by 2030, and to obtain at least 10% of renewable energy in the transport sector, measured based on the energy contribution of renewable sources compared to the total energy consumed in this sector.

RED II not only provides guidelines, but also sets out operational measures that EU Member States must adopt, that are:

- rules for financial support for renewable energy production, including rules on transparency and stability of support schemes;
- provisions on self-consumption and distributed generation, with the aim of facilitating the direct participation of consumers and energy communities in renewable production, through Legislative Decree 199/2021;
- criteria for cooperation between Member States in order to achieve common objectives;
- information and training requirements aimed at developing technical skills and maturity in renewable energy markets.

The directive also establishes specific sustainability and greenhouse gas emission reduction criteria for biofuels, bioliquids and fuels obtained from biomass. These criteria also include requirements related to the efficient use of resources, with the aim of ensuring that the growth of renewable sources does not generate negative environmental effects or undesirable impacts on ecosystems.

As is often the case, directives are updated, and in fact, RED II has been revised over the years, raising the target (from 32%) of renewable sources used for energy production to 42.5% by 2030, with the aspiration to reach 45% (Directive 2023/2413, also called RED III). This revision, which came into force in November 2023, also introduces specific measures to speed up plant authorisation procedures and promote the integration of renewables in various economic sectors [45], [46].

3.1.2 Fit For 55

It is linked to the update of the RED II directive. In fact, this legislative package was presented by the European Commission in July 2021 and will subsequently be approved by the Parliament and the Council by 2023, with the aim of reducing net greenhouse gas emissions by at least 55% by 2030 compared to 1990 levels, in line with the provisions of the European Climate Law and the Green Deal itself [47]. One of the main initiatives for decarbonisation is the European Trading Scheme (ETS), based on the exchange of emission allowances between various industries in Member States, which has also been extended to the transport and buildings sectors, introducing new rules for energy efficiency and revising the main energy and climate directives to align them with the emission reduction target [38]. For example, the buildings sector is aiming for a 49% share of renewable energy by 2030, while measures are planned for transport to reduce emissions (Figure 20) and ensure a minimum share of renewable energy in fuels themselves [43]:

Figure 20: objectives of the European "Fit for 55" package for ecological transition and climate neutrality by 2050 [45].

Fit For 55 also promotes the use of renewable hydrogen and low-emission gases through several policy measures, such as:

- promoting a competitive market and dedicated infrastructure for hydrogen;

- facilitating the integration of renewable and low-impact gases into the gas network, including the removal of cross-border tariff barriers;

- certification systems and common terminology for gas quality, including hydrogen;

- specific targets for electrolysis capacity and renewable hydrogen production by 2030 (e.g. 40 GW of electrolysers and 10 million tonnes of renewable hydrogen) [38].

These measures are designed to promote decarbonisation, particularly in sectors that are difficult to abate, and to facilitate the integrated transition between electricity and gas systems.

Fit For 55 also provides social support to mitigate the economic impact of the energy transition on vulnerable citizens and businesses. It adopts the Social Climate Fund, designed to provide financial assistance to low-income households and micro-enterprises affected by changes to the ETS system, with significant European resources allocated to the energy renovation of buildings and sustainable transport. Finally, this package also focuses on simplifying authorisation procedures for the construction of renewable energy plants, speeding up approval times for new projects, and promoting the adoption of innovative technologies to accelerate the deployment of renewable structures and technologies [38], [43].

3.1.3 PNIEC

The Integrated National Energy and Climate Plan (PNIEC) is the strategic tool with which Italy, since 2020, has been implementing the binding targets set by the European Union on energy, climate and renewables at national level.

These are the main targets that the PNIEC aims to achieve by 2030:

- a share of energy from renewable sources of at least 30% of gross final energy consumption, in line with European targets;

- increased energy efficiency through energy saving and consumption reduction measures in the residential, industrial and transport sectors.

The PNIEC also covers other sectors, such as:

- the growth of installed renewable energy capacity, with strong development of wind and photovoltaic power and a growing role for green hydrogen integrated into energy and industrial systems;

- the decarbonisation of industry, encouraging the adoption of low-emission technologies, energy efficiency and more sustainable production processes;

- the promotion of energy storage systems and smart grids to increase the flexibility of the electricity system, increasingly integrating distributed generation and variable sources;

- the adoption of sustainable mobility policies, with electric and hydrogen vehicles, incentives for low-emission public transport, and incentives for the use of renewable fuels in transport.

Thanks to the PNIEC, new implementation measures have been developed in Italy, such as:

- the FER Decrees (FER 2 and FER X) for renewable energy incentives;

- technical and administrative regulations for energy communities;

- planning of infrastructure for hydrogen production and storage [48], [49].

3.1.4 REPowerEU

The REPowerEU plan is a strategic initiative adopted by the European Commission in May 2022 in response to the energy crisis triggered by Russia's invasion of Ukraine, which highlighted the European Union's heavy dependence on imported fossil fuels, particularly gas, oil and coal from Russia. The aim is therefore to reduce this dependence as much as possible, thereby accelerating the clean energy transition.

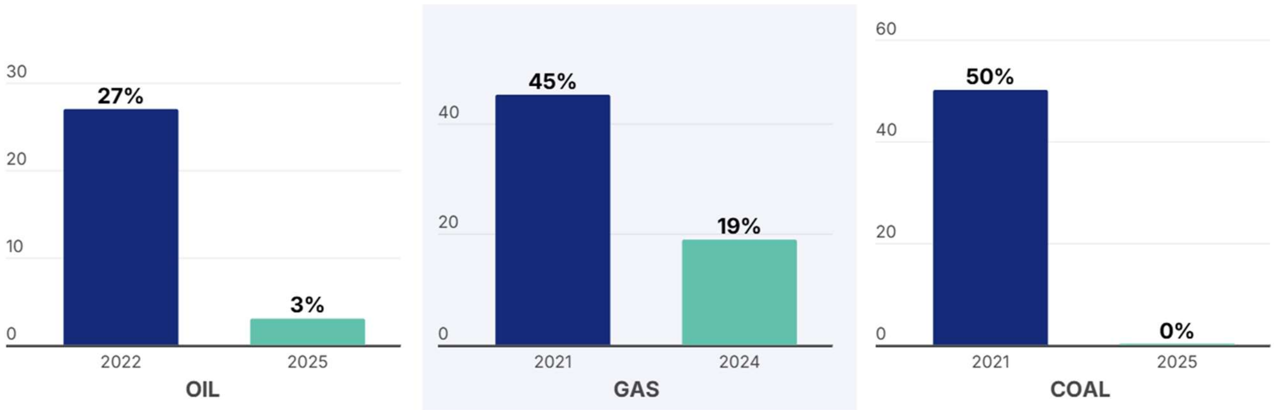


Figure 21: targets for reducing fossil fuel imports from Russia to Europe for the period 2024–2025; data are updated to 2025 [51].

As can be seen in Figure 21, the EU has banned all coal imports from Russia, while gas and oil imports have fallen sharply compared to 2021 [50].

The REPowerEU strategy is based on three fundamental pillars:

- energy saving, promoting more efficient energy use by citizens, businesses and institutions, with technical and behavioural measures to curb demand for gas and other fossil fuels;

- diversification of energy supplies, which is useful for reducing dependence on countries outside Europe, particularly regarding fuels, thereby increasing the use of alternative fuels and boosting the development of supply and storage infrastructure;

- clean energy production, by accelerating the deployment of renewable sources and renewable hydrogen through investment, technological innovation, regulatory simplification and incentives. To this end, REPowerEU proposes to increase the share of renewables in the European energy mix, with the technical objective of achieving much higher generation levels than those forecast in the Fit for 55 package and extending the installed capacity of solar, wind and other clean sources [51].

REPowerEU also aims to promote renewable hydrogen as a key energy carrier in the decarbonisation of the industrial and transport sectors through incentives that will help achieve the targets set out in the European Hydrogen Strategy: 10 million tonnes of renewable hydrogen produced domestically and a further 10 million tonnes imported by 2030. To achieve these targets, it is estimated that approximately 40 GW of electrolyser capacity will need to be developed across the EU by 2030 [14].

Economic support for the REPowerEU plan is provided by the Recovery and Resilience Facility, which allocates €225 billion, plus €20 billion in non-repayable grants; the latter are funded 60% by the Innovation Fund and the remaining 40% by proceeds from ETS auctions [51].

3.1.5 FER-1, FER-2 and FER-X

These are three different incentive mechanisms linked, as mentioned above, to renewable energy, that are Italian ministerial decrees, that have been introduced over time to meet European and national decarbonisation targets. These instruments, regulated by the Ministry of the Environment and Energy Security (MASE), aim to support the construction of renewable energy plants through economic incentives based on all-inclusive tariffs (i.e. tariffs that the State pays to anyone who feeds electricity produced from renewable sources into the grid) and competitive procedures.

Ministerial Decree 04/07/2019, also known as FER-1, represented the first comprehensive version of the renewable energy incentive system in Italy, replacing previous incentive mechanisms (such as green certificates and all-inclusive tariffs under the 2012 and 2016 decrees) [52].

FER 1 rewards plants that generate electricity from renewable sources, remunerating them based on the energy fed into the grid over time, with remuneration varying according to the power of the plant. In fact, for plants with a power output of less than 1 MW, FER uses direct all-inclusive tariffs, while for more powerful plants, it uses incentives linked to the difference between a reference tariff and the zonal price of energy.

FER 1 also aims to promote photovoltaic, onshore wind, hydroelectric and gas from purification processes, thus contributing to the achievement of national renewable energy targets in the context of the PNIEC [53].

The FER 2 Decree, adopted by Ministerial Decree 19/06/2024 and in force since 11 December 2024, introduces a new incentive scheme focused on “innovative projects or projects with high generation costs”. This decree was therefore designed for technologies that are not yet competitive (i.e. with a TRL of 7-8), thus broadening the range of technologies eligible for incentives compared to FER 1.

Eligible types of plants include:

- biogas plants smaller than 300 kW and biomass plants with a capacity of up to 1 MW;
- thermodynamic solar plants;
- floating offshore wind and floating photovoltaic plants;
- other marine technologies such as wave motion and tidal fluctuation.

FER 2 incentives can be obtained through tenders launched by the Energy Services Manager (GSE), in which interested parties submit bids at a discount compared to a reference tariff. Furthermore, tariffs and incentives vary depending on the type of technology used, based on the generation costs for innovative systems, ensuring stable remuneration over time for the selected plants. The operating rules published by the Ministry of the Environment and Energy Security (MASE) and the GSE establish the detailed criteria for participation, the technical and administrative requirements, the timetable and the ranking of plants [54], [55].

The FER-X, on the other hand, approved at the end of 2024 and gradually coming into force in 2025, is the most recent evolution of the Italian renewable energy incentive system. It aims to enhance previous schemes by simplifying access to incentives and adapting mechanisms to the needs of the current energy market and updated decarbonisation targets. In fact, there are two main new support schemes proposed by FER X:

- Direct incentives for small-scale plants (generally less than 1 MW), which can access them directly without the need to participate in competitive procedures.
- Competitive procedures managed by the GSE for plants with a capacity greater than 1 MW, with periodic calls for tenders in which power quotas are allocated on a competitive basis and with tariff reductions as a selection parameter [56].

For example, the tariffs planned for 2024, valid until 31 December 2028 and allocated directly for small plants and on an auction basis for large plants, are:

- €85/MWh for photovoltaics;
- €80/MWh for wind power;
- €110/MWh for hydroelectric power;
- €100/MWh for purification gases (i.e. biogas obtained from the anaerobic digestion of residual sludge from wastewater treatment).

The rankings of the first auctions showed strong participation by photovoltaics, with total power allocations of several thousand megawatts [57].

Considering these assumptions, the FER X decree plays a central role in the national energy transition process, acting as a support tool that is fully consistent with decarbonisation objectives, as well as with the promotion of renewable energy communities and the development of distributed electricity generation.

3.2 Renewable Energy Communities (REC)

RECs are one of the main innovations introduced by Italian and European legislation to promote the energy transition through collective self-consumption and the sharing of energy from renewable sources. In Italy, thanks to Ministerial Decree 414/2023, also known as the CACER Decree (Configurazioni di Autoconsumo per la Condivisione dell'Energia Rinnovabile, or Self-Consumption Configurations for the Sharing of Renewable Energy) and the GSE Operating Rules, the main regulatory and procedural references for the establishment, operation and incentivisation of RECs have been introduced.

A Renewable Energy Community is defined as a “legal entity consisting of citizens, small and medium-sized enterprises or local authorities that collaborate to produce, consume, store and sell renewable energy generated by plants built by members of the community itself or shared between them”. The advantage for REC members lies in virtual self-consumption, which consists of being connected to the REC’s primary substation in order to use its energy, while physical self-consumption is based on drawing energy directly from the renewable source (e.g. photovoltaic panels).

Energy communities also pursue social, environmental and economic objectives, such as the dissemination of renewable sources on a territorial scale, the inclusion of vulnerable individuals, the reduction of energy costs for members and the promotion of local energy self-sufficiency [58], [59].

3.2.1 Widespread self-consumption

Widespread self-consumption is a regulatory institution closely linked to Renewable Energy Communities, as it allows multiple parties to collectively share and self-consume electricity produced by renewable energy plants, even in the absence of a direct physical connection between the production plants and the consumers. In this model, the public electricity grid allows for the balancing of energy production and consumption between different users, overcoming the limitations of traditional self-consumption, which instead requires a direct connection between the plant and the point of withdrawal. Widespread self-consumption can take place if at least two entities (households, businesses or local authorities) participate in sharing the energy produced by one or more renewable plants, even if located at different points in the distribution network. Through this mechanism, the energy generated can be virtually attributed to each participant, according to their consumption profiles, while the public grid allows energy to be transferred without the need for dedicated connections between each producer and each end user. This promotes the spread of renewable sources even in rural areas and encourages the aggregation of local producers and consumers [59].

The widespread self-consumption mechanism was established through the Integrated Text for Widespread Self-Consumption (TIAD), originally defined by ARERA resolutions 318/ 2020/R/EEL and then supplemented by ARERA resolution 727/2022/R/EEL, with the aim of regulating the various possible configurations of widespread self-consumption, including self-consumption groups and Renewable Energy Communities (RECs). These rules were then supplemented by the CACER Decree, which came into force on 24 January 2024 [60].

The TIAD identifies seven possible configurations of distributed self-consumption, which include both forms of collective self-consumption, such as condominiums or buildings with multiple users, and larger communities, such as RECs, which therefore represent a subcategory of distributed self-consumption, characterised by legal, economic and administrative integration among members, with benefits that go beyond the simple exchange of energy, including economic, social and environmental effects. The legislation requires both RECs and widespread self-consumption to comply with technical and administrative requirements, such as belonging to the same primary substation and the establishment of a reference entity responsible for managing shared energy. Furthermore, in order to access the economic incentives and subsidies provided, the widespread self-consumption configuration must be formally registered with the GSE, through the dedicated operating rules [61].

3.2.2 Incentives and tariffs for RECs

The Italian RECs incentive system essentially provides for two main forms of economic support, both recognised and managed by the GSE: the shared energy incentive tariff (TCEC) and the ARERA valuation fee.

The incentive tariff, recognised by the GSE for each MWh of renewable energy self-consumed and shared within the REC, is subject to power criteria and energy market values. The duration of the incentive is typically 20 years from the date of commissioning of the renewable energy plant; during this period, the GSE calculates annually the energy shared virtually among REC members in order to determine the tariff premium and the valuation fee; in addition, the energy produced but not absorbed by consumers in the community is fed into the electricity system without benefiting from the GSE incentive component, limiting the right to the premium to the shared energy quota only.

The tariff values are mainly modulated according to the nominal power of the RES plant:

Nominal Power (kW)	Fixed rate based on the power of the system	Variable rate depending on the zonal price	Maximum tariff for non-photovoltaic sources	Maximum total tariff for PV systems		
				South	Central	North
P<=200	80 €/MWh (+ geographic component for the PV)	0 – 40 €/MWh	120 €	120 €	124 €	130 €
200<=P<=600	70 €/MWh (+ geographic component for the PV)	0 – 40 €/MWh	110 €	110 €	114 €	120 €
P>600	60 €/MWh (+ geographic component for the PV)	0 – 40 €/MWh	100 €	100 €	104 €	110 €

Table 3: summary table of GSE incentive mechanisms for agrivoltaic plants and green hydrogen production, included in Annex 1 of the CACER decree [64].

As can be seen from the table, the fixed portion of the incentives decreases as power P increases, while the variable portion is linked to the dynamics of zonal energy prices on the Italian electricity market. Depending on market conditions, the variable portion can reach up to €40/MWh, increasing the overall tariff incentive.

In addition, for photovoltaic systems, as shown on the right-hand side of the table, there are tariff surcharges linked to geographical location:

- + €10/MWh in northern Italy;
- + €4/MWh in central Italy, to take into account the different conditions of solar radiation and energy productivity [62].

In addition to the incentive tariff, RECs can benefit from a "value-added fee for shared self-consumed energy" defined by the Regulatory Authority for Energy, Networks and Environment (ARERA). This fee, also expressed in €/MWh, is intended to compensate for the tariff components of shared energy and is determined annually. For example, in 2023, the ARERA fee stood at around €8.48/MWh, which, as can be clearly seen, is about 10 times lower than the premium tariffs [63].

There are also other incentives available to RECs, known as "capital grants", which can be obtained thanks to resources from the NRRP (National Recovery and Resilience Plan); in fact, for RECs whose production facilities are located in municipalities with a population of less than 50,000 inhabitants (this condition has been updated recently; previously, the limit was 5,000 inhabitants), a capital grant of up to 40% of investment costs is available, applicable to eligible project components and managed through GSE procedures.

However, this contribution is limited by a maximum ceiling on eligible expenditure in relation to the capacity of the system:

- €1,500/kW for systems with a capacity of less than or equal to 20 kW;
- €1,200/kW for plants with a capacity between 20 and 200 kW;
- €1,100/kW for plants with a capacity between 200 and 600 kW;
- €1,050/kW for plants with a capacity between 600 and 1,000 kW.

This contribution can be combined with the incentive tariff, although the tariff may be reduced proportionally if the community receives a capital contribution above a certain threshold [59]. In fact, a formula is applied for RECs that use both the premium tariffs and the NRRP contribution:

$$TCET\ reduced = full\ TCEC * (1 - F) \quad \textbf{EQ.22}$$

where F refers to the percentage of the contribution for investment costs which, if it reaches 40%, i.e. the maximum threshold, leads to a further 10% increase in the value of F, thereby reducing the premium rate by 50%.

Under the regulations, RECs may also include storage systems associated with RES plants, and these configurations allow for the inclusion of infrastructure such as electric vehicle charging stations, whose energy consumption is considered in the shared energy calculations for incentive purposes. The final key requirement for obtaining incentives is that, in order to produce green hydrogen, the plant must not exceed 3 tonnes of CO_2eq per tonne of H_2 produced, in order to make the project environmentally sustainable.

Finally, there is also the possibility of combining incentives with other public support instruments (e.g. tax deductions or regional grants), always in compliance with the limits set out in the operating rules [59], [62].

CHAPTER 4: Case study of the “La Cerea” farm

This chapter introduces the practical case study on which this thesis is based, highlighting the economic problem that will subsequently lead to the aggregate solution of Renewable Energy Communities (REC). The analysis focuses on the “La Cerea” farm, a Piedmontese enterprise located near Pralormo, which manages a herd of Friesian cows, with associated electricity and heat consumption for milking, ventilation and milk refrigeration. In addition, there are chicken and rabbit farms, which require constant and costly heating (heating of the sheds) and ventilation, especially during the winter months and summer peaks. The production cycle is completed by the management of large areas of land used for cereals (such as maize and wheat) and fodder crops (such as ryegrass and alfalfa). This activity involves high energy requirements, linked both to the consumption of fuel (agricultural diesel) for mechanisation operations and to the electricity needed to power irrigation systems.

Currently, the company has a photovoltaic system with a nominal power of approximately 130 kW, whose production covers about 50% of annual energy consumption. Despite the significant contribution of Renewable Energy Sources (RES), the company regularly generates a significant surplus of electricity during periods of maximum irradiation and low internal demand, which is currently fed into the public grid at a marginal economic value.

The initial hypothesis of the thesis project was to design an on-site Power-to-Hydrogen-to-Power system aimed at intercepting this surplus and using it to try to ensure energy self-sufficiency, especially during periods of low irradiation.

4.1 Description of the study site and existing energy infrastructure

The La Cerea farm, located in Piedmont, enjoys good sunlight radiation, although, being in northern Italy, solar radiation is lower than in central and southern regions. Furthermore, the photovoltaic panels, being positioned on the roof of the cowshed, take its inclination and also its direction, which unfortunately faces east and west, and this affects the energy that can potentially be obtained from that area, as the best orientation for photovoltaic panels is south [64]:

Figure 22: zenithal view of the "La Cerea" farm (source: Google Earth); the roof area where the panels are installed is marked in red.

Although the modules were installed in 2024, the system only became fully operational on 1 January 2025. The estimated annual energy production was calculated using the technical documentation available on the Azzurro ZCS management platform. In addition, the panels are connected to five inverters (four hybrid and one photovoltaic) with a power output of 20 kW each. The hybrid inverters record the battery charge status, the energy stored (power recharge) and released (power discharge), and the power generated by the panels connected to them, while the photovoltaic inverter only records the generated power.

4.1.1 Initial data and assumptions

This section will examine the data required for energy analysis, which is preparatory to defining load profiles and configuring the modules intended for hydrogen generation. The main components of the planned plant will be the following: photovoltaic panels, PEM electrolyser, diaphragm compressor, tanks, fuel cells (PEMFC). The choice of these components was guided by their ability to effectively manage the intermittency and variability of solar resources, thanks in particular to the high operational flexibility of polymer membrane (PEM) technologies.

The first phase of the case study analysis involved the acquisition of photovoltaic production data, extracted from the Azzurro ZCS monitoring portal. The datasets, exported in spreadsheet format (.xlsx), have a temporal resolution of 6 minutes, recording the instantaneous power values generated by the module strings.

As far as the electrolyser is concerned, the key variable is the specific energy consumption SEC (kWh/kgH_2), which describes the amount of energy used to produce 1 kg of hydrogen; this parameter allows the mass production, the volumes generated and the relative mass and volumetric flow rates to be determined.

The size of the compressor is linked precisely to the mass flows and compression efficiency, which can be used to calculate the power absorbed by the compression system, depending on the flow rate at the electrolyser outlet.

At the same time, the storage capacity of the tanks is determined by analysing the same flow rates, to ensure that storage is consistent with production rates.

Finally, the characterisation of the fuel cell requires knowledge of the annual hydrogen production, which is essential for estimating its nominal power and overall energy performance over the period considered:

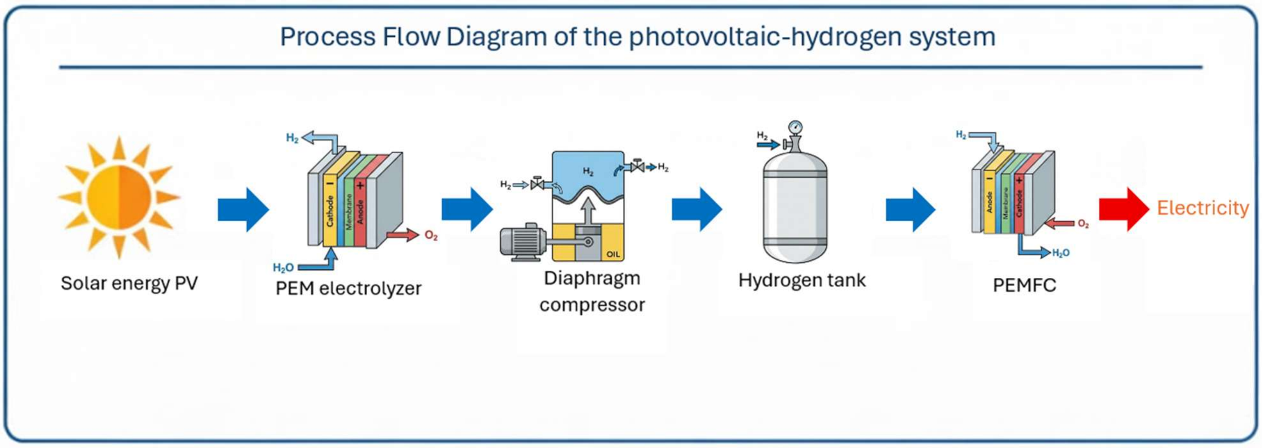


Figure 23: functional diagram of the Power-to-Hydrogen-to-Power (P2H2P) cycle integrated with the photovoltaic system of the company "La Cerea".

4.2 Methodology for calculating and analysing energy flows

Using data extracted from the Azzurro ZCS monitoring portal, the total annual energy production was calculated. Between 1 January 2025 and 31 December 2025, the plant generated approximately 94,045 kWh. The analysis shows that a significant portion of this energy is not consumed instantly, but fed into the grid as surplus; this energy surplus has been identified as the primary resource for powering the electrolyser:

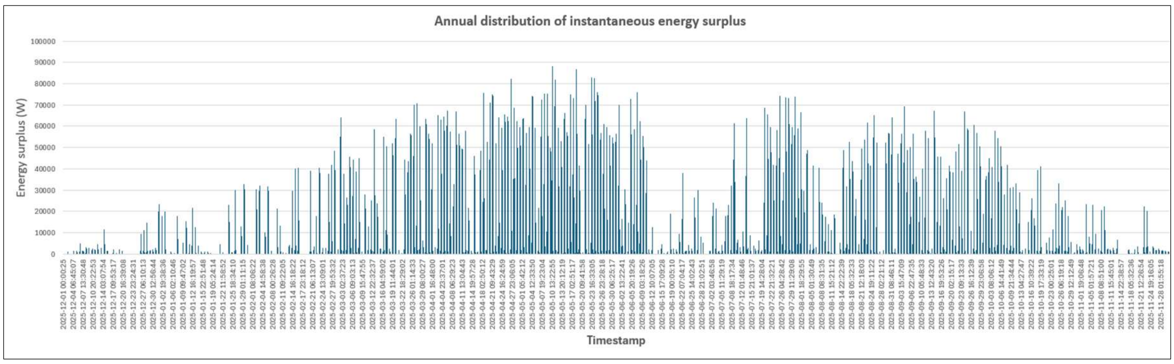


Figure 24: annual distribution of excess power (energy surplus) produced by the agrivoltaics system of the 'La Cerea' farm, obtained by processing data in Excel.

The use of hydrogen as an alternative to direct injection into the national electricity grid is an option worth considering, as the grid in rural areas may not be able to absorb high peaks of surplus energy, risking congestion or voltage instability. Furthermore, hydrogen acts as a seasonal storage system, as it can be stored for long periods without the losses typical of batteries, thus ensuring energy availability at times of production deficits. Finally, it can be used for heat generation, either directly, through dedicated boilers, or indirectly, by recovering waste heat produced by fuel cells (as discussed in CHAPTER 5). This approach makes it possible to replace fossil fuels with a high environmental impact, such as diesel, drastically reducing emissions from the agricultural sector.

4.2.1 Energy calculations for the PEM electrolyser

It has been calculated that the total surplus energy production in one year is approximately 27,421 kWh. The period in which the data was collected is considered representative of the company's standard operations, as it takes into account seasonal irrigation peaks (maximum consumption) and periods of maximum photovoltaic productivity, reflecting a load profile consistent with the local production and climate conditions.

The procedure used to calculate the total surplus energy required several steps. First, the historical series of data on exchanges with the electricity grid, obtained from the Azzurro portal, was analysed, sampled at 6-minute intervals (0.1 hours). In the column, negative data represent withdrawals from the grid, while positive data represent feed-in to the grid; consequently, a function was used to filter all positive values and set negative values to 0:

$$P_{surplus} = MAX(0; grid) \quad \textbf{EQ.23}$$

Where $P_{surplus}$ represents the power exchanged (in Watts) with the grid, and "grid" represents the cell containing the value in Watts exchanged. Having thus obtained a new column with cells containing the number 0 or positive numbers, the calculation "=COUNTIF(cells,">0")* 0.1" was used to obtain the number of cells with a value greater than 0, and the total was multiplied by 0.1, since, as mentioned above, each cell was sampled at 6-minute intervals, which then had to be converted into hours.

With this data, it is then possible to calculate hydrogen production, using the specific energy consumption of the electrolyser, using the formula:

$$Total\ hydrogen\ mass = total\ energy\ surplus\ /\ SEC \quad \textbf{EQ.24}$$

Assuming an SEC of 50 kWh/kgH_2 [18], we obtain a hypothetical annual hydrogen mass of approximately 548 kg.

Using the data from the portal, it is also possible to get the number of hours the electrolyser is used over the course of a year, which is approximately 1,777. Using this data, it is possible to obtain the average operating power of the electrolyser:

$$Average\ power\ consumption = Annual\ energy\ /\ operative\ time \quad \textbf{EQ.25}$$

The calculated power is equivalent to approximately 15.4 kW. However, as this is an average, it is lower than the energy peaks that can occur during the months with the highest surplus; consequently, the same calculations were made for the period between 6 and 11 May, where the maximum surplus peak can be seen (Figure 24). This period is also representative of the company's standard operations, as confirmed by direct feedback from the company's manager.

Therefore, by calculating the mass of hydrogen, the energy used by the electrolyser, and the operating time for that period, a peak power of approximately 25.8 kW is obtained. This value is decisive in defining the capacity of the electrolysis system capable of guaranteeing the exploitation of a significant portion of the energy surplus, without completely saturating it. In fact, as shown in Figure 24, generation peaks can reach values close to 88 kW, exceeding the nominal capacity of an electrolyser sized at 25.8 kW.

However, adopting an 88-kW system would be inefficient for three fundamental reasons. Firstly, peaks of this intensity are sporadic and rarely occur during the year, meaning that the plant would be underutilised for most of the time. Secondly, such oversizing would lead to a dramatic increase in CAPEX (initial costs), compromising economic sustainability, which will be analysed in the following paragraphs. Finally, there would be a critical technical trade-off: for many types of machinery (such as the electrolyser) with a too high power rating, has an equally high minimum activation threshold. This means that, during periods of low generation, the system would not even be able to start up, paradoxically causing a loss of usable energy greater than that which one would like to recover.

Consequently, to simulate the total energy actually usable by the electrolyser, the logical function "=IF(surplus >= 25; 25; surplus)" was applied in Excel. this formula defines the physical limit of the machine: in fact, if solar production exceeds 25 kW, the electrolyser operates at its nominal power (25 kW), "cutting" the surplus; if, on the other hand, solar production is less than 25 kW, the electrolyser absorbs all the energy available at that moment.

The result obtained from this simulation leads to an effectively usable amount of energy of approximately 18.331 kWh. Consequently, the initially calculated amounts of hydrogen will also decrease.

Therefore, using **EQ.24**, it is possible to obtain an annual hydrogen production of approximately 367 kg, which is lower than previously calculated.

Having obtained the mass of hydrogen, it is now possible to calculate the average mass flow rate of hydrogen production by dividing the mass by the operating time of the electrolyser:

$$Hydrogen\ output\ rate = Total\ mass\ /\ operative\ time \quad \textbf{EQ.26}$$

This results in an average flow rate of approximately 0.21 kg/h, produced by a PEM electrolyser with a capacity of 25 kW.

4.2.2 Compressor energy calculations

Before choosing a compressor, it is necessary to define the operating pressure parameters at the system inlet and outlet. In PEM electrolysers, the gas generation pressure can reach significant values, with peaks of around 70 bar (7 MPa). For this case study, a delivery pressure from the electrolyser of 35 bar (3.5 MPa) was set; this value ensures stable and safe operation of the electrolyser, while also acting as the suction pressure for the subsequent compression stage.

Consequently, the determination of the final storage pressure was guided by the need to optimise the specific volume of the gas, balancing the accumulated energy density with the required plant complexity. Therefore, a final storage pressure of 350 bar (35 MPa) was chosen. This configuration represents the optimal balance (sweet spot) between thermodynamic efficiency and energy density; in fact, compared to the standard 200 bar, the pressure of 350 bar allows for a reduction in storage volume of more than 30%, while avoiding the critical issues typical of 700 bar systems. The latter would actually entail an excessive increase in compression work, the need to install complex gas pre-cooling systems and the use of composite material tanks, which are significantly more expensive. The choice of 350 bar is also in line with international standards for storage and distribution in the heavy and industrial mobility sector [18], [65].

Having determined the mass flow rate for the compressor, we now need to calculate the specific consumption of the compressor, in kWh/kgH_2, which can be obtained using the formula:

$$E_{spec} = W_{iso} * \eta_{iso} \quad \textbf{EQ.27}$$

The first term, on the right side of the equation, represents isentropic work, i.e. the ideal work required to compress hydrogen, which can be obtained using the formula:

$$W_{iso} = \frac{R*T}{M_{H_2}} * \ln\left(\frac{P_{in}}{P_{out}}\right) \quad \textbf{EQ.28}$$

With R being the universal gas constant (8.314 J/mol*K), T being the average operating temperature (298.15 K), M_{H2} being the molecular weight of hydrogen (0.002016 kg/mol), and P_{in} and P_{out} being the two pressures, respectively 35 and 350 bar; the formula gives W_{iso} = 2,831,196.4 J/kg, which, converting J to kWh, is equivalent to approximately 0.7864 kWh/kg.

The second term represents isentropic efficiency, mainly linked to the input and output pressures of the compressor.

The image below shows the trends in the isentropic efficiencies of diaphragm compressors, based on pressure [66]:

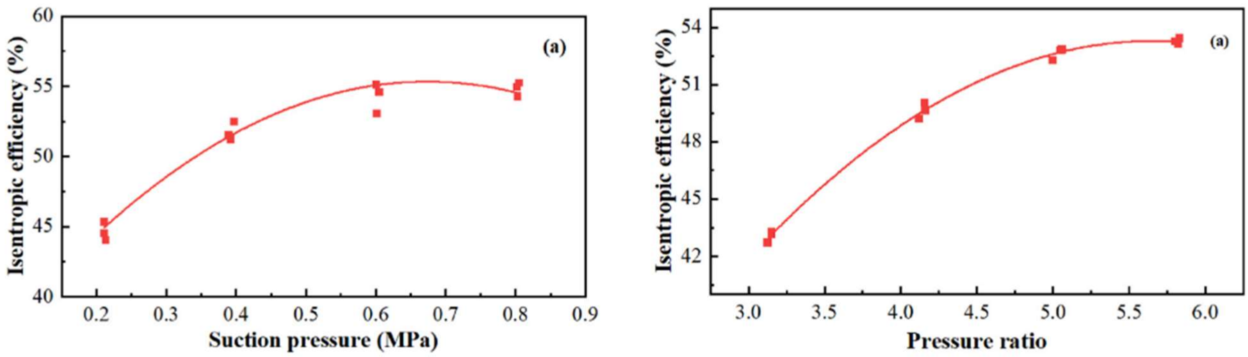


Figure 25: analysis of diaphragm compressor performance: the figure on the left (a) shows the trend in isentropic efficiency as a function of suction pressure, while the figure on the right (b) shows isentropic efficiency as a function of the compression ratio [66].

From the two profiles, maximum efficiency (approximately 55%) can be achieved with a suction pressure of approximately 60 bar and a pressure difference between Pin and Pout of approximately 5.8; in our case, with P_{in} = 35 bar and P_{out} = 350 bar, based on image 25, it is possible to estimate an isentropic efficiency of 52%; this value has been estimated because the experimental curve shows a clear upward trend as the compression ratio increases, and it has been hypothesised that, once the value of 5.8 has been exceeded, the efficiency tends to stabilise before undergoing a possible decline due to thermal losses. It was therefore decided not to continue with the linear increase in efficiency, but to stabilise at a conservative value of 52% to take into account the mechanical and thermal irreversibilities inherent in a high pressure jump (from 35 to 350 bar), thus ensuring an estimate of energy consumption (1.51 kWh/kg) closer to the actual performance of an industrial machine.

Consequently, **EQ.27** is used to calculate the specific consumption of the compressor, which is approximately 1.51 kWh/kg.

As regards operating parameters, although a higher suction pressure (60 bar) would favour the isentropic efficiency of the compressor, a PEM outlet pressure of 35 bar was chosen. This choice was motivated by the need to preserve the integrity of the polymer membrane, minimising the phenomenon of gas crossover and ensuring a high standard of operational safety. This configuration allows the compressor's energy consumption to be kept within competitive levels without compromising the useful life of the electrolyser, which is the fundamental element of the project.

With the specific consumption and mass flow rate, it is therefore possible to calculate the average and peak power of the compressor:

$$Power\ consumption = mass\ flow\ rate * E_{spec} \quad \textbf{EQ.29}$$

Applying this formula, we obtain an average power consumption of approximately 0.31 kW. Although this value is low compared to industrial standards for large compressors, it is consistent with the flow rates produced by the electrolyser in question.

The next paragraph will not yet analyse the tanks, but rather the PEMFC, as the final size of the tank can be defined after analysing the energy requirements of the fuel cell. The tank acts as the energy reservoir of the system: its size depends not only on the production of the electrolyser but must also be calibrated to ensure the necessary autonomy for users, especially during periods of low sunlight.

4.2.3 Fuel cell energy calculations

Regarding PEMFCs, analyses reported in the literature (and summarised in Table 2) indicate that electrical efficiency can reach peaks of 60%. However, for the purposes of this study, a conservative value of 55% has been adopted to take into account ancillary losses in the system, commonly referred to as balance of plant (or BoP). The 55% electrical efficiency indicated above is supported by the operating pressure conditions of the system; in fact, although hydrogen is stored at 350 bar, the use of a control valve allows the PEMFC to be supplied at a controlled pressure of 200 kPa (approximately 2 bar above atmospheric pressure); in fact, operating at 200 kPag allows a higher cell voltage to be obtained than atmospheric pressure, reducing activation losses and improving the transport of reactants to the membrane [67]. It is also important to note that PEMFCs are cogeneration systems: in addition to electrical energy, they produce residual heat which, if properly recovered, can increase overall thermodynamic efficiency to around 85-90%.

Consequently, it is possible to calculate the amount of energy that can be generated by the fuel cell using the formula:

$$Electrical\ energy\ produced = LHV_{H2} * electrical\ efficiency * hydrogen\ mass \quad \textbf{EQ.30}$$

The Lower Heating Value (LHV) of hydrogen is approximately 33.33 kWh/kg and, using the total mass as a starting point, this gives an annual production of approximately 6,720 kWh.

To calculate the electrical power linked to average hydrogen production, the following formula is used:

$$Average\ power = LHV_{H2} * electrical\ efficiency * mass\ flow\ rate \quad \textbf{EQ.31}$$

This results in a power output of approximately 3.78 kW. However, to determine the size of the PEMFC, it is essential to integrate this data with the company’s energy consumption profile in order to optimise the size of the fuel cell.

The company’s consumption data, extracted from the Azzurro ZCS portal, show an annual energy requirement of approximately 191,000 kWh. Currently, 35% of this requirement is met directly by the photovoltaic system (net of energy fed into the grid). Translating these values on a daily basis, we get an average daily consumption of approximately 524 kWh; this value is chosen because hydrogen, which can be stored, allows its intrinsic energy to be used at any time of the year, even during periods of peak consumption by the company. Furthermore, the average contribution of photovoltaics (equal to 182.5 kWh/day) is subtracted from the average daily consumption, leaving a residual amount of 341.5 kWh that the company must draw from the grid or from alternative storage systems.

Residual load analysis is essential for the correct sizing of both the PEMFC and the storage system. The objective is to guarantee three working days of autonomy in scenarios with low insolation;

consequently, the total hypothetical energy required to cover the three days would amount to approximately 1000 kWh.

To obtain 1000 kWh of electricity from the fuel cell, considering the efficiency discussed above, the hydrogen requirement would be approximately 55 kg, calculated as follows:

$$Hydrogen\ mass = Energy\ needed\ /\ (LHV_{H2} * electrical\ efficiency) \quad \textbf{EQ.32}$$

However, to exploit the 55 kg of hydrogen in energy production, a fuel cell based on an average of 3.78 kW would produce 1000 kWh in approximately 11 days, more than triple the number of days previously established. Consequently, a 14 kW PEMFC was chosen, in line with the peak power calculated previously and therefore representing an optimal compromise: with continuous operation for 72 hours (equivalent to 3 days of support), it allows the energy corresponding to the hydrogen stored in the tank to be supplied to cover priority loads, ensuring the company's energy resilience even during prolonged periods of bad weather.

4.2.4 Calculations for tank sizing

Now we will focus on the tanks, which will have to store hydrogen gas at 350 bar. The choice of tanks depends mainly on their type; in fact, there are four types of storage containers on the market: type I, metal container (typically steel), without metal welding; type II, metal container without joints and wrapped with a composite resin fibre frame; type III, with a metal coating, with the addition of complete resin fibre wrapping, and with operating standards of 350 bar; type IV, with a polymer coating, wrapped with resin fibre:

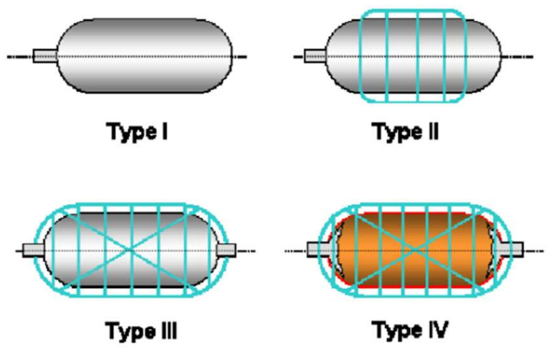


Figure 26: types of tanks for storing hydrogen gas [68].

The latter is more technologically advanced and lighter, but more expensive than type III, while the first two types of containers offer lower safety and are much heavier [65].

Knowing the mass of hydrogen to be stored (55 kg), the total storage volume must be calculated to size the tank:

$$Storage\ volume = Hydrogen\ mass * 11.12 * \left(\frac{p_{amb}}{p_{comp}}\right) \quad \textbf{EQ.33}$$

Since the specific volume of hydrogen under normal conditions (0 °C and 1 atm) is 11.12 m^3/kg, where p_{amb} is the ambient pressure of 1 atm or 1.013 bar, and p_{comb} is the compression pressure (350 bar), a storage volume of approximately 1.8 m^3 is obtained, making the installation compatible with company spaces.

In addition to the main 350 bar tank, linked to process storage, it is also necessary to use a "strategic" tank, located downstream of the electrolyser. this tank will be used to store low-pressure hydrogen (35 bar) to ensure a stable flow to the compressor, absorbing production fluctuations and allowing for optimal management of operational transients.

The tank will not be large, as it will be designed to handle a volume of hydrogen linked to the electrolyser's average production over 2 hours; consequently, referring to the peak hourly production of approximately 0.15 kg/h, we will obtain a quantity of approximately 0.4 kg of hydrogen to be stored, which in volume, compressed to 35 bar using the **EQ.33**, will be equivalent to approximately 0.13 Nm^3, or 133 litres.

4.3 Economic evaluation of the plant

Following the technical sizing of the components, this section aims to assess the economic feasibility of the proposed energy system. The analysis will not be limited to the acquisition cost of the technologies but will adopt a multi-criteria approach to estimate the long-term financial sustainability of the project, specifically for 20 years of use.

Specifically, the costs relating to the electrolyser, the compression system, the storage tanks, and the PEMFC will be analysed, broken down into the following items:

- CAPEX (Capital Expenditure): includes the initial investment costs for the purchase of machinery, installation, and commissioning of the entire plant.

- OPEX (Operating Expenditure): includes the operating and maintenance costs necessary to ensure the efficiency of the components during their useful life.

In addition to the above parameters, the analysis will be supplemented by two further key indicators, specifically related to hydrogen as an energy carrier; these elements are fundamental for assessing the overall economic sustainability of the system and its competitiveness in the current energy context:

- LCOH (Levelised Cost Of Hydrogen): used to determine the actual cost of producing each kilogram of green hydrogen generated from photovoltaic surplus (€/kgH_2).

- Payback Period: aimed at estimating how long it will take for the savings made on the company's electricity bill, thanks to the reduction in grid withdrawals, to offset the initial costs.

This analysis will make it possible to define the costs of self-produced energy and the system's potential for economic resilience in the face of market price volatility.

4.3.1 CAPEX

The calculation of investment costs is based on theoretical parameters derived from scientific and economic studies related to the components of the plant. Although the actual cost of the components is closely linked to market prices provided by manufacturers, the data used in this analysis represents a solid basis for assessing the financial sustainability of the project.

Investment costs were calculated using specific parameters for each technology: for the electrolyser, compressor and fuel cell, the parameter €/kW was used, while for the storage system, reference was made to the cost per unit of mass, expressed in €/kg. The costs relating to the Balance of Plant (BoP) (which includes control systems, piping and valves) and installation and testing costs were added to the analysis of the main components. The CAPEX summary is shown in the table below:

CAPEX							
Equipment	Unite measure	Quantity	Cost parameter	Equipment cost	BoP cost	Installation cost	Total cost
PEM ELECTOLYZER	kW	25	1,800 €/kW	45,000 €	9,000.0 €	8,100.00 €	62,100.00 €
BUFFER TANK	m^3	0.15	5,627.44€/m^3	844.12 €	168.8 €	151.94 €	1,164.88 €
DIAPHRAGM COMPRESSOR	kW	0.35	16,533.11 €/kW	5,787 €	1,157.3 €	1,041.59 €	7,985.50 €
TYPE IV TANK	m^3	1.8	9,442.87 €/m^3	16,997 €	3,399.4 €	3,059.49 €	23,456.08 €
PEMFC	kW	14	2,600 €/kW	36,400 €	7,280.0 €	6,552.00 €	50,232.00 €
TOTAL CAPEX							**144,938.46 €**

Table 4: analysis of capital expenditure (CAPEX) for the integrated system of the company 'La Cerea'; the data was processed using Excel.

The first element for which the cost was estimated was the PEM electrolyser, with a nominal capacity of 25 kW; based on various studies examined, the specific cost of the unit was estimated at approximately €1,800/kW, bringing the purchase cost of the stack to €45,000 [3], [68]. It should be noted that the costs associated with these technologies (particularly for electrolysers and fuel cells) present nowadays a high variability, mainly because these technologies are evolving in recent years and that, depending on the size of the plant, specific costs can differ by hundreds of euros per kW of installed power. Consequently, the value of €1,800/kW has been adopted as a current and conservative estimate, reflecting market prices for small-scale units, without the need for additional time discounting coefficients, as the figure is already representative of today's economic context.

In addition to the cost of the main machinery, the BoP, estimated at 20% of the cost of the electrolyser, was also evaluated economically to cover the auxiliary systems necessary for operation, while installation costs were calculated as 15% of the sum of the equipment cost and the BoP; consequently, the total investment is the sum of these three elements, calculated in such a way as to ensure a complete conservative estimate for the CAPEX of this unit, which amounts to €62,100.

The second element is the buffer tank, which acts as a precautionary measure to regulate the flow of hydrogen, protecting the compressor from pressure transients and ensuring a constant hydrogen supply. Given the specificity of the 35-bar application, the purchase cost was estimated using a methodology well established in process engineering, namely the "Six-Tenths Rule". Originally formalised by Roger Williams Jr. in 1947, this power law allows the cost of equipment to be scaled from a known capacity unit according to the following relationship:

$$C_a = C_b * (\frac{Q_a}{Q_b})^\wedge n \quad \textbf{EQ.34}$$

Where C_a is the cost of the desired component, C_b is the cost of the existing component, Q_a is the physical parameter (power, volume) of the desired machinery, while Q_b is the physical parameter of the existing component, whose cost is known, and n is the cost exponent, generally equal to 0.6, but which in reality can vary for different types of materials and equipment [69].

Consequently, a reference unit with technological characteristics similar to the project component was identified, with a capacity of 1 m^3 and a purchase cost of €1,882. Applying the Six-Tenths Rule to scale the cost to the project volume (0.15 m^3), a value of approximately €602 was obtained; this value is multiplied by a correction factor (f_c) of 1.4; this coefficient relates to the indirect costs for machinery that handles fluids, i.e. the costs associated with engineering and design, contingency allowances in the event of unforeseen events, and any transport costs.

Consequently, multiplying the correction factor by €602 gives an equipment cost of €844.12 [70], [71]. In line with the economic analysis set out above, the cost of the machinery was added to the Balance of Plant and installation costs, giving a final total cost of approximately €1,165.

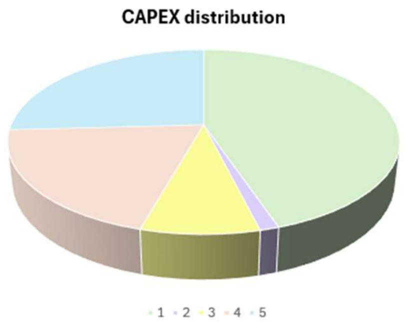
The same was done for the 1.8 m^3 type IV tank, but obviously with different costs and capacities; in fact, a cost C_b of approximately €4,300 was used for a commercial tank with a capacity of 0.32 m^3, and multiplying by the factor n = 0.6, a total cost of approximately €23,456 was obtained.

The Six-Tenths Rule was also applied to the diaphragm compressor estimate, parameterising the cost according to the nominal power (in kW) rather than the volume. Starting from a reference unit with a capacity of 5.5 kW, a purchase cost of €21,581, scaling to the project size (0.35 kW), and multiplying everything by the location factor, it was possible to determine the base cost of the machinery, equal to approximately €5,787. Then, by adding in the BoP and installation costs, the total investment for the compression section comes to about €7,985.

As regards PEMFC, a specific reference cost of €2,600/kW has been adopted. For a nominal power of 14 kW, this translates into an equipment cost of €36,400 which, including auxiliary systems and commissioning, brings the total cost of the unit to €50,232.

In conclusion, the aggregation of the costs relating to all the functional units described leads to a total plant CAPEX of €144,938.

The percentage breakdown of initial investment costs (CAPEX) is presented below. Analysis of the pie chart clearly shows that the electrolyser represents the most significant cost item, accounting for the majority of the total investment. This data confirms that hydrogen generation technology is still the main economic driver in the financial dimensioning of systems of this type:



PEM ELECTROLYZER	43%
PEM FUEL CELL	34%
DIAPHRAGM COMPRESSOR	6%
TYPE IV TANK	16%
BUFFER TANK	1%

Figure 27: percentage breakdown of investment costs for each component of the plant; the data was processed using Excel.

4.3.2 OPEX

As with CAPEX, OPEX estimates were defined based on technical and economic parameters derived from scientific literature in the sector. The analysis of operating costs was broken down specifically for each functional unit of the plant, focusing mainly on the heterogeneity of the operational characteristics and maintenance regimes of the components. In particular, the assessment includes both direct costs related to resource consumption (energy and water) and indirect costs, such as routine maintenance, cyclical replacement of degradable components (stacks) and inspections required by safety regulations. The OPEX summary is shown in the following table:

PEM ELECTROLYZER	70000.00	Operational lifetime (h)
	1777.00	Annual operating hours (h)
	39.39	Equivalent years (y)
	22500.00	Replacement cost (€)
	2.41	Annual water cost (€)
	1863.00	Operation and Maintenance cost (€)
	2436.59	**Annual OPEX (€)**
BUFFER TANK	**200.00**	**Annual inspections (€)**
DIAPHRAGM COMPRESSOR	80000.00	Operational lifetime (h)
	1777.00	Annual operating hours (h)
	45.02	Equivalent years (y)
	2893.30	Replacement cost (€)
	165.88	Annual energetic cost (€)
	239.56	Operation and Maintenance cost (€)
	469.72	**Annual OPEX (€)**
TYPE IV TANK	**800.00**	**Annual inspections (€)**
PEMFC	50000.00	Operational lifetime (h)
	483.90	Annual operating hours (h)
	103.33	Equivalent years (y)
	18200.00	Replacement cost (€)
	1506.96	Operation and Maintenance cost (€)
	1683.10	**Annual OPEX (€)**
OPEX	**5589.41**	**TOTAL OPEX (€)**

Table 5: analysis of annual operating costs, inspections and replacement costs for electrolysers, compressors and fuel cells; the data was processed using Excel.

The OPEX analysis for the PEM electrolyser begins with the definition of the operational life, estimated at 70,000 hours. This parameter, compared to the annual hours of use (1,777 hours), allows the equivalent years of life of the system to be determined before the end of its technological cycle.

The replacement cost of the stack is another important factor to consider; in fact, given that the performance of PEM membranes tends to degrade over time, it is expected that the unit will need to be partially or totally refurbished. In line with technical and economic literature standards, this cost has been estimated at 50% of the initial equipment cost (CAPEX), assuming that the auxiliary structures (BoP) do not need to be replaced.

With regard to consumption, direct operating costs include water supply, based on an average specific consumption of 22 l/kgH_2 produced and a unit cost of water of approximately €0.0002/l; electricity, calculated on the basis of an average cost of withdrawal from the grid of €0.22/kWh; finally, the Operation and Maintenance cost (O&M), estimated on a flat-rate basis as 3% of the total installed cost (CAPEX), to cover preventive maintenance and monitoring [2], [72].

In conclusion, the annual OPEX of the electrolyser is obtained by adding the direct costs (water and energy) to the maintenance costs and the annual provision for replacement costs (calculated as the ratio between the replacement cost and the equivalent years), resulting in a total of approximately €2,436/year [73].

As regards the storage section, consisting of the buffer tank and type IV high-pressure cylinders, the OPEX was estimated by focusing on preventive maintenance costs and, above all, on inspections required by law. Being static components, the cylinders have a long service life but require a rigorous inspection plan to ensure their operational safety over time.

Both tanks have a single OPEX item, namely annual inspections, quantified at €200 for the buffer tank and €800 for the type IV tank. This allocation reflects the different criticality of the components and the need to comply with Ministerial Decree 329/2004, which regulates periodic integrity and functional checks on pressure equipment in Italy. The decree provides for costs such as: verification of the correct installation of the system; integrity and requalification checks; checks on safety accessories (valves, for example); administrative and technical costs, i.e. those related to the cost of specialised personnel for the checks; communicate the decommissioning or restarting of the equipment [74].

The total OPEX of the storage section (€1,000/year) is necessary not only for technical maintenance, but also for regulatory compliance, thus ensuring optimal safety requirements for the plant.

The diaphragm compressor is one of the most critical mechanical components of the system, with an estimated operational lifetime of 80,000 hours [75]. Considering an annual usage of approximately 1,777 hours, the machine has a very high theoretical longevity, exceeding 45 equivalent years. However, to ensure such operational continuity, a rigorous cyclical maintenance plan is necessary; in fact, the operation and maintenance cost, again estimated at 3% of CAPEX, amounts to approximately €239/year and includes periodic replacement of hydraulic oil and monitoring of control systems. Meanwhile, for direct costs, energy costs were used, calculated based on nominal power consumption and operating hours, for a total of approximately €166/year. Finally, replacement costs include the costs of replacing the diaphragm and components subject to mechanical wear. Adding up the above costs, we obtain a total annual OPEX for the compressor of approximately €470, a figure that guarantees the availability of the system and the integrity of the compression membranes.

The PEM fuel cell is the unit responsible for converting hydrogen into electrical energy. Its operational life has been set at 50,000 hours, a benchmark value for small stationary applications, which reflects the current state of the art [76].

Economic parameters such as replacement cost have also been evaluated for the PEMFC, which is expected to be €18,200, considering the fact that, at the end of its useful life, the degradation of the catalyst and polymer membranes makes it necessary to replace the electrochemical "core", while the auxiliary components (BoP) are retained. Having chosen a fuel cell with a capacity of 14 kW, a load profile of approximately 483 h/year was used, which leads to the end of the nominal life after approximately 50 years, making the annual provision for replacement a sustainable item in the long term. Finally, operational and maintenance costs have been estimated at approximately €1,506/year (again using 3% of CAPEX) and include the replacement of air filters, thermal management system maintenance and the verification of humidity and pressure sensors.

The annual OPEX of the PEMFC therefore amounts to approximately €1,683, including both preventive maintenance and the technological depreciation of the stack.

Adding up all annual operating costs gives a total OPEX of approximately €5,589.

4.3.3 LCOH

The main economic assessment linked to the proposed plant is based on the Levelised Cost Of Hydrogen, which, as mentioned above, allows the average production cost per kg of hydrogen produced to be assessed, spreading the investment costs (CAPEX) and operating costs (OPEX) over the entire life of the system. In 2025, global benchmarks for the various types of hydrogen produced showed that, for green hydrogen, the average production cost was between 4 and 9 USD/kg (3.5 and 7.8 €/kg); blue hydrogen, on the other hand, still has a lower cost, ranging from €1.5 to €4/kg, while grey hydrogen remains the cheapest option (€1-3/kg), although it is subject to increasing economic pressure due to carbon taxes in markets such as Europe [77].

Consequently, the LCOH associated with the proposed plant will now be calculated to verify the economic positioning of the system compared to the global average for the sector. The formula to be used is as follows:

$$LCOH = \frac{CAPE \quad \sum_{t=1}^{N}\frac{OPEX_t}{(1+r)^t}}{\sum_{t=1}^{N}\frac{M_t}{(1+r)^t}} \quad \text{EQ.35}$$

Where N is the estimated lifetime of the plant (in this case 20), r is the discount factor, estimated at 6%, and M_t is the mass of hydrogen produced.

LCOH			
Year	Discounted hydrogen mass (kg)	Discounted annual OPEX (€)	Discount rate
1	345.8785094	5273.026932	0.06
2	326.3004806	4974.55371	Annual hydrogen production (kg)
3	307.8306421	4692.975198	366.63122
4	290.4062661	4427.335092	Cumulative discounted hydrogen mass (kg)
5	273.9681756	4176.731219	4205.23121
6	258.460543	3940.312471	Cumulative discounted OPEX (€)
7	243.8307009	3717.275916	64110.07571
8	230.0289631	3506.864072	**LCOH (€/kgH2)**
9	217.0084558	3308.362332	**49.71 €**
10	204.7249583	3121.096539	
11	193.1367531	2944.430698	
12	182.2044841	2777.764809	
13	171.8910227	2620.532839	
14	162.1613422	2472.200791	
15	152.9823983	2332.264897	
16	144.3230172	2200.249903	
17	136.1537899	2075.707456	
18	128.4469716	1958.214581	
19	121.1763883	1847.372246	
20	114.3173474	1742.804006	

Table 6: calculation of the Levelised Cost Of Hydrogen linked to the discount rate, total annual hydrogen production, OPEX and CAPEX; the data was processed in Excel.

As can be seen from the table, the calculation of the plant's LCOH returned a significantly high value compared to the above-mentioned standards; however, this result was expected, as the global benchmarks referred to MW or GW scale plants, while for a small plant such as the one studied, the CAPEX will be significantly higher. Furthermore, the plant's operating hours are approximately 1,777 or 20% of the total hours in a year (i.e. 8,760); more intensive use would allow more hydrogen to be produced and therefore spread the fixed costs over a larger mass of hydrogen.

Consequently, the value of almost €50/kgH_2 is realistic for current small-scale technology. It indicates that, while technical feasibility is established, economic competitiveness will require future reductions in component prices and energy management strategies aimed at maximising the system's operating hours.

4.3.4 Payback Period

The payback period represents the time interval required for the cash flows generated by the plant to equal the initial investment (CAPEX). It is a fundamental indicator for assessing the financial risk of the project and its ability to pay for itself over time.

It should be noted that, given the experimental nature of the system, the small size of the components and the previously calculated LCOH value (which is higher than global standards), the economic analysis will almost certainly not have an optimal or competitive return on investment compared to traditional fossil fuel or renewable technologies.

The formula for calculating the payback period is very simple, being the ratio between CAPEX and gross earnings minus OPEX; for the determination of earnings, it was decided not to consider direct revenues from the sale of energy, but rather the avoided costs (savings). Specifically, cash flows were calculated based on the annual electricity producible by the PEMFC (in kWh) and the average price of energy in the agricultural sector (€0.22/kWh). This methodological choice reflects the actual configuration of the plant, in which the main economic benefit does not derive from immediate monetary gain, but from the savings generated by self-consumption, thus avoiding the purchase of energy from the national grid:

$$Avoided\ grid\ costs = greed\ price * energy\ produced \quad \textbf{EQ.36}$$

In line with the findings of the LCOH analysis, it should be noted that, due to the high specific cost of small-scale technology and operating costs, a return on investment comparable to conventional energy systems cannot be expected. Consequently, **EQ.36** shows avoided costs of approximately €1,479/year; therefore, for the plant, in order to be considered economically sustainable, the payback period must be less than or equal to 20 years:

$$Payback\ period = CAPEX\ /\ (annual\ savings - OPEX) \quad \textbf{EQ.37}$$

Unfortunately, the formula returns a negative result, indicating that the project is not currently economically sustainable. This result highlights how the costs of hydrogen technology remain prohibitive compared to conventional energy sources, preventing the investment from reaching break-even within its useful life.

4.4 Assessment of CO_2 avoided

Beyond purely financial considerations, the main rationale for adopting a green hydrogen-based system lies in its reduced environmental impact compared to conventional energy solutions. To quantify this benefit, the annual mass of carbon dioxide avoided was calculated by comparing the energy produced by PEMFC with the emission factor of the national electricity grid.

The following parameters were used for the calculation:

- Annual electricity produced by PEMFC: 6,720 kWh.
- Average emission factor of the Italian grid (ISPRA data): approximately 215.9 gCO_2/kWh.

Multiplying these two factors together, the emission of approximately 1.45 tonnes of CO_2 per year is avoided [78]; this figure constitutes the main added value of the project, technically offsetting the high LCOH and long payback period in the context of the global energy transition. However, it is important to note that the owner of "La Cerea" farm utilizes Guarantee of Origin (GO) certificates, as regulated by GSE, ensuring that his grid-supplied electricity is sourced from 100% renewable plants [79]. Consequently, the emissions savings for this scenario were calculated using a "location-based" approach, based on the national average grid emission factor. This choice was made to demonstrate the objective decarbonization potential of the P2H2P system for a generic user who does not yet utilize certified renewable energy, thereby highlighting the technology's replicability and its impact on the actual energy mix.

4.5 Results’ discussion

This analysis of the plant highlighted parameters that reflect the technological transition phase in which the hydrogen sector finds itself. The small size of the plant in terms of power has led to high specific machinery costs, and as a result, it does not benefit from the economies of scale typical of large industrial plants. This has led to a significantly high Levelised Cost Of Hydrogen but reflects the high cost of electricity and technological amortisation on limited production volumes. Furthermore, the return on investment time, being more than double the estimated lifetime of the plant, confirms the lack of direct profitability for a system such as the one proposed.

Despite this, the plant saves in theory around 1.5 tonnes of CO_2 per year, thus ensuring a significant environmental benefit.

The plant is therefore a good starting point for energy independence and agricultural decarbonisation, but in order to make the system economically attractive on a large scale and overcome the current temporal and financial barriers, the following will be decisive: the reduction of CAPEX through the standardisation of components on a global scale; the use of new incentives that allow for long-term planning for companies and, as mentioned above, an increase in annual production hours, thus spreading fixed costs over a larger mass of hydrogen.

CHAPTER 5: Solution to the case study, implementation of the REC

In the previous chapter, we demonstrated how investing in a Power-to-Hydrogen-to-Power system for the La Cerea farm alone proved to be economically unsustainable, due to the LCOH of €49.71/kgH_2, resulting from the low utilisation factor of the electrolyser and the inability to amortise the high plant costs on a limited production scale.

To overcome this problem, research has shifted towards a collective management model: the Renewable Energy Community (REC). This paradigm represents not only a technical architecture but also a fundamental socio-economic strategy for the decarbonisation of rural areas. In fact, according to recent studies on the sustainability of local energy networks, the aggregation of multiple users allows individual energy surpluses to be transformed into a shared resource, stabilising the network and drastically improving the economic return on investments in P2H2P technologies [4].

The thesis project therefore proposes the establishment of an agricultural REC, which includes the "La Cerea" farm and two other neighbouring farms located in the municipality of Pralormo. This aggregation allows the consumption and production profiles of three different connection points to be added together, ensuring a much higher volume of shared energy.

This chapter is therefore dedicated to the design and sustainability verification of this new model. The technological and functional architecture of the REC will be illustrated, along with the optimal sizing of the P2H2P in relation to the new aggregate load profiles and, above all, the new LCOH will be calculated. The ultimate goal is to demonstrate quantitatively whether regulatory support and GSE incentives, applied on a community scale, can effectively make the decarbonisation project economically feasible.

5.1 Description of the study site and existing energy facilities

The proposed REC has a membership base consisting of three agricultural businesses located in the municipal area of Pralormo. The choice of these three businesses is strategic: they share the same geographical area and, as a result, can be connected to the same primary substation, a fundamental requirement for participation in an Energy Community according to current legislation (Legislative Decree 199/2021). All the farms follow a homogeneous production model based on the integration of livestock farming and cereal cultivation, which guarantees similar and complementary electricity and heat consumption profiles.

The other two potential farms included in the Renewable Energy Community are: Cascina Risolero, which contributes to the REC with a 110-kW photovoltaic system. Its load profile is characterised by consumption peaks linked to stable activities and waste management. Risolero's participation makes it possible to capture a significant amount of surplus solar energy which, individually, would be fed into the grid with little value; while the other farm, Agrisapori, represents the third pillar of the energy community, with a 90-kW photovoltaic system. Although it is the smallest system, its presence is essential for the spatial diversification of production and for increasing the overall volume of shared energy. Furthermore, all companies have new plants, which became operational at the end of 2024 and at the beginning of 2025.

As with the other two companies, consumption is dominated by refrigeration systems, field irrigation and agricultural product conditioning:

Figure 28: territorial classification of the sites covered by the study and their geographical coordinates (source: Google Earth).

To ensure that the proposed model complies with GSE and ARERA requirements, a detailed cartographic verification was carried out using the official map of Conventional Areas, updated to 2025 [80]. Analysis of the local electricity grid showed that the territory of Pralormo formally falls within the conventional area identified by code AC001E01142. As this is an area without its own physical substation, it is electrically connected to the Ceresole Alba Primary Substation (Area Code: AC001E01123), which acts as the main distribution hub for the entire district. Furthermore, Cascina Risolero belongs to a different conventional area from the other two farms (AC001E01143), which also does not have its own physical substation but is also connected to Ceresole Alba:

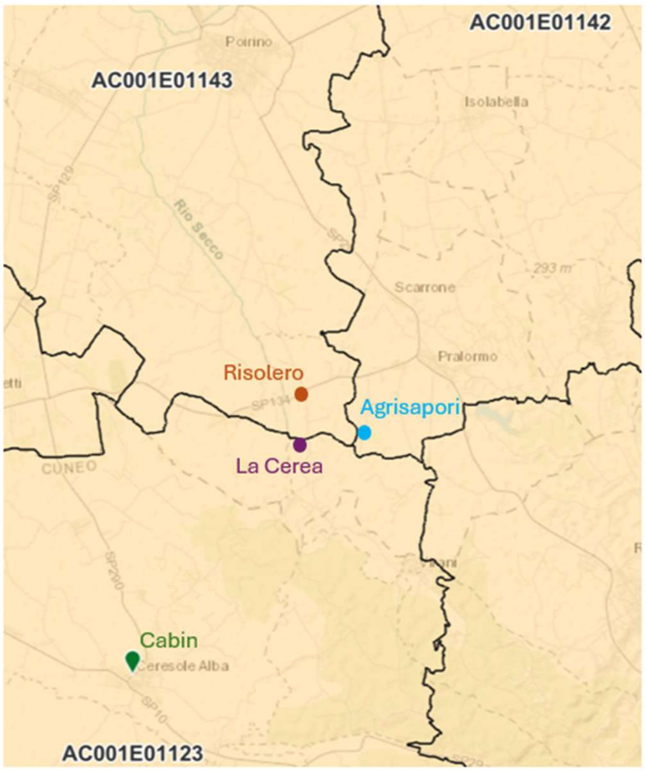


Figure 29: classification of the companies "La Cerea", "Risolero" and "Agrisapori" within the map of the GSE Primary Cabins.

This technical evidence is of fundamental importance: the fact that the agricultural cluster comprising La Cerea, Cascina Risolero and Agrisapori belongs to the same portion of the network ensures that the energy fed into it can be accounted for as shared energy in accordance with the Integrated Text on Distributed Self-Consumption (TIAD), thus ensuring the feasibility of the REC.

5.1.1 Hypothetical scenarios for the Renewable Energy Community

To identify the most advantageous management strategy for the Pralormo REC, two operational scenarios were defined, reflecting different philosophies regarding the use of hydrogen as an energy carrier and regulatory incentives.

As regards the first scenario, it will be similar to the case study previously analysed in CHAPTER 4; in fact, the surplus energy produced by the photovoltaic systems of the three companies will be used to power the electrolyser. The remaining energy, which cannot be used for power supply, is sent to the grid in order to obtain the revenue deriving from the RECs Premium Tariff.

Considering the specifications of the plant (with a nominal power between 200 kW and 600 kW) and its geographical location in Northern Italy, the system can benefit from a maximum incentive of €120/MWh. However, this configuration has a significant operational limitation: the operation of the electrolyser is constrained by the availability of surplus solar energy, thus settling again at around 1,777 hours per year. This limitation will negatively affect the plant's utilisation factor and, consequently, the payback period of the initial investment (CAPEX), which will be calculated later.

The second scenario, on the other hand, aims to minimise the Levelised Cost Of Hydrogen (LCOH) by using the electrolyser as a tool for local flexibility. The electrolyser will use all the photovoltaic energy produced by the three companies to produce hydrogen, thus increasing the number of working hours during the year, compared to the case of "La Cerea" and the first scenario, while the energy that it is unable to absorb (mainly due to power limitations) will be fed into the grid to obtain revenue from the premium tariff.

The advantage is that the shared energy quota on which the premium tariff is based will be higher than in the first scenario, as there will be much more energy available.

As for the use of hydrogen in both scenarios, it will play a key role: powering the fuel cell to produce electricity and heat (cogeneration); in fact, the heat produced during the electrochemical reaction is recovered through heat exchangers and used to replace the oil heating of the three farms involved.

This cogeneration-based scheme is feasible for several reasons. First, the fact that the three farms belong to the same primary substation ensures ideal geographical proximity for the development of a local microgrid, thereby minimising heat transport losses. This proximity also facilitates the technological replacement of current systems, as the heat produced by fuel cells is compatible with the thermal requirements of warehouses and agricultural production processes. Finally, the use of heat generated by fuel cells will lead to the replacement of agricultural diesel, resulting in economic savings and a reduction in CO_2 emissions, both of which are linked to the use of fossil fuels.

5.1.2 System configuration and data collection from PVGIS

Unlike La Cerea, the photovoltaic production of the other two companies was estimated using the Photovoltaic Geographical Information System (or PVGIS). This portal, made available by the European Commission, is a widely recognised tool for calculating photovoltaic potential in any geographical area [81].

For the analysis of the Renewable Energy Community (REC), the same plant architecture defined in Paragraph 4.1.1 was adopted. The plant therefore maintains its configuration based on photovoltaic modules, PEM electrolysers, diaphragm compression systems, tank storage and PEMFCs, once again exploiting the flexibility of polymer membrane technology for solar resource management.

The PVGIS software was essential for obtaining hourly photovoltaic production data from the other two companies; in fact, the tool allows input data to be entered to obtain accurate estimates of photovoltaic energy production:

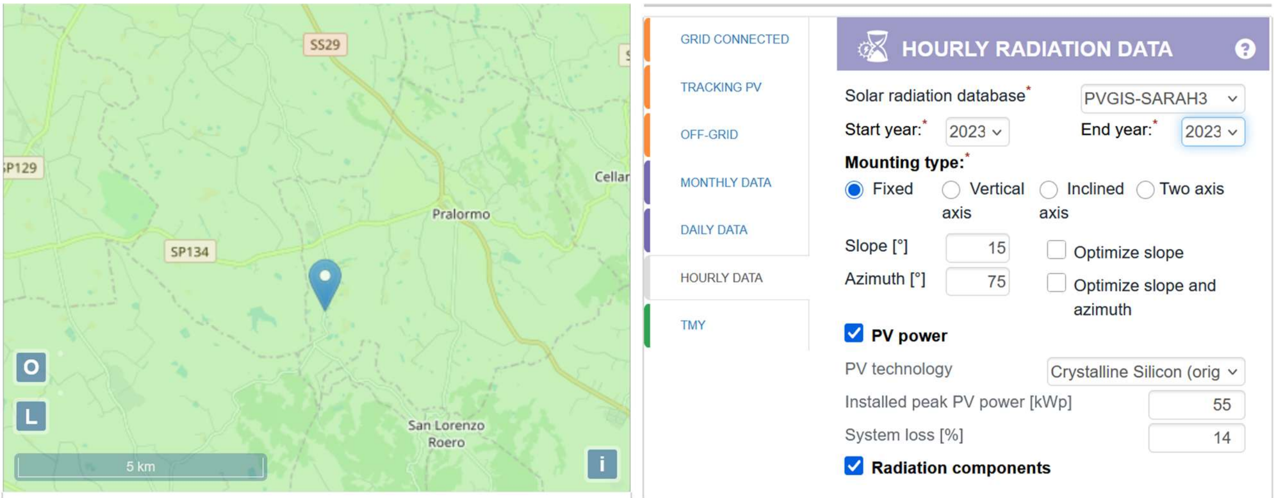


Figure 30: input parameters for simulating photovoltaic producibility using the PVGIS-SARAH3 database.

The PVGIS tool interface, shown in the figure, allows users to configure various key parameters for the simulation. In addition to geographical location, the input data mainly consists of:

- Climate and weather data: it is possible to select the solar radiation database (such as SARAH3) and the reference time interval (start and end year) for statistical analysis.

- System configuration: the software allows you to choose between different installation modes, ranging from fixed systems to different types of solar tracking (single-axis vertical, inclined or dual-axis).

- Geometric parameters (for fixed systems): the user defines the tilt of the modules and the azimuth (orientation relative to the south).

- Technological specifications: the nominal installed power, module technology (crystalline silicon, CIS or CdTe) and overall system losses (default 14%) can be set, considering cable and inverter inefficiencies and natural component degradation.

Once the input parameters have been configured, PVGIS processes the simulations and returns the results in spreadsheet format (.xlsx). The output provides a historical series with hourly time resolution, in which the main data is represented by the instantaneous power generated by the system (PV system power), expressed in Watts (W).

5.2 Methodology for calculating and analysing energy flows

After discussing the potential of the tool, we will now proceed with the analytical modelling of the photovoltaic systems of the two companies involved. To obtain data consistent with the previous climate analysis, the SARAH-3 database was used, taking the year 2023 as a reference for both.

The Risolero company's system has a roof configuration with east-west exposure. To accurately reflect the energy yield of this type of installation, the total nominal power of 110 kW was divided in two; consequently, a value of 55 kW was used for each side of the roof. The roof pitch was estimated at 15°, while the building axis required an angle of +75° for the east-facing side and -75° for the west-facing side.

This breakdown of the calculation allows for more accurate modelling of the daily production curve, which is typically more spread out over the morning and afternoon hours than a single south-facing system.

A similar methodology was adopted for the Agrisapori company. Using the three-dimensional analysis provided by Google Earth, a steeper roof slope than in the previous case was estimated, equal to 20°. In addition, the total power of 90 kW was divided into two sections of 45 kW per side, while the orientation again depended on the layout of the building and, as a result, the panels were modelled with respect to the azimuth of +85° and -85°.

From the data obtained from the spreadsheet, the values of the two configurations were added together, resulting in a total annual energy production of approximately 127,555 kWh for Risolero and 103,734 kWh for Agrisapori. Adding up the production of the three companies, the total renewable electricity production is approximately 325,336 kWh.

5.2.1 Technical modelling of the P2H2P plant (1st scenario)

The first scenario analysed for the REC will utilise an electricity surplus of approximately 82,226 kWh, available for hydrogen production. This number was obtained by assuming that the other two companies also had the same surplus as the company "La Cerea", that was approximately 27,421 kWh; to obtain that data, **EQ.23** was used, and it was multiplied by 3.

The same methodology described in the previous chapter was used to size the components and define the operating parameters. The plant layout for this configuration is summarised in the following diagram:

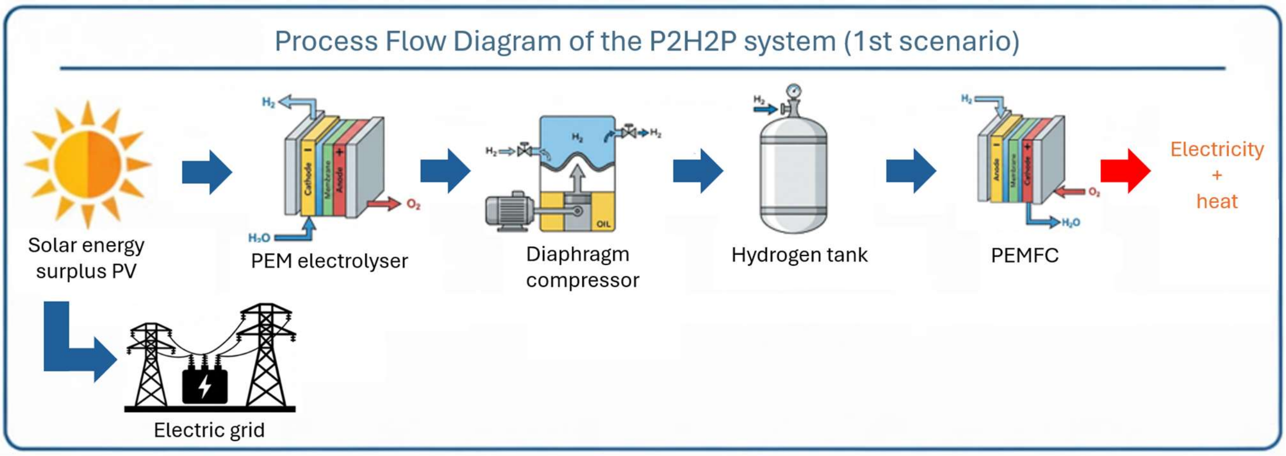


Figure 31: process flow diagram linked to the first scenario; compared to the configuration of the single company "La Cerea", the grid has been added to the diagram, which will supply electricity to the electrolyser.

As regards the size of the electrolyser, a specific consumption of 50 kWh/kg was assumed. In line with previous analyses, it was decided not to use the entire available photovoltaic surplus: although production peaks reach values significantly higher than 260 kW, they are too sporadic to justify investment in excessive nominal capacity. In fact, sizing based on maximum peaks would result in a low utilisation factor for the equipment, penalising the economic sustainability of the project.

In addition, the size of the system was optimised by favouring the thermal production of the fuel cell; in fact, analysis of consumption data provided directly by the managers of the “La Cerea” farm showed an annual consumption of approximately 1,500 litres of diesel for heating; considering a calorific value of diesel of approximately 10.5 kWh/l, a total thermal requirement of approximately 15,750 thermal kWh/year was estimated. The thermal potential recoverable from the fuel cell was therefore calculated using the following equation:

$$Thermal\ energy\ produced = LHV_{H2} * thermal\ efficiency * hydrogen\ mass \quad \textbf{EQ.38}$$

Assuming a thermal efficiency of 35% for the fuel cell and referring to the lower heating value (LHV) of hydrogen, it was possible to determine the thermal energy recoverable from the cogeneration process.

The size of the electrolyser was then set with the aim of ensuring sufficient hydrogen production to cover the entire thermal demand of one of the three companies in the community, equal to 15,750 kWh, completely replacing the current consumption of diesel fuel. To simulate the behaviour of the system and manage power peaks, the logical function “=IF (surplus >= 105; 105; surplus)". In this configuration, the nominal capacity of the electrolyser was increased to 105 kW (compared to 25 kW in the single case); this size represents the minimum value necessary to ensure annual thermal production that meets the set target, while optimising the use of the REC’s energy surplus.

On this basis, annual hydrogen production was calculated using **EQ.21**. Considering an amount of electricity that can actually be drawn from the photovoltaic surplus of 67,559 kWh/year, the total production is approximately 1,351 kgH2/year.

Subsequently, using **EQ.34**, the total thermal energy recoverable from the PEMFC system was estimated. The result, equal to approximately 15,762 kWh/year, confirms the validity of the sizing carried out: this value is in fact slightly higher than the set target of 15,750 kWh, ensuring the complete replacement of diesel fuel for the thermal requirements of the company in question.

The sizing of the buffer tank, operating at a pressure of 35 bar, was redesigned with the aim of optimising the compressor’s working cycles, minimising the mechanical stress resulting from excessive starts and stops. Despite the continuous operating regime assumed for this scenario, the integration of an intermediate storage volume remains a necessary design choice to ensure the stability of the entire process.

The parameters considered are the mass flow rate and the storage capacity required to cover a time span of approximately 2 hours. This interval ensures sufficient operating buffer to manage the hydrogen produced and to feed the compressor safely. The tank has the fundamental task of dampening the pressure pulsations induced by the compression cycle, ensuring stable and safe back-pressure for the PEM electrolyser membranes.

From a quantitative point of view, considering a flow rate of 0.76 kg/h, obtained using **EQ.23**, the system can store approximately 1.5 kg of hydrogen in two hours. At the established operating pressure, this requires a volume of approximately 0.5 m3, obtained using **EQ.30**.

For the sizing of the compressor, on the other hand, using the previously calculated specific consumption (1.51 kWh/kg), the energy required to compress the hydrogen (in kWh) and consequently the power of the compressor can be determined using **EQ.26**, which is approximately 1.2 kW.

The sizing of the second storage system (Tank IV) plays a crucial role: it can no longer be considered a simple "lung" of reduced size as in the previous case study, as it must compensate for the meteorological variability of the "winter" period, which has been assumed to be 211 days, starting on 1st October and ending on 30th April. During this time window, any prolonged periods of low irradiation or peaks in thermal demand could compromise the operational continuity of the PEMFC; storage must therefore be able to accumulate the hydrogen produced during the "summer" period, from 1 May to 30 September, to make it available during the "winter" period.

In fact, another determining factor for sizing is the seasonality of the load: the fuel cell operates exclusively during the 211 days defined by the heating season, remaining inactive during the summer when there is no heating requirement.

Through the analysis of hourly data on an annual basis, the energy surplus in the summer period has been quantified, corresponding to a hydrogen production of approximately 884 kg. This quantity represents the stock necessary to guarantee part of the thermal demand coverage during the "winter" season, acting as a seasonal storage system. It should be noted that once the "winter" season begins, the tank will empty, but at the same time it will be filled with the hydrogen produced during that period, to guarantee all the thermal energy required by the company. Applying **EQ.30**, the storage tank (Type IV tank) was then sized, defining a geometric volume of approximately 28.5 m³.

The last component of the system, the PEMFC, was sized according to the maximum hydrogen flow rate from the tank and the daily thermal load required over 211 days. The latter, equal to approximately 75 kWh/day, requires a mass of hydrogen for its generation that can be determined according to the following relationship:

$$Hydrogen\, mass = Energy\, needed/(LHV_{H2} * thermal\, efficiency) \quad \textbf{EQ.39}$$

The daily hydrogen requirement to power the PEMFC is estimated at approximately 6.4 kg. Assuming steady-state operation (24 hours a day, for the 211 days of the "winter" period), the mass flow rate calculated using **EQ.23** is 0.27 kg/h. This value allows us to determine a nominal electrical power of the PEMFC of 5 kW (**EQ.28**) and a thermal power of 3.1 kW, obtained from the following relationship:

$$Thermal\, power = LHV_{H2} * thermal\, efficiency * mass\, flow\, rate \quad \textbf{EQ.40}$$

This data is fundamental for sizing the last component of the system: the Hot Water Tank (or thermal storage tank), which is essential for interfacing between the fuel cell and the end user and it's sized to store the thermal energy produced daily.

The parameters used for the calculation are the thermal energy required (Q), equal to 75 kWh/day; the specific heat of water (c_p), assumed to be 1.16 Wh/kg*K, and the useful temperature difference ΔT, which represents the temperature differential between the supply and return circuits. The mass of water required was then determined using the following equation:

$$Water\ mass = \frac{Q}{c_p * \Delta T} \quad \textbf{EQ.41}$$

The calculation returns a total water mass of approximately 1,610 kg. This system allows heat to be stored during periods of constant production and released according to peaks in demand, ensuring thermal stability in the heating circuit and eliminating energy waste.

5.3 Economic assessment of the plant (1st scenario)

Similar to what was outlined in CHAPTER 4, we will now proceed to assess the economic sustainability of this first operational scenario for the REC.

The operational strategy defined for scenario 1 is methodologically consistent with the analysis presented in the previous chapter but evolves towards an optimised configuration for cogeneration heat recovery. This approach not only aims at decarbonising consumption but is also structured to maximise the benefits deriving from the current incentive framework for RECs. In particular, the analysis integrates the Premium Tariff on shared energy, the ARERA valorisation fees and the capital contribution provided for by the NRRP funds.

The economic analysis follows the structure of the models described above, but includes the operational savings generated by PEMFC cogeneration. The latter, by providing heat with low environmental impact, allows for a direct reduction in the costs of supplying agricultural diesel, significantly improving the project's profitability indicators.

In addition to classic indicators such as CAPEX, OPEX, LCOH and the Payback Period, the analysis will include the calculation of the Net Present Value (NPV), a fundamental parameter for determining the real profitability of the investment over the entire time horizon of the project.

5.3.1 CAPEX (1st scenario)

Here is presented the table that shows the investment costs:

CAPEX							
Equipment	Unite measure	Quantity	Cost parameter	Equipment cost	BoP cost	Installation cost	Total cost
PEM ELECTOLYZER	kW	105	1,700 €/kW	178,500 €	35,700.0 €	32,130.00 €	246,330.00 €
BUFFER TANK	m^3	0.5	3,476.64 €/m^3	1,738.32 €	347.7 €	312.90 €	2,398.88 €
DIAPHRAGM COMPRESSOR	kW	1.2	10,099.72 €/kW	12,120 €	2,423.9 €	2,181.54 €	16,725.14 €
TYPE IV TANK	m^3	28.5	3,128 €/m^3	89,150 €	17,829.9 €	16,046.94 €	123,026.57 €
PEMFC	kW	5	2,600 €/kW	13,000 €	2,600.0 €	2,340.00 €	17,940.00 €
PEMFC therm	kW	3	18 €/kW	54	2500	623.10 €	4,777.10 €
Hot water tank	l	1,600	1 €/l	1,600 €	-		
TOTAL CAPEX							411,197.70 €
							277,757.70 €

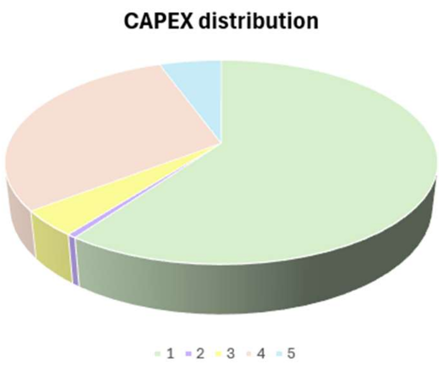
Table 7: analysis of investment expenditure (CAPEX) for the REC system comprising the three companies "La Cerea", "Risolero" and "Agrisapori", concerning 1st scenario; the data was processed using Excel.

The economic assessment includes the costs relating to the thermal section of the PEMFC. Specifically, the investment includes the heat exchanger, whose cost has been estimated at €18/kW based on average market prices, and the hot water tank, valued at approximately €1,600 (consistent with the previously calculated capacity of 1,600 litres). Including the items relating to the Balance of Plant (BoP) and installation costs, the total cost for the integration of the thermal system amounts to approximately €4,777. This figure represents the investment required to transform the fuel cell into a cogeneration system capable of serving the company's utilities.

In addition, a reduction in the specific cost of the electrolyser has been applied, bringing it to €1,700/kW. This decrease of €100/kW compared to the parameters in CHAPTER 4 is justified by economies of scale: the nominal power of the system has more than quadrupled, allowing for a reduction in the unit cost of the investment.

The total investment amounts to approximately €411,197. However, thanks to the non-repayable grant provided for in the NRRP, the actual CAPEX to be borne by the REC is reduced to approximately €277,757. The grant was calculated taking into account the limits related to the hydrogen production capacity of the plant shown in Table 7, which reaches a total capacity of 111.2 kW; consequently, as this installed capacity is between 20 and 200 kW, it has been calculated that the maximum grant obtainable is approximately €133,440, which represents approximately 32% of the original CAPEX.

As shown in Figure 32, the breakdown of investment costs shows that, in this configuration, the economic impact of the storage tank (Type IV) is greater than that of the PEMFC. This imbalance is a direct consequence of the sizing required to ensure seasonal hydrogen storage: the high storage volume is in fact a fundamental requirement to ensure the complete replacement of diesel as a heat carrier during the winter months, although it does entail an increase in CAPEX:



PEM ELECTROLYZER	60%
PEM FUEL CELL	5%
DIAPHRAGM COMPRESSOR	4%
TYPE IV TANK	30%
BUFFER TANK	1%

Figure 32: percentage breakdown of investment costs for each component of the REC plant; once again, the electrolyser is the most expensive piece of equipment; the data was processed using Excel.

5.3.2 OPEX (1st scenario)

PEM ELECTROLYZER	70000.00	Operational lifetime (h)
	1777.00	Annual operating hours (h)
	39.39	Equivalent years (y)
	89250.00	Replacement cost (€)
	5.95	Annual water cost (€)
	7389.90	Operation and Maintenance cost (€)
	9661.52	**Annual OPEX (€)**
BUFFER TANK	**200.00**	**Annual inspections (€)**
DIAPHRAGM COMPRESSOR	80000.00	Operational lifetime (h)
	1777.00	Annual operating hours (h)
	45.02	Equivalent years (y)
	6059.83	Replacement cost (€)
	2043.75	Annual energetic cost (€)
	501.75	Operation and Maintenance cost (€)
	2680.10	**Annual OPEX (€)**
TYPE IV TANK	**1230.27**	**Annual inspections (€)**
PEMFC	50000.00	Operational lifetime (h)
	5064.00	Annual operating hours (h)
	9.87	Equivalent years (y)
	6500.00	Replacement cost (€)
	538.20	Operation and Maintenance cost (€)
	0.32	Annual water cost (€)
	1196.52	**Annual OPEX (€)**
OPEX	**14968.41**	**TOTAL OPEX (€)**

Table 8: analysis of annual operating costs, inspections and replacement costs for the electrolyser, compressor and fuel cell for the 1st scenario; the data was processed using Excel.

In the analysis of operating costs (OPEX) relating to this first scenario, an expense item was introduced concerning the water supply for filling the hot water tank. However, this cost is marginal, amounting to approximately €0.32 per year.

Regarding the maintenance and inspection costs of the high-pressure tank (Type IV), the estimation methodology has been refined compared to CHAPTER 4. The cost of annual inspections has been conservatively calculated as 1% of the total CAPEX of the compression and storage system, resulting in an annual operating cost of approximately €1,230. This increase reflects the greater management complexity and safety requirements associated with the volume of hydrogen stored in the energy community configuration.

5.3.3 LCOH (1st scenario)

The **EQ.35** can be used to recalculate the costs for hydrogen levelling, which are summarised in this table:

LCOH			
Year	Discounted hydrogen mass (kg)	Discounted annual OPEX (€)	Discount rate
1	1274.71	14121.14	0.06
2	1202.55	13321.83	Annual hydrogen production (kg)
3	1134.48	12567.77	1351.19
4	1070.27	11856.38	Cumulative discounted hydrogen mass (kg)
5	1009.69	11185.27	15498.03
6	952.53	10552.14	Cumulative discounted OPEX (€)
7	898.62	9954.85	171686.48
8	847.75	9391.37	**LCOH (€/kgH2)**
9	799.77	8859.78	**29.00**
10	754.50	8358.28	
11	711.79	7885.17	
12	671.50	7438.84	
13	633.49	7017.77	
14	597.63	6620.54	
15	563.80	6245.79	
16	531.89	5892.26	
17	501.78	5558.73	
18	473.38	5244.09	
19	446.59	4947.25	
20	421.31	4667.22	

Table 7: calculation of the Levelised Cost Of Hydrogen linked to the discount rate, total annual hydrogen production, OPEX and CAPEX for the 1st scenario; the data was processed in Excel.

The analysis returns an LCOH value of €29.00/kgH_2. This result highlights the persistent economic challenges of Scenario 1: despite the integration of capital incentives (NRRP non-repayable grant) and the adoption of an electrolyser larger than 100 kW, the Levelised Cost Of Hydrogen remains significantly higher than market benchmarks.

Although annual production has grown significantly compared to the single case (from 367 kg to 1,351 kg), the plant utilisation factor, limited to only 1,777 operating hours per year, is not sufficient to dilute the impact of fixed costs. Since LCOH is closely dependent on CAPEX and OPEX (both of which have increased significantly in this configuration), the increase in production fails to offset the initial economic outlay, despite the mitigation offered by incentives.

In conclusion, although there is an improvement compared to the results in CHAPTER 4, the analysis confirms that government incentives alone are not sufficient to ensure the competitiveness of the carrier; it therefore appears necessary to increase the operating hours of the system or explore more advanced energy sharing models.

5.3.4 Payback Period and Net Present Value (1st scenario)

To estimate the payback period, **EQ.36** and **EQ.37** were applied again, integrating the benefits deriving from the premium tariff and ARERA fees into the cash inflows; in particular, for the premium tariff, the maximum value of €120/MWh was assumed (as indicated in Table 3), to which the ARERA incentives are added, estimated for 2024 at approximately €10.57/MWh for shared energy [62]. The total gross benefit is therefore €130.57/MWh. However, in accordance with current legislation, this incentive must be reduced due to its accumulation with the NRRP non-repayable grant.

Using **EQ.22**, the correction factor is calculated since CAPEX was able to take advantage of 39.5% of the incentives, and consequently the premium tariff will have an F factor of 0.395, thus obtaining a net tariff of €78.65/MWh.

Considering a volume of shared energy in the grid of 14,703 kWh, the annual revenue from incentives amounts to approximately €1,300.

Additional positive economic flows derive from fossil fuel savings. Replacing traditional boilers with fuel cell heat recovery avoids the consumption of 1,500 litres of agricultural diesel per year. Considering an average price of agricultural diesel of €0.9/l, the operating savings generated by not purchasing fuel amount to approximately €1,350 per year [82].

Added to this value are savings linked to the purchase of electricity from the national grid. By using the energy produced directly by the PEMFC (approximately 24,770 kWh/year) to cover the companies' needs, there is no need to draw from the grid. Valuing this energy at the estimated average market price of 0.22 €/kWh, the avoided cost (i.e. net savings on the bill) is approximately €5,450 per year.

Adding up the three items of revenue and savings analysed, we obtain a positive gross economic flow of approximately €8,095/year. However, in line with what has already emerged in CHAPTER 4, this value is not sufficient to fully cover the high operating costs (OPEX) of the system.

The application of **EQ.37** returns a negative value, confirming that, in this specific configuration, the system is not able to generate an operating profit.

Considering the results obtained, it can be seen that the system is unable to generate positive cash flows. Since the payback period was negative, the Net Present Value (NPV) calculation was not taken into consideration, as it is an indicator based on the discounting of future profits over the useful life of the plant, which does not apply in a context of constant operating losses. In this configuration, not only is the investment not recovered, but it generates a deficit that increases over time. This analysis confirms the economic unsustainability of a hydrogen system powered entirely by the energy surplus given by the PV plant, making further assessment of the net return on capital unnecessary.

5.4 Assessment of CO_2 avoided (1st scenario)

The analysis of avoided greenhouse gas (GHG) emissions is the main strength of this scenario. The environmental benefit derives primarily from the complete replacement of 1,500 litres of agricultural diesel fuel through the use of the PEMFC. Considering an emission factor of 2.64 $kgCO_{2eq}/l$, this intervention avoids the release of approximately 4 tonnes of CO_{2eq} into the atmosphere per year.

Added to this contribution are the savings deriving from the self-consumption of renewable electricity which, by avoiding withdrawal from the national grid, further reduces the system's carbon footprint.

Assuming an average emission factor for the Italian electricity grid of 215.9 gCO_{2eq}/kWh, a reduction of approximately 5.34 tonnes of CO_{2eq} is estimated.

Overall, the system avoids the emission of approximately 9.34 tonnes of CO_{2eq} per year. This result is of fundamental importance as it establishes the classification of the product vector as green hydrogen, ensuring full compliance with the environmental sustainability requirements and emission reduction thresholds imposed by the CACER Decree and the relevant European legislation.

5.5 Technical modelling of the P2G plant (2nd scenario)

The second scenario introduces a substantial change in the management of energy priorities within the Renewable Energy Community. In this configuration, locally produced photovoltaic energy is prioritised for direct supply to the PEM electrolyser. Excess energy (i.e., energy that the system is unable to convert into hydrogen due to the nominal capacity constraints of the electrolyser) is fed into the national grid, contributing to the valorisation of shared energy. From a technical point of view, the plant architecture remains consistent with the configuration described in the previous scenario, as summarised in the following operating diagram:

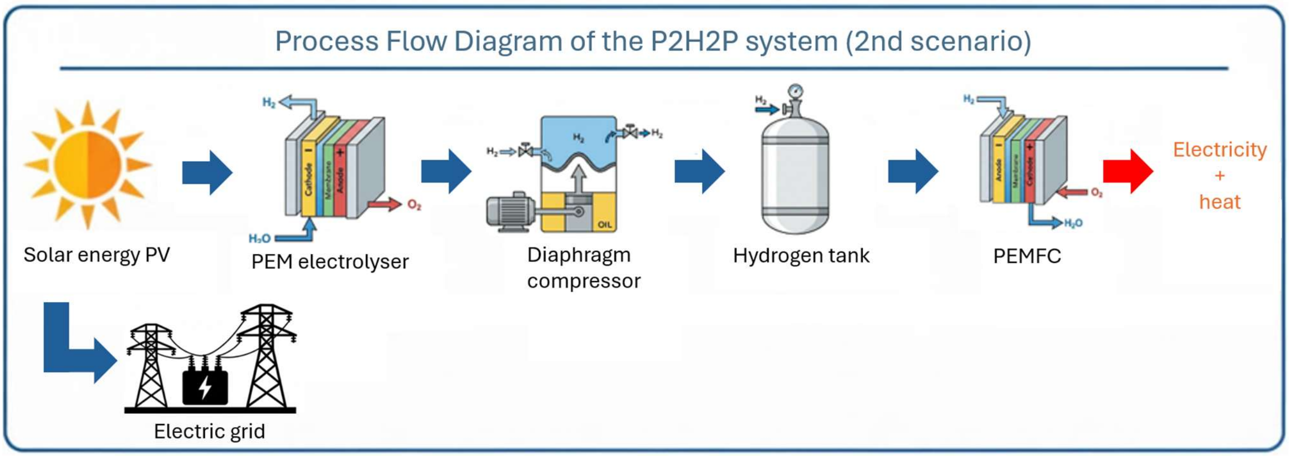


Figure 33: process flow diagram linked to the second scenario; compared to the last scenario, the grid has been added to the diagram, which will receive surplus electricity from the photovoltaic system, that isn't used for the electrolyser.

To accurately estimate the energy that can actually be absorbed, an hourly database was constructed on an annual basis. This operation required a tabular calculation to harmonise data from different sources; in fact, for the Risolero and Agrisapori companies, the generation data was extracted from the PVGIS database with hourly resolution, while for La Cerea, the available data had a resolution of 6 minutes (10 samples per hour).

To add up the profiles, it was necessary to bring the data for La Cerea to the same time scale as the others. The tabular calculation involved taking the arithmetic mean of the 10 6-minute samples for each solar hour, thus obtaining an average hourly power consistent with the rest of the dataset. Once the "Total REC Generation" column was obtained, the "SUM" logarithmic function was applied to obtain the total energy obtainable from the three plants, which, as seen previously, is approximately 325,336 kWh.

The same energy management strategy was then applied to the system; in fact, as described in the previous scenario, the operational strategy is based on the seasonal storage of hydrogen produced during the summer months to meet the thermal demand of the PEMFC during the 211-day winter period.

The substantial discontinuity lies in the electrolyser's energy input: in this configuration, the system no longer draws solely on surplus energy, but on the entire aggregate photovoltaic production (325,336 kWh/year). This approach aims to completely decarbonise the heating processes of the three agricultural users that make up the REC. Assuming homogeneous consumption profiles (equal to 1,500 litres of diesel per year per farm), the total requirement to be met amounts to 4,500 litres of diesel. Consequently, the system is designed to generate a thermal output from the fuel cell of approximately 47,250 thermal kWh, ensuring the total replacement of fossil fuels for the entire community.

Consequently, for the actual behaviour of the electrolyser, the Excel command "=IF(surplus >= 65; 65; surplus)", replacing the 105 kW with 65 kW of the model chosen for the three companies. Thanks to this simulation, it was possible to calculate that the electrolyser will operate for approximately 4,199 hours/year, managing to convert into hydrogen only the amount of energy compatible with its technological size and ensuring the sustainability of the subsequent thermal process.

This strategy allows to produce approximately 4,354 kg of hydrogen per year, using about 217,000 kWh, with which the fuel cell is able to generate approximately 50,800 thermal kWh. This production is slightly higher than the set target, ensuring a safety margin that is essential for the energy resilience of the users involved and, at the same time, minimising the investment costs (CAPEX) associated with the size of the electrolyser.

Obviously, the failure to use almost 108,000 kWh of solar energy does not represent a net loss for the company: it is in fact fed back into the grid or accounted for to increase the economic value deriving from the premium tariff, as will be detailed in the analysis of revenues in the following paragraphs.

The system configured in this way guarantees a hydrogen mass flow rate of approximately 0.94 kg/h, output from the electrolyser, which feeds the storage system (buffer tank), which has been sized with a capacity equivalent to two hours of electrolyser operation (approximately 2 kg of hydrogen); operating at a pressure of 35 bar, the tank requires a geometric volume of approximately 0.6 m^3. The compressor has also been sized considering the mass flow rate, achieving a power of approximately 1.5 kW (**EQ.29**).

The storage system, based on Type IV tank, was sized to accommodate the entire quantity of hydrogen produced during the summer season, estimated at approximately 2,285 kg. Although this value has a significant volumetric and logistical impact, storage of this size is essential for the technical feasibility of the second scenario, ensuring the necessary energy reserve to cover the REC's winter heating requirements.

For the sizing of the PEMFC, it was estimated that the REC would need approximately 223 kWh of heat per day over the 211 days; the amount of hydrogen needed to generate that energy from the

PEMFC is approximately 19.2 kg; this result was obtained using **EQ.39**, and considering a 24-hour period, the mass flow rate of hydrogen leaving Tank IV was estimated at approximately 0.8 kg/h. This parameter is fundamental for the sizing of the PEMFC; in fact, by applying **EQ.31**, it was possible to determine the nominal power of the fuel cell, which stands at approximately 15 kW.

As for the other elements of the system, the configuration follows that of the first scenario, thus obtaining a nominal power of the compressor of approximately 1.5 kW, while the hot water tank maintains a capacity of 4,850 litres, which is the ideal size for managing the gradual release of heat produced by the fuel cell to agricultural users.

5.6 Economic assessment of the P2H2P plant (2nd scenario)

The economic analysis of the second scenario follows the same methodological structure as the previous case, but is developed on a different energy scale. The increase in processed electricity and the tripling of replaced diesel fuel (from 1,500 to 4,500 litres per year) suggest a potential improvement in the project's profitability. Although the need for significantly larger storage capacity entails an increase in CAPEX related to the Type IV tank, this cost is offset by a significantly higher volume of revenues and operating savings. In this configuration, in fact, the amortisation of fixed costs is distributed over a greater quantity of thermal energy and hydrogen produced, making the scenario potentially more favourable from an economic point of view.

Consequently, by analysing the indicators already used (CAPEX, OPEX, LCOH and Payback Period), we aim to verify whether the reduction in variable costs ultimately allows us to achieve a positive Net Present Value (NPV). In this context, NPV becomes the crucial parameter for confirming whether the project, once freed from energy dependence on the grid, is capable of generating real value over the entire time horizon considered.

5.6.1 CAPEX (2nd scenario)

CAPEX							
Equipment	Unite measure	Quantity	Cost parameter	Equipment cost	BoP cost	Installation cost	Total cost
PEM ELECTOLYZER	kW	65	1,700 €/kW	110,500 €	22,100.0 €	19,890.00 €	152,490.00 €
BUFFER TANK	m^3	0.6	3,232.12 €/m^3	1,939.27 €	387.9 €	349.07 €	2,676.19 €
DIAPHRAGM COMPRESSOR	kW	1.5	9,237.30 €/kW	13,856 €	2,771.2 €	2,494.07 €	19,121.23 €
TYPE IV TANK	m^3	73.5	2,142.27 €/m^3	157,457 €	31,491.4 €	28,342.30 €	217,290.94 €
PEMFC	kW	15	2,600 €/kW	39,000 €	7,800.0 €	7,020.00 €	53,820.00 €
PEMFC therm	kW	11	18 €/kW	198.00 €	2,500.00 €	1,132.20 €	8,680.20 €
Hot water tank	l	4,850	1 €/l	4,850 €	-		
TOTAL CAPEX							454,078.56 €
							356,278.56 €

Table 10: analysis of investment expenditure (CAPEX) for the REC system comprising the three companies "La Cerea", "Risolero" and "Agrisapori", concerning the 2nd scenario; the data was processed using Excel.

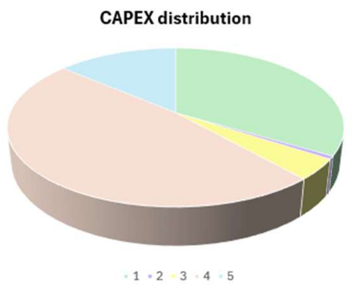
As shown in the summary table, the initial investment for the second scenario don't varies too much from the previous configuration, with regard to non-incentivised investments.

The most significant differences in the cost structure between the two scenarios stem from the substantial change in the size of the main components. Firstly, the Type IV tank emerges as the predominant expense item, with a total investment of approximately €217,290; this component thus becomes the most expensive part of the entire system, reflecting the economic impact of high-pressure seasonal storage.

This is followed by the electrolyser, whose 65-kW technological size entails a total cost of approximately €152,500. The power of the PEMFC has been optimised to 15 kW, which is three times higher than the previous configuration, thus leading to a proportional increase in cost.

At the same time, the cost of the buffer tank has also been recalculated based on the volumes necessary to guarantee the thermal autonomy required by the case study.

Considering access to incentive mechanisms (NRRP), and evaluating that the total installed capacity of the hydrogen plant is 81.5 kW, the accessible contribution is approximately €97,800, or 21% of the original CAPEX, which is therefore reduced to €356,300, that is €78,000 higher than the one associated to the first scenario:



PEM ELECTROLYZER	34%
PEM FUEL CELL	13%
DIAPHRAGM COMPRESSOR	4%
TYPE IV TANK	48%
BUFFER TANK	1%

Figure 34: percentage breakdown of investment costs for each component of the REC plant; this time, the high capacity of the Type IV tank brings it to be the most expensive equipment of the plant; the data was processed using Excel.

5.6.2 OPEX (2nd scenario)

PEM ELECTROLYZER	70000.00	Operational lifetime (h)
	4199.00	Annual operating hours (h)
	16.67	Equivalent years (y)
	55250.00	Replacement cost (€)
	19.16	Annual water cost (€)
	4574.70	Operation and Maintenance cost (€)
	0.00	Annual energetic cost (€)
	7908.07	**Annual OPEX (€)**
BUFFER TANK	**200.00**	**Annual inspections (€)**
DIAPHRAGM COMPRESSOR	80000.00	Operational lifetime (h)
	4390.03	Annual operating hours (h)
	18.22	Equivalent years (y)
	6927.98	Replacement cost (€)
	1448.71	Annual energetic cost (€)
	573.64	Operation and Maintenance cost (€)
	2402.52	**Annual OPEX (€)**
TYPE IV TANK	**2172.91**	**Annual inspections (€)**
PEMFC	50000.00	Operational lifetime (h)
	5064.00	Annual operating hours (h)
	9.87	Equivalent years (y)
	19599.00	Replacement cost (€)
	1614.60	Operation and Maintenance cost (€)
	0.97 €	Annual water cost (€)
	3600.56	**Annual OPEX (€)**
OPEX	**16284.06**	**TOTAL OPEX (€)**

Table 8: analysis of annual operating costs, inspections and replacement costs for the electrolyser, compressor and fuel cell for 2nd scenario; the data was processed using Excel.

The OPEX analysis for the second scenario reflects the dimensional evolution of the system. The greater availability of photovoltaic energy, distributed more efficiently throughout the year, has made it possible to significantly increase the load factor of the main components. Specifically, the operating hours of the electrolyser and compressor have tripled compared to the previous configuration. On the contrary, the operating regime of the PEMFC has remained unchanged (5,064 hours, corresponding to 211 days in the winter period), in line with the objective of meeting the set seasonal thermal demand.

The expansion of the system led to a natural increase in certain items of expenditure, such as the maintenance of type IV tank, which increased by approximately €1,000 compared to the first scenario, due to the increase in CAEPX and the replacement costs of the PEMFC, which increased proportionally due to the increase in nominal installed capacity.

Despite these increases, the total OPEX of €16,284 does not show linear growth in relation to production: the operational efficiency achieved suggests that the impact of these costs on the final LCOH value will be mitigated by economies of scale, favouring greater economic sustainability of the vector produced.

5.6.3 LCOH (2nd scenario)

LCOH			
Year	Discounted hydrogen mass (kg)	Discounted annual OPEX (€)	Discount rate
1	4107.61	15362.32	0.06
2	3875.10	14492.75	Annual hydrogen production (kg)
3	3655.76	13672.41	4354.06
4	3448.83	12898.50	Cumulative discounted hydrogen mass (kg)
5	3253.61	12168.40	49940.77
6	3069.44	11479.62	Cumulative discounted OPEX (€)
7	2895.70	10829.83	186776.86
8	2731.79	10216.82	**LCOH (€/kgH2)**
9	2577.16	9638.51	**10.87**
10	2431.29	9092.93	
11	2293.67	8578.24	
12	2163.84	8092.68	
13	2041.36	7634.60	
14	1925.81	7202.45	
15	1816.80	6794.77	
16	1713.96	6410.16	
17	1616.94	6047.32	
18	1525.42	5705.02	
19	1439.07	5382.09	
20	1357.62	5077.45	

Table 9: calculation of the Levelised Cost Of Hydrogen linked to the discount rate, total annual hydrogen production, OPEX and CAPEX for 2nd scenario; the data was processed in Excel.

The Levelised Cost of Hydrogen (LCOH) calculated for this scenario confirms the effectiveness of the strategy based on direct integration of photovoltaics and seasonal storage. The value obtained, equal to €10.87/kgH_2, is almost three times lower than the previous configuration, marking a clear improvement in the economic sustainability of the system.

This progress is mainly attributable to the optimisation of the electrolyser utilisation factor: the increase in operating hours (from 1,777 to 4,199 hours per year) has made it possible to increase hydrogen production in a manner that is more than proportional to the increase in initial investment.

The economies of scale generated by the higher volume of hydrogen produced have made it possible to dilute the impact of CAPEX (despite the latter being much higher due to the oversizing of storage), drastically reducing the unit cost of green fuel.

Although the value remains higher than traditional fossil fuels, an LCOH of €10.87/kg is encouraging for the future of hydrogen plants in agriculture, placing the project in a pre-competitive market range, if support instruments such as the NRRP non-repayable grant are available.

Ultimately, this scenario demonstrates that the economic sustainability of green hydrogen is not an abstract hypothesis, but a reality that can be achieved through proper planning of self-consumption and the promotion of cogeneration.

5.6.4 Payback Period (2nd scenario)

To estimate the payback period, **EQ.36** and **EQ.37** were applied again, integrating the cash flows deriving from incentives and operational savings. As in the previous configuration, the premium tariff and ARERA fees (equal to a gross amount of €130.57/MWh) were adjusted using **EQ.22** to consider the accumulation with the NRRP funds, which in this scenario amounts to 22% of total CAPEX, bringing the F value to 0.22, thus obtaining a net tariff value of approximately €102/MWh.

In this scenario, the share of shared energy benefiting from this incentive generates an annual revenue of approximately €10,967. Added to this are the direct savings already analysed: the thermal savings, due to the non-purchase of 4,500 litres of agricultural diesel, which thus entails a lower expenditure of €4,050/year, and the avoided electricity cost, due to the energy generated by the PEMFC and used for the company's needs (valued at €0.22/kWh), generates a net saving on the bill of €17,560/year.

Adding these three items together gives a gross positive cash flow of approximately €32,577 per year. Unlike the first scenario, this value is now well above the operating costs (OPEX) of the system, which amount to approximately €16,293 per year.

Subtracting operating costs (OPEX) from gross cash flow gives an annual net margin of approximately €13,112. By applying **EQ.37**, it was possible to determine a payback period of approximately 21 years. Unfortunately, this value does not fall within the 20-year time frame set by the GSE incentives, as the goal of generating profit within that time frame is not met. However, the transition from the structural economic deficit of the first scenario to a configuration capable of generating net profits, albeit not high enough to cover the initial costs, demonstrates how the integration of photovoltaics, hydrogen and heat recovery represents a technically feasible way to make PEM technology sustainable in the agricultural sector.

5.6.5 Net Present Value (2nd scenario)

To assess whether the investment will be profitable in the long term, the NPV (Net Present Value) was calculated. Unlike the simple Payback Period, this indicator allows us to determine whether the project will actually generate value, taking into account the cost of money over time and tax pressure.

To obtain a result that reflects the operational and regulatory reality, the calculation was divided into two phases. First, the annual Net Cash Flow (NCF_t) was determined by applying the following formula:

$$NCF_t = (R_t - OPEX_t) * (1 - \tau) + D_t * \tau \quad \textbf{EQ.42}$$

In this formula, the parameter R_t represents the revenue and savings generated which, when subtracted from the annual OPEX, returns the value of net earnings; τ, on the other hand, represents the overall tax rate, assumed to be 28%. This value reflects the average tax burden for corporations in Italy, derived from the sum of the national IRES tax (24%) and the regional IRAP tax (estimated at approximately 4%); while D_t indicates the depreciation of the plant components over a period of 20 years, corresponding to an annual rate of 5%, which allows for the tax shield generated by the recovery of the investment over the entire useful life of the plant to be taken into account.

Subsequently, the flows thus obtained were discounted to calculate the overall NPV:

$$NPV = -CAPEX + \sum_{t=1}^{N} \frac{CF_t}{(1+r)^t} \quad \textbf{EQ.43}$$

CAPEX is the net initial investment; r is the discount rate, set at 6%. This value was chosen as a reference for the WACC (Weighted Average Cost of Capital), consistent with the expected rates of return for the risk profile of investments in hydrogen infrastructure and renewable sources; N is the time horizon of the analysis, set at 20 years. The following table summarises the calculations described above:

VALUES	PARAMETERS	YEAR	NPV calculation
16284.06	OPEX (€)	0	-356,278.56 €
32636.39	Gross revenues (€)	1	15,812.81 €
17813.93	Depreciation (€)	2	14,917.75 €
0.28	Tax rate τ	3	14,073.35 €
16761.58	NFC (€)	4	13,276.74 €
0.06	Discount rate WACC	5	12,525.23 €
-164024.56	**Total NPV (€)**	6	11,816.25 €
		7	11,147.41 €
		8	10,516.42 €
		9	9,921.15 €
		10	9,359.58 €
		11	8,829.79 €
		12	8,329.99 €
		13	7,858.48 €
		14	7,413.66 €
		15	6,994.02 €
		16	6,598.13 €
		17	6,224.65 €
		18	5,872.32 €
		19	5,539.92 €
		20	5,226.34 €

Table 10: calculation of Net Present Value and cash flow projections over a 20-year time horizon for the P2H2P system.

The analytical analysis shows a negative NPV of approximately €-164,000. Although from a purely financial point of view this value indicates that the investment will not reach the break-even point within 20 years, as previously announced in the payback period analysis, the result should be interpreted with caution; in fact, as highlighted in the technical literature, NPV is a static parameter, which is strongly influenced by the choice of rate (r) and, moreover, does not highlight non-monetisable benefits, such as decarbonisation and energy independence, in its calculation. However, the dramatic improvement compared to scenario 1 remains evident, confirming that the second scenario lays the concrete foundations for the energy transition of the companies involved.

5.7 Assessment of CO_2 avoided (2nd scenario)

This second scenario complies with the requirements of the CACER decree, promoting the generation of green hydrogen in agriculture and delivering significant environmental benefits through the total replacement of fossil fuels. Specifically, avoiding the combustion of 4,500 litres of diesel results in a direct saving of approximately 11.88 tonnes of CO_2.

However, a more rigorous net emissions balance must account for the electricity that the farms must now withdraw from the national grid, to compensate for the solar energy diverted to the electrolyser. In this context, knowing that that the owner of "La Cerea" utilizes Guarantee of Origin (GO) certificates, his plant guarantees zero emissions, while for the other two farms (Risolero and Agrisapori), the grid electricity has been calculated using the average Italian emission factor (215.9 gCO_2/kWh).

Of the electrolysers' total consumption of 217,000 kWh, approximately 95,000 kWh are supplied by the photovoltaic system of the company "La Cerea" which ensures that the energy replaced by the P2H2P system is not polluting. The remaining 122,000 kWh, drawn from the electricity grid to meet the needs of the other two companies in the cluster, involve an indirect emission of approximately 26.4 tonnes of CO_2. On the other hand, the 80,000 kWh of electricity produced by the fuel cell in turn allows for CO_2 savings of approximately 17.23 tonnes, resulting in a total net balance of approximately 2.71 tonnes of CO_2 saved. Although this value is lower than in the first scenario, it represents a superior technological achievement, as it demonstrates the feasibility of complete thermal decarbonisation of utilities through a self-produced energy carrier.

By way of comparison, an annual saving of 2.7 tons is equivalent to the absorption capacity of a forest consisting of approximately 100 trees, confirming that the P2H2P system serves as a functional step toward the complete decarbonization of the agricultural cluster [83].

5.8 Discussion of the results of the two scenarios

The comparative analysis between the two scenarios highlights how the sustainability of an investment in the hydrogen economy is the result of a complex synergy between the incentive framework provided by the Italian State and the hydrogen utilisation strategies that companies employ to integrate it into their processes, exploiting it to the best of their ability.

In addition to the configurations analysed, technical literature and industrial practice suggest other ways of exploiting hydrogen, which, however, have been excluded from this study for reasons of agronomic and logistical consistency. One example is the conversion of hydrogen into ammonia for the creation of fertilisers; although this is a well-known strategy for the in-situ production of nitrogen fertilisers, this option was not feasible for the cluster of companies analysed. The three companies, in fact, adopt conservation agriculture methods, which drastically reduce the amount of chemical inputs to the soil. Therefore, self-production of fertilisers would not have generated sufficient economic savings to justify the necessary plant complexity.

The use of fuel cell or hydrogen internal combustion tractors was also considered, but this option was rejected due to the embryonic state of the market and the limited commercial availability of such vehicles. Furthermore, preliminary calculations showed that the hydrogen production envisaged by the system would be insufficient to cover the energy requirements of even three units, making the integration of such vehicles economically and technically unsustainable in the current configuration of the plant.

A potential additional source of income could have come from the sale of the oxygen produced during electrolysis. However, monetising this by-product would have required additional investment (CAPEX) in purification, compression and cryogenic storage systems, as well as the need to identify industrial or medical buyers in geographical proximity to the plant, which is currently not possible.

Ultimately, the proposed scenarios represent the most realistic and balanced solutions for the current context. Figure 35 and Figure 36 summarise the key results obtained, comparing the economic efficiency of the two systems analysed:

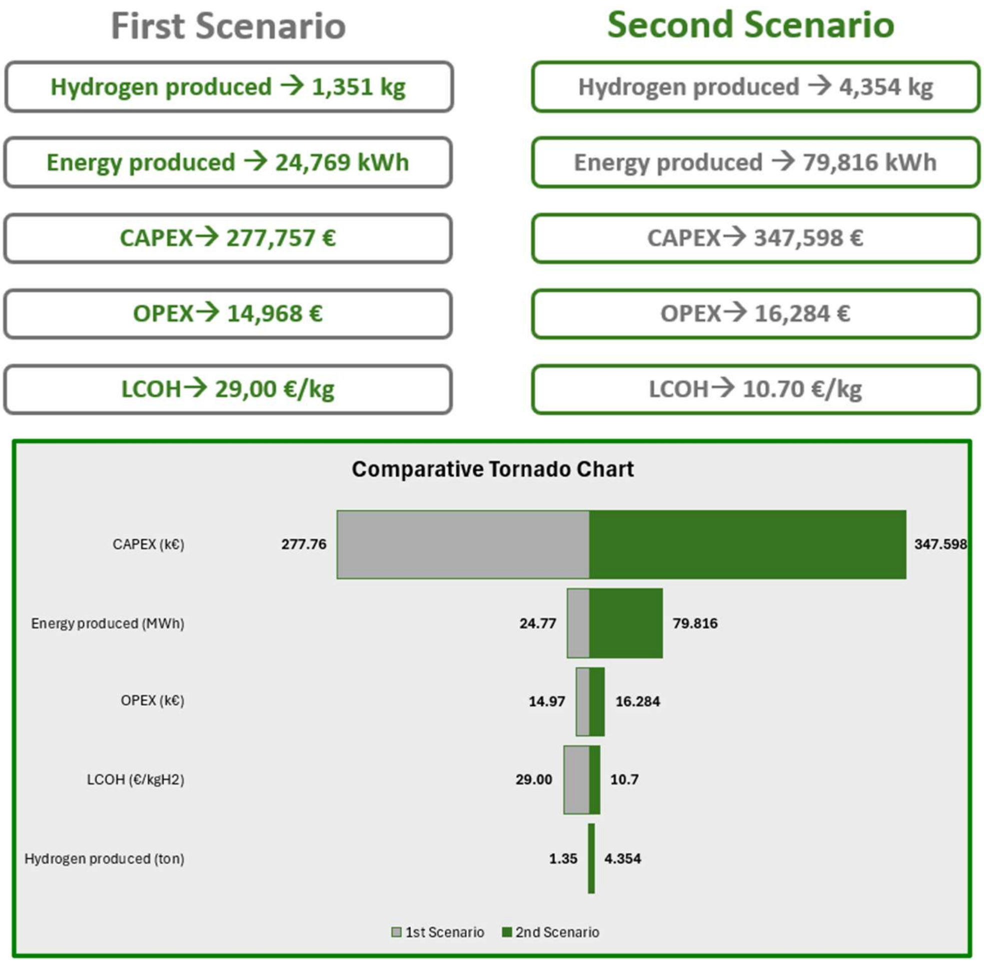


Figure 35: comparative analysis of the technical and economic results between the first scenario and the second scenario. The second image shows a tornado chart, which highlights which variables have the greatest impact on the profitability and sustainability of the project in the two case studies.

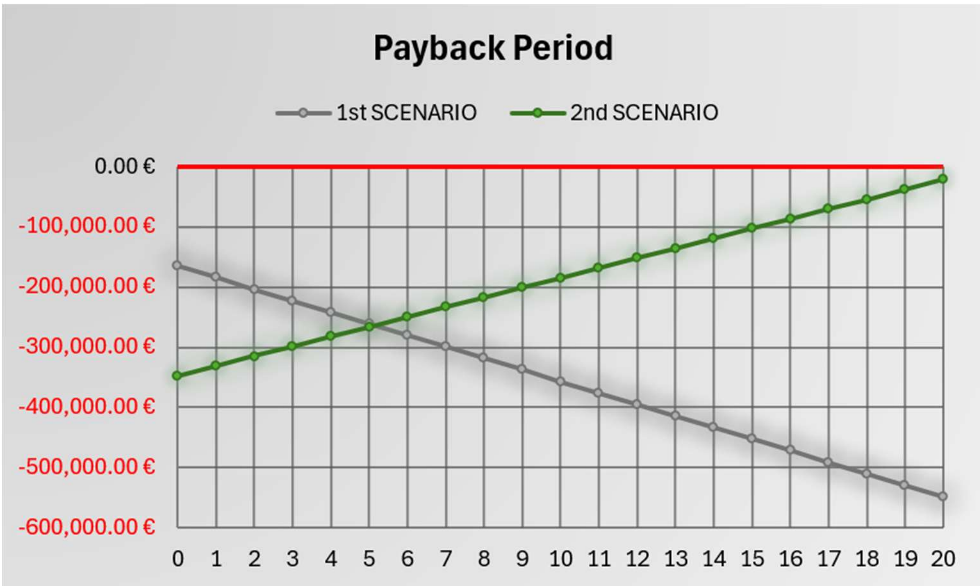


Figure 36: comparative analysis of the payback period for the two scenarios analysed above; the first scenario (grey), having a negative net cash flow, will never reach the red line, which represents the point at which the project begins to be economically profitable, while the second scenario (green) has a payback period of 21 years, over the limit with GSE incentives, and this can be seen that the green line is below the red line, right at the end of the x-axis.

To contextualise the results obtained from the two scenarios, it is appropriate to compare them with feasibility studies conducted in similar agricultural contexts in northern Europe. For example, a study of a 300-hectare Swedish cereal farm powered by wind energy calculated an LCOH ranging from 16 to 22.90 USD/kgH_2. The value obtained in this study is consistent with this range, confirming that for stand-alone or small-scale agricultural plants, the cost of green hydrogen is currently higher than that of diesel [84].

Another study, however, highlights two key factors that validate the conclusions of this thesis: the first concerns the effect of plant scale, which greatly influences the cost of hydrogen production; in fact, moving from a production of 50 kg/h to 500 kg/h, the LCOH drops dramatically. This explains why, in the case of La Cerea, despite a high unit LCOH, the investment requires a strategic approach based on incentives, as it cannot yet benefit from large industrial economies of scale.

Another important factor is the plant utilisation rate, which is inversely proportional to the cost of hydrogen. This fact was effectively demonstrated in the first scenario, where, with the same amount of usable energy, increasing the hours of production reduced the power of the electrolyser, which in turn led to a cut in initial costs:

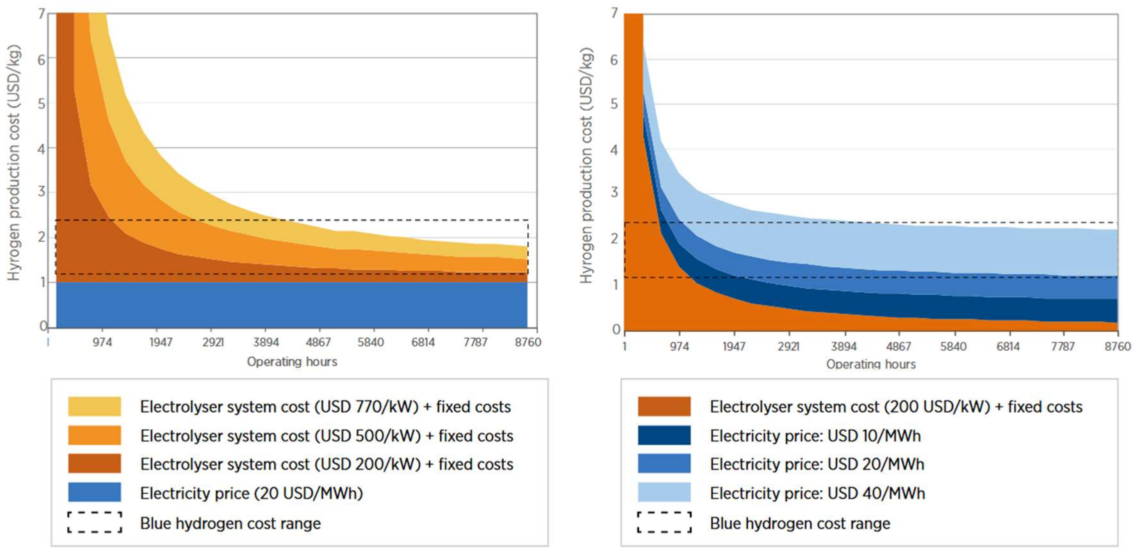


Figure 37: sensitivity analysis of hydrogen production cost (in USD/kg) as a function of operating hours, stack cost and electricity price. The graph on the left shows how, as the cost of the electrolyser decreases, the cost of hydrogen production also decreases, while in the image on the right, the cost of the electrolyser is kept fixed, while the cost of electricity (USD/MWh) varies, and it can be seen that at high operating hours, the cost of hydrogen production via electrolysers can be competitive compared to the cost range associated with blue hydrogen [18].

In conclusion, the result obtained for the Italian cluster of the three farms is not only "good" but represents a realistic transition scenario. As highlighted by Cranfield researchers and Swedish case studies, green hydrogen in agriculture is not yet fully competitive with fossil fuels on a purely economic basis, but it becomes so when environmental externalities (such as the 29.11 tonnes avoided) and protection from fossil fuel price volatility, which is estimated to increase significantly in the coming decades, are taken into account [4].

CHAPTER 6: Future developments for green hydrogen

The path to decarbonisation of the agricultural sector through green hydrogen, analysed in the previous chapters through the case study of the three companies, provides an accurate snapshot of a technology in a crucial transition phase. In fact, although current technical and economic analyses highlight significant challenges, mainly related to investment costs (CAPEX) and production costs (LCOH), which are still far from parity with other energy production technologies, the results obtained should not be considered as a static limit, but as the basis for a model destined to evolve rapidly.

In fact, the global outlook outlined in the latest strategic documents, such as the International Energy Agency's "Global Hydrogen Review 2025" (also called IEA) and the "Green Hydrogen Cost Reduction" report of International Renewable Energy Agency (IRENA), confirm that the sector is on the verge of unprecedented acceleration. While the IEA highlights a few rapidly growing projects and demand that is beginning to take shape on an increasingly global scale, IRENA estimates that green hydrogen production costs could fall by up to 85% in the long term. However, this decline will have to be driven by a combination of low-cost renewable electricity and, above all, a drastic reduction in the cost of electrolysis systems, thanks to economies of scale and standardisation of production processes:

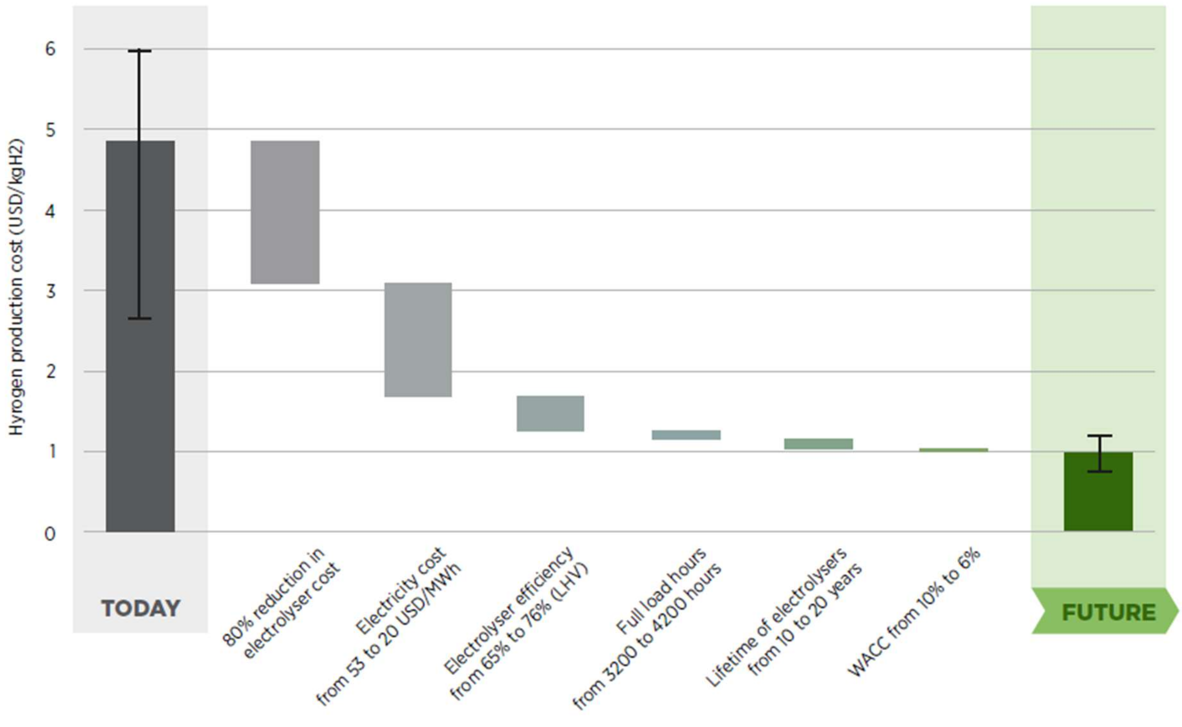


Figure 38: analysis of factors related to the cost of hydrogen production (LCOH): it is estimated that by increasing the efficiency of electrolysers, lowering the cost of electricity and the cost of producing the electrolysers themselves, and improving their quality of life, it will be possible to achieve an LCOH of around 1 USD/kgH₂ produced in the future [18].

In this context, the effectiveness of integrated systems for agriculture, such as the one studied for the Italian cluster, is set to improve significantly in the coming years. The consolidation of hydrogen as a pillar of agricultural energy resilience will depend on various factors, which will be analysed in this chapter. Among these, technological innovations play a central role, aimed at overcoming the current limitations of generation systems, starting with technical improvements that will affect the technological heart of the entire process: the electrolyser [18], [77].

6.1 Technical improvement of PEM electrolysers

The future of green hydrogen depends primarily on the performance of electrolysers, whose technological evolution is currently at the heart of global research and development (R&D) strategies. However, optimising these systems is not a linear process, but is governed by a complex network of interdependencies and technical compromises.

Innovation strategies are divided into four main objectives, which must be balanced to ensure the economic sustainability of the technology. These are: increasing efficiency at the cell and stack level, so as to reduce operating costs for the same amount of hydrogen produced; increasing current density (measurable in A/m^2), which is also linked to hydrogen production; extending durability, with an estimated target for 2050 of at least 100,000 hours of operation; reducing CAPEX, which is the main burden on the economic sustainability of green hydrogen systems.

The main problem with the engineering challenge is that improving one of these parameters often leads to a deterioration in the others:

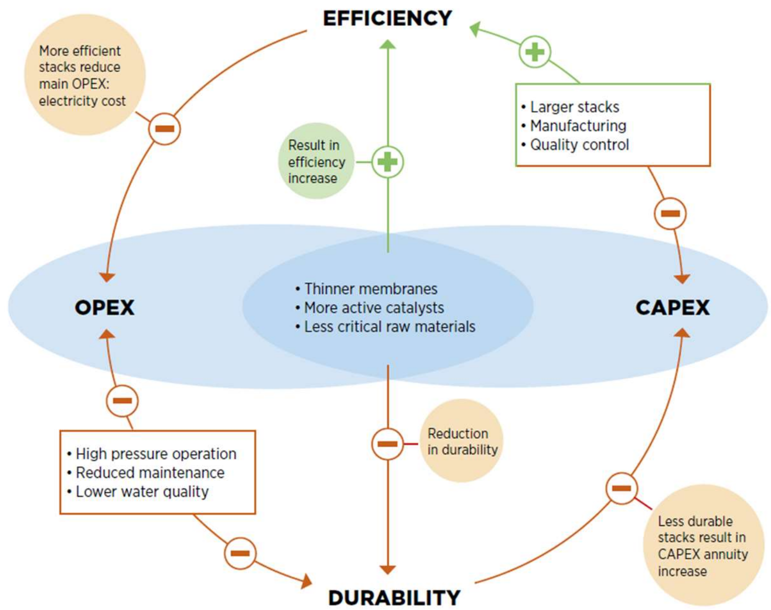


Figure 39: diagram showing the interdependencies and trade-offs between the performance and economic parameters of an electrolysis system; the image shows how an improvement in overall quality can lead to a reduction in OPEX, but an increase in CAPEX, due to the materials and techniques required for such improvement; a deterioration in the quality of the materials used, on the other hand, can reduce the durability of the system, thus affecting replacement costs, but on the other hand allows for a reduction in operating costs (OPEX) [18].

For example, regarding PEM electrolysers, the use of thinner membranes (moving from the current standard of 180 μm to solutions of 20 μm) allows for a drastic reduction in charge transport resistance, thereby increasing system efficiency and reducing energy consumption by approximately 20%. However, such thin membranes are mechanically more fragile, more prone to defects and perforations (pinhole failure) and have a significantly shorter service life than thicker, more robust membranes.

Similarly, the search for more active catalysts to improve efficiency conflicts with long-term stability. The use of ruthenium, for example, offers superior performance compared to iridium, but degrades faster. Furthermore, the need to eliminate critical and expensive raw materials (such as platinum and gold) from bipolar plate coatings requires the development of new protective materials that do not compromise conductivity or corrosion resistance.

In the coming years, the redesign of stacks will aim for a leap in scale and performance: the goal is to move from the current densities of 2 A/cm² to over 6 A/cm², while simultaneously increasing the electrode area from 1,500 to 10,000 cm². This would enable the transition from the current 1 MW stacks to new-generation 5 or 10 MW stacks:

	2020	Target 2050	R&D focus
	PEM electrolysers		
Nominal current density	1-2 A/cm^2	4-6 A/cm2	Design, membrane
Voltage range (limits)	1.4-2.5 V	< 1.7 V	Catalyst, membrane
Operating temperature	50-80°C	80°C	Effect on durability
Cell pressure	< 30 bar	> 70 bar	Membrane, reconversion catalysts
Load range	5%-120%	5%-300%	Membrane
H_2 purity	99.9%-99.9999%	Same	Membrane
Voltage efficiency (LHV)	50%-68%	>80%	Catalysts
Electrical efficiency (stack)	47-66 kWh/Kg H_2	< 42 kWh/Kg H_2	Catalysts/membrane
Electrical efficiency (system)	50-83 kWh/Kg H_2	< 45 kWh/Kg H_2	Balance of plant
Lifetime (stack)	50 000-80 000 hours	100 000-120 000 hours	Membrane, catalysts, PTLs
Stack unit size	1 MW	10 MW	MEA, PTL
Electrode area	1 500 cm^2	> 10 000 cm^2	MEA, PTL
Cold start (to nominal load)	< 20 minutes	< 5 minutes	Insulation (design)
Capital costs (stack) minimum 1 MW	USD 400/kW	< USD 100/kW	MEA, PTLs, BPs
Capital Costs (system) minimum 10 MW	700-1400 USD/kW	< 200 USD/kW	Rectifier, water purification

Table 11: comparative analysis between the state of the art of PEM electrolysis systems (2020 data) and the technological targets set for 2050, highlighting the main areas of research and development [18].

A further technical and physical obstacle to the scalability of electrolysers, particularly for PEM technology, is the use of critical and rare materials. During electrolysis, electrical energy reaches potentials of 1.4 volts; this value is higher than the thermodynamic oxidation potential of water, which is approximately 1.23 V, and therefore leads to the dissociation of water molecules, which release hydrogen ions and free radicals, creating an oxidising environment. In this type of environment, common metals such as iron or copper are corroded, which is why precious metals (Platinum Group Metals) such as platinum and iridium are used [18].

The criticality of these precious metals lies not only in their rarity, but also in their high geographical concentration, given that over 70% of global platinum and more than 85% of iridium come from a single country, South Africa. This dependence exposes the hydrogen supply chain to geopolitical risks and potential supply shortages:

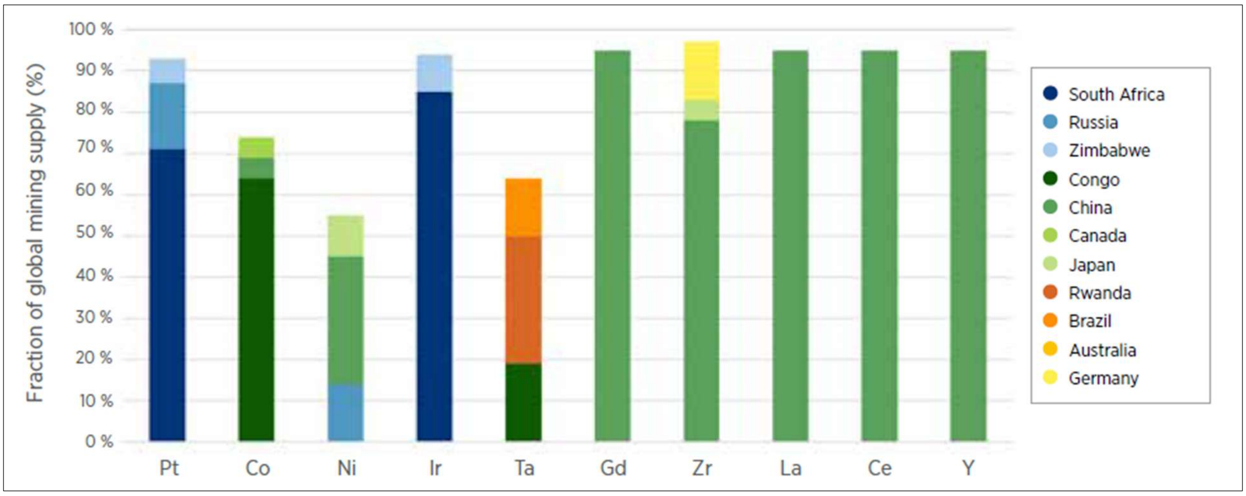


Figure 40: graph showing the main countries producing critical raw materials for electrolysers. The marked geographical concentration of reserves are South Africa and China, that have a near-total monopoly on platinum and iridium mines (essential for PEM catalyst) and elements such as nickel, gadolinium, zirconium, lanthanum, cerium and yttrium [18].

Today, platinum production reaches 200 tonnes per year, which is sufficient for a potential installation of approximately 200 GW per year for electrolysers. However, global iridium production reaches only 7 tonnes per year, which, if used at an average of 1-2.5 g/kW per electrolyser, the potential annual installation capacity would be limited to only 3-7.5 GW, making a drastic reduction in its use imperative.

In addition to physical scarcity, the production of these metals has a significant energy and environmental impact; in fact, platinum production dominates almost all categories of environmental impact, including acidification, eutrophication and photochemical oxidation. Extraction is extremely energy-intensive, requiring approximately 243 GJ for every kg of platinum produced.

To mitigate these risks and improve the economic and environmental sustainability of the sector, the main objective of the research and development strategy will be to reduce the catalyst load per unit of installed capacity (g/kW). Possible techniques already investigated include the use of catalysts based on tin or titanium oxides with a high surface area, or the engineering of iridium nanoparticles supported on conductive semiconductor oxides.

Another key factor in environmental sustainability is recycling. Hydrometallurgical treatment or selective electrochemical dissolution techniques can enable the recovery of precious metals from end-of-life stacks, creating a circular economy that reduces pressure on virgin raw materials.

The synergistic implementation of these strategies promises extraordinary results: in the long term, it is estimated that the specific content of iridium can be reduced by 96% and that of platinum by 97.5%. Even considering the increase in current densities, the load (g of material) per unit of capacity (kW) could be reduced by 70% and 80% respectively, making PEM technology compatible with deployment on a TW scale, which is necessary for global climate neutrality targets:

	TODAY	FUTURE
Current density (A/cm²)	2	5
Electrode area (cm²)	1200	5000
Iridium loading (mg/cm²)	5	0.2
Iridium loading (g/kW)	1.3	0.4
Platinum loading (mg/cm²)	2	0.05
Platinum loading (g/kW)	0.5	0.1

Table 12: strategies for reducing iridium and platinum loads to improve the efficiency of PEM electrolysers [18].

With this process of industrialisation and standardisation, despite having to manage the technical, physical and energy-intensive compromises mentioned before, it will be possible to reduce the specific cost of the system [18].

6.1.1 Green hydrogen costs

The economic landscape of green hydrogen is currently characterised by cost heterogeneity in the market, based on the variety of technologies available and the different architectures of electrolysis systems. To date, alkaline and PEM technologies are the most advanced and commercially widespread. Alkaline electrolysers boast the lowest installation costs, while PEM systems offer competitive advantages in terms of current density, output pressure and, above all, physical size.

Although the long-term goal is ambitious, with projections for 2050 predicting costs below €140/kW for plants larger than 10 MW, the current situation shows significant performance and cost gaps between the dominant technologies. For example, a 2018 study highlighted an extremely wide price gap for PEM systems, ranging from €306 to €4,748/kW, demonstrating the impact of project scale and scope of supply.

In general, the total cost can be divided into three main parts of the electrolyser: the single cell, which is the electrochemical heart of the system; the stack, which includes the cells, bipolar plates (often coated with gold or platinum) and structural components, which together account for approximately 40-50% of the total cost; while the last economically burdensome component is the BoP, which includes power rectifiers, water and gas purification systems, and cooling systems.

The key strategy for reducing the costs of the three elements mentioned above lies in achieving adequate economies of scale and optimising manufacturing processes. In fact, while the stack offers limited benefits (since its size cannot grow indefinitely due to mechanical stability and leakage issues), the Balance of Plant shows much more efficient scalability. For example, a compressor ten times larger (from 1 to 10 MW) does not increase its cost tenfold but only increases it by about four times. Consequently, as the size of the module increases, the stack's share ends up dominating the total cost of the system.

Consequently, the determining factor for the future competitiveness of hydrogen with other fuels is undoubtedly the transition from the current scale to a massive industrial scale. One study has estimated that investments of around €69,000 per MW of installed production capacity per year will be required for electrolysers [85]. Furthermore, the transition from a manufacturing scale of 10 MW/year to 1 GW/year would allow for a 70% reduction in the cost of the stack.

It is important to note that the advantages of mass production will not only affect large industrial plants. Thanks to factory automation and the creation of standard components (the same for everyone), even small plants for farms will become much cheaper and more accessible [18].

The analysis carried out for the three farms and similar models shows that, at this stage, the cost gap compared to other types of hydrogen remains a significant barrier. In order to bridge this gap and stimulate private investment, it is also necessary to focus on the political side, which is essential for obtaining regulations and incentives that are useful for the development of green hydrogen technologies. One example is the imposition of minimum quotas for green hydrogen in industry or transport, as in Portugal, which has set targets for blending hydrogen with other gases (such as methane) of 2-5% in industry by 2030, rising to 20-25% by 2050.

The success of hydrogen projects also depends heavily on tax incentives. Positive examples such as the Netherlands, which offers tax breaks of up to 41.5% of the cost of replacing fossil fuels, or the United States, with production tax credits, i.e. cash rewards that allow producers to obtain up to $0.42 per kg of hydrogen produced, show how public support is essential to reduce the initial economic risk and make small and medium-scale plants profitable.

Another key factor is the tracking of green hydrogen, which allows it to be certified throughout the supply chain (production, transport, conversion), enabling producers themselves to receive cash rewards linked to low CO_2 emissions [18].

In conclusion, the transition from pilot projects to a massive industrial scale is not only a technical challenge, but a systemic process. The integration of research and development on materials, manufacturing automation and stable regulatory frameworks will enable increasingly cheaper electrolysis technologies, making projects such as those analysed for the agricultural sector not only technically feasible, but economically advantageous in the next decade.

6.2 Future projects around the world

The low-emission hydrogen sector is undergoing a paradigm shift, moving from a phase of pure strategic planning to one of operational execution. This transition is driven by a diversification of regional approaches and progressive technological maturity, although the market still faces significant challenges, particularly in terms of investment costs and project robustness.

Globally, policy actions taken by economically advanced countries focus on the use of incentives, while emerging countries are exploiting their territorial advantage to position themselves as future exporters:

Comparison of hydrogen policy approaches adopted across selected hydrogen markets

Category	European Union	United States	China	Japan	India
Targets	2030: 40 GW of domestic electrolyser capacity	-	2025: 100-200 kt green hydrogen production	2030: 3 Mtpa of hydrogen consumption	2030: 5 Mtpa green hydrogen production
Supply	European H_2 Bank IPCEI Innovation Fund	Inflation Reduction Act (45V, 45Q, 45Z, 48C)	Provincial subsidies; roll-out through SOEs	CfD scheme	Financial support for electrolysis, ammonia, manufacturing
Infrastructure	H_2 and gas markets decarbonisation IPCEI; AFIR; CEF	Support for hydrogen refuelling stations	Support for new hydrogen pipelines	Clusters support scheme; CAPEX subsidy for storage	Hydrogen Valley Innovation Clusters
Demand	RED; ReFuel Aviation; FuelEU Maritime; CISAF; IPCEI	Loan guarantees, tax credits, ZEV mandates	Implementation plan for industry; FCEV tax exemptions/subsidies	Hub support; tax credits for industry; FCEV subsidies	Guaranteed offtake through SECI
Certification	Delegated Acts for renewable and low-carbon hydrogen	Clean Hydrogen Production Standard (CHPS)	Clean and Low-Carbon Hydrogen Energy Evaluation Standards	Hydrogen Society Promotion Act	Green Hydrogen Standard
R&D	Clean Hydrogen Partnership	Offices of Energy Efficiency, Renewable Energy, FECM	Demo programmes across the entire value chain	Green Innovation Fund	R&D scheme of National Green Hydrogen Mission

Table 13: comparison of strategies and policy approaches for the global hydrogen market. The European Union has set extremely ambitious targets, such as achieving 40 GW of electrolysis capacity by 2030, supporting this vision with a solid regulatory framework and dedicated financial instruments, such as the European Hydrogen Bank. The United States, on the other hand, is focusing on the use of direct tax incentives, such as those introduced by the Inflation Reduction Act, to drastically reduce production costs. At the same time, China is focusing on massive industrial-scale production, directly involving large state-owned companies, while other countries, such as Japan and India, are prioritising the creation of industrial clusters, known as Hydrogen Valleys, guaranteeing long-term purchase security to stabilise the market [77].

The most ambitious nations have already set extremely aggressive LCOH targets for 2030, aiming to close the cost gap with other types of fuel. Some examples are Chile, which aims to achieve an LCOH of 1.5 USD/kg, aiming to be the cheapest producer in the world, and Australia, which, with its "H2 under 2" project, aims to achieve an LCOH of less than 1.4 USD/kg. Japan's goal is to reduce the cost of electrolysers to around €325/kW.

China currently accounts for almost 60% of global electrolyser manufacturing capacity. This is because producing green hydrogen in China costs around 40-45% less than in Europe or the United States. This gap is due to significantly lower installation and BoP component costs, linked to the fact that there is a huge availability of renewable technologies, justified by the large number of solar and wind-based companies, which in recent years have also converted their expertise to the hydrogen sector.

Currently, however, the difference between the costs of green hydrogen and grey or black hydrogen remains wide, and parity in hydrogen production costs can only be achieved through a combination of technological cost reductions and the imposition of a carbon tax, which in Europe will have to be around €70/tCO_2, while in the US or the Middle East it would need to exceed €140/tCO_2 to be effective [18].

Unfortunately, in recent years, estimates for hydrogen production by 2030 have been revised downwards from 49 Mtpa (million tonnes per annum) to 37 Mtpa. This is mainly due to delays in transposing directives, difficulties in finding long-term buyers, a lack of infrastructure for transporting hydrogen and a lack of space to accommodate large-scale plants, but above all, the high number of projects that, from the initial phase, have not reached the "Final Investment Decision" (FID), which today covers only about 9% of total projects.

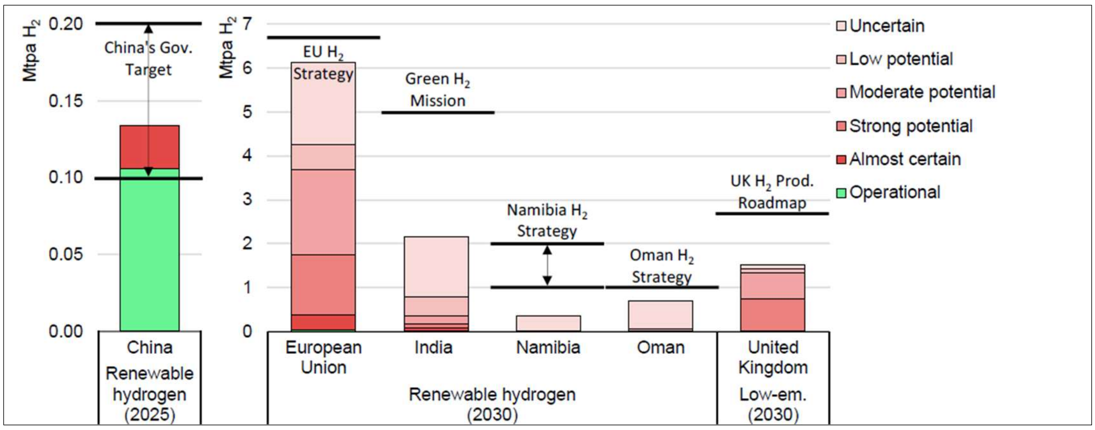


Figure 41: comparison between announced low-emission hydrogen projects and government targets for 2025 and 2030; Europe has the highest number of projects with targets for 2030, while China has already exceeded its targets for 2025 [80].

In conclusion, although the target capacity for 2030 was around 440 GW, the realistic estimate is around 65-70 GW. This consolidation phase, albeit slowed down, is nevertheless leading to the emergence of more solid and bankable projects, mainly concentrated in industrial hubs, where demand is aggregated and risk is reduced, being shared among several players [77].

6.2.1 Future projects in Europe

The European Union currently has the most ambitious and structured strategy in the world for the development of green hydrogen. In fact, in 2020, the European Commission outlined a path that sees hydrogen not only as a fuel, but as a key energy carrier for system integration and renewable energy storage.

The European targets are clear: 40 GW by 2030, with domestic production of 10 million tonnes of renewable hydrogen per year. To achieve these volumes, the EU anticipates the need for an additional 40 GW of electrolysis in neighbouring countries (such as North Africa) for importation.

Given that renewable technologies are necessary to obtain green hydrogen, from an investment perspective, between 2020 and 2030, between €220 and €340 billion will be spent on renewable electricity production and between €24 and €42 billion on electrolysers alone. Instruments such as the NextGenerationEU fund and the Clean Hydrogen Alliance are the main drivers for consolidating this technological leadership and creating local jobs.

The European ambition is also supported by the national strategies of individual Member States, each with a specific role based on its own resources: Germany, with an investment of €9 billion (including

€2 billion for international partnerships), aims to install 5 GW by 2030. Its focus is on the decarbonisation of "hard-to-abate" sectors such as the steel industry and refineries, which will require around 80 TWh of green hydrogen by 2050.

The Netherlands, on the other hand, is exploiting the strategic position of the port of Rotterdam to become the logistics hub for hydrogen in Europe. The Dutch strategy envisages that by 2050, 30-50% of final energy consumption will be via gaseous carriers (hydrogen and biogas).

Portugal, thanks to record low costs for renewables (such as solar at 13.1 USD/MWh), aims to install 2-2.5 GW by 2030, with 10-15% of gases mixed with hydrogen. A concrete example is the "Green Flamingo" project, which involves the creation of a transnational export corridor connecting the port of Sines with the Rotterdam one. The technological heart of the initiative lies in the installation of a 1 GW electrolyser, as part of a total investment plan estimated at around €57 billion, aimed at strengthening the entire green hydrogen value chain on a European scale.

Europe, despite having the largest number of announced projects (around 25% globally), has seen a 20% decline in its roadmap. This is because many of these projects do not have a sufficiently solid profit outlook to attract interested investors. In fact, 6 Mtpa of hydrogen are ready for delivery by 2030, but for the reasons mentioned above, only 2 Mtpa are considered almost certainly achievable.

Consequently, Europe's challenge will be to increase the installed capacity of renewable technologies for green hydrogen production as much as possible by 2030, with the aim of transforming projects currently under study into Final Investment Decisions [77].

6.2.2 Future projects in Italy

In line with other major industrialised countries, Italy sees hydrogen as a flexible and clean energy carrier, essential for addressing the vulnerability of the national electricity system and the high dependence on hydrocarbon imports. For Italy, the development of a "Hydrogen Economy" is not only an environmental objective linked to the Kyoto Protocol or the Paris Agreements, but a strategic necessity for energy security.

The Italian strategy, confirmed in the PNIEC, sets ambitious short and long-term goals, such as the installation of 3 GW of electrolysis capacity and an estimated demand of 137 ktpa (thousand tonnes per annum) for transport and 115 ktpa for industry. By 2050, however, installed electrolysis capacity is expected to be between 15 and 30 GW, with total hydrogen demand likely to range between 2.2 and 4.2 Mtpa. Economically, financing this project will require between €29 and €57 billion, with an expected impact on employment of between 4,700 and 9,000 new jobs.

According to estimates, Italy's green hydrogen production potential is 7.1 million tonnes per year, divided between solar radiation (3 million tonnes), biomass (3.36 million tonnes), wind power (460,000 tonnes) and hydropower (280,000 tonnes).

The practical implementation of the strategy is taking shape through the NRRP, which has allocated €500 million for the creation of new hydrogen valleys. Although these are small-scale plants (1-5 MW), they are essential for gaining experience on different project configurations [86].

An example related to hydrogen investments concerns the Italian company Fincantieri, which in April 2025 began construction of the world's first two cruise ships powered by liquid hydrogen and fuel cells, with delivery scheduled for the end of 2026. This project demonstrates how Italian industry is ready to compete in high value-added markets. Unfortunately, Italy is also experiencing significant delays in the operational implementation of projects and in attracting investment. These dynamics are fuelled by the territorial and decision-making fragmentation that has historically characterised the country. Despite the dynamism of regions such as Piedmont, Lombardy, Veneto, Tuscany, Lazio and Abruzzo (which have been able to launch programmes of strategic importance), the absence of a coordinated national framework risks compromising the competitiveness of the country's economy in the long term. In this scenario, the National Platform on Hydrogen and Fuel Cells operates with the aim of promoting synergies between the world of research and industrial application; however, persistent regulatory uncertainty and limited coordination between the relevant ministries are currently the main obstacles to large-scale technological development [14], [77].

CONCLUSIONS

The analysis conducted on the two case studies highlighted the structural criticalities that currently characterise Power-to-Hydrogen-to-Power technology. The main obstacle to large-scale commercial development remains the high-cost profile, influenced by a Technology Readiness Level (TRL) that is not yet consistent for all system components. Although some machines are technically mature, system integration still suffers from a lack of economies of scale that would make commercialisation competitive.

A further intrinsic limitation is conversion efficiency (Round-Trip Efficiency), which, at around 30%, makes lithium-based technologies preferable for short-term storage. However, research shows that hydrogen becomes an irreplaceable vector for seasonal storage, where batteries have physical and economic limitations. Analysis of the second scenario confirmed this potential: the ability to store 2,285 kg of hydrogen for a period of approximately 150 days represents a technically sound solution for ensuring energy independence during periods of low solar generation.

Globally, the transition to green hydrogen is supported by substantial investment plans with targets set for 2030 (e.g. European targets) and 2050 (total decarbonisation). However, there remains a gap between theoretical objectives and practical implementation, often slowed down by delays in the disbursement of public funds and the need for further advances in scientific research.

The results of this thesis show that, at present, the P2H2P system is economically critical for both individual companies and small Renewable Energy Communities (RECs). An increase in the scale of the project and the number of REC members (while remaining within the 1 MW power limit for access to GSE subsidies) could favour a positive assessment of the Net Present Value (NPV) over the 20-year horizon provided for in the CACER decree. For small farms, on the other hand, economic sustainability will inevitably depend on the technological learning curve of electrolysers and the reduction in component costs in the coming years.

In conclusion, green hydrogen remains an expensive energy carrier, with a production cost (LCOH) of over €10/kg, making it currently uncompetitive compared to fossil fuels. However, its competitive advantage lies in the drastic reduction in CO_2 emissions. In the context of the necessary ecological transition, hydrogen remains one of the fundamental pillars for the future use of renewable energy, offering a concrete solution for the decarbonisation of hard-to-abate sectors and for territorial energy resilience.

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