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Techno-economic optimization of offshore green hydrogen with dynamic storage modelling

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A nonna,

per l’immenso amore.

Abstract

The global energy transition needs innovative solutions for decarbonizing oil&gas sector, with green hydrogen emerging as a pivotal energy carrier. This master's thesis presents a comprehensive techno-economic analysis of two distinct strategies for integrating green hydrogen into an existing offshore oil and gas platform. The primary objective is to evaluate their technical feasibility and economic viability.

Scenario 1 encompasses a complex system integrating green hydrogen production via electrolysis, biomethanation (Power-to-Gas, P2G) utilizing captured CO_2, direct blending with natural gas, and flare for surplus H_2. Scenario 2, conversely, adopts a much more simple approach, focusing only on direct blending of green hydrogen with natural gas, with flaring as the only alternative for excess H_2. Both scenarios are built upon realistic operational profiles, including dynamic wind data for hydrogen production and a dynamic modeling of hydrogen storage.

The techno-economic assessment reveals significant differences in capital expenditure (CAPEX), operational expenditure (OPEX), and financial performance indicators (NPV, IRR, Payback Period). The study conclusively demonstrates that, under the analyzed conditions, Scenario 2 (direct blending) is significantly more economically viable than Scenario 1 (biomethanation + blending). This outcome is primarily attributed to the substantial CAPEX and additional OPEX associated with the biomethanation unit and the complex CO_2 capture and handling systems required in Scenario 1. While Scenario 1 offers environmental benefits through CO_2 valorization, its higher cost structure impacts overall profitability and investment recovery time. Both scenarios, however, exhibit high efficiency in hydrogen utilization, with minimal flaring losses.

Acknowledgements

I would like to thank my supervisors for their guidance, availability, and support throughout this journey.

A special thought goes to my mom and dad, for the endless love and fr supporting me through every difficulty; to my uncle and aunt, for their constant and tireless presence; and to my sister and cousins, who have shared my worries and always offered invaluable advice.

Last but certainly not least, I want to thank my friends.

We have learned that a point load can create unsustainable conditions, while the same load, if distributed, is easier to bear. I can say without hesitation that you managed to make this inferno a little less scorching. By sharing tears and laughter, you have shown me how the strength of friendship can warm even a cold, gray city (and prevent a nervous breakdown…). I know that wherever we are, in 10, 30, or 50 years, no time or distance will ever fade our shared memories and the affection we have for each other. You have become my chosen family.

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Thank you to those who were my anchor when my bubble was about to burst. To those who have been there for a lifetime, it is wonderful to grow up knowing we can always count on each other; and to those who became my guiding light as soon as I arrived in this city.

I believe there is a red thread that connects people who are meant to meet. This thread may stretch or tangle, but it never breaks.

I hope you know how grateful I am to have you in my life.

As someone once said, "Happiness is real only when shared"!

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1. Introduction

1.1. Context

Global warming is nowadays one of the main environmental, social and economic threats. The rise of the mean temperature, due to the accumulation of greenhouse gases (GHG) in the atmosphere, has already overcome +1.1 °C with respect to pre-industrial temperature (IPPC, 2023), causing glaciers melting, rising of sea level, extreme weather conditions and loss of biodiversity. According to the Intergovernmental Panel on Climate Change, without a decrease in CO_2 and methane emissions, global warming could reach +2.7°C by 2100, well above the target set by the Paris Agreement (+1.5 °C) (IPCC, 2023; United Nations, 2015).

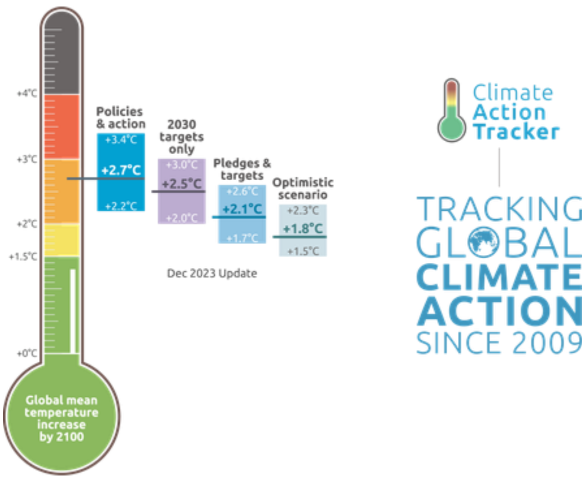

Figure 1: Warming projected by 2100 (Source: Climate Action Tracker)

By now, *Energy transition* is acknowledged as a global urge to limit global warming, and the decarbonization of offshore platforms plays a crucial role in this path. This structures, typically fed by gas turbines or diesel generators, consume beyond 16 TWh per year (2019 data), emitting significant amount of CO_2 and methane (Zhao, 2022), while water from the process releases contaminants (such as PAH), responsible for negative impacts on marine ecosystems (Zhao, 2022). As a response, this sector has implemented new advanced technological solutions:

electrification via submarine cable, as in the cases of the Norwegian fields Troll A (1996), Gjøa (100km from Mongstad, 2010) and JohanSverdrup (2019), has reduced emissions to 0.67kg CO_2/barrel, well below the regional average of 9kg; Hywind Tampen project, opened in 2023, provides 88 MW of floating electricity (11 Siemens Gamesa turbines), meeting 35% of the needs of the Gullfaks and Snorre fields, with an annual. In addition to wind power, *microgrid hybrid systems* (wind + PV + batteries + hydrogen) as the case of PLOCAN, have shown reductions in total emissions and operative costs lower than 15% (Romero-Filgueira, 2025). Another way to decarbonize is offshore *Carbon Capture & Storage (CSS)*: Sleipner project, operating since 1996, stores 1 Mt CO_2/year in an underwater aquifer and represents a benchmark for studies of life cycle extension up to +24 Mt CO_2 (Ringrose & Meckel, 2019), although experience reveals criticalities, such as unplanned CO_2 migrations and revision of the stored volume (-30 %). Finally, *Green Hydrogen* is emerging as a clean energy carrier: simulations in the North Sea suggest that a wind/hydrogen infrastructure could integrate up to 420 GW of renewables, with savings of up to €15 billion/year.

Despite these promising technologies, trade-offs are significant: electrification requires relevant investments in HVDC cables and adaptation of subsea supply chains; CSS needs rigorous regulations and continuous monitoring systems; the production of green hydrogen offshore leads to high costs and uncertainties in energy-maritime governance. Moreover, the use of renewable energies to feed platforms, although it reduces emissions, could protract fossil extraction and put off decarbonization. As a response, there are some innovative proposals: reconversion of platforms into energy islands, that can accommodate integrated hub of wind power, electrolyzers and CCS; adaptive legislations that can regulate the retrofitting and provide modulated incentives (electrification, hydrogen, storage) according to the platform's life cycle; and financial models based on public-private partnerships, which accelerate the transition without penalizing competitiveness. From a political point of view, European regulations and international agreements (such as the extension of the London Protocol and the Fit for 55 Directive) provide favorable frameworks to implement the said strategies (Snedecker, 2024).

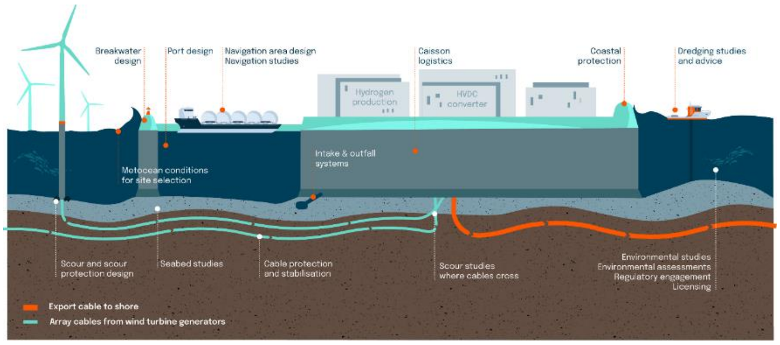

Figure 2: Expertise needed to construct an energy island (Source: hr wallingford)

1.2. Research problem

In the context of energy transition and of increasing awareness of climate neutrality, CO_2 emissions generated by offshore extractive activities represent one of the most critical environmental challenges. Gas turbines used for self-production of energy on oil and gas platforms are a significant source of climate changing emissions, due to their low thermodynamic efficiency and to their usage in isolated environments form a structural point of view (Harald G. Svendsen, 2022). In Ekofisk platform, located in the North Sea and managed by ConocoPhillips, it has been estimated that beyond 70% of annual CO_2 emissions - about 200-250 ktCO_2 per year (ConocoPhillips, 2023) - come from the work of gas turbines, that are necessary to support pumping and compressing operations (Equinor, 2023). In particular, in the North Sea, the emission problem is even more aggravated by a rigorous climate taxing system. Norway adopted a carbon tax in 1991, which has been applied on the gas combustion associated with oil and gas activities in the Norwegian Continental Shelf, according to CO_2 Tax Act on Petroleum Activities. In

2024, the tax is NOK 1.85 per Sm3 of gas burned, equivalent to about NOK 790 per tonne of CO_2 emitted. In addition, Norway has joined the EU ETS emissions trading scheme, which imposes an additional cost linked to the market price of CO_2 allowances. In 2023, the average price of an emission allowance was around €85.28/tCO_2. The combined effect of these two tax instruments means that companies operating offshore in Norway (such as Equinor, which covers about 70% of national production) pay up to 1750 NOK/tCO_2, or 133 €/tCO_2, a much higher value than other producing countries (Norwegian Petroleum, 2024; Herrera Anchustegui et al., 2024). This level of tax burden has important strategic and economic implications. According to Norwegian Petroleum (2024), in 2021 alone, Equinor spent about 978 million dollars to cover the costs of both the Norwegian carbon tax and ETS allowances. In this scenario, the electrification of platforms, the adoption of heat recovery technologies, the integration of renewable sources (such as offshore wind) and the use of power-to-gas systems (e.g. hydrogen production from excess renewable energy) emerge as technically feasible and increasingly necessary strategies. However, the actual applicability of these solutions depends on their technical feasibility, the operational environment of the platform and the associated cost-benefit analysis. The aim of this study is precisely to analyze an alternative and optimized energy scenario for a multi-fuel offshore platform, simulating the integration of renewable resources and energy conversion technologies, with the goal of reducing CO_2 emissions and the associated economic penalty.

1.3.Objectives

This work, contributing to decarbonization strategies of offshore hydrocarbons production systems, aims to develop a design which can lead to the reduction of CO_2 emissions associated with energy generation on the platform. To do so, the starting point of this research is an already existing solution examined in

Francisca's thesis (2024) – "*Energy optimization of an oil and gas platform*" – where it is explored the integration of an offshore wind power system to support the operations of the already existing gas turbines. Then, the surplus of electricity would be exploited to feed an electrolyzer, producing green hydrogen from desalinated water.

From these assumptions, the current work proposes a further optimization of the energetic system in two different scenarios:

- *Scenario 1 - Bio methanation + Blending + Flare system*: the produced hydrogen is used in a biomethanation process, by combining it with CO_2 captured from flue gas of the turbines to produce synthetic methane (CH_4), which will be injected into the gas pipeline. The possible H_2 surplus is mixed with natural gas in the pipeline, considering the limits of this operation. If there is still some available hydrogen, it is finally burnt in the flare.
- *Scenario 2: Blending + Flare system*: it is considered a system without biomethanation, where hydrogen is used exclusively to blend with natural gas and, if there is a surplus, burn in flare.

The goal of this thesis is to evaluate both scenarios from an economic point of view, taking into account the costs linked to carbon takes, to identify which one is more feasible for Ekofisk platform.

1.4. Thesis structure

The thesis is divided into six chapters, each with a specific purpose to guide through the analysis and interpretation of the results.

Chapter 1, "Introduction", contextualizes the research, defines the problem and outlines its objectives. Chapter 2, "Literature and State of the Art," offers an overview of key technologies and the offshore energy context, including hydrogen production, storage and conversion systems. Chapter 3, "Methodology", describes in detail the modelling approach, presenting the two scenarios analyzed, the storage tank and flare dimensioning methodologies (such as) and the basic assumptions. Chapter 4, "Analysis of Results", sets out the technical and economic data obtained from simulations for both scenarios, and presents the main result of the comparison. Chapter 5, "Discussion", critically interprets the results, analysing cost-benefit factors, implications for offshore energy planning, strengths of the work and its limitations. Finally, Chapter 6, "Conclusions", summarizes the main findings, responds to the research question, highlights the contribution of the work and proposes a final message on the value of the study in the energy transition.

2. Literature and state of art

2.1.Offshore platforms and energy context of Ekofisk

2.1.1. Operations and energy requirements of offshore platforms

Offshore platforms collect fluids extracted from wells (crude oil, natural gas and water) and treat them *in situ*. These include extraction and lifting facilities (e.g. surface pumps), separation of oil, gas and water, treatment and pumping of products. For instance, extracted gas is separated from water and sent to the gas pipeline; crude oil is sent to oil pipeline; water treated and again injected into the system. These operations require multiple devices: compressors and pumps to move fluids, heat exchangers, cooling systems and storage systems. As a result, the energy requirement is quite high: on average, platforms need tens to hundreds of MW of power. For example, it is estimated that a typical 50 MW continuous platform would consume approximately 8.76×10^6 MWh over 20 years (Nguyen, 2016), confirming the significant energy commitment required. Much of this energy is used to power the pumps and compressors needed for daily operations.

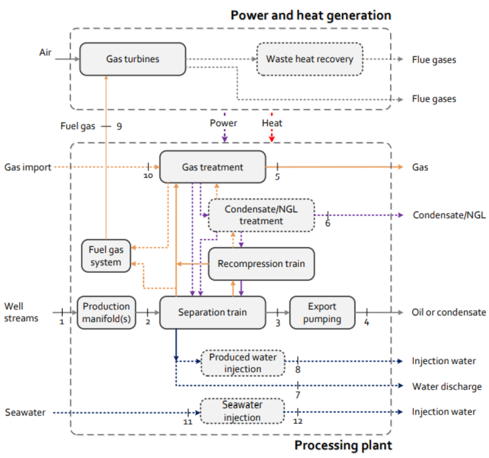

Figure 3:General system overview of an oil and gas platform. (Source: Nguyen et al., 2016)

2.1.2. Compressors

In this context, compressors aim to increase the pressure of the gas to move it towards Norpipe gas pipelines (440km long to Emden, Germany) or, like in this innovative case, to compress hydrogen produced from electrolysis. In traditional configurations, such as in Ekofisk, compression is fed by gas turbines and supported by electric motors, aiming at increasing pressure up to the one necessary for the transport of natural gas (200 bar, that is 20 MPa). In the context of progressive decarbonization, which includes production of green hydrogen via water electrolysis, also this one must be compressed in order to be stored or injected into the gas pipeline. Hydrogen exits from the electrolyzer at relatively low pressure (about 35 bar) and must therefore be brought to those of the natural gas export network (200 bar) (Svendsen et al., 2023; Francisca, 2024).

For this application the use of piston compressors is assumed, considering their good suitability to manage small volumes and high pressures. These devices use pistons driven by electric motors which, through a crankshaft system, convert rotary motion into alternating motion. During the intake phase, the piston's descent creates a vacuum that allows hydrogen to enter the cylinder. Subsequently, during the compression phase, the piston rises, closing the intake valve and, once the desired pressure is reached, opening the exhaust valve, allowing the gas to pass to the next compression stage or to the network.

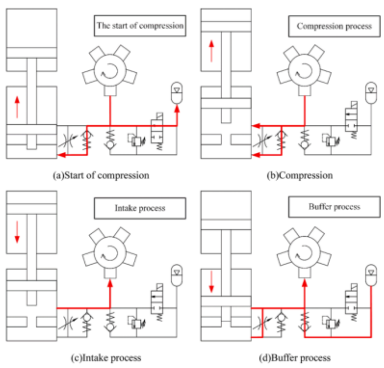

Figure 4: Hydraulic control circuit of single stage compressor. (Source: Zhou et al., (2021))

For the Ekofisk case, compression is assumed to occur in two stages in series, each one with intermediate pressures calibrated to optimize energy efficiency and reduce thermodynamic losses. The electrical consumption of this system is calculated similarly to that of natural gas compressors but expressed as a function of the mass of hydrogen generated, thus allowing a direct comparison between scenarios and technological configurations (Francisca, 2024).

2.1.3. Gas turbines

As reported by Francisca (2024), Ekofisk platform is fed by three generators that are gas turbines of aeronautic derivation (model General Electric LM2500), each of nominal power 21.8 MW. This model is produced by General Electric (USA), and it is one of the most common among the world, considering more than 2500 sold units and 97 million of operating hours (General Electric, 2019). These turbines can work in cogenerative mode, providing both heating and electricity. The lower operative load is equal to 3.5 MW, which corresponds to 16.05% of the nominal load. The electric efficiency is equal to 34.7% on nominal load and 20% at 20% of nominal load. The natural gas used for power is that extracted locally from the platform. Export revenues are highly dependent on the market price of gas: in October 2024, the European TTF was €41.54/MWh, equivalent to approximately €0.46/Sm^3, while the American Henry Hub stood at $2.3/MMBtu, equivalent to €0.08/Sm^3 assuming a lower calorific value of approximately 36 MJ/Sm^3 (Francisca, 2024).

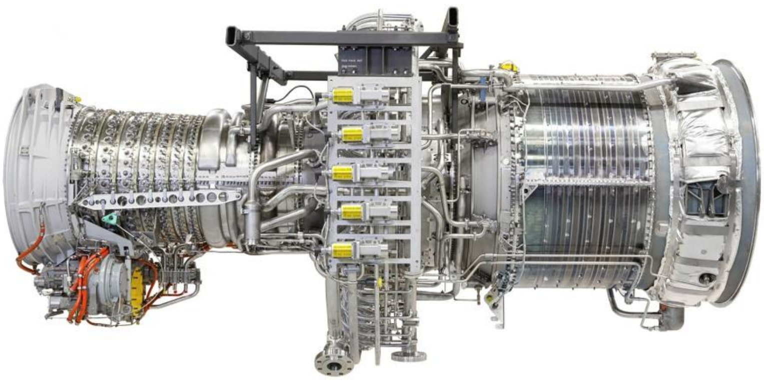

Figure 5: General Electric LM2500 gas turbine.

2.2. CO_2 emissions and regulatory context

Climate change is directly linked to greenhouse gases emissions, of which CO_2 is the main contributor, coming from the combustion of fossil fuels. Offshore platforms contribute significantly to national emissions: for example, Norway's offshore oil and gas sector generated over 20–30% of the country's total CO_2 emissions (Nguyen, 2016). To decrease these emissions, Norway has implemented carbon taxes, as analyzed in the following subchapters.

2.2.1. Carbon tax in Norway

To strengthen the will of reducing emissions, Norway applies a carbon tax on CO_2 emissions on any company who is emitting. As Norwegian Petroleum (2025) reports, "The combination of the carbon tax and the emissions trading system means that companies on the Norwegian shelf pay approximately NOK 1565 per tonne for their CO_2 emissions…" (approximately €133/tCO_2), which represents a significant economic penalty. The more a platform pollutes, the more taxes it pays; so, this tax incentive boosts efficiency measures and the adoption of cleaner energy sources, in addition to the direct benefit of reducing climate impact.

2.3. Decarbonization solutions and energy management

In order to mitigate offshore emissions, renewable energy and energy management strategies are being investigated. On of the most promising is the installation of offshore wind turbines, that are able to integrate or substitute gas turbines. Wind power is particularly strong and available, and can generate clean electricity to be used immediately or converted into alternative energy carriers (as it will be later analyzed). In the following subsection we describe the role of offshore wind turbines in the context of a platform.

2.3.1. Wind turbines

As stated by BOEM – Bureau of ocean energy management (n.d.): "All wind turbines operate in the same basic manner. As the wind blows, it flows over the airfoil-shaped blades of wind turbines, causing the turbine blades to spin. The blades are connected to a drive shaft that turns an electric generator to produce electricity [....]. Offshore winds tend to blow harder and more uniformly than on land. Since higher wind speeds can produce significantly more energy/electricity, developers are increasingly interested in pursuing offshore wind energy resources. ". For the case of Ekofisk platform, the integration of wind turbines seems to be very suitable to reduce the share of electricity produced from gas combustion, lowering both operating costs and CO_2 emissions. As a result of the analysis conducted by Francisca (2024) using the simulation software HOMER Pro, the implementation of three Siemens-Gamesa 8.0-167 DD offshore wind turbines (8 MW each) was found to be the most cost-effective solution for partial electrification of Ekofisk. These turbines have a rotor diameter of 167 meters, a cut-in wind speed of 4 m/s, and a cut-off wind speed of 25 m/s. According to the optimization results, "this configuration yields an actualized economic saving of approximately €45 million over 25 years, assuming a discount rate of 5.88%, and enables a 39% reduction in CO_2 emissions compared to the base case scenario", which relies only on gas turbines (Francisca, 2024). Surplus energy can be generated during high-wind periods.

Figure 6: Siemens Gamesa SG 8.0-167 DD prototype (Source: offshoreWIND.biz)

2.4. Technologies to reduce CO_2 emissions

In an offshore context, where gas combustion occurs, the integration of carbon capture and storage solutions (CSS) represents a fundamental strategy to reduce the carbon footprint of the operations.

2.4.1. Carbon capture

Carbon capture technology aims to capture CO_2 before its release in the atmosphere, allowing a reduction in GHG emissions. According to Chao et al. (2021), among the different technologies, "post-combustion is currently the most mature and widely deployed technique for CO_2 mitigation", since it can be integrated with little modifications in the actual structure.

One of the most consolidated solutions for post combustion capture is the employment of amine solvents, particularly *Monoethanolamine (MEA)*.

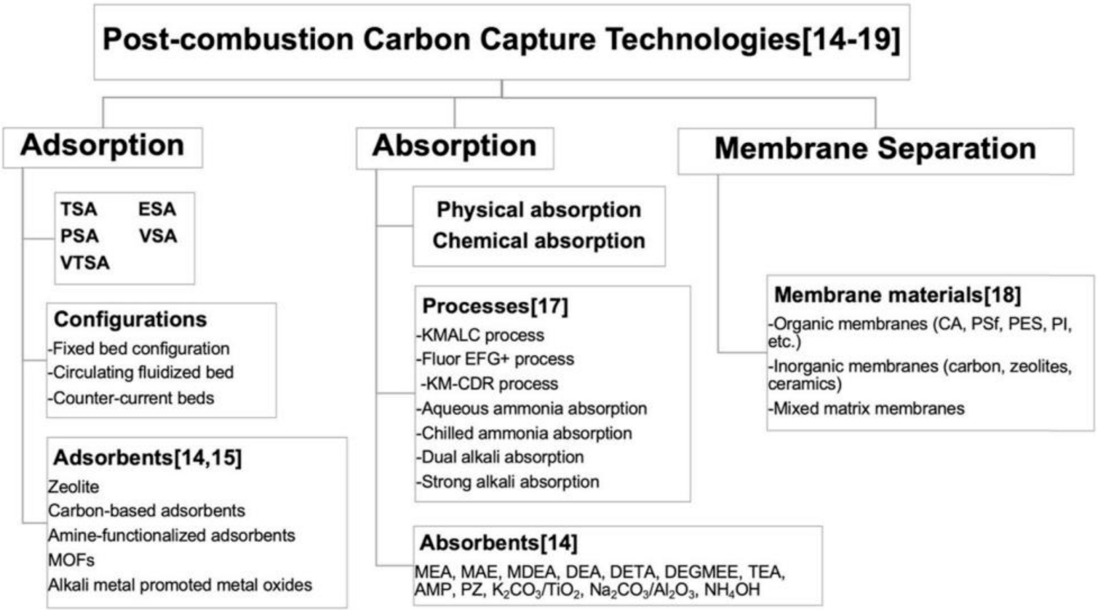

Figure 7: Post-combustion carbon capture technologies. (Source: Chong Chao et al., 2021)

MEA, primary amine, react quickly with CO_2 of the glue gas, allowing the extraction with high efficiency (85-90%) even at low concentrations (3-5%), which are typical in fumes from natural gas turbines (Catillaz et al., 2021).

MEA process is analogue to the other amines:

1. Flue gas, after being cooled down, is injected into the column from the bottom, and it goes through a heat exchanger that cools down the temperature (usually 40.50°C);

2. Inside the column, gas goes up with ascending motion, meanwhile the *lean* aqueous MEA solution (poor in CO_2, usually around 25-30 %wt) goes down countercurrent.

3. CO_2 in the flue gas is absorbed via chemical, forming carbamates and bicarbonates, with a removal efficiency that can be up to 85-90%.

4. A *sweet* gas exits from the head of the column, with low CO_2 and controlled temperatures.

5. Liquid, which is now enriched in CO_2 (*rich* MEA solution), exits from the bottom and enters a heat exchanger, in order to be heated up by the contact with the regenerated solvent (lean).

6. Then, the solution is sent to the regenerative column (*stripping*): here, vapor (coming from the reboiler) is injected at medium pressure, in order to break CO_2-MEA bonds.

7. CO_2 vapor, now rich in acid gases, is sent to a condenser, where the separation between gaseous CO_2 and water takes place, and it is now ready to be compressed and stored.

8. *Lean* solution is now cooled down, and it goes back to the absorption column to start again the cycle.

This circuit requires pumps, exchangers, steam boilers, chillers and sometimes heat recovery systems (e.g. hot-fume flow preheaters) to optimize overall efficiency. The initial implants can be quite bulky (high columns >10 m in diameter), but there are modular designs for medium sizes.

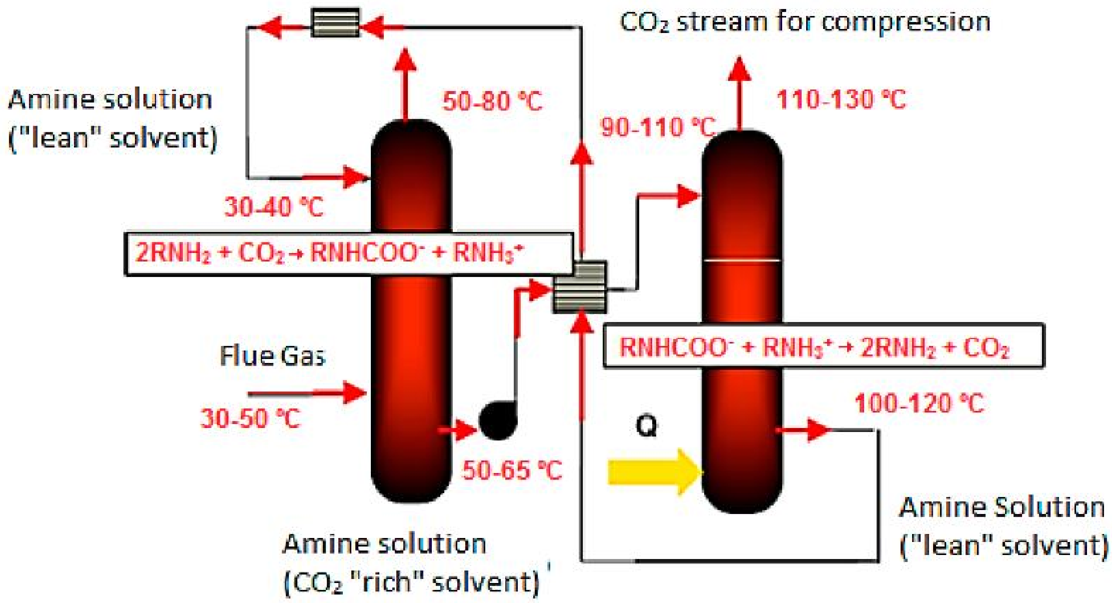

Figure 8: Plant layout. (Scource Santos, S. P. et al., 2016)

This process, even if effective (with a capture efficiency that can exceed 90%), involves significant energy consumption, mainly for the heating of the regeneration column, which can vary between 3 and 4 GJ per tonne of CO captured (IEAGHG, 2013).

To estimate the costs associated with MEA technology, the same approach adopted by Francisca (2024) was used, based on average values reported by Butterworth (2023). Specifically, Table 4.8 from his analysis provides a CAPEX estimate of 800 USD/tCO_2/year and an OPEX of 40 USD/tCO_2:

- CAPEX: 637,000 €
- OPEX: 34,640 €/y

2.4.2. Carbon storage

Considering the bioreactor (which will be described later on) necessity of a CO_2 continuous flow, a dedicated carbon storage system will be adopted. In this study, a setup as the one adopted in Francisca's analysis (2024) will be considered: a transportable storage tank similar to the ASCO CO_2 Semi-Trailer, with a storage capacity of 25 m^3 and a maximum pressure of 24 bar (Asco Carbon Dioxide LTD, 2023). Given a CO_2 production flow rate of 50 Nm^3/h, the compressor for the tank is sized assuming double capacity (100 Nm^3/h) to account for operational contingencies and guarantee system continuity during CO_2 supply interruptions. The specific electricity consumption for the compression of carbon dioxide was estimated based on the volumetric flow and the density of CO_2 under standard condition, which was calculated to be approximately 13 kW, representing the required compressor size (Francisca, 2024).

"As for the economic aspects, due to the lack of precise compressor cost data in the literature, the capital expenditure (CAPEX) of the CO_2 compressor was estimated using the same correlation applied to the hydrogen compressor. The storage tank cost was assumed to be €1,000 per cubic meter, based on standard industrial quotations for pressurized vessels" (Francisca, 2024). Operating expenditures (OPEX) are considered negligible for this component, as also hypothesized in Francisca's study

- COMPRESSOR
  - CAPEX: 17,500 €
  - OPEX: 525 €/y (3% of CAPEX)
- STORAGE TANK
  - CAPEX: 25,000 €
  - OPEX: -

2.5. Alternative energy carriers and conversion technologies

2.5.1. Desalinator

Water electrolysis for green hydrogen production requires a pure water source, with a salinity level and extremely low electric conductivity. Seawater, even though largely available, is not immediately suitable to be used in an electrolyzer, due to its high concentration of dissolved solids (TDS – Total Dissolved Solids), organic compounds, microorganisms and other impurities. To make seawater compatible with the quality requirements of the electrolysis, it is necessary to let the water undergo a desalination process, the Reverse Osmosis (RO). In a RO system, seawater passes through a semipermeable membrane, which lets only water molecules pass through and holds back salts (like Na^+, Cl^-, Mg^{2+}), heavy metals, bacteria and organic substances. In the modelled system, the desalinator is fed by the energy produced by wind turbines and directly supplies the demineralised water needed for the electrolysis process. The costs associated with the desalinator have been estimated on the basis of the daily flow rate of treated water, in line with what is reported in the reference literature. In particular, the CAPEX and OPEX values adopted are derived from Francisca's thesis, which in turn reports them from Trombini (2021) and summarizes them in Table 4.1 (Francisca, 2024):

- CAPEX: 1208 €/m^3/d
- OPEX: 72.5 €/(m^3 •y)/d (6% of CAPEX)

2.5.2. Electrolyzer

Water electrolysis is the core process of green hydrogen production, where surplus of energy generated by wind turbines is exploited to divide water (H_2O) into its gaseous components, hydrogen (H_2) and oxygen (O_2). Essentially, electric current goes through purified water, thus water molecules divide themselves based on the overall reaction $2H_2O \rightarrow 2H_2 + O_2$, releasing oxygen into the atmosphere and accumulating hydrogen (Puretech Systems, n.d.). Considering that electricity is provided by renewable sources, produced hydrogen id defined as "green", with zero CO_2 emissions.

The main commercial technologies are Alkaline Electrolysis (AEL) and Proton Exchange Membrane Electrolysis (PEM). AEL technology employs an alkaline liquid solution (usually potassium hydroxide) as electrolyte and porous separator between anode and cathode. Alkaline electrolyzer are usually cheaper due to their materials and robustness: they better tolerate feed impurities (e.g. traces of CO_2 or salts), have longer life and high production capacity (John Cockerill, 2024; Senza Hydrogen, n.d.). On the other hand, their efficiency is usually lower than PEM. PEM electrolysers use a polymer solid membrane that carries protons. They have higher efficiency (typically 70-80%) and fast response times to damping of variable loads (Senza Hydrogen, n.d.) and produce very high purity hydrogen. They are compact and operate at lower temperatures (also <80°C), but require catalysts based on noble metals (Platinum/Iridium) making them more expensive in terms of investment and subject to limited duration. Based on this comparison, PEM technology allows to combine high operating flexibility and efficiency similar to AELs', making it particularly suitable to cope with rapid power changes, which are very frequent using wind energy.

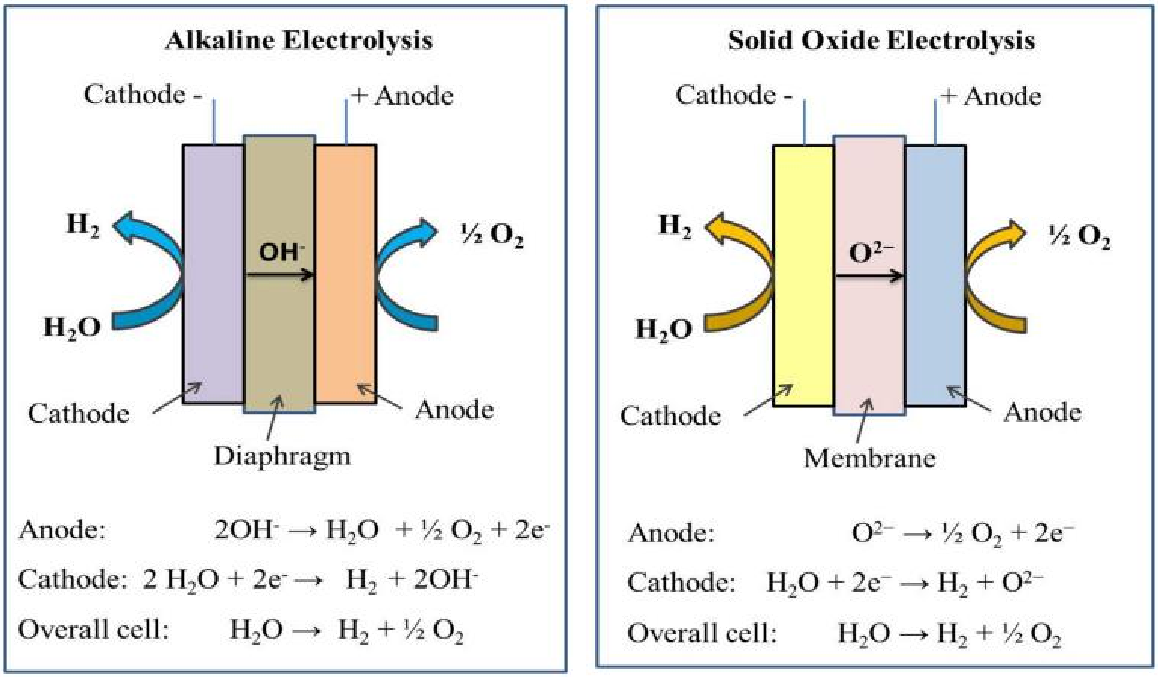

Figure 9: Schematic illustration of alkaline and solid oxide water electrolysis (S. S. Kumar et al., 2019)

In this study, based on the simulations reported in Francisca's thesis (2024), an optimal size for the electrolyser of 4.5 MW was selected, with an electrical efficiency of 65%, an operating pressure of 35 bar, a minimum electrical load of 5% and a useful life of the stack of 10 years. For the estimation of costs, the same values used by Francisca (2024) were adopted: CAPEX is based on Davies et al. (2021), while OPEX is assumed to be 4% of CAPEX, as indicated by Monitor Deloitte (2020). Both values also include the costs of the rectifier required for the operation of the unit.

- CAPEX: 700 €/kW
- OPEX: 28 €/kW/y (4% CAPEX)

2.5.3. Hydrogen compressor

As also Francisca (2024) states, if hydrogen is to be exported via the same pipeline as natural gas or stored locally, compression is required. The electrolyser is assumed to operate at 35 bar, whereas the gas transmission pipeline connected to the offshore platform operates at 20 MPa (200 bar) (Svendsen et al., 2023). Thus, a two-stage compression system is used. Empirical formulas adapted from natural gas compression and expressed per unit mass of hydrogen were used to estimate the electrical consumption of the compressor. The resulting electricity requirement is 0.97 kWh per kg of hydrogen compressed (Francisca, 2024). For the economic assessment, the CAPEX of the compression unit was derived by Francisca from the empirical formula adapted from Van Leeuwen et al. (2018).

- CAPEX: $13800 \cdot \left(\frac{Sx}{10\ kW}\right)^{0.9}$ €
- OPEX: 3% CAPEX

2.5.4. Hydrogen storage

Green hydrogen production via electrolysis from renewable sources implies inevitably variability in production, due to primary energy intermittency (in this case, wind). To guarantee continuity with the hydrogen fed to the biomethanation reactor – which requires continuous feeding -, it is essential to integrate a storage system. Hydrogen storage makes it possible to balance supply and demand based on the request per hour, per day or per season, and it can enable the participation in electricity flexibility markets. Many different hydrogen storage solutions exist, differing from each other for physical state (gas, liquid, solid), operating conditions (pressure, temperature), costs (CAPEX/OPEX), energy density and final application. Compressed storage remains simpler and less expensive than liquefaction, although the latter guarantees greater volumetric density at a much higher complexity price. In this study, pressurized gaseous hydrogen storage is assumed, as it can operate at ambient temperature and avoids the need for cryogenic technologies. Typical storage pressures range between 175 and 700 bar (Cheng et al., 2024), mainly due to the low volumetric energy density of hydrogen in its gaseous form (0.0852 kg/Sm³ and 0.01079 MJ/L). However, despite these high pressures, large volumes are still required—one of the main limitations of this storage method. Pressurized storage tanks are classified into four types, from Type I (metal tanks) to Type IV (fully composite), with increasing pressure resistance and cost. For the present application, a storage pressure of 200 bar is assumed. Following the approach proposed by Francisca (2024), Type I tanks—made entirely of steel—were selected due to their simplicity, cost-effectiveness, and suitability for stationary installations. The capital and operational expenditures (CAPEX and OPEX) associated with this type of tank have been taken directly from the techno-economic assumptions in Francisca's work, which refers to a CAPEX expressed per unit of daily water treated in the case of desalination and per kgH_2 stored for the storage tanks. Specifically, the same cost data used in Table 4.1 and Table 4.6 of her thesis were adopted, originally derived from Trombini (2021) and Van Leeuwen et al. (2018), and adjusted for consistency with the system configuration assumed in this study (Francisca, 2024).

- CAPEX: 225 €/kg_{H_2}
- OPEX: 1.5% CAPEX

2.5.5. Biomethanation reactor

Biomethanation is well known as "Power-To-Methane" and it is based on the exothermic reaction of Sabatier:

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \qquad \Delta H = -165\ kJ/mol$$

Existing biomethanation reactors are typically pressurized CSTR systems (such as continuously stirred tank reactors). However, in the literature can also be found implementations in batch, fed-batch, or semi-continuous modes. In this work, the system is assumed to operate between 20% and 100% of its nominal capacity, based on the modular nature of the selected bioreactor.

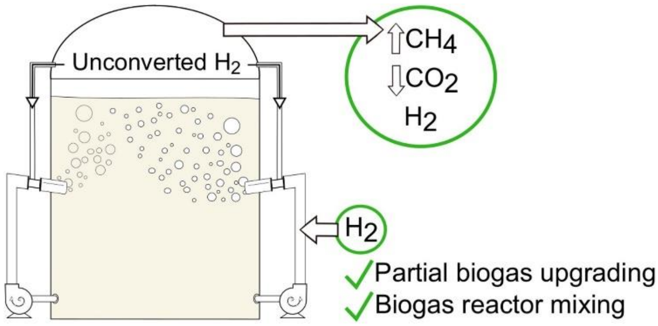

Figure 10: Graphical abstract of biomethanation (Source: M.B. Jensen et al., 2020).

Biological methanation shows some important features:

- Pollutant tolerance: hydrogenotrophic archaea is particularly resilient to impurities commonly present in flue gases, such as H_2S and NH_3;
- Operational flexibility: the system has a rapid response times (minutes), which allows frequent load variations and start–stop cycles without affecting microorganism activity;
- High methane purity: methane content can be more than 98% in a single-stage process, making it suitable for grid injection (Francisca, 2024).

In the present work, a suitable configuration is the Electrochaea “BioCat1” modular reactor, which has been analyzed in previous techno-economic assessments for its ability to produce up to 50 Nm³/h of biomethane.

Table 1: Techinical parameters of BioCat1. Adapted from Francisca (2024).

Parameters	**Typical value**
CH_4 production	50 Nm³/h
Volume	3570 L

Temperature	63 °C
Pressure	10 bar
Outlet CH_4 purity	>98%
Operative mode	20-100% of nominal load

According to cost data reported by Van Leeuwen et al. (2018) and used in Francisca's analysis (2024), the BioCat1 reactor has the following costs:

- CAPEX: €578,000;
- OPEX: €28,900/year (5% CAPEX).

These values of costs have been used in the optimization study by Francisca (2024) and are assumed here for consistency in the overall modeling.

2.5.6. Hydrogen blending with natural gas

In December 2021, the European Commission presented the proposal for the *Hydrogen and Decarbonised Gas Package*, a legislative package that represents the first comprehensive EU regulatory framework for hydrogen and other renewable gases (Freshfields, 2022). This package includes measures for the creation of an infrastructure dedicated to hydrogen, including the definition of cross-border networks and efficient markets for this energy carrier, reviewing and recasting existing legislation for natural gas (Regulation (EU) 715/2009 and Directive 2009/73/EC).

As already mentioned, blending occurs in both *Scenario 1* and *Scenario 2*. Blending solution to mix a percentage of Hydrogen (H_2) into the flow rate of natural gas. This solution grants to take advantage of the already existing equipment of the gas pipeline and "is considered a possible interim first step towards decarbonising natural gas" (Freshfields, 2022). However, some limitations occur: pipelines and industrial/domestic devices are designed for gas with specific physical and chemical characteristics, where hydrogen wasn't considered. According to Freshfields (2022), the draft EU Gas Package sets a 5% hydrogen blending limit in existing natural gas networks: "The draft Regulation generally leaves it to the Member States to allow for blending in their national natural gas systems but sets a blending threshold of up to 5% hydrogen content in gas flows at interconnection points to harmonize cross-border natural gas flow. Consequently, from 1 October 2025, transmission system operators will have to accept natural gas with a blended hydrogen level below this threshold" (Freshfields, 2022). This threshold was set in order to reduce risks linked to material embrittlement and change in calorific value (Freshfields, 2022). For instance, some studies have shown that mixing hydrogen more than 5% in volume increases significantly risks of leakage and embrittlement of ferrous materials ("hydrogen embrittlement") (Utility Dive, 2022). Higher percentages may require changes to valves, counters and appliances (boilers, stoves, etc.) to ensure proper tightness and ignition (Utility Dive, 2022). In addition, H_2 has a lower calorific value per volume than CH_4, so the addition of H_2 slightly reduces the energy content of the mixed gas (this must be compensated for in the calibration of combustion appliances). In practice, for reasons of compatibility of existing networks and safety, the model foresees a limit of 5% H_2 in the mixture, in line with the threshold indicated by international standards (Freshfields, 2022).

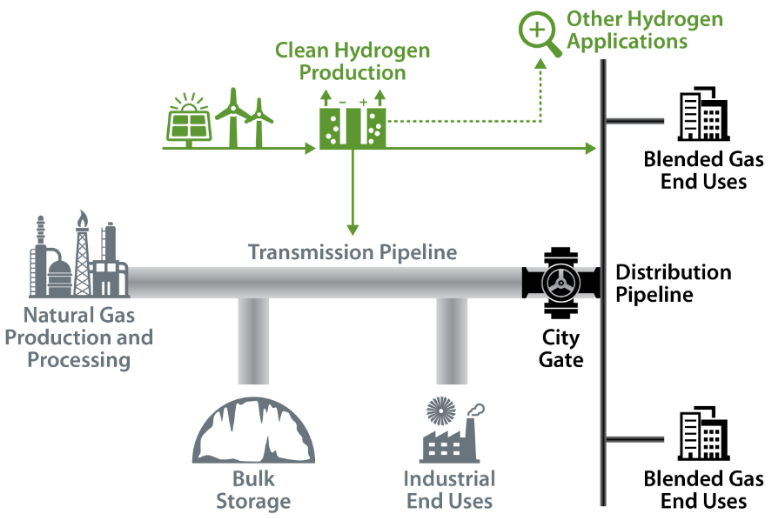

Figure 11: Supply chain and components of blending in natural gas networks (Source: U.S. Department of Energy, 2022).

2.5.7. Flare systems

Flare is a fundamental safety system in every gas plant: it is needed to burn in a controlled way the possible surplus of gas, avoiding dangerous accumulations. In the case of process anomalies or overproduction of hydrogen, the flare acts as a «relief valve»: the hydrogen is diverted to the flare and burned into the atmosphere at a continuous flame. This eliminates the potential for explosive or uncontrolled emissions: the H_2 is converted into H_2O, instead of being dispersed intact (Number Analytics, 2025). In an offshore scenario *self-supported flares* are usually employed, that is free towers on themselves without the need for additional ties or structures. The self-supporting flarees are mounted on a single pedestal and require only one foundation base (Zeeco, n.d.). According to Number Analytics (2025), this kind of structure allows to reduce the footprint on the ground and eliminates the problems of tensioning anchor cables, making the system more suitable for the space limitations of a platform.

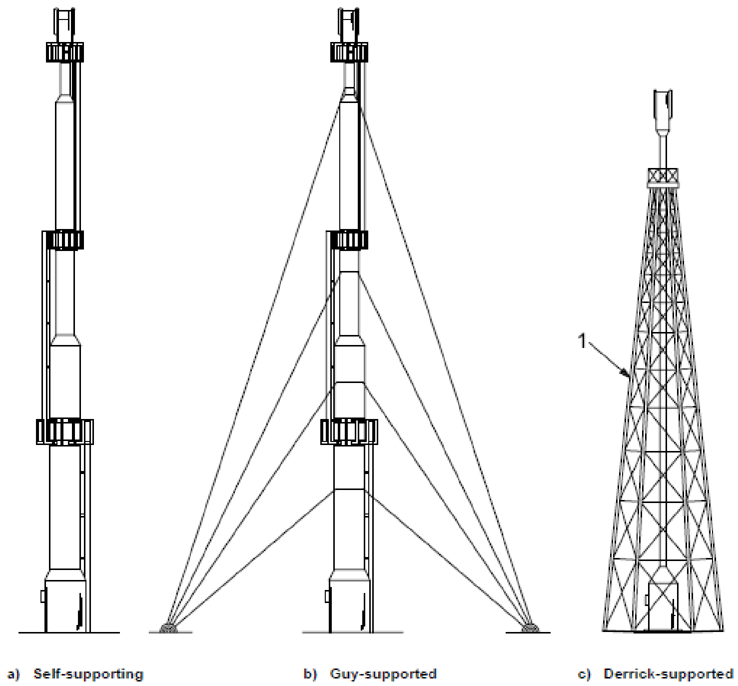

Figure 12: Elevated Flare Support Structures (from API STD 521).

3. Methodology

3.1. Basis of the previous work

The reference model is based on the dataset developed by Francisca (2024), who combined offshore wind power generation, the thermal and electrical demand of the platform, and green hydrogen production via electrolysis by using simulation software, HOMER PRO. The electrical and thermal load demands were obtained by modeling the interaction between hydrocarbon and water production flows and the energy requirements of the platform's main equipment and auxiliary services. In this model, it is distinguished between variable loads (dependent on production levels) and constant loads (unaffected by operational changes). The simulated system included wind turbines, compressors, an electrolyzer, and gas turbines, and yielded hourly hydrogen production values over a 10-year period: a total of 8,760 data points per year, expressed in Sm^3/h. Natural gas production profiles were derived from real data from the British offshore field Saturn (2008), chosen for its regular behavior and production values similar to those of the reference platform LEOGO. To simulate the full 25-year lifetime of the field, the first five years were modeled as a plateau phase with constant production; the last 10 years, the decline phase, is modeled based on an exponential model, assuming a 10% annual reduction in hourly production. Additionally, oil and water production profiles were calculated assuming constant GOR (Gas-to-Oil Ratio) and WC (Water Cut), assuring that all three production curves (gas, oil, water) followed the same hourly trend. The resulting hydrogen and natural gas hourly datasets were then used as inputs to model both the hydrogen storage system and the flare unit.

3.2. Scenarios

3.2.1. Scenario 1 – BHM

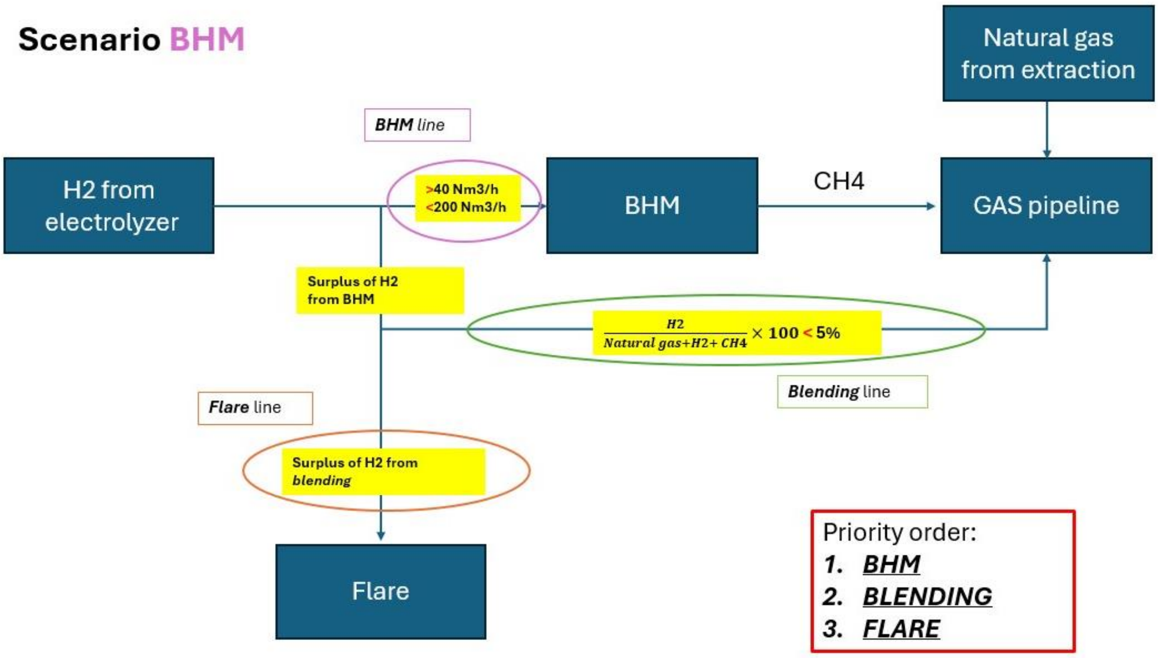

Figure 13: Scenario BHM logic (Author's own work).

The hydrogen produced is primarily allocated for biomethane production. Considering the operating assumption that the biomethanation reactor functions between 20% and 100% of its nominal capacity, it may occur that the hourly hydrogen flow exceeds the maximum intake of the reactor. In this case, any surplus hydrogen is directed to the storage tank, provided there is available capacity. If the storage tank is already full and further hydrogen surplus exists, the excess is diverted to the natural gas stream for blending, always ensuring that the hydrogen share does not exceed the upper limit of 5% by volume. Any remaining hydrogen beyond this threshold is flared for safety.

Opposite, if the hydrogen flow is lower than 20% of the reactor's nominal capacity, the system draws from the storage tank to compensate and meet the minimum required inlet. If the tank is not able to fully compensate, then the priority becomes to refill the tank as much as possible with the available hydrogen. Any residual hydrogen is then directed to blending (within the 5% limit), and if necessary, flaring is used to dispose of the remaining amount. If the storage tank is already full in this case as well, the system proceeds directly to blending and, if needed, to flaring. The tank level is set at zero at the beginning of the simulation and it is dynamically updated over time. The hydrogen level in the tank is not reset at the beginning of each year; that is, it is continuously carried over across the simulation period.

3.2.2. Scenario 2 – Blending only

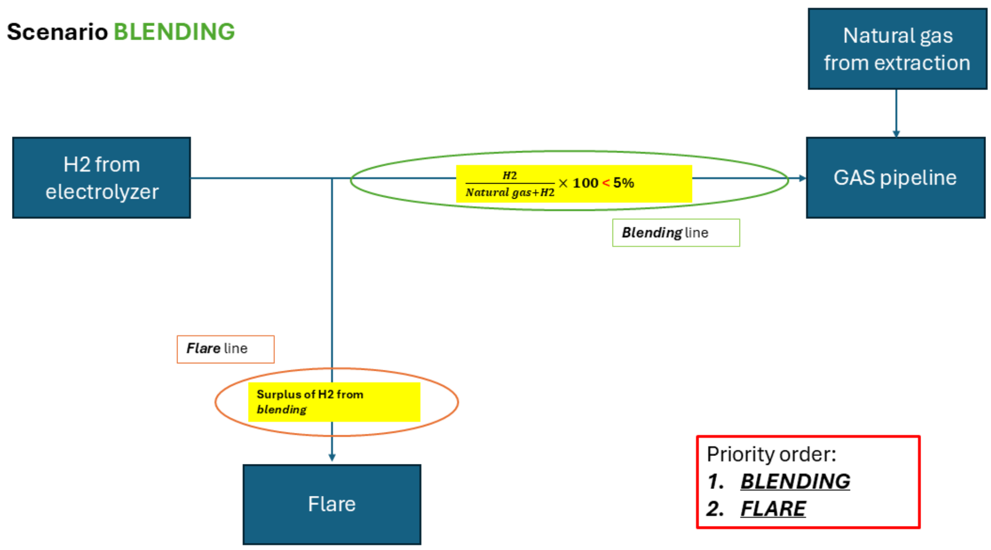

Figure 14: Scenario Blending only logic (Author’s own work).

Scenario 2, unlike Scenario 1, does not involve upgrading the produced hydrogen to CH_4; as a result, the H_2 storage tank is no longer required. In this configuration, all the hydrogen produced is directed to blending, always respecting the 5% volumetric limit. In the event of excess hydrogen due to this blending constraint, the surplus will be burned in the flare system.

3.2.3. Hydrogen storage tank sizing

One of the key objectives of this work is to minimize the cost of the hydrogen storage tank by identifying the minimum required volume. In the analysis conducted by Francisca (2024) for the Ekofisk platform, the tank was sized to store up to 3,500 kg of H_2, allowing a constant supply of 200 Nm³/h to the biomethanation reactor. This corresponded to an estimated tank volume of approximately 250 m³.

In this work, a different strategy was adopted to optimize the tank size, considering the intermittency of wind energy and the need for a continuous hydrogen feed to the biomethanation reactor. The approach involved a year-long analysis of hourly wind speed data at 50 meters height for the Ekofisk location, using data retrieved from the NASA POWER database for the year 2023.

After converting the wind speeds to meters per second, all hours falling below the turbine cut-in speed (4 m/s) or above the cut-off threshold (25 m/s) weTanre identified. The longest uninterrupted sequence of such hours was 36 consecutive hours, during which the wind turbines would not be able to produce energy, and thus no hydrogen could be generated via electrolysis. As a result, the biomethanation reactor would lack H_2 input during this critical period.

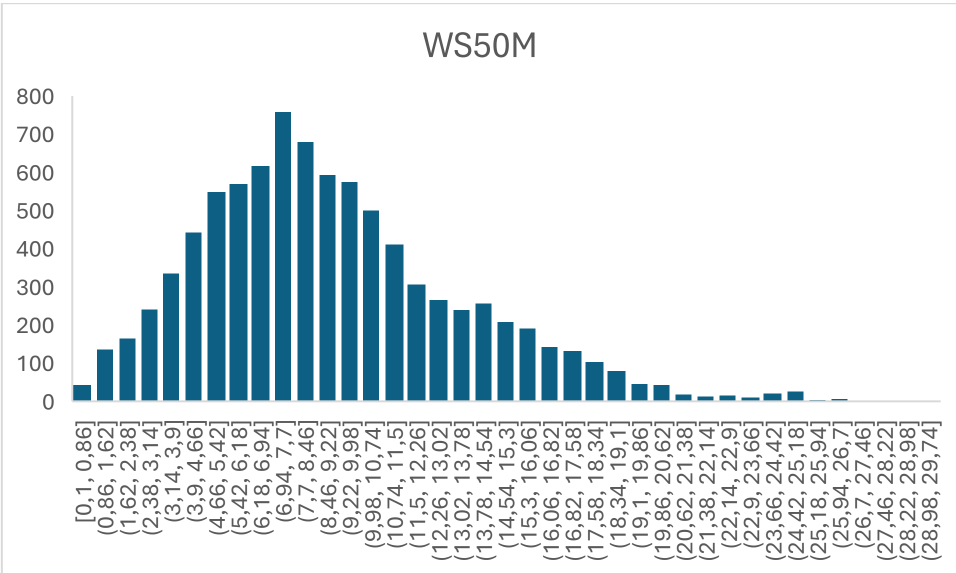

Figure 15: Frequency distribution of wind speed at 50 meters in Ekofisk (Author's own work).

To ensure reactor continuity, the hydrogen tank must be capable of supplying the minimum required flow rate of 52.196 Sm³/h for 36 hours.

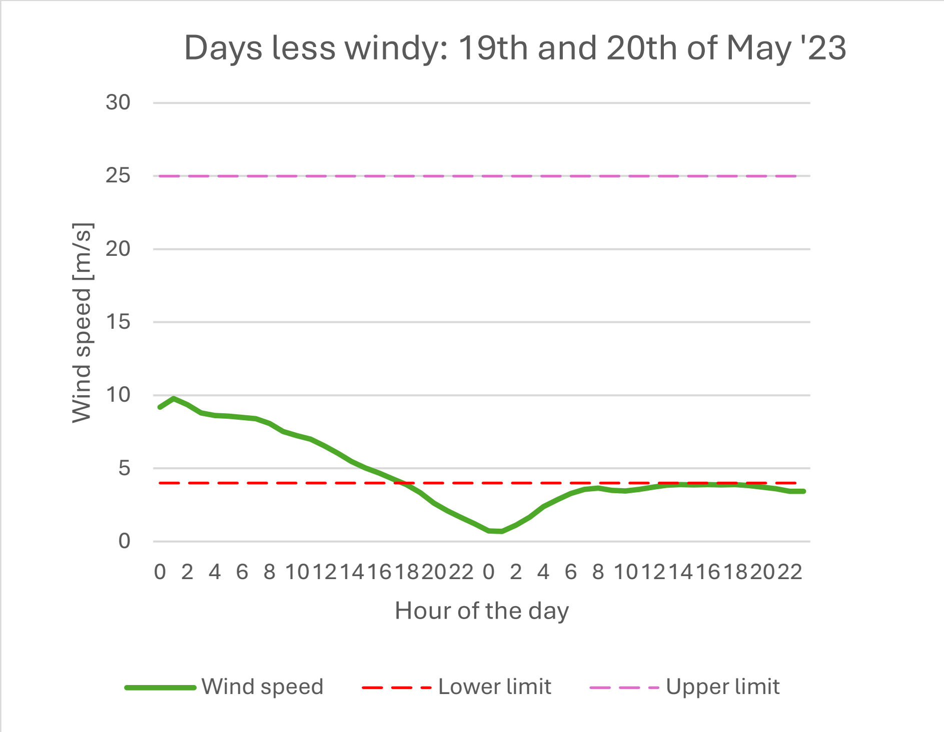

Figure 16: Hourly wind speed profile on less Windy days: May 19th and 20th, 2023 (Author's own work).

Taking into account the hydrogen compressibility factor which assumed to be Z = 1.04 (Makridis, 2016) and an assumed storage pressure of 200 bar, the following hydrogen storage requirement was derived:

$$Tank\ volume = 36\ h\ \times\ 52.196 \frac{Sm^3}{h} \times \frac{1.04}{200\ bar} = 9.77\ m^3 \approx\ 10\ m^3$$

$$H_2\,mass\ to\ be\ stored =\ 36\ h\ \times\ 52.196\ Sm^3/h\ \times\ 0.08522\ kg/Sm^3 \approx\ 160\ kg\ of\ H_2$$

The resulting capital and operational costs for the hydrogen tank were calculated using the cost assumptions provided in Table 4.6 of Francisca (2024), which refer to estimates from Trombini (2021) and Van Leeuwen et al. (2018):

- CAPEX = 225 €/kg × 160 kg = €36,300
- OPEX = 1.5% of CAPEX = €545.4 €/year

3.2.4. Flare system sizing

The emergency flare system was introduced following an analysis of the hydrogen and natural gas export data. In particular, while the gas flow remains relatively table with minor fluctuations, sudden and significant drops (downward spikes) are observed during specific time intervals.

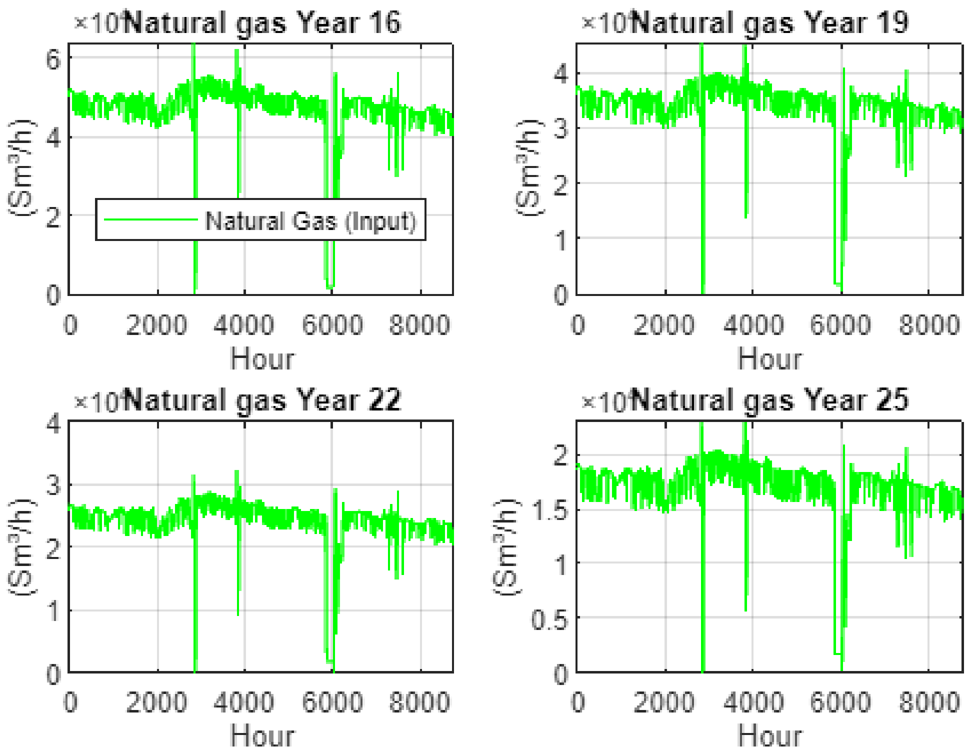

Figure 17: Hourly gas flow rate over the years.

These downward spikes occur around the same hours each year (approx. hours 3000 and 6000). Such patterns could represent planned maintenance shutdowns or short operational pauses, which are often carried out at regular intervals to guarantee the facility's efficiency and safety. Alternatively, they could simulate unexpected faults in equipment such as compressors, separators, or export systems, which may cause a temporary halt in gas extraction. However, since the hourly gas flow data in this study were derived from a daily production profile (taken from the Saturn field in 2008) and interpolated using a spline method, it is also reasonable to assume that these drops may result from artifacts of the interpolation process. In particular, the spline fitting could introduce artificial minima at the same positions in each year if the original dataset shows regular low values or discontinuities at certain points.

Plotting the annual extracted gas confirms that it follows the exponential decline model hypothesized by Svendsen (2022):

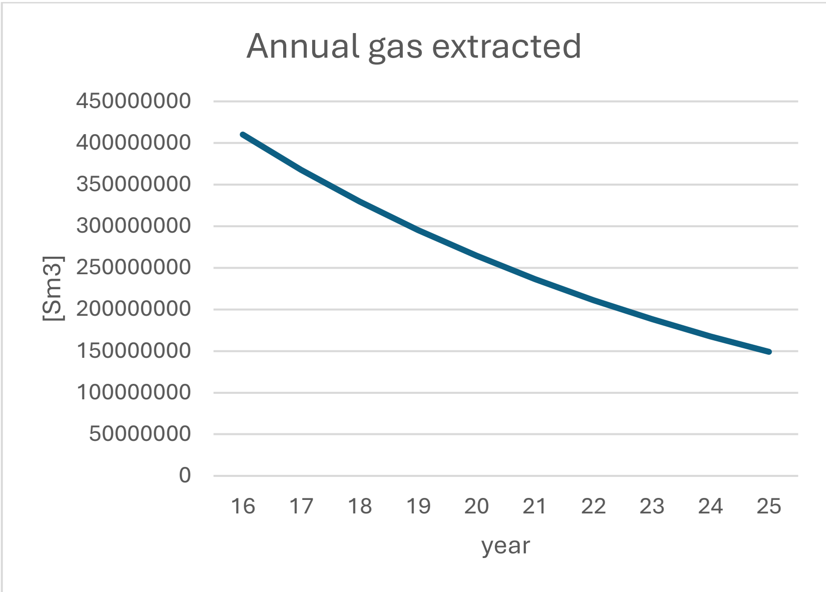

Figure 18: Annual gas extracted.

In contrast, analyzing the annual hydrogen production over the same years reveals an exponential growth trend:

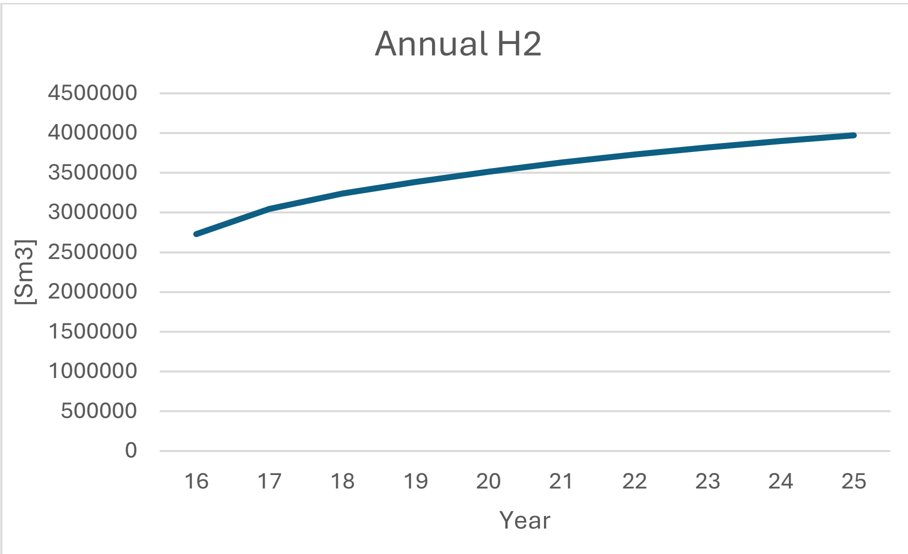

Figure 19: Annual hydrogen produced.

By comparing the two datasets and considering the 5% volumetric blending limit, it was possible—through a MATLAB script—to graphically identify when the hydrogen injected into the gas pipeline exceeded the permitted threshold:

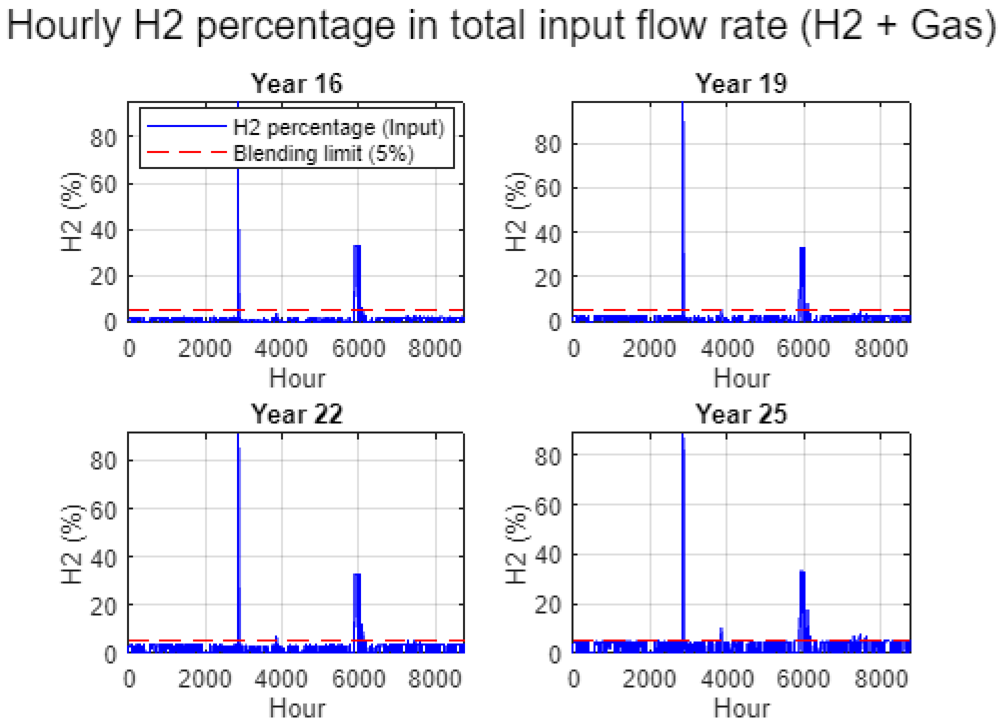

Figure 20: Hourly H_2 percentage in total input flow.

The recurring spikes observed around hour 3000 and 6000 each year are due to zero-flow periods in the gas output, which cause the hydrogen blending percentage to "spike" upward. In fact, plotting the volumetric flow rates shows that the hydrogen flow remains relatively constant, while the 5% blending limit exhibits sudden downward shifts:

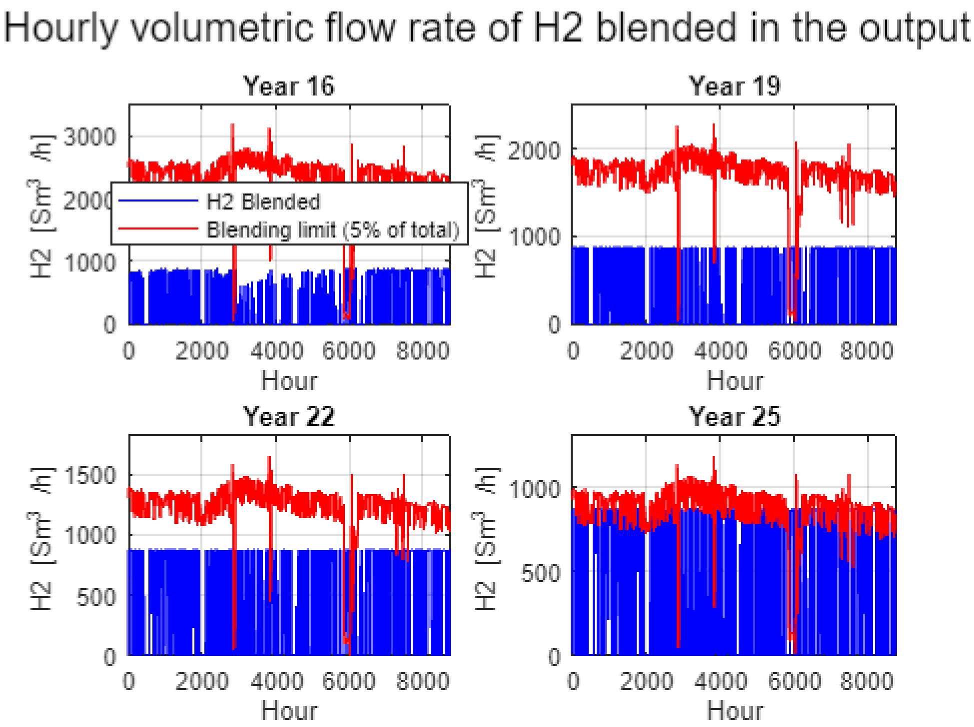

Figure 21: Hourly volumetric flow rate of H_2 blended in the output.

In any case, it becomes clear—especially in the later years—that there are situations where the amount of hydrogen produced exceeds the amount that can be blended. Therefore, an emergency system such as the flare becomes necessary.

To size the flare system, the most critical scenario observed during the final 10 years of platform operation was selected. Specifically, Scenario 2 (hydrogen blending only) was chosen, as the hydrogen flow rates directed to the flare are logically higher compared to Scenario 1, where part of the hydrogen is also used for other purposes (e.g., biomethanation). In this scenario, the maximum hourly hydrogen flow rate directed to the flare is 74.1 kg/h, occurring at hour 2858 in year 9. Additionally, the maximum annual flare operating time is 384 hours, recorded in year 25.

These values were therefore selected as reference conditions for sizing the emergency flare. For the actual sizing, the EPA Flare Cost Estimation Spreadsheet (U.S. Environmental Protection Agency [EPA], 2022) was used. This Excel tool enables the estimation of flare system parameters based on operational input data and cost models. Considering the limited available space (offshore environment) and the emergency role of the flare system (lowest operational priority), a self-supported flare configuration was selected. Finally, the dimensions obtained are a flare tip diameter of 15.14 cm and a stack height of 9.14 m, both adequate to ensure safe hydrogen combustion and dispersion under the defined peak conditions.

- CAPEX= € 253508.205
- OPEX = €59552.7

3.3. Earning methodology

The earnings from the different scenarios result from various revenue streams:

- *Scenario 1 – BHM*
  - Sale of methane injected into the pipeline at the natural gas price;
  - Sale of hydrogen injected into the pipeline (blending) at the hydrogen price;
  - Revenue from avoided CO_2 emissions (133 €/tCO_2);
- *Scenario 2 – Blending only*
  - Sale of hydrogen injected into the pipeline (blending) at the hydrogen price.

3.4. Assumptions and limitations

The sale price of natural gas was set at 0.08 €/Sm³. This value is consistent with the analysis conducted by Francisca (2024), who opted for the Henry Hub benchmark to represent a more stable and realistic estimate of the wholesale gas price. "The Henry Hub price, derived from the American market, was considered more appropriate because it excludes transportation, distribution, and storage costs. This approach is particularly suitable for the offshore platform case, where the gas is directly injected into the transmission network before undergoing any downstream operations that would significantly increase the final retail price." (Francisca, 2024).

Similarly, the sale price of hydrogen, set at 5 €/kg H_2, is aligned with the assumptions made by Francisca (2024), who in turn refers to projections by the Clean Hydrogen Partnership (2024). Furthermore, to evaluate the discounted cash flows, an interest rate of 5.88% was adopted. This value results from a nominal interest rate of 8% and a discount rate of 2%, consistent with the targets set by the European Central Bank.

Lastly, regarding the limitations, it should be noted that the gas data were derived from a simplified mathematical model. As for wind data, the year 2023 was selected as a representative due to the completeness and high resolution of available wind data for that year. Moreover, preliminary analysis of wind patterns over a multi-year period revealed that 2023 falls within the lower percentile range of wind energy availability. This conservative approach reduces the risk of overestimating economic returns.

4. Results analysis

Below the main results are shown. These results have been obtained by a MATLAB code, which can be found in *Annex I.*

4.1. Results *Scenario 1* – BHM

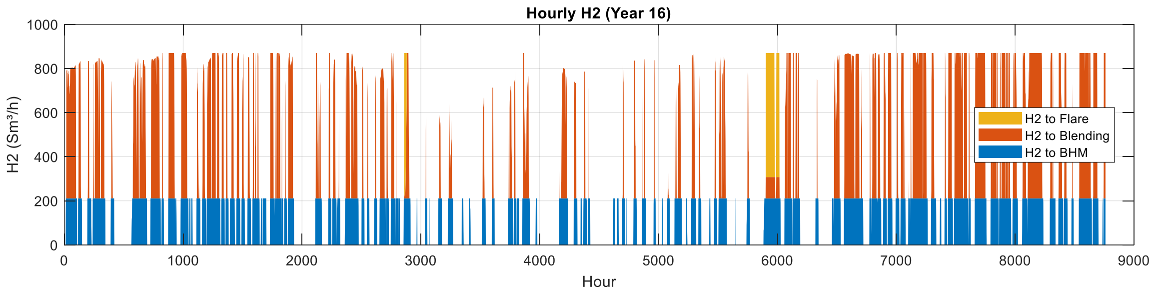

Figure 22: Hourly flow rate of H_2 per destination in the 16th year.

Figure 22 shows the hourly flow rate of H_2 per destination in the 16th year, which corresponds to the year with the lowest energy surplus. Here it's quite clear how the priority falls on biomethanation, considering its almost constant trend. Most of the hydrogen surplus is sent to blending. Yellow bars (H_2 to Flare) are much less common and indicate the loss of H_2 by flare burning, which occurs only when it cannot be stored or used for blending. This highlights the efficiency of the system in minimizing waste by sending only hydrogen to the flare that cannot be managed otherwise.

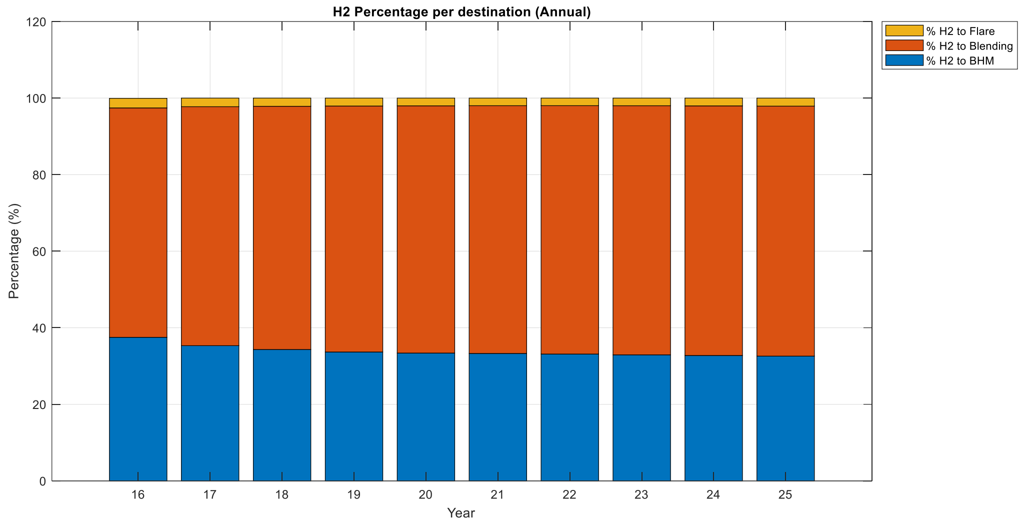

Figure 23: H_2 percentage per destination (Annual).

In *Figure 23* the relative percentage per destination of annual H_2 is shown, from year 16 to year 25. The percentage of H_2 destined for biomethanation (blue) seems to be relatively stable around 30-35%. The largest percentage is constantly devoted to blending (orange), occupying most of the remaining share (about 60-65%). The percentage of H_2 at the Flare (yellow) is almost invisible and remains very low, confirming that the use of H_2 is highly efficient and waste is minimal in all years considered.

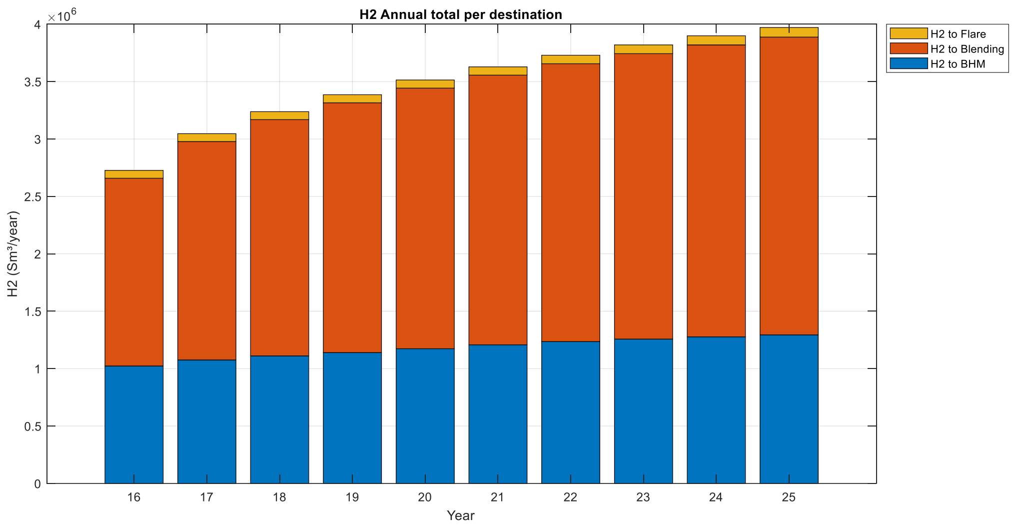

Figure 24: H_2 Annual total per destination.

Figure 24 provides an aggregated view of H_2 usage over time. It is noted that the largest share of H_2 is always destined for blending (orange), which grows significantly over the years. H_2 for Biomethanation (blue) remains relatively constant or has a slight increase, indicating perhaps a more stable load for the reactor. H_2 sent to the Flare (yellow) is marginal, confirming the effectiveness of priority use and storage strategies to minimize waste. The overall bar growth suggests an increase in total H_2 production over the years (possibly linked to year 25 as the year of maximum production, as mentioned in the tank sizing).

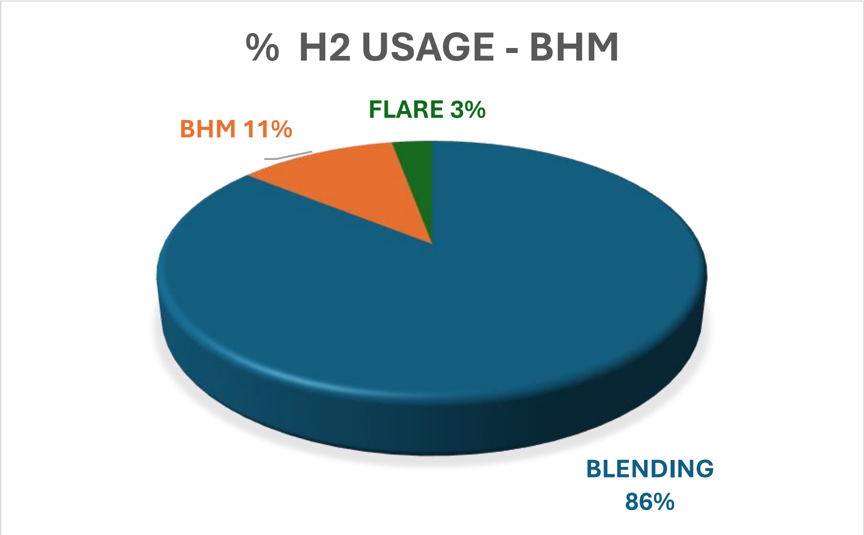

Figure 25: Percentage of H_2 usage in Scenario 1.

Overall, most of the H_2 produced (86%) is destined for blending, which makes it the main channel of use. A smaller share (11%) is allocated to Biomethanation (BHM), which, while being a priority, consumes less H_2 in percentage terms than blending. Only a small part (3%) is lost through the flare, confirming the optimization of hydrogen use and minimization of waste.

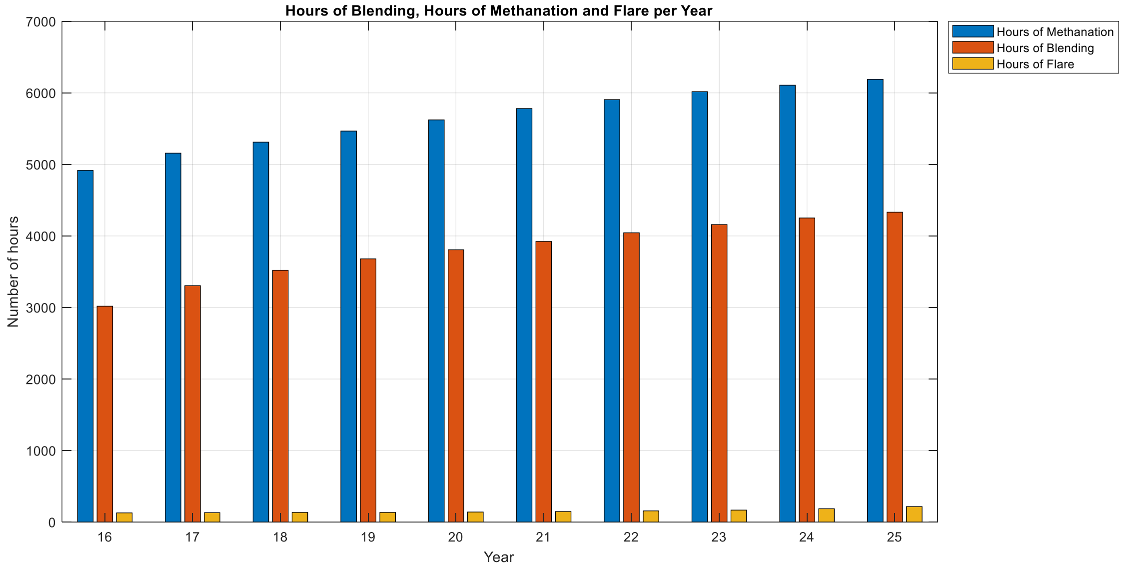

Figure 26: Hours of Blending, Hours of Methanation and Flare per Year.

Figure 26 shows the duration of operations. Biomethanation hours (blue) are the highest and increasing, suggesting that the reactor is operating for an increasing number of hours (highest priority). The hours of blending (orange) are also significant and increasing, indicating that the surplus of H_2 is managed by blending over an ever longer period of time. Flare (yellow) hours are extremely low, pointing out that flare burning is a rare and limited event, used only as a last resort. The overall increase in operating hours in all categories (with the exception of the flare which remains marginal) indicates an increasing activity and production of H_2 in the system.

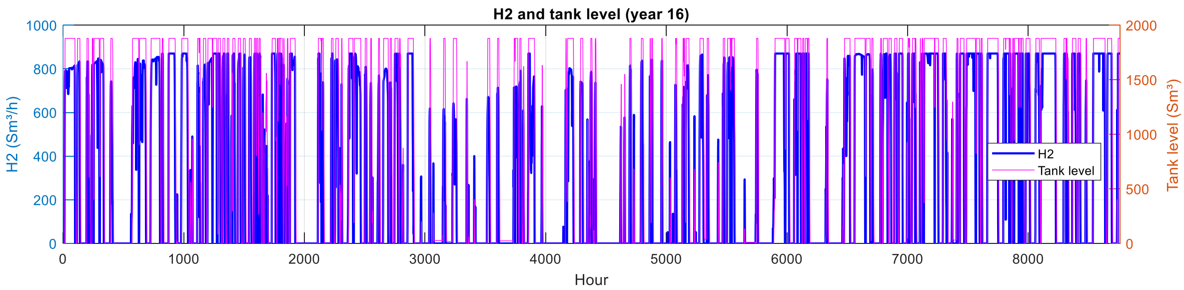

Figure 27: H_2 and tank level for the 16th year.

There is a strong correlation between the production of H_2 (the strongly varying blue line) and the tank level (the magenta line following fluctuations). The H_2 production peaks are very evident, reaching almost 900-1000 Sm^3/h at certain times, probably in conjunction with the availability of wind energy. The tank level adapts to these fluctuations, rising when there is a surplus and falling when demand exceeds instant supply.

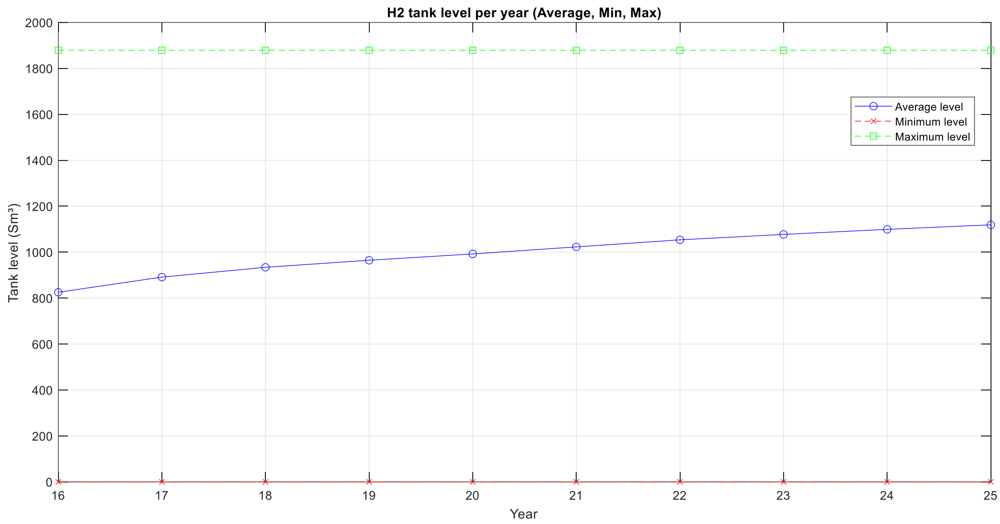

Figure 28: *H_2 tank level per year (average, min, max).*

The graph in *Figure 28* is essential to assess the stability and long-term management of the tank. It is noted that the minimum level (red) always remains at zero, which confirms that tank sizing (as described above) is effective in preventing total depletion by ensuring continuity of H_2 flow to the reactor. The maximum level (green) remains constant, suggesting that the maximum capacity is not exceeded. The average level (blue) shows a slight increase over time, indicating that the system handles annual fluctuations well and may have a slight accumulated surplus on average in subsequent years, or that management adapts to an increasing output in the final years.

4.1.1. Costs - *Scenario 1*

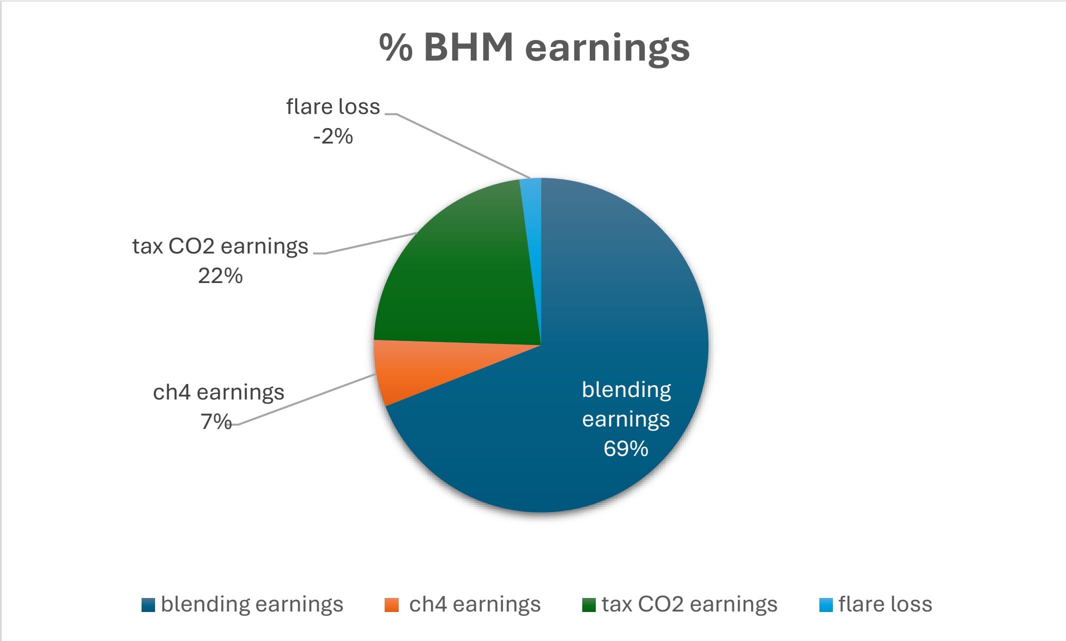

Figure 29: Percentage of earnings in Scenario 1.

Blending is the main economic "engine", generating an impressive 69% of total revenues. This suggests that, while biomethanation is the technology target, the ability to sell excess hydrogen through blending in the existing pipeline represents the main revenue stream. Tax benefits or CO_2 credits (22%) are also a vital component, underlining the importance of supporting environmental policies. Direct gains from biomethane (7%) are more modest, and losses from the flare (-2%) are, as expected, almost negligible, confirming the optimization of the entire hydrogen life cycle.

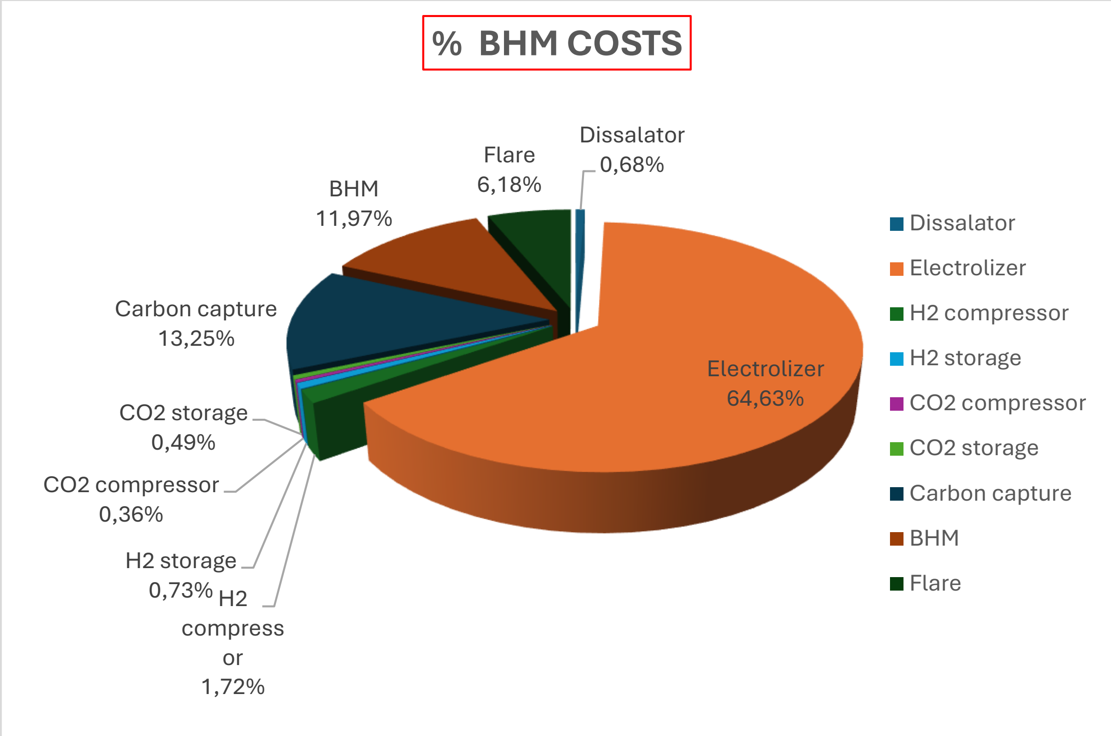

Figure 30: Percentages of costs in Scenario 1.

Figure 29 shows the percentage distribution of costs (CAPEX and OPEX combined) of the different components of the plant, such as the electrolyzer, the compressor H_2 , the storage H_2 , the bioreactor of biomethanation (BHM), the capture and storage of CO_2 , the desalinator and the flare. It clearly shows that the Electrolyzer (64.63%) represents the dominant cost item in the system, which is typical for green hydrogen production projects. Carbon Capture (13.25%) and BHM (11.97%), are also significant costs. All other components (Flare, Dissalator, compressors and H_2 /CO_2 storage) have a much lower percentage impact on total costs. This chart is crucial to understand the economic distribution of the project and identify areas where cost reduction would have the greatest impact.

Table 2: Scenario 1- Cash flow.

Year	Scenario 1 - BHM +Natural gas blending (<5% H_2)			
	Nominal cash flow		Discounted cash flow (i=5.88%)	
	Annual	Cumulative	Annual	Cumulative

0	-5.031.616,41 €	-5.031.616,41 €	-5.031.616,41 €	-5.031.616,41 €
16	520.710,04 €	-4.510.906,37 €	491.792,63 €	-4.539.823,78 €
17	638.479,71 €	-3.872.426,66 €	569.533,45 €	-3.970.290,33 €
18	707.367,98 €	-3.165.058,68 €	595.941,46 €	-3.374.348,87 €
19	759.968,11 €	-2.405.090,57 €	604.699,54 €	-2.769.649,33 €
20	802.756,63 €	-1.602.333,94 €	603.273,48 €	-2.166.375,84 €
21	839.027,27 €	-763.306,67 €	595.514,69 €	-1.570.861,15 €
22	871.561,68 €	108.255,01 €	584.252,53 €	-986.608,62 €
23	901.215,74 €	1.009.470,75 €	570.581,00 €	-416.027,62 €
24	926.803,04 €	1.936.273,79 €	554.194,30 €	138.166,68 €
25	949.584,68 €	2.885.858,46 €	536.283,42 €	674.450,10 €

Table 2 is crucial for the financial evaluation of the project.

It is assumed that the investment is made in Year 0 and that the earnings, due to the putting into use of the biomethanation solution, start from year 16, because the project was designed to work in the last 10 years of life of the platform.

The negative initial cash flow (Year 0) of -5,031,616.41 € represents the initial investment (CAPEX). Annual cash flow becomes positive from Year 16 and grows steadily over time, both in nominal and discounted terms. The nominal cumulative cash flow becomes positive between Year 21 and Year 222 (going from - -763.306,67 € to +108,255.01 €). The cumulative discounted cash flow becomes positive between Year 23 and Year 25 (going from -416.027,62 € to -138,166.68 €).

This indicates that the project recovers its initial investment (Payback Period) within the last years, based on discounted cash flows, demonstrating its long-term profitability.

Table 3: Final indicators of the economic feasibility of the project.

TIR	8%
TIR Discounted	2%
PBP	7,9 years
PBD	9,8 years
NPV	674450,1 €
ROI	13,4 %

In *Table 3* final indicators of the economic feasibility of the project are shown:

- IRR (8%) and IRR Discounted (2%): The nominal IRR is fair, while the discounted IRR, although lower, still indicates a positive return higher than the discount rate used, making the investment attractive.
- PBP (7.9 years) and PBD (9.8 years): These values are in line with what is observed in the cash flow table, indicating a return on investment within a reasonable period of time (less than 10 years for PBD).
- NPV (€674,450.1): A positive NPV indicates that the project is financially profitable, generating added value after covering all costs and considering the time value of money. This value corresponds to the Cumulative Discounted of year 10 in the previous table, suggesting that the calculation is for 10 years.
- ROI (13.4%): A positive and relatively high ROI indicates that the project generates a good return on initial investment.

4.2. Results *Scenario 2* – Blending only

This scenario represents a more lean approach to the use of hydrogen, focusing almost exclusively on direct injection into the natural gas network (blending), eliminating biomethanation.

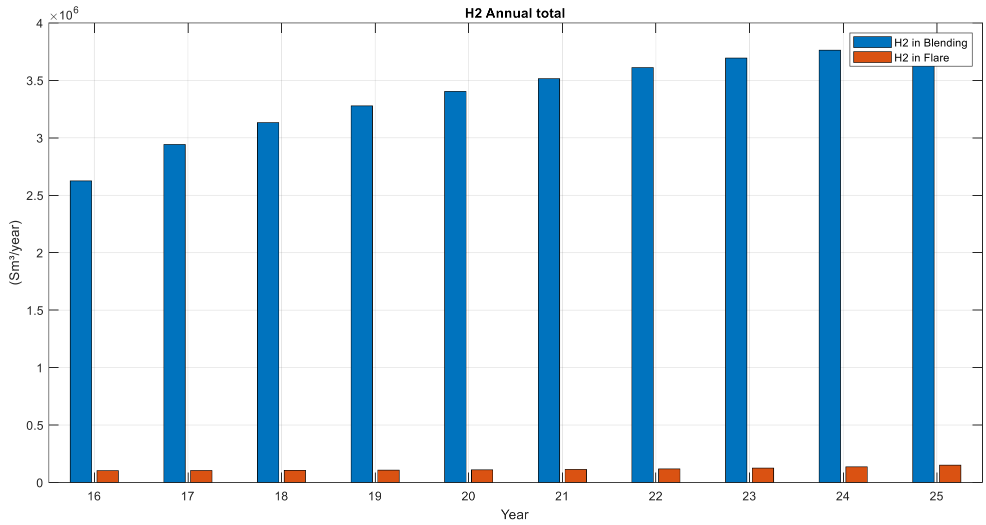

Figure 31: Annual total H_2 .

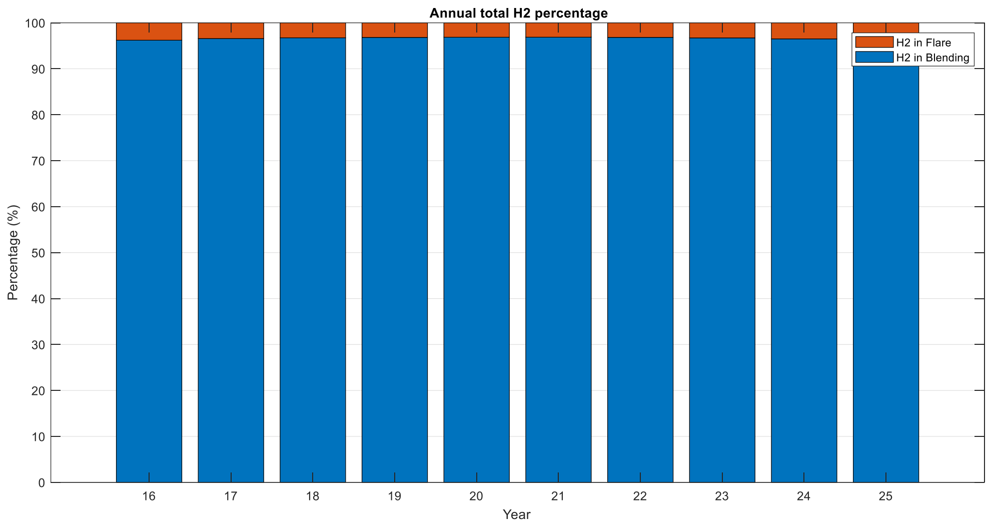

Figure 32: Annual total H_2 percentage.

Both *Figure 31* and *Figure 32* show that almost all the hydrogen produced is destined for blending (blue bars), with a minimum and almost constant amount sent to the flare (orange). *Figure 31* shows a significant increase in the total amount of H_2 handled over the years (from 16 to 25), suggesting an increasing production of hydrogen (probably related to the maximum production in year 25, as discussed above). *Figure 32* confirms that the percentage of H_2 in blending is constantly around 97-98%, while that sent to the flare is always marginal, at 1-2%.

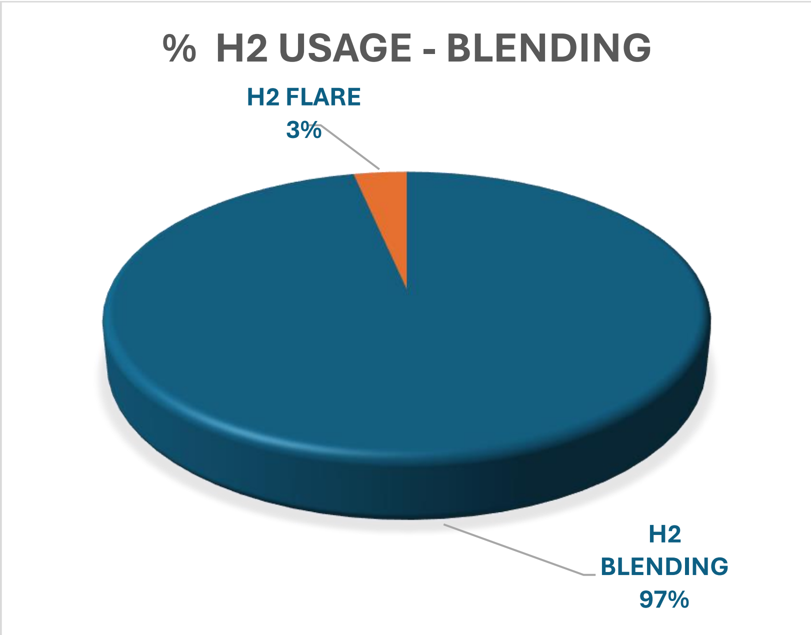

Figure 33: Overall H_2 percentage per destination.

Figure 33, very simple compared to the previous scenario, shows an unequivocal predominance of H_2 in blending (97%) over H_2 in flare (3%). This is the heart of this scenario: maximum efficiency in direct injection, with minimal losses.

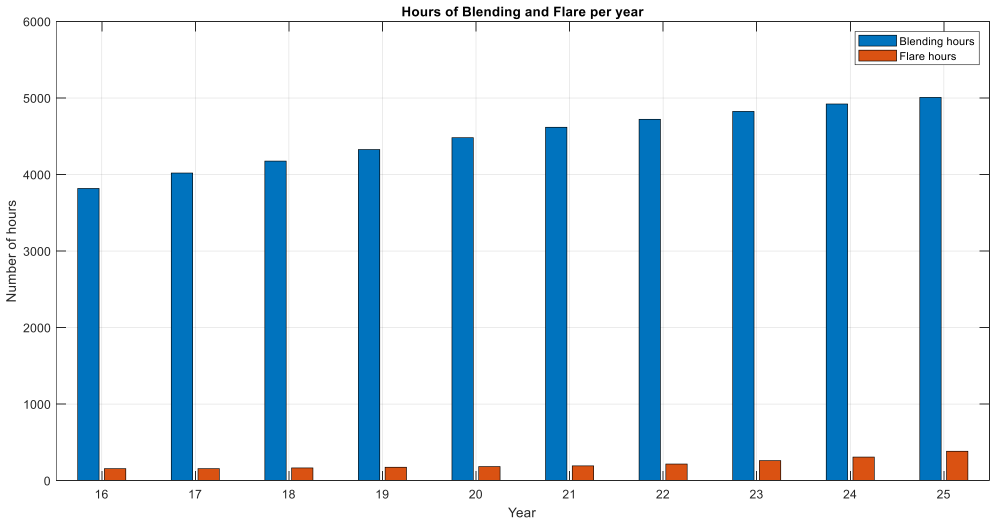

Figure 34: Hours of Blending and Flare per year.

The hours of blending (blue bars) are predominant and in constant increase from year to year, testifying to an almost continuous and increasing use of the blending channel. Flare (orange) hours are very limited, reaffirming that combustion is a rare and circumscribed event.

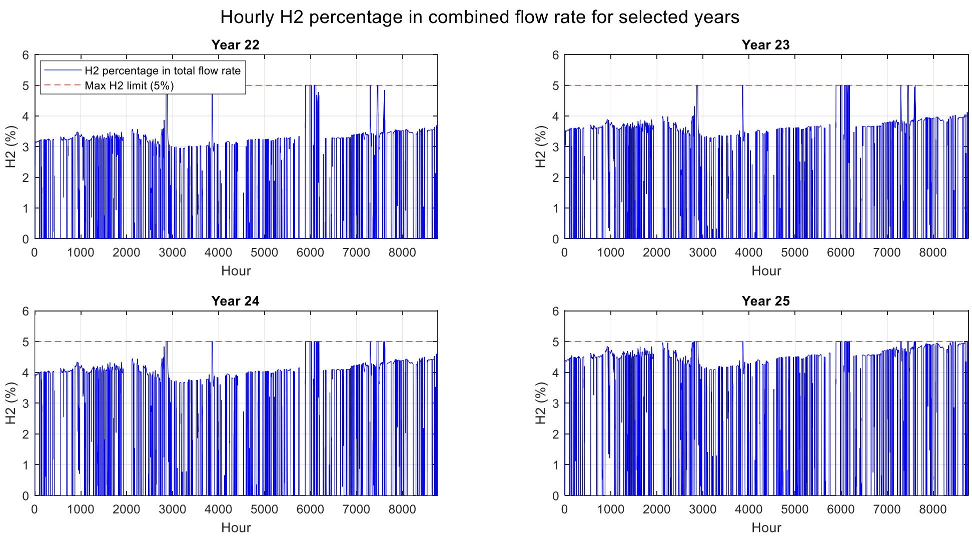

Figure 35: Hourly H_2 percentage in combined flow rate for selected years.

It is evident that the system operates constantly close to this limit or at high levels, demonstrating a strong capacity to feed H_2 into natural gas. The 5% peaks indicate that the system is making full use of the grid's capacity to accept hydrogen. The absence of a biomethanation tank and dedicated flows simplifies management, but at the same time makes blending the primary outlet for H_2 production.

4.2.1. Costs – Scenario 2

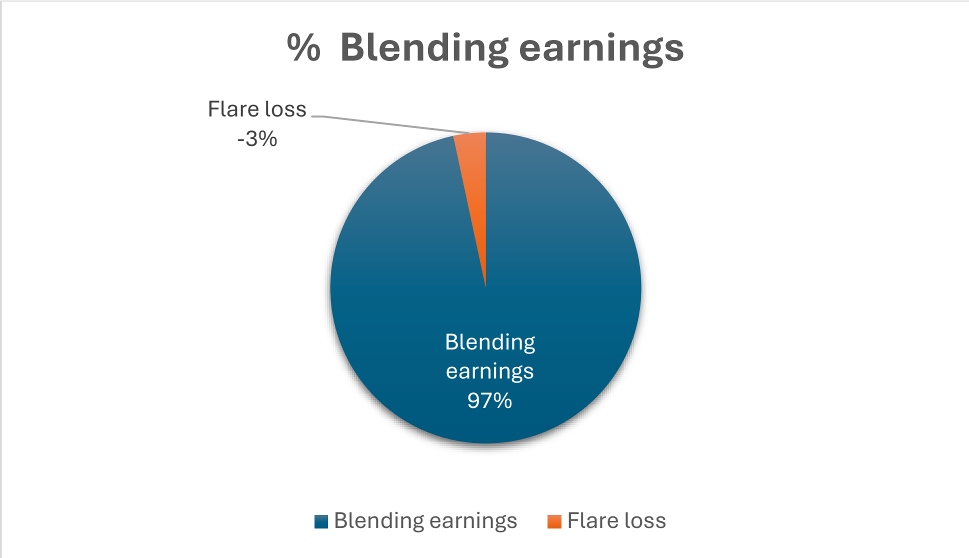

Figure 36: Earnings for Scenario 2.

Figure 36 confirms the total dependence of this scenario on a single source of income: blending (97%). The only economic "loss" comes from the flare (-3%), but it is clearly negligible. This means that the profitability of the project depends almost exclusively on the capacity to sell the mixed hydrogen and the price of the natural gas at which it is sold.

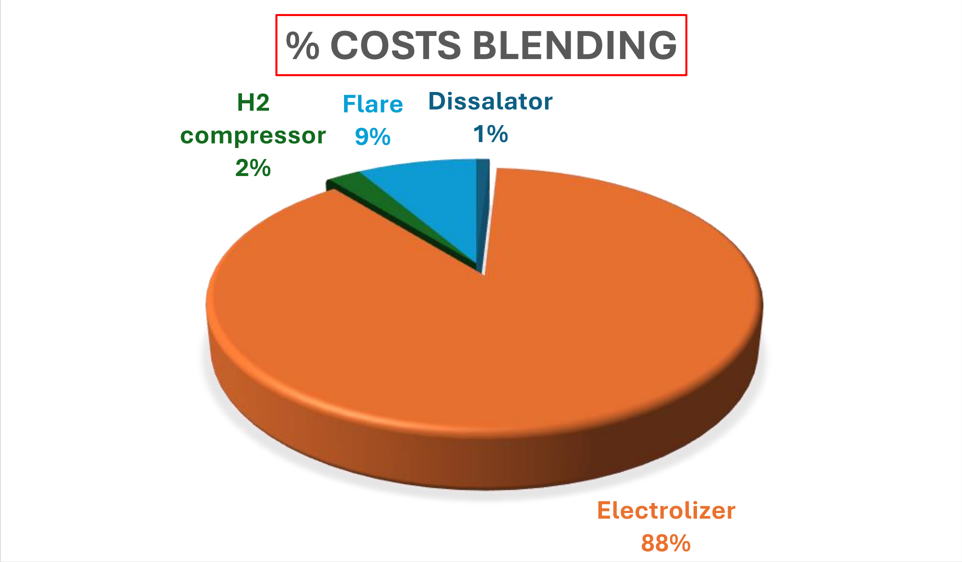

Figure 37: Percentages of costs for Scenario 2.

The figure above reveals a much more concentrated structure than in the previous scenario. The Electrolyzer dominates the scene with a whopping 88% of total costs. This is logical, given that in this scenario the significant costs associated with biomethanation and CO_2 capture are eliminated. The other items such as the H_2 compressor (2%), the flare (9%) and the desalinator (1%) are marginal. This simplified cost structure indicates that the cost of hydrogen is almost entirely determined by the cost of the electrolyser and the energy required to operate it.

Year	Only Natural gas blending (5% H2)			
	Nominal cash flow		Disconuntes cash flow (i=5.88%)	
	Annual	Cumulative	Annual	Cumulative
0	-3.520.608,21 €	-3.520.608,21 €	-3.520.608,21 €	-3.520.608,21 €
1	884.484,23 €	-2.636.123,97 €	835.364,78 €	-2.685.243,42 €
2	1.019.059,88 €	-1.617.064,09 €	909.016,65 €	-1.776.226,77 €

3	1.099.762,80 €	-517.301,29 €	926.525,18 €	-849.701,58 €
4	1.160.943,53 €	643.642,24 €	923.751,94 €	74.050,36 €
5	1.213.357,43 €	1.856.999,67 €	911.840,95 €	985.891,31 €
6	1.259.285,85 €	3.116.285,52 €	893.800,78 €	1.879.692,08 €
7	1.298.424,05 €	4.414.709,57 €	870.400,28 €	2.750.092,36 €
8	1.330.699,67 €	5.745.409,24 €	842.497,44 €	3.592.589,80 €
9	1.355.228,88 €	7.100.638,12 €	810.377,28 €	4.402.967,08 €
10	1.373.525,94 €	8.474.164,06 €	775.706,69 €	5.178.673,77 €

TIR	29%
TIR Discounted	21%
PBP	4,45 €
PBD	4,92 €
NPV	5.178.673,77 €
ROI	68,0

Table 4 and *Table 5* for Scenario 2 are extremely positive and significantly better than for Scenario 1.

- The initial investment in Year 0 is -3,520,608.21 €, significantly lower than Scenario 1, since it does not include the costs of biomethanation and CO_2 capture.
- Annual cash flows become positive between Year 18 and Year 19 and grow steadily.
- The Payback Period (PBP) is only 4.45 years, and the Discounted Payback Period (PBD) is 4.92 years. This is an outstanding result, indicating a very rapid return on investment.
- The Net Present Value (NPV) is €5,178,673.77, a much higher value than in Scenario 1, indicating an extremely profitable project.
- The Internal Rate of Return (IRR) is 29%, with a discounted IRR of 21%. These values are extremely high and make the project extremely attractive to investors.
- Return on Investment (ROI) is 68.0%, confirming the financial advantage of this scenario.

4.3. Main result

From the comparative economic analysis, it emerges incontrovertibly that Scenario 1 (Biometanathion + Blending + Flare) has overall higher total costs than Scenario 2 (Blending + Flare). This cost disparity results in lower profitability and longer payback times for Scenario 1, as evidenced by its less favorable financial indicators (NPV, IRR, PBP).

5. Discussion

As highlighted in the previous chapter, *Scenario 2 -Blending only* is the most convenient from an economic point of view.

5.1. Determinants of cost effectiveness

One of the main differences between the two scenarios is in their intrinsic structure in costs. *Scenario 1* requires a significantly higher initial investment (CAPEX). This initial burden is mainly due to the need to implement the bio methane reactor (BHM) and the complex CO_2 capture and purification systems. These components, although technologically advanced and functional to broader sustainability objectives, involve a start-up cost that significantly affects the budget of the project, with an estimated CAPEX of around 5 million euros in Year 0, against the estimated 3.5 million in *Scenario 2*. Moreover, the presence of BHM also introduces a number of additional operating costs (OPEX). These include the costs of the energy needed to run the bioreactor and the processes for compressing and transporting CO_2 , as well as specific maintenance costs and the need for qualified personnel to manage a biological process. Such recurring OPEX, in addition to the higher CAPEX, slows the recovery of the investment and negatively impacting crucial financial indicators like the Net Present Value (NPV) and the Internal Rate of Return (IRR) of *Scenario 1.*

In contrast, Scenario 2, by eliminating these costly components, becomes inherently lighter from a financial point of view. The main investment remains the electrolyser (whose percentage share of total costs goes up, precisely because the other significant items are missing), but the flow of hydrogen is channeled directly to the blending, which, as we have seen, is the most robust and established monetization channel. The efficiency of converting hydrogen to economic value is higher in Scenario 2 because the costs per unit of H_2 sold through blending are lower than the costs per unit of H_2 converted into biomethane. This allows the project to generate a positive cash flow much faster and accumulate significantly higher net worth over time.

Finally, *Scenario 2* shows a better optimization in earnings and costs with respect to *Scenario 1.*

5.2. Technical and economic implications

The results of this comparative analysis are not merely academic; they offer key insights and lessons for energy planning and the practical implementation of green hydrogen projects in challenging contexts such as existing offshore platforms or future maritime infrastructures.

Firstly, this analysis highlighted a dilemma between "ambitious" and "pragmatic" decarbonization. *Scenario 1* is the most environmentally sustainable but still comes with a significant economic burden. Considering the economic and space limitations that a company might face, it's important to closely evaluate the feasibility of the project. On the contrary, *Scenario 2* seems to be the favorable strategy in the short and long term, being a good solution to get a sustainable product (green hydrogen) before implementing a more complex one, such as the biomethanation integration.

In this optic, hydrogen costs are a critical factor. In both scenarios, electrolyzer represents the main cost. This statement features the necessity of continuous investments in research and development in the mass industrialization of electrolysis technologies.

Another crucial implication is the role of blending in natural gas. The convenience of *Scenario 2* can be found in the capability of gas pipelines to absorb increasing percentage of hydrogen. This leads to the necessity of building infrastructures that can transport a mix of H_2 and natural gas with higher percentages of hydrogen, harmonizing and updating technical standards and regulations.

This study has also focused on the importance of hydrogen storage optimization. Dynamic modelling of the tank has clearly demonstrated how it acts as an essential "buffer", decoupling the inherently variable nature of H_2 production (influenced by fluctuations in renewable sources such as wind) from demand, which may be more stable or subject to different profiles. Accurate dimensioning based on realistic analysis of production and consumption profiles, such as that adopted in this study, is vital not only to ensure the continuity of operations of downstream processes (biomethanation or blending), but also to optimize costs and maximize the utilization of the hydrogen produced.

Finally, this work highlighted a critical sensitivity to carbon pricing and incentive mechanisms. The economic attractiveness of more complex and environmentally ambitious processes, such as biomethanation and CO_2 capture, is strongly linked to the economic value attributed to CO_2 itself. Without appropriate carbon pricing mechanisms or robust incentives for CO_2 capture and use (CCU), cost-effectiveness leans in favor of simpler solutions. This suggests that future energy and environmental policies will play a key role in shaping the investment landscape for these projects, potentially re-balancing the cost-benefit balance in favor of more environmentally integrated solutions. These findings line up with the already exiting literature, in which it is assessed that green hydrogen projects remain economically marginal without robust incentives. Shafiee & Schrag (2024) report that green H_2 is non-competitive in the absence of strong policy support. Moreover, Curcio (2025) shows that carbon pricing above 100 USD/tCO_2, combined with tax credit mechanisms like those under the U.S. Inflation Reduction Act, is essential for making green hydrogen financially viable at scale.

6. Conclusions

This analysis led to a conclusion regarding the initial question about the economic convenience between two different approaches in hydrogen management. Based on the conditions and assumptions analysed, this study has shown that the hydrogen surplus management scenario based solely on blending with natural gas (Scenario 2) is more cost-effective than the one that also includes a biomethanation plant (Scenario 1).

The main contribution of this work is represented by an advanced and realistic modelling of the hydrogen storage tank. Unlike more simplified approaches, the tank capacity has been determined in a dynamic and robust way, ensuring nominal flow continuity even in the absence of wind-dependent production. This dimensioning was not based on static averages, but on the analysis of the production profile in the year of maximum yield of the wind farm and on the guarantee that the level of the tank would never fall below the critical threshold.

In addition, the integrated approach allowed to consider the entire hydrogen value chain, from production (wind-powered electrolysis) to storage and different end-use routes (biomethanation, blending, flare). This systemic view has made it possible to capture the complex interdependencies and provide a holistic assessment of performance, providing a more comprehensive and pragmatic picture for decision-makers. Anchoring to operational data, such as the profile of a real deposit, has further strengthened the industrial relevance of results.

6.1. Final considerations

The energy transition is a multifactorial challenge that requires innovative but also economically sustainable solutions. The results of this study, led to the conclusion that the most direct and cost-effective way to integrate green hydrogen in the short-medium term lies in optimizing the blending with existing natural gas. This does not mean abandoning more ambitious decarbonisation targets, but rather recognizing that economic efficiency can act as a catalyst for large-scale hydrogen adoption.

This work emphasizes that technological innovation must always be accompanied by careful economic analysis and accurate modelling of systems. Green hydrogen, with its many applications, is a key pillar for a sustainable energy future. The ability of platforms such as those analysed to produce and inject it directly into existing infrastructures represents a concrete and scalable step towards decarbonisation of the energy sector. By supporting investments in key technologies such as electrolysers and fostering a regulatory framework that enhances blending, the transition to a cleaner, more efficient and resilient energy system can accelerate.

Finally, further research could focus both on integrated energy system optimization and advanced real-time control for gas-electric-hydrogen networks, which provides a promising path to dynamically evaluate and manage blending and surplus hydrogen flows. Additionally, more studies should concentrate on reducing the cost of electrolysis, which remains one of the main economic burdens in this type of decarbonization context.

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9. Appendix I

9.1. Scenario 1 - BHM

```
clc; clear all;

% PARAMETRI
H₂ _min = 42.196;      % Sm³/h
H₂ _max = 210.98;      % Sm³/h
CH4_factor = 1/4;     % 4 H₂ --> 1 CH₄
tank_max = 1879;      % Sm³
BLEND_MAX_PERC = 0.05;

% IMPORT DATI
H₂ _data = xlsread('BHM.xlsx');      % H₂  orari
GAS_data = xlsread('GAS.xlsx');     % GAS orari
[num_ore, num_col] = size(H₂ _data);

% PREALLOCAZIONE
CH4_output = zeros(num_ore, num_col);
blending = zeros(num_ore, num_col);
torcia = zeros(num_ore, num_col);
tank_level = zeros(num_ore, num_col);
H₂ _used = zeros(num_ore, num_col);
ore_torcia = zeros(1, num_col);
ore_blending = zeros(1, num_col);
ore_CH4 = zeros(1, num_col);

% INIZIALIZZA IL LIVELLO DEL TANK QUI, FUORI DAL CICLO ANNUALE
% il tank cosi mantiene il suo livello tra gli anni
tank = 0;

% CICLO PER ANNO
for col = 1:num_col
    % NON RESETTO tank = 0 QUI, si resetta solo all'inizio della simulazione

    for t = 1:num_ore
        H₂  = H₂ _data(t,col);
        GAS = GAS_data(t,col);
        CH4_this_hour = 0;
        blend_this_hour = 0;
        flare_this_hour = 0;
        used_H₂ _CH4 = 0;

        % FASE 1: CH4
        available_H₂  = H₂  + tank;
```

```
        if available_H₂  >= H₂ _min
            used_H₂ _CH4 = min(available_H₂ , H₂ _max);
            CH4_this_hour = CH4_factor * used_H₂ _CH4;
            ore_CH4(col) = ore_CH4(col) + 1;

            if H₂  >= used_H₂ _CH4
                H₂  = H₂  - used_H₂ _CH4;
            else
                tank = tank - (used_H₂ _CH4 - H₂ );
                H₂  = 0;
            end
        end

        % FASE 2: Tank
        add_to_tank = min(H₂ , tank_max - tank);
        tank = tank + add_to_tank;
        H₂  = H₂  - add_to_tank;

        % FASE 3: Blending
        tot_gas = GAS + CH4_this_hour;
        max_H₂ _blend = (BLEND_MAX_PERC * tot_gas) / (1 - BLEND_MAX_PERC);
        blend_this_hour = min(H₂ , max_H₂ _blend);
        ore_blending(col) = ore_blending(col) + (blend_this_hour > 0);
        H₂  = H₂  - blend_this_hour;

        % FASE 4: Torcia
        if H₂  > 0
            flare_this_hour = H₂ ;
            ore_torcia(col) = ore_torcia(col) + 1;
        end

        % OUTPUT ORARI
        CH4_output(t,col) = CH4_this_hour;
        blending(t,col) = blend_this_hour;
        torcia(t,col) = flare_this_hour;
        tank_level(t,col) = tank; % Salva il livello del tank per quest'ora
        H₂ _used(t,col) = used_H₂ _CH4 + blend_this_hour + flare_this_hour;
    end

    % NON SI SVUOTA IL TANK QUI ALLA FINE DI OGNI ANNO
    % Il tank manterrà il suo livello per l'anno successivo

    % ESPORTAZIONE ANNUALE PARZIALE (somma della torcia oraria per ogni
anno)
    CH4_annuo(col) = sum(CH4_output(:,col));
    H₂ _blending_annuo(col) = sum(blending(:,col));
    H₂ _torcia_annuo(col) = sum(torcia(:,col)); % Questo è il totale della
torcia oraria per l'anno
 end
```

```
% SVUOTA IL TANK SOLO ALLA FINE DELL'ULTIMO ANNO SIMULATO (dopo il ciclo for
col)
% 'num_col' contiene il numero dell'ultimo anno processato (25esimo)
if tank > 0
    fprintf('Il livello della tank alla fine della simulazione (25esimo
anno) è di %d', tank)
    % torcia(end,num_col) = torcia(end,num_col) + tank; % Aggiungi
all'ultima ora dell'ultimo anno
    % H₂ _used(end,num_col) = H₂ _used(end,num_col) + tank; % Aggiorna H₂
_used
    % ore_torcia(num_col) = ore_torcia(num_col) + 1; % Incrementa il
conteggio ore torcia
    tank = 0; % Svuota il tank dopo l'operazione finale
end
```

```
Il livello della tank alla fine della simulazione (25esimo anno) è di 1879
```

```
%% Calcolo delle ore massime di attività (tra tutti gli anni)
[max_ore_torcia, anno_max_ore_torcia] = max(ore_torcia);
[max_ore_blending, anno_max_ore_blending] = max(ore_blending);
[max_ore_CH4, anno_max_ore_CH4] = max(ore_CH4);

fprintf('\n--- Riepilogo Ore Massime di Attività (tra tutti gli anni) ---
\n');
```

```
--- Riepilogo Ore Massime di Attività (tra tutti gli anni) ---
```

```
fprintf('Ore massime di Torcia: %.0f ore (nell''anno %d)\n', max_ore_torcia,
anno_max_ore_torcia+15);
```

```
Ore massime di Torcia: 217 ore (nell'anno 25)
```

```
fprintf('Ore massime di Blending: %.0f ore (nell''anno %d)\n',
max_ore_blending, anno_max_ore_blending+15);
```

```
Ore massime di Blending: 4332 ore (nell'anno 25)
```

```
fprintf('Ore massime di Metanazione (CH4): %.0f ore (nell''anno %d)\n',
max_ore_CH4, anno_max_ore_CH4+15);
```

```
Ore massime di Metanazione (CH4): 6189 ore (nell'anno 25)
```

```
fprintf('------------------------------------------------------------\n');
```

```
------------------------------------------------------------
```

```
%% Calcolo dei flussi massimi di H₂  e Gas (tra tutti gli anni e tutte le ore)

% Flusso massimo di H₂  prodotto (input)
[max_H₂ _flow, idx_max_H₂ _linear] = max(H₂ _data(:)); % H₂ _data(:) appiattisce la matrice in un vettore
[ora_max_H₂ _flow, anno_max_H₂ _flow] = ind2sub(size(H₂ _data), idx_max_H₂ _linear);

fprintf('\n--- Riepilogo Flussi Massimi (tra tutti gli anni e le ore) ---\n');
```

```
--- Riepilogo Flussi Massimi (tra tutti gli anni e le ore) ---
```

```
fprintf('Flusso massimo di H₂  prodotto: %.2f Sm³/h (nell''ora %d dell''anno %d)\n', ...
        max_H₂ _flow, ora_max_H₂ _flow, anno_max_H₂ _flow+15);
```

```
Flusso massimo di H₂  prodotto: 870.09 Sm³/h (nell'ora 821 dell'anno 16)
```

```

% Flusso massimo di Gas Naturale (input)
[max_GAS_flow, idx_max_GAS_linear] = max(GAS_data(:)); % GAS_data(:) appiattisce la matrice in un vettore
[ora_max_GAS_flow, anno_max_GAS_flow] = ind2sub(size(GAS_data), idx_max_GAS_linear);

fprintf('Flusso massimo di Gas Naturale: %.2f Sm³/h (nell''ora %d dell''anno %d)\n', ...
        max_GAS_flow, ora_max_GAS_flow, anno_max_GAS_flow+15);
```

```
Flusso massimo di Gas Naturale: 63782.37 Sm³/h (nell'ora 2833 dell'anno 16)
```

```
fprintf('----------------------------------------------------------\n');
```

```
----------------------------------------------------------
```

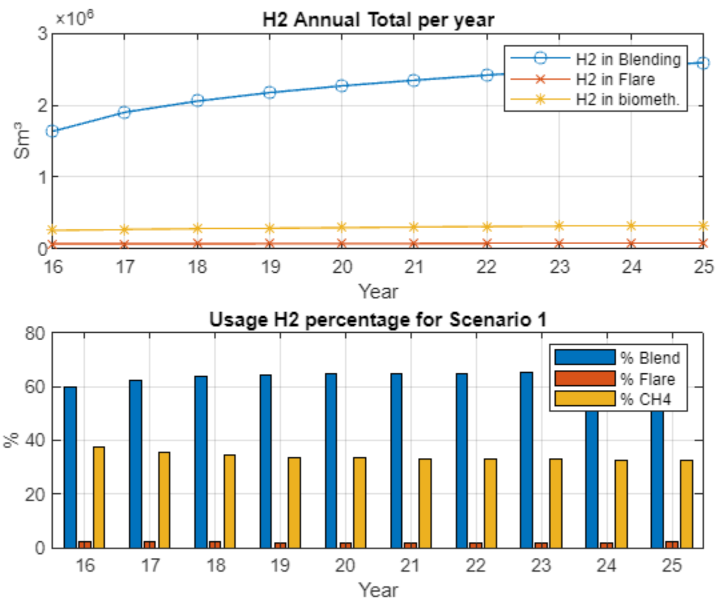
```
% Flusso max di Torcia
[max_TORCIA_flow, idx_max_TORCIA_linear]= max(torcia(:));
[ora_max_TORCIA_flow, anno_max_TORCIA_flow] = ind2sub(size(torcia), idx_max_TORCIA_linear);

fprintf('Flusso massimo in torcia: %.2f Sm³/h (nell''ora %d dell''anno %d)\n', ...
        max_TORCIA_flow, ora_max_TORCIA_flow, anno_max_TORCIA_flow+15);
```

```
Flusso massimo in torcia: 655.76 Sm³/h (nell'ora 2861 dell'anno 19)
```

```
fprintf('----------------------------------------------------------\n');
```

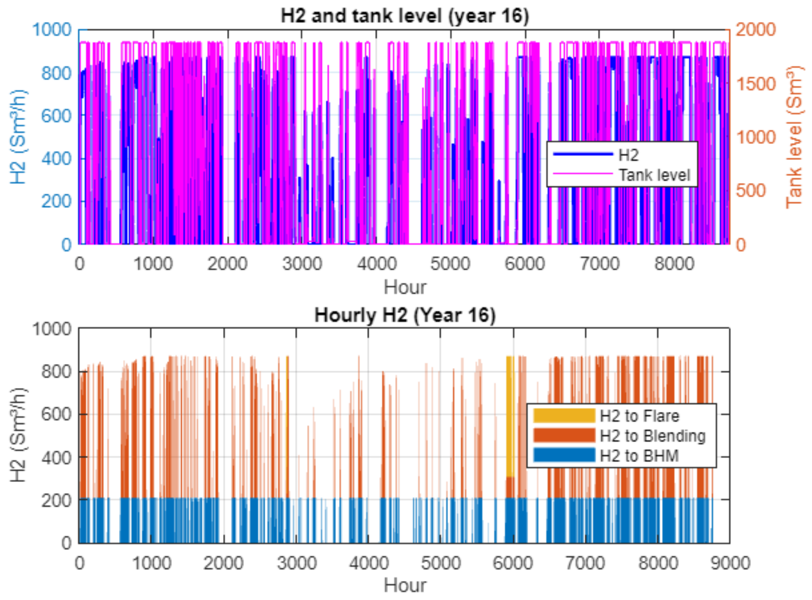
```
----------------------------------------------------------
```

```
% ESPORTA FILE
xlswrite('output_CH4_BHM.xlsx', CH4_output);
xlswrite('output_tank_level_BHM.xlsx', tank_level);
xlswrite('output_blending_BHM.xlsx', blending);
xlswrite('output_torcia_BHM.xlsx', torcia);
xlswrite('output_H₂ _used_BHM.xlsx', H₂ _used);

% GRAFICI
figure;
subplot(2,1,1);
plot(sum(blending,1),'-o'); hold on;
plot(sum(torcia,1),'-x'); hold on;
plot(sum(CH4_output), '-*');
legend('H₂  in Blending','H₂  in Flare', 'H₂  in biometh.'); grid on;
title('H₂  Annual Total per year'); xlabel('Year'); ylabel('Sm³');
xticklabels(16:25);

subplot(2,1,2);
totH₂  = sum(H₂ _data);
bar([100*H₂ _blending_annuo'./totH₂ ' 100*H₂ _torcia_annuo'./totH₂ '
100*CH4_annuo'*4./totH₂ ']);
legend('% Blend','% Flare','% CH4'); grid on;
xlabel('Year'); ylabel('%');  xticklabels(16:25);
title('Usage H₂  percentage for Scenario 1');
```

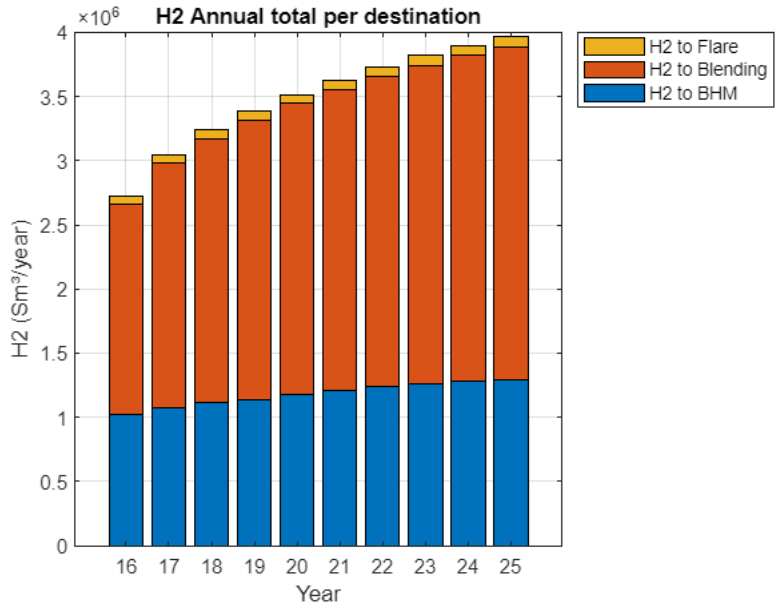



```
%% Altri GRAFICI

% --- Categoria 1: Bilancio orario dettagliato ddel serbatoio ---
```

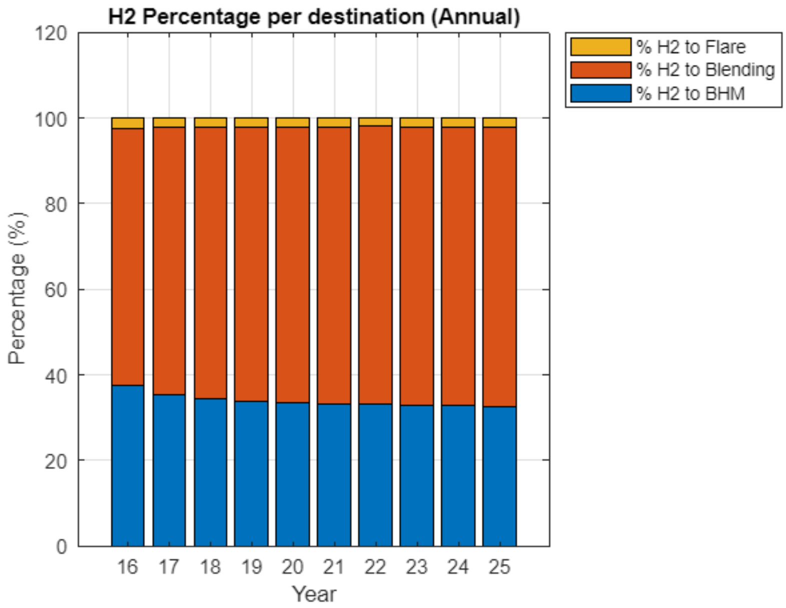
```
 anno_debug_plot = 1;
 if num_col >= anno_debug_plot
     figure('Name', sprintf('Dettaglio Orario Anno %d', anno_debug_plot+15));

     % Grafico 1.1: Produzione H₂  e Livello serbatoio
     subplot(2,1,1); % 2 righe, 1 colonna, primo grafico
     yyaxis left;
     plot(1:num_ore, H₂ _data(:, anno_debug_plot), 'b', 'LineWidth',
1.5,'DisplayName', 'H₂ ');
     ylabel('H₂  (Sm³/h)');
     hold on;
     yyaxis right;
     magenta_con_trasparenza = [1, 0, 1, 0.6]; % Vettore colore: [R, G, B,
Alpha]
     plot(1:num_ore, tank_level(:, anno_debug_plot), 'Color',
magenta_con_trasparenza, 'LineWidth', 0.5, 'DisplayName', 'Tank level');
     ylabel('Tank level (Sm³)');
     title(sprintf('H₂  and tank level (year %d)', anno_debug_plot+15));
     xlabel('Hour');
     xlim([0 8760])
     grid on;
     legend('show', 'Location', 'best');
     hold off;

     % Grafico 1.2: Destinazione Oraria dell'H₂
     subplot(2,1,2); % 2 righe, 1 colonna, secondo grafico
     area_data = [CH4_output(:, anno_debug_plot)*4, blending(:,
anno_debug_plot), torcia(:, anno_debug_plot)];
     % 1. Salva gli handle del grafico 'area' nella variabile 'h'
     h = area(1:num_ore, area_data);

     % Applica le modifiche a ogni singola area del grafico
     for i = 1:length(h)
         h(i).EdgeColor = 'none';
         h(i).LineStyle = 'none'; % Aggiungiamo anche questo per sicurezza
     end

     title(sprintf('Hourly H₂  (Year %d)', anno_debug_plot+15));
     xlabel('Hour');
     ylabel('H₂  (Sm³/h)');
     legend('H₂  to BHM', 'H₂  to Blending', 'H₂  to Flare', 'Location',
'best');
     grid on;
 end
```



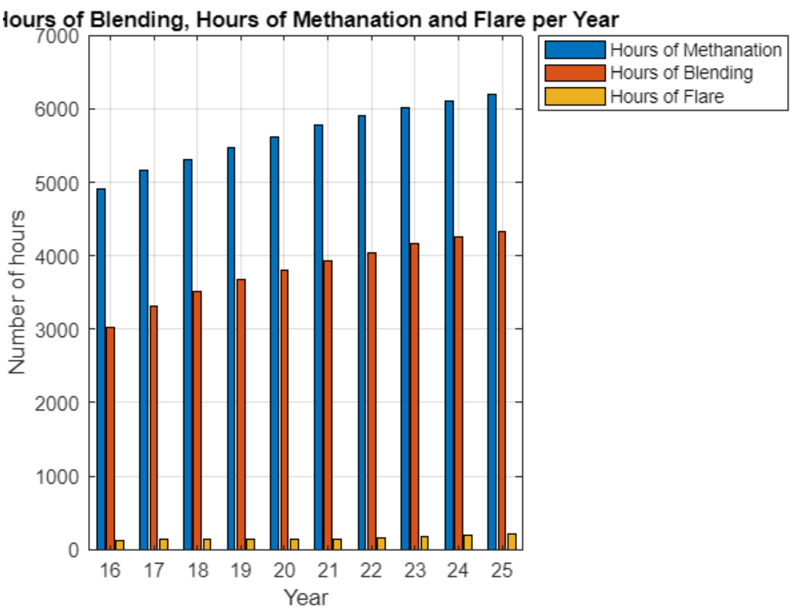

```
% --- Categoria 2: Indicatori di Performance Annuali ---

% Grafico 2.1: H₂  Totale Annuo per Destinazione (Stacked Bar)
figure('Name', 'H₂  Annual total per destination');
bar_data_annual = [CH4_annuo * 4; H₂ _blending_annuo; H₂ _torcia_annuo]'; %
Trasponi per avere anni come righe
bar(bar_data_annual, 'stacked');
title('H₂  Annual total per destination');
xlabel('Year');
ylabel('H₂  (Sm³/year)');
legend('H₂  to BHM', 'H₂  to Blending', 'H₂  to Flare', 'Location',
'bestoutside');
xticklabels(1+15:num_col+15); % Etichette per gli anni
grid on;
```



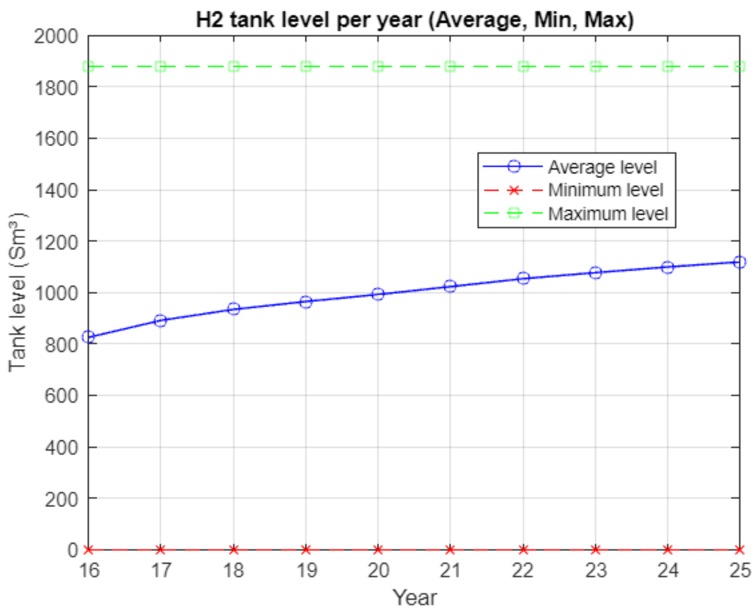

```
% Grafico 2.2: Percentuale H₂  per Destinazione (Stacked Bar al 100%)
figure('Name', 'Percentuale H₂  per Destinazione');
% Ricalcola le percentuali per la visualizzazione se la tabella non è stata
creata o per sicurezza
perc_CH4_plot = 100 * (CH4_annuo * 4) ./ totH₂ ;
perc_blend_plot = 100 * H₂ _blending_annuo ./ totH₂ ;
perc_torcia_plot = 100 * H₂ _torcia_annuo ./ totH₂ ;
perc_data_annual = [perc_CH4_plot; perc_blend_plot; perc_torcia_plot]';
bar(perc_data_annual, 'stacked');
title('H₂  Percentage per destination (Annual)');
xlabel('Year');
ylabel('Percentage (%)');
legend('% H₂  to BHM', '% H₂  to Blending', '% H₂  to Flare', 'Location',
'bestoutside');
xticklabels(1+15:num_col+15);
grid on;
```




```
% Grafico 2.3: Ore di Attività per Funzione
figure('Name', 'Ore di Attività Annuale');
bar_hours_data_annual = [ore_CH4; ore_blending; ore_torcia]';
bar(bar_hours_data_annual);
title('Hours of Blending, Hours of Methanation and Flare per Year');
xlabel('Year');
ylabel('Number of hours');
legend('Hours of Methanation', 'Hours of Blending', 'Hours of Flare',
'Location', 'bestoutside');
xticklabels(1+15:num_col+15);
grid on;
```



```
% Grafico 2.4: Livello Medio, Minimo e Massimo del Serbatoio per Anno
figure('Name', 'Annual tank level');
tank_mean = mean(tank_level);
tank_min = min(tank_level);
tank_max = max(tank_level);

plot(1:num_col, tank_mean, 'b-o', 'DisplayName', 'Average level');
hold on;
plot(1:num_col, tank_min, 'r--x', 'DisplayName', 'Minimum level');
plot(1:num_col, tank_max, 'g--s', 'DisplayName', 'Maximum level');
hold off;
title('H₂  tank level per year (Average, Min, Max)');
xlabel('Year');
ylabel('Tank level (Sm³)');
legend('show', 'Location', 'best');
xticklabels(1+15:num_col+15);
grid on;
```



9.2. Scenario 2 – Blending only

```
clc
clear all


%% PARAMETRI DEL MODELLO
BLEND_MAX_PERC = 0.05;   % Percentuale massima di H2  consentita nel gas
finale (5%)


%% IMPOSTAZIONI DI DEBUGGING (per vedere il bilancio orario)
%  DEBUG_ACTIVE = true --> stampe dettagliate nella Command Window
%  DEBUG_ACTIVE = false --> intera simulazione senza output di debugging
DEBUG_ACTIVE = false;
DEBUG_COL    = 1;      % anno da debuggare
DEBUG_HOURS  = 24;     % quante ore stampare per il debugging


%% IMPORT DATI
H2 _data     = xlsread('BHM.xlsx'); % Dati di produzione oraria di H2
GAS_data    = xlsread('GAS.xlsx'); % Dati di portata oraria di Gas Naturale
[num_ore, num_col] = size(H2 _data); % Numero di ore e anni
```

Grafico andamento GAS

```
% Anni da plottare
anni_GAS_pure = [1, 4, 7, 10];

% Numero di subplot necessari
num_subplots_GAS_pure = length(anni_GAS_pure);

% Determina le dimensioni della griglia dei subplot
rows_GAS_pure = ceil(sqrt(num_subplots_GAS_pure));
cols_GAS_pure = ceil(num_subplots_GAS_pure / rows_GAS_pure);

figure('Name', 'Hourly Natural gas (Input) flow rate for selected years');

for i = 1:num_subplots_GAS_pure
    current_year = anni_GAS_pure(i);

    % Procedura per non far bloccare il codice (assicurarmi che l'anno
esista nei dati simulati)
    if current_year <= num_col
        subplot(rows_GAS_pure, cols_GAS_pure, i); % Crea il subplot corrente

        plot(1:num_ore, GAS_data(:, current_year), 'g', 'DisplayName',
'Natural Gas (Input)');
```

```
        title(sprintf('Natural gas Year %d', current_year+15));
        xlabel('Hour');
        ylabel('(Sm³/h)');
        grid on;
        xlim([0 8760]);

        if i == 1 %solo nel primo subplot
            legend('show', 'Location', 'best');
        end
    else
        fprintf('Attenzione: L''anno %d non esiste nei dati GAS_data.
num_col = %d\n', current_year, num_col);
    end
end

sgtitle('Hourly Natural gas (Input data) flow rate for selected years');
```

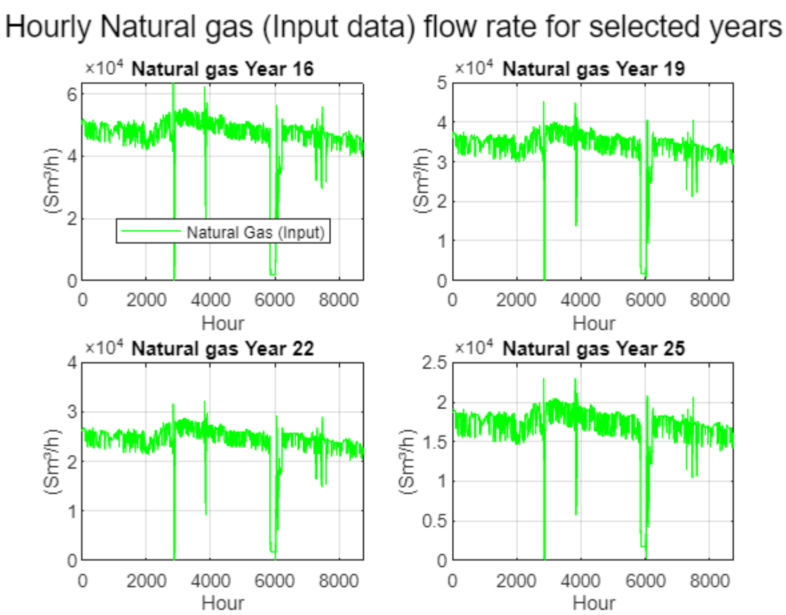


Grafico andamento H_2

```
% Vedo come va H₂  negli anni che mi interessano
% Anni da plottare
anni_H₂ _pure = [1, 4, 7, 10];

% Numero di subplot necessari
num_subplots_H₂ _pure = length(anni_H₂ _pure);

%  dimensioni della griglia dei subplot
rows_H₂ _pure = ceil(sqrt(num_subplots_H₂ _pure));
cols_H₂ _pure = ceil(num_subplots_H₂ _pure / rows_H₂ _pure);
```

```
figure('Name', 'Hourly H₂  flow rate (input data) for selected years');

for i = 1:num_subplots_H₂ _pure
    current_year = anni_H₂ _pure(i);

    % come prima per evitare si blocchi tutto
    if current_year <= num_col
        subplot(rows_H₂ _pure, cols_H₂ _pure, i); % Crea il subplot corrente

        plot(1:num_ore, H₂ _data(:, current_year), 'b', 'DisplayName', 'H₂
produced');

        title(sprintf('H₂  Year %d', current_year+15));
        xlabel('Hour');
        ylabel('Sm³/h');
        grid on;
        xlim([0 8760]);

        if i == 1 % legenda solo nel primo subplot
            legend('show', 'Location', 'best');
        end
    else
        fprintf('Attenzione: L''anno %d non esiste nei dati H₂ _data.
num_col = %d\n', current_year, num_col);
    end
end

sgtitle('Hourly H₂  flow rate (input data) for selected years');
```

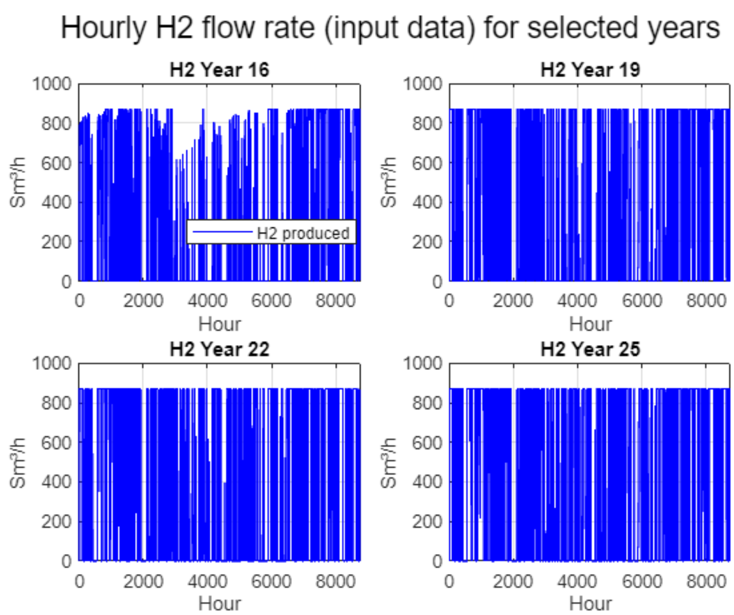


Grafico andamento H_2 + Gas

```
% andamento Orario H₂  + Gas

% Anni da plottare
anni_da_plottare_pure_volumes = [1, 4, 7, 10];

% Numero di subplot necessari
num_subplots_pure_volumes = length(anni_da_plottare_pure_volumes);

% dimensioni della griglia dei subplot
rows_pure_volumes = ceil(sqrt(num_subplots_pure_volumes));
cols_pure_volumes = ceil(num_subplots_pure_volumes / rows_pure_volumes);

figure('Name', 'Hourly H₂  and Natural gas flow rate (input data) for
selected years');

for i = 1:num_subplots_pure_volumes
    current_year = anni_da_plottare_pure_volumes(i);

    %%%%
    if current_year <= num_col
        subplot(rows_pure_volumes, cols_pure_volumes, i); % Crea il subplot
corrente

        plot(1:num_ore, H₂ _data(:, current_year), 'b', 'DisplayName', 'H₂
produced (Input)');
        hold on;
        plot(1:num_ore, GAS_data(:, current_year), 'g', 'DisplayName',
'Natural gas (Input)');


        hold off;

        title(sprintf('Year %d', current_year+15));
        xlabel('Hour');
        ylabel('(Sm³/h)');
        grid on;
        xlim([0 8760]);

        if i == 1 %  legenda solo nel primo subplot
            legend('show', 'Location', 'best');
        end
    else
        fprintf('Attenzione: L''anno %d non esiste nei dati. num_col =
%d\n', current_year, num_col);
    end
end

sgtitle('Hourly H₂  and Natural gas flow rate (input data) for selected
years');
```

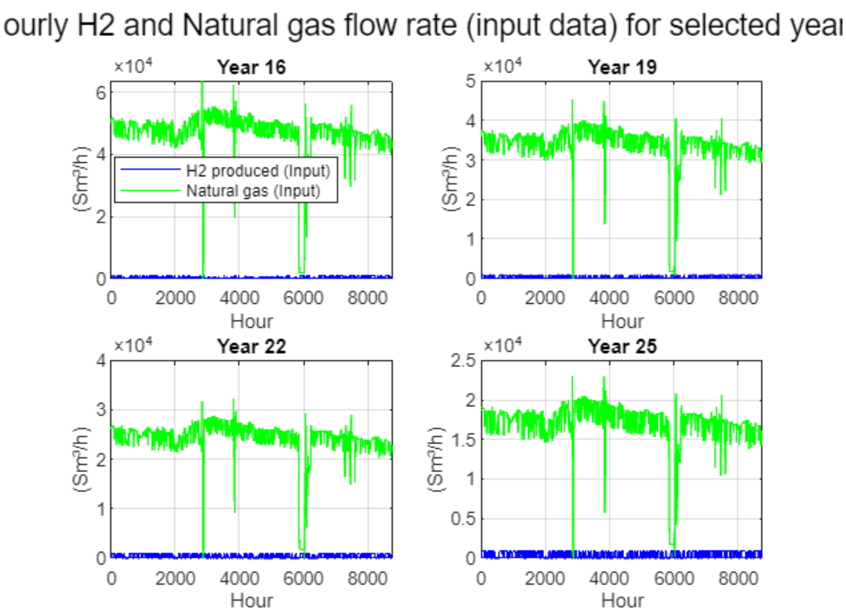
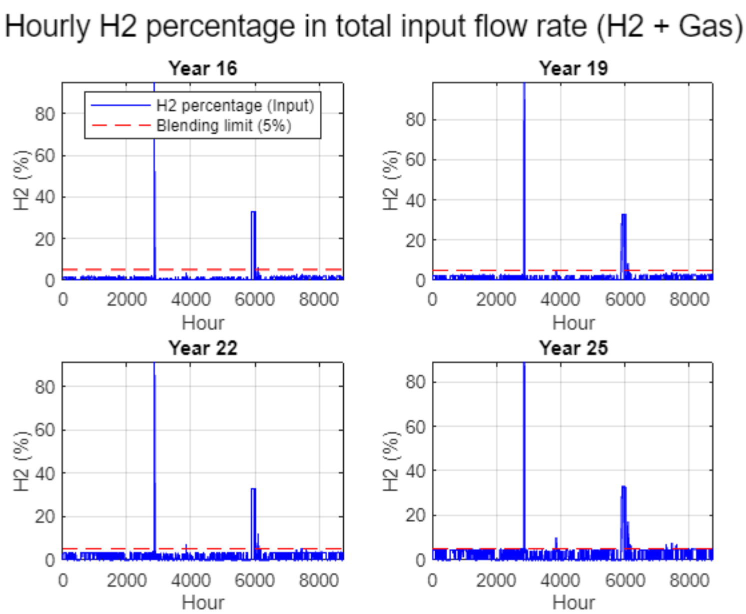


Grafico con Subplot: Percentuale Oraria H_2 nel Flusso Totale "Puro" (H_2 _data + GAS_data) per Anni Selezionati

```
% Anni da plottare
anni_da_plottare_pure = [1, 4, 7, 10];

% Numero di subplot necessari
num_subplots_pure = length(anni_da_plottare_pure);

% dimensioni della griglia dei subplot
rows_pure = ceil(sqrt(num_subplots_pure));
cols_pure = ceil(num_subplots_pure / rows_pure);

figure('Name', 'Hourly H₂  percentage in total flow rate for selected years
(H₂  + Gas)');

for i = 1:num_subplots_pure
    current_year = anni_da_plottare_pure(i);

    % %%
    if current_year <= num_col
        subplot(rows_pure, cols_pure, i); % Crea il subplot corrente

        % Calcola il flusso totale per l'anno corrente
        total_pure_flow_this_year = H₂ _data(:, current_year) + GAS_data(:,
current_year);

        % Calcola la percentuale di H₂  nel flusso totale
        perc_H₂ _in_pure_flow = zeros(num_ore, 1);
        %se il flusso totale è zero, la percentuale è zero
        valid_indices = total_pure_flow_this_year > 0;
```

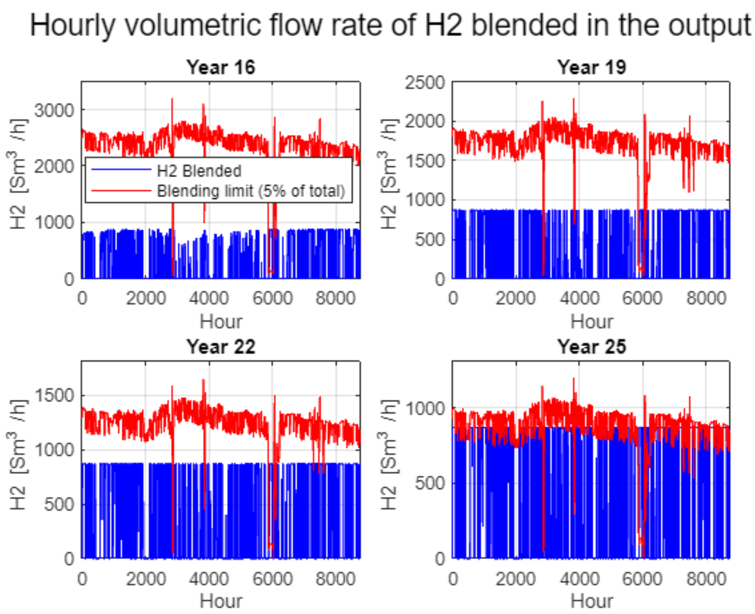
```
        perc_H₂ _in_pure_flow(valid_indices) = (H₂ _data(valid_indices, current_year) ./ total_pure_flow_this_year(valid_indices)) * 100;

        plot(1:num_ore, perc_H₂ _in_pure_flow, 'b', 'DisplayName', 'H₂ percentage (Input)');
        hold on;
        % Aggiungere  una linea orizzontale per il limite massimo di blending (5%) per riferimento
        plot([1 num_ore], [BLEND_MAX_PERC*100 BLEND_MAX_PERC*100], 'r--', 'DisplayName', sprintf('Blending limit (%.0f%%)', BLEND_MAX_PERC*100));
        hold off;

        title(sprintf('Year %d', current_year+15));
        xlabel('Hour');
        ylabel('H₂  (%)');
        grid on;
        xlim([0 8760])
        ylim([0 max(max(perc_H₂ _in_pure_flow), BLEND_MAX_PERC*100 + 5)]); % Adatta il limite Y

        if i == 1 % Mostra la legenda solo nel primo subplot
            legend('show', 'Location', 'best');
        end
    else
        fprintf('Attenzione: L''anno %d non esiste nei dati. num_col = %d\n', current_year, num_col);
    end
end

sgtitle('Hourly H₂  percentage in total input flow rate (H₂  + Gas)');
```



<u>*--> plotto con volumetrie*</u>

```
% Anni da plottare
anni_da_plottare_pure = [1, 4, 7, 10];

% Numero di subplot necessari
num_subplots_pure = length(anni_da_plottare_pure);

% dimensioni della griglia dei subplot
rows_pure = ceil(sqrt(num_subplots_pure));
cols_pure = ceil(num_subplots_pure / rows_pure);

figure('Name', 'Hourly blended H₂  (output) flow rate for selected years');

for i = 1:num_subplots_pure
    current_year = anni_da_plottare_pure(i);

    if current_year <= num_col
        subplot(rows_pure, cols_pure, i); % Crea il subplot corrente

        % Calcola il flusso totale "puro" per l'anno corrente (H₂ _data +
GAS_data)
        total_pure_flow_this_year = H₂ _data(:, current_year) + GAS_data(:,
current_year);


        blended_H₂ _flow = H₂ _data(:, current_year);

        % Calcola la portata volumetrica del limite del 5% di blending
rispetto al flusso totale "puro"
        % Questo rappresenta il 5% del flusso totale (H₂  + Gas) come
        % portata di H₂
        blend_limit_flow = BLEND_MAX_PERC * total_pure_flow_this_year;

        plot(1:num_ore, blended_H₂ _flow, 'b', 'DisplayName', 'H₂
Blended');
        hold on;
        % Aggiungere una linea per il limite massimo di blending (5% come
portata)
        plot(1:num_ore, blend_limit_flow, 'r', 'DisplayName',
sprintf('Blending limit (%.0f%% of total)', BLEND_MAX_PERC*100));
        hold off;

        title(sprintf('Year %d', current_year + 15));
        xlabel('Hour');
        ylabel(' H₂  [Sm^3 /h]');
        grid on;

        % Adatta il limite Y per includere il flusso blended e il limite
        max_y_val = max(max(blended_H₂ _flow), max(blend_limit_flow));
```

```
        ylim([0 max_y_val * 1.1]); % Aggiungi un 10% di margine per
visibilità
        xlim([0 8760]);
        if i == 1 % Mostra la legenda solo nel primo subplot
            legend('show', 'Location', 'best');
        end
    else
        fprintf('Attenzione: L''anno %d non esiste nei dati. num_col =
%d\n', current_year, num_col);
    end
end

sgtitle('Hourly volumetric flow rate of H₂  blended in the output');
```



---- ripresa codice di BLENDING ----

```
%% PREALLOCAZIONE MATRICI DI OUTPUT
% tank_level non è necessaria --> ho solo blending
blending           = zeros(num_ore, num_col); % H₂  orario miscelato con Gas
Naturale
torcia             = zeros(num_ore, num_col); % H₂  orario inviato in torcia
H₂ _used            = zeros(num_ore, num_col); % Totale H₂  usato/smaltito
per ora

% Contatori per indicatori di performance annuali
ore_blending       = zeros(1, num_col); % Numero di ore con blending attivo
ore_torcia         = zeros(1, num_col); % Numero di ore con torcia attiva

% Totali annuali per report finale
H₂ _blending_annuo = zeros(1, num_col);
H₂ _torcia_annuo    = zeros(1, num_col);
```

```
%% CICLO DI SIMULAZIONE (per ogni anno e per ogni ora)
for col = 1:num_col
    % Gestione del debugging: se attivo, processa solo la colonna
specificata
    if DEBUG_ACTIVE && col ~= DEBUG_COL
        continue;
    end


    for t = 1:num_ore
        % Gestione del debugging: se attivo, processa solo le prime N ore
specificate
        if DEBUG_ACTIVE && t > DEBUG_HOURS
            break;
        end

        H₂ _produced_this_hour = H₂ _data(t, col);   % H₂  prodotto nell'ora
corrente
        GAS_this_hour         = GAS_data(t, col);  % Portata di gas naturale
nell'ora corrente

        % Inizializzazione delle variabili orarie
        blending_this_hour   = 0;
        torcia_this_hour     = 0;

        if DEBUG_ACTIVE
            fprintf('\n--- Anno: %d, Ora: %d ---\n', col, t);
            fprintf('H₂  Prodotto (input): %.2f Sm³/h\n', H₂
_produced_this_hour);
        end


        % --- FASE 1: BLENDING (Priorità) ---

        % Calcola il massimo H₂  che può essere blendato in quest'ora
        % in base al flusso di GAS naturale e al limite del 5%
        % Formula: H₂  / (H₂  + GAS) <= BLEND_MAX_PERC
        % => H₂  <= BLEND_MAX_PERC * (H₂  + GAS)
        % => H₂  <= BLEND_MAX_PERC * H₂  + BLEND_MAX_PERC * GAS
        % => H₂  * (1 - BLEND_MAX_PERC) <= BLEND_MAX_PERC * GAS
        % => H₂  <= (BLEND_MAX_PERC / (1 - BLEND_MAX_PERC)) * GAS

        max_H₂ _for_blend = (BLEND_MAX_PERC * GAS_this_hour) / (1 -
BLEND_MAX_PERC);

        % L'H₂  che andrà in blending è il minore tra l'H₂  prodotto e il
massimo consentito
```

```
        blending_this_hour = min(H₂ _produced_this_hour, max_H₂ _for_blend);
        ore_blending(col) = ore_blending(col) + (blending_this_hour > 0);

        % L'H₂  prodotto viene ridotto della quantità blendata
        H₂ _remaining_after_blend = H₂ _produced_this_hour -
blending_this_hour;

        if DEBUG_ACTIVE
            fprintf('  -> Max H₂  per Blending (0.05/0.95 * GAS): %.2f
Sm³\n', max_H₂ _for_blend);
            fprintf('  -> Blending Effettivo: %.2f Sm³\n',
blending_this_hour);
            fprintf('  -> H₂  Residuo dopo Blending: %.2f Sm³\n', H₂
_remaining_after_blend);
        end


        % --- FASE 2: TORCIA (Tutto il rimanente) ---
        % Tutto l'H₂  che non è stato blendato va direttamente in torcia
        if H₂ _remaining_after_blend > 0
            torcia_this_hour = H₂ _remaining_after_blend;
            ore_torcia(col) = ore_torcia(col) + 1;
            if DEBUG_ACTIVE
                fprintf('  -> Torcia: %.2f Sm³\n', torcia_this_hour);
            end
        end


        % --- FASE 3: AGGIORNAMENTO OUTPUT E BILANCIO ORARIO ---
        blending(t,col)    = blending_this_hour;
        torcia(t,col)      = torcia_this_hour;


        % H₂ _used rappresenta l'H₂  che è stato effettivamente CONSUMATO o
ELIMINATO dal sistema =somma di blending e torcia
        H₂ _used(t,col)     = blending_this_hour + torcia_this_hour;

        if DEBUG_ACTIVE
            fprintf('--- Riepilogo Ora %d ---\n', t);
            fprintf('Blending: %.2f | Torcia: %.2f\n', blending_this_hour,
torcia_this_hour);
            fprintf('H₂  Usato (output totale ora): %.2f Sm³/h\n', H₂
_used(t,col));
                        fprintf('--------------------------\n');
        end
    end

    % --- CALCOLO INDICATORI ANNUALI E CONTROLLO BILANCIO DI MASSA  per
vedere che torni tutto ---
```

```
    H₂ _blending_annuo(col) = sum(blending(:,col));
    H₂ _torcia_annuo(col)   = sum(torcia(:,col));

    H₂ _in  = sum(H₂ _data(:,col)); % L'input totale di H₂  nel sistema per l'anno (solo la produzione)
    H₂ _out = sum(H₂ _used(:,col)); % L'output totale di H₂  dal sistema per l'anno (tutto ciò che è uscito)

    % if DEBUG_ACTIVE
    %     fprintf('\n--- BILANCIO ANNUALE Anno %d ---\n', col);
    %     fprintf('H₂  IN TOTALE: %.2f Sm³\n', H₂ _in);
    %     fprintf('H₂  OUT TOTALE: %.2f Sm³\n', H₂ _out);
    %     fprintf('DIFFERENZA (H₂ _in - H₂ _out): %.2f Sm³\n', H₂ _in - H₂ _out);
    %     fprintf('-----------------------------\n');
    % else
    %     fprintf('Bilancio Anno %d: H₂ _in = %.1f, H₂ _out = %.1f, Differenza = %.1f\n', ...
    %             col, H₂ _in, H₂ _out, H₂ _in - H₂ _out);
    % end
    %
    % % Se stiamo debuggando una sola colonna, possiamo fermarci qui per evitare
    % % di processare le altre colonne inutilmente in modalità debug.
    % if DEBUG_ACTIVE && col == DEBUG_COL
    %     break;
    % end
end

[torcia_max, idx_max_linear] = max(torcia(:)); % Trova il valore massimo e il suo indice lineare

[ora_max_torcia, anno_max_torcia] = ind2sub(size(torcia), idx_max_linear); % Converte l'indice lineare in indici di riga e colonna

fprintf('The maximum flow rate of hydrogen in the flare is %d Sm3/h (Occurred in hour %d of year %d)\n', max(torcia(:)), ora_max_torcia, anno_max_torcia);
```

```
The maximum flow rate of hydrogen in the flare is 8.695449e+02 Sm3/h (Occurred in hour 2858 of year 9)
```

```
%% Calcolo delle ore massime di attività per dimensionare torcia (tra tutti gli anni)
[max_ore_torcia, anno_max_ore_torcia_idx] = max(ore_torcia);
[max_ore_blending, anno_max_ore_blending_idx] = max(ore_blending);
```

```
fprintf('\n--- Riepilogo Ore Massime di Attività (tra tutti gli anni) ---
\n');
```

```
--- Riepilogo Ore Massime di Attività (tra tutti gli anni) ---
```

```
fprintf('Ore massime di Torcia: %.0f ore (nell''anno %d)\n', max_ore_torcia,
anno_max_ore_torcia_idx);
```

```
Ore massime di Torcia: 384 ore (nell'anno 10)
```

```
fprintf('Ore massime di Blending: %.0f ore (nell''anno %d)\n',
max_ore_blending, anno_max_ore_blending_idx);
```

```
Ore massime di Blending: 5008 ore (nell'anno 10)
```

```
fprintf('------------------------------------------------------------\n');
```

```
------------------------------------------------------------
```

```
%% Calcolo dei flussi massimi di H₂  e Gas (tra tutti gli anni e tutte le
ore)

% Appiattisce le matrici H₂ _data e GAS_data in vettori colonna per trovare
il massimo globale
H₂ _data_flat = H₂ _data(:);
GAS_data_flat = GAS_data(:);

% Flusso massimo di H₂  prodotto (input)
[max_H₂ _flow, idx_max_H₂ _linear] = max(H₂ _data_flat);
[ora_max_H₂ _flow, anno_max_H₂ _flow] = ind2sub(size(H₂ _data), idx_max_H₂
_linear);

fprintf('\n--- Riepilogo Flussi Massimi (tra tutti gli anni e le ore) ---
\n');
```

```
--- Riepilogo Flussi Massimi (tra tutti gli anni e le ore) ---
```

```
fprintf('Flusso massimo di H₂  prodotto: %.2f Sm³/h (nell''ora %d dell''anno
%d)\n', ...
        max_H₂ _flow, ora_max_H₂ _flow, anno_max_H₂ _flow);
```

```
Flusso massimo di H₂  prodotto: 870.09 Sm³/h (nell'ora 821 dell'anno 1)
```

```
% Flusso massimo di Gas Naturale (input)
[max_GAS_flow, idx_max_GAS_linear] = max(GAS_data_flat);
[ora_max_GAS_flow, anno_max_GAS_flow] = ind2sub(size(GAS_data),
idx_max_GAS_linear);
```

```
fprintf('Flusso massimo di Gas Naturale: %.2f Sm³/h (nell''ora %d dell''anno
%d)\n', ...
        max_GAS_flow, ora_max_GAS_flow, anno_max_GAS_flow);
```

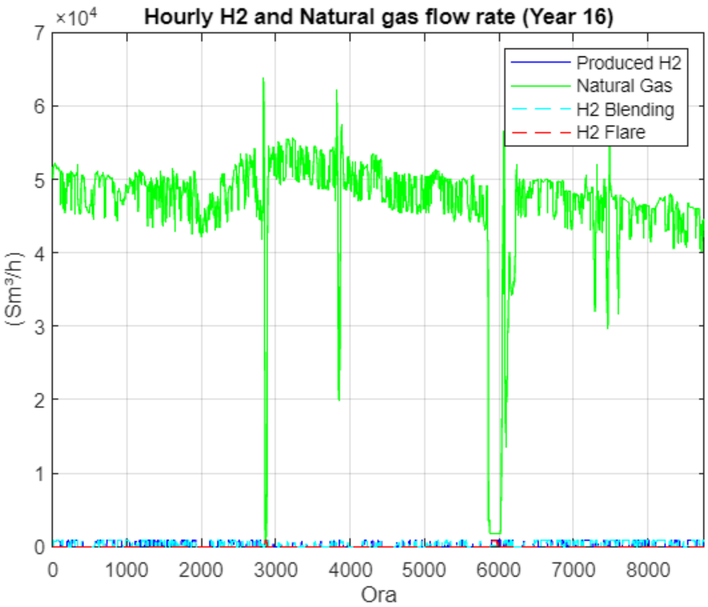
```
Flusso massimo di Gas Naturale: 63782.37 Sm³/h (nell'ora 2833 dell'anno 1)
```

```
fprintf('----------------------------------------------------------\n');
```

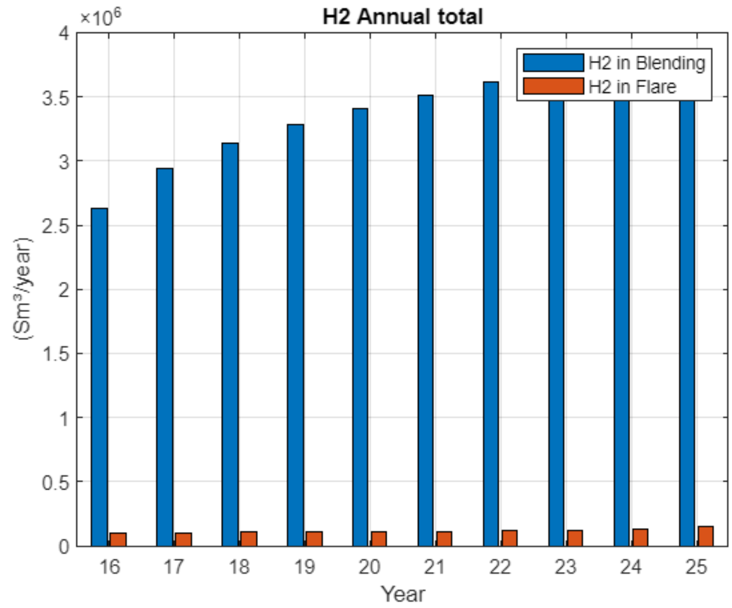
```
----------------------------------------------------------
```

```
%% ESPORTAZIONE DEI RISULTATI
% Le esportazioni avvengono solo se la modalità debug è disattivata,
% oppure se è attivata ma il ciclo di tutte le colonne è terminato (cioè
DEBUG_COL non è impostato).
if ~DEBUG_ACTIVE || (DEBUG_ACTIVE && col == num_col)

    xlswrite('output_blending_BLE.xlsx',   blending);
    xlswrite('output_torcia_BLE.xlsx',     torcia);
    xlswrite('output_H₂ _used_BLE.xlsx',    H₂ _used);

    totH₂  = sum(H₂ _data);
    T = table((1:num_col)', H₂ _blending_annuo', H₂ _torcia_annuo', ...
              100*H₂ _blending_annuo'./totH₂ ', ...
              100*H₂ _torcia_annuo'./totH₂ ', ...
        'VariableNames', {'Anno','H₂ _blend_Sm3','H₂
_torcia_Sm3','Perc_blend','Perc_torcia'});
    writetable(T,'output_indicatori_BLE.xlsx');
end



% Grafico 1: Andamento Orario (per un anno specifico)
if num_col >= 1
    anno_da_analizzare = 1;
    figure;
    plot(1:num_ore, H₂ _data(:, anno_da_analizzare), 'b', 'DisplayName',
'Produced H₂ ');
    hold on;
    plot(1:num_ore, GAS_data(:, anno_da_analizzare), 'g', 'DisplayName',
'Natural Gas');

    % Per plottare max_H₂ _for_blend_hourly, dovresti ricalcolarlo o
salvarlo durante il ciclo
    % Esempio:
    % max_H₂ _for_blend_all_hours = (BLEND_MAX_PERC * GAS_data) / (1 -
BLEND_MAX_PERC);
    % plot(1:num_ore, max_H₂ _for_blend_all_hours(:, anno_da_analizzare),
'k--', 'DisplayName', 'Max H₂  per Blending');
```

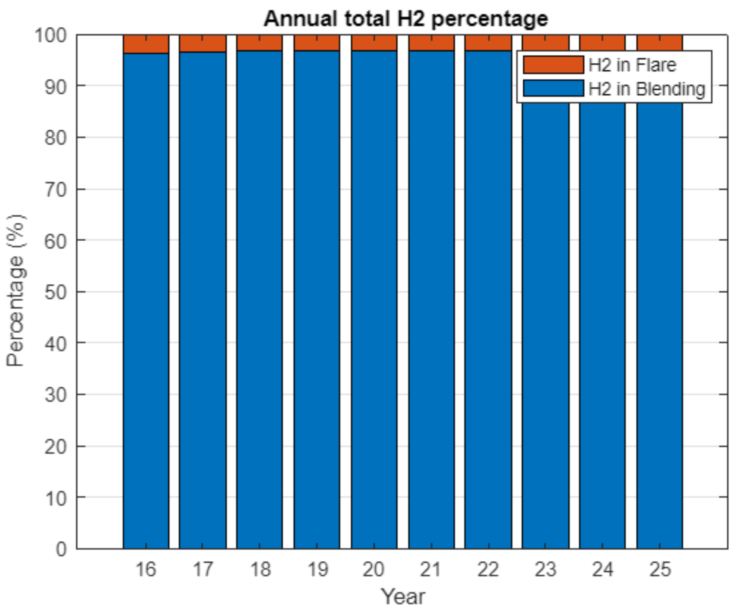
```
    plot(1:num_ore, blending(:, anno_da_analizzare), 'c--', 'DisplayName',
'H₂  Blending');
    plot(1:num_ore, torcia(:, anno_da_analizzare), 'r--', 'DisplayName', 'H₂
Flare');
    hold off;
    title(sprintf('Hourly H₂  and Natural gas flow rate (Year %d)',
anno_da_analizzare+15));
    xlabel('Ora');
    ylabel('(Sm³/h)');
    legend('show');
    grid on;
    xlim([0 8760]);
 end
```



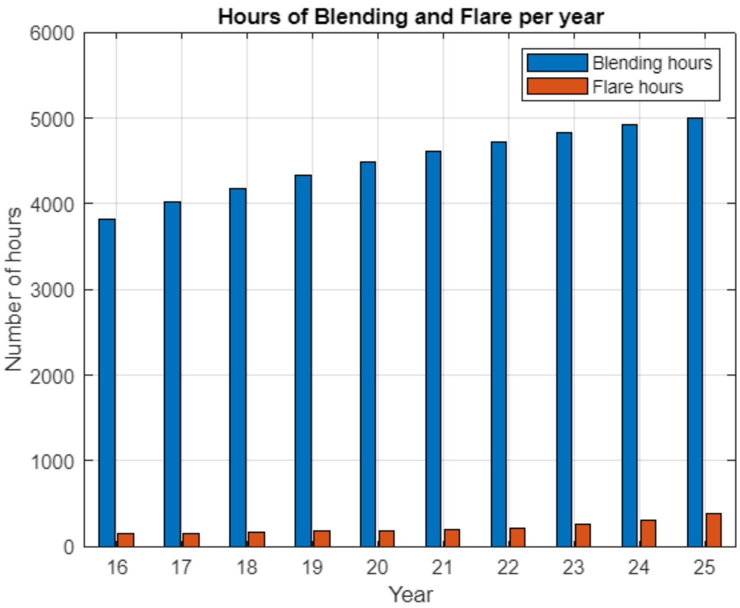

```
 % Grafico 3: H₂  Totale annuo per destinazione
 figure;
 bar_data = [H₂ _blending_annuo; H₂ _torcia_annuo]'; % Trasponi per avere
anni come righe
 bar(bar_data);
 title('H₂  Annual total');
 xlabel('Year');
 ylabel('(Sm³/year)');
 legend('H₂  in Blending', 'H₂  in Flare');
 xticklabels(1+15:num_col+15); % Etichette per gli anni
 grid on;
```




```
% Grafico 4: Percentuale di H₂  per Destinazione (Annuale)
figure;
perc_data = [100*H₂ _blending_annuo./totH₂ ; 100*H₂ _torcia_annuo./totH₂ ]';
bar(perc_data, 'stacked');
title(' Annual total H₂  percentage');
xlabel('Year');
ylabel('Percentage (%)');
legend('H₂  in Blending', 'H₂  in Flare');
xticklabels(1+15:num_col+15);
grid on;
```



```
% Grafico 5: Ore di Attività (Annuale)
figure;
bar_hours_data = [ore_blending; ore_torcia]';
bar(bar_hours_data);
title('Hours of Blending and Flare per year');
xlabel('Year');
ylabel('Number of hours');
legend('Blending hours', 'Flare hours');
xticklabels(1+15:num_col+15);
grid on;
```



<u>Grafico per mostrare blending in percentuale di BLENDING per anni da 7 a 10</u>

```
% Anni da plottare
anni_da_plottare = [7,8,9 10];

% Numero di subplot necessari
num_subplots = length(anni_da_plottare);

% Determina le dimensioni della griglia dei subplot
rows = ceil(sqrt(num_subplots));
cols = ceil(num_subplots / rows);

figure('Name', 'Hourly H₂  percentage in combined flow rate for selected
years');

for i = 1:num_subplots
    current_year = anni_da_plottare(i);

    % %%
```

```
     if current_year <= num_col
         subplot(rows, cols, i); % Crea il subplot corrente

         % Calcola il flusso totale (Gas Naturale + H₂  blendato) per l'anno
corrente
         total_flow_this_year = GAS_data(:, current_year) + blending(:,
current_year);

         % Calcola la percentuale di H₂  nel flusso combinato
         perc_H₂ _in_total_flow = zeros(num_ore, 1);
         valid_indices = total_flow_this_year > 0;
         perc_H₂ _in_total_flow(valid_indices) = (blending(valid_indices,
current_year) ./ total_flow_this_year(valid_indices)) * 100;

         plot(1:num_ore, perc_H₂ _in_total_flow, 'b', 'DisplayName', 'H₂
percentage in total flow rate');
         hold on;
         % linea orizzontale per il limite massimo consentito (5%)
         plot([1 num_ore], [BLEND_MAX_PERC*100 BLEND_MAX_PERC*100], 'r--',
'DisplayName', sprintf('Max H₂  limit (%.0f%%)', BLEND_MAX_PERC*100));
         hold off;

         title(sprintf('Year %d', current_year +15));
         xlabel('Hour');
         ylabel('H₂  (%)');
         grid on;
         ylim([0 BLEND_MAX_PERC*100 + 1]); % Imposta il limite Y per
visualizzare bene il 5%
         xlim([0 8760]);

         % Mostra la legenda solo nel primo subplot
         if i == 1
             legend('show', 'Location', 'best');
         end
     else
         fprintf('Attenzione: L''anno %d non esiste nei dati. num_col =
%d\n', current_year, num_col);
     end
 end

 %titolo generale
 sgtitle('Hourly H₂  percentage in combined flow rate for selected years');
```

Statement on the Use of Generative Artificial Intelligence Tools

Editorial support: Generative AI tools were used exclusively for editorial support, such as grammar correction, translations, paraphrasing suggestions, or readability improvement.

Idea development: Generative AI tools were used to assist with brainstorming ideas and literature synthesis.

Content generation and analytical support: Generative AI provided substantial contributions in data analysis, code generation, argument formulation, creation of images/figures, or the development of design elements.

Regardless of the level of AI involvement, all AI-generated content was critically reviewed, verified, and revised to ensure academic rigor. Citations and arguments were independently verified. The author assumes full responsibility for the accuracy, originality, and integrity of the final work.