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Energy, economic, and environmental evaluations on paper industry decarbonization by implementing electrolytic hydrogen

A. Perna[a], G. Di Cicco[a], E. Jannelli[b], C. Bassano[c], D. Lanni[a,*], M. Minutillo[d]

[a] Department of Civil and Mechanical Engineering, University of Cassino and Southern Lazio, 03043, Cassino, Italy
[b] Department of Engineering, University of Naples "Parthenope", 80143, Naples, Italy
[c] Italian National Agency for New Technologies, Energy and Sustainable Economic Development, 00123, Rome, Italy
[d] Department of Industrial Engineering, University of Salerno, 84084, Fisciano, Italy

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ABSTRACT

Paper mills are considered Hard-to-Abate sectors due to their high energy demand and reliance on fossil fuels, making cost-effective decarbonization challenging. This paper explores the potential of using hydrogen as a viable solution to reduce carbon dioxide emissions of a paper mill through a case study. A methodological approach is proposed to evaluate the technical, economic, and environmental performances of a hydrogen supply chain that includes an electrolysis unit powered by a photovoltaic plant. The hydrogen is blended with natural gas in a cogeneration plant, which supplies the electrical and thermal demands needed for the paper production process.

Based on the technical analysis, the optimal sizes of the photovoltaic plant and the electrolysis unit were estimated at 45.6 and 16.1 MW, respectively, to achieve a hydrogen production of 1553 t/year. The environmental evaluation enabled the calculation of the avoided carbon dioxide emissions, which are equal to 9797 t/year. The economic assessment allowed to estimate the levelized cost of hydrogen, which is 4.24 €/kg. Finally, the break-even analysis highlighted the need for economic and financial instruments, including incentives for green hydrogen production and mechanisms aimed at supporting emissions reduction, to ensure that the industry grows in a sustainable, competitive, and resilient manner.

Nomenclature

Symbols	Description
$CO_{2,avoided}$	Avoided carbon dioxide emissions (kg)
CRF	Capital recovery factor (–)
C_S	Specific energy consumption (kWh/kg)
f	Expected inflation rate (–)
f_i	Maintenance cost coefficient (–)
f_{NG}	Natural gas emission factor (–)
f_{PV}	Photovoltaic Load Factor (kWh/kW$_p$)
$FExp$	Fuel expenditure (€)
i	Nominal discount rate (%)
I_r	Real interest rate (%)
p_{CO_2}	Carbon price (€/kgCO$_2$)
p_{NG}	Natural Gas price (€/kg)
R	Revenues (€)
$T_{exh,stack}$	Exhaust stack temperature (°C)
W	Power (kW)
$\Delta T_{ECO,app}$	Economizer approach temperature difference (°C)
$\Delta T_{EVA,pp}$	Evaporator pinch temperature difference (°C)
$\cdot$	scalar multiplication
Acronyms	**Description**
CHP	Combined Heat and Power
HSC	Hydrogen Supply Chain
HRSG	Heat Recovery Steam Generator
LCOH	Levelized Cost of Hydrogen
PEMEL	Proton Exchange Membrane Electrolyzer
EU	European Union
Subscripts	**Description**
a	Annualized
$COMP$	Compression unit
d	Demand
DB	Discharge
EL	Electrolysis unit
$from\_grid$	From the electricity grid

(continued on next page)

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* Corresponding author.
E-mail address: davide.lanni@unicas.it (D. Lanni).

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(*continued*)

Symbols	Description
to_grid	To the electricity grid
Inv	Investment
max	Maximum
n	Year
O&M	Operating and Maintenance
PV	Photovoltaic plant
Rep	Replacement
RES	Renewable Energy Sources
S	Storage unit
t	Time (h)

1. Background

Since the Paris Agreement was established in 2015, decarbonization has emerged as a critical focus for Europe and numerous other nations globally (IRENA, 2019). The primary objective is to advance sustainable development by decoupling economic growth and greenhouse gas emissions. Achieving decarbonization, therefore, requires a combination of mitigation strategies and technological innovations, while also considering the unique characteristics of major CO_2-emitting sectors. Among these, the industrial sector stands out, as it is responsible for approximately 9 gigatons of CO_2 annually, accounting for about a quarter of total emissions associated with energy systems (International Energy Agency IEA, 2022). To meet the target of net-zero emissions by 2050, substantial reductions in emissions from this sector are essential. This challenge is particularly pressing for industries considered "Hard-to-Abate", where energy demands are high and decarbonization solutions are urgently needed. These include sectors such as cement, iron, steel, glass manufacturing, heavy transportation, and the production of chemicals like ammonia, soda, and caustic soda (Yang et al., 2022; Liu et al., 2023).

The paper manufacturing industry can also be classified among the Hard-to-Abate sectors, as it ranks among the top five energy-intensive industries globally. A recent study by CEPI (Circular Economy in the European Pulp and Paper Industry) reported that in 2022, producing 1 kton of paper resulted in an average emission of 0.27 kton of equivalent CO_2 (Cepi Key Statistics, 2023). In this context, hydrogen and hydrogen-based fuels are essential to address these areas where electricity cannot feasibly or cost-effectively substitute fossil fuels, since they enable the conversion of large quantities of renewable electricity into chemical energy, easier to control, store, and utilize for end-use industries (Azadnia et al., 2023).

This paper is part of the research path dedicated to investigating the real potential and identifying and resolving the significant difficulties associated with using hydrogen to decarbonize the Hard-to-Abate sectors. Thus, in the context of a paper mill case study, this work aims to propose a methodological approach for estimating the technical, economic, and environmental performances of a hydrogen supply chain (HSC) designed to support the decarbonization process of this energy-intensive industry.

The proposed hydrogen supply chain includes an electrolysis unit powered by a photovoltaic plant and storage systems; the produced hydrogen is blended with natural gas (NG) in a Gas Turbine (GT) cogeneration plant to supply the electrical and thermal energy needed for paper production.

1.1. *Literature review on the hydrogen use in the hard-to-abate industries*

In Hard-to-Abate industries, hydrogen can be applied through two main approaches. The first is as an alternative fuel or blended with other fuels, such as natural gas, enabling efficient use of existing energy systems while achieving significant emissions reductions. Several studies have assessed hydrogen co-firing in different energy systems, including internal combustion engines (Boretti, 2020; Raimondi et al., 2024; Lanni et al., 2025a) and gas turbines (Noble et al., 2021; Öberg et al., 2022a, 2022b; Franco and Giovannini, 2023; Zhou et al., 2024).

The second approach involves using hydrogen as a chemical agent in industrial processes, such as steel production, where it acts as a reducing agent in blast furnace-basic oxygen processes (Pudukudy et al., 2014; Amirante et al., 2017; Parra et al., 2019; Dawood et al., 2020; Bararzadeh Ledari et al., 2023) or as a feedstock for chemical compounds like ammonia, methanol, and synthetic methane (Ostadi et al., 2020; Lanni et al., 2023; Nemmour et al., 2023).

The economic feasibility of these approaches has been investigated extensively. Mayrhofer et al. (2021) studied hydrogen-natural gas mixtures for industrial furnaces, finding that significant CO_2 reductions are achievable but financially viable only at carbon prices of 627.2 €/t. Vogl et al. (2018) analyzed steel production with hydrogen replacing part of the iron ore reducing agent, estimating costs of 361–640 €/t of liquid steel depending on renewable electricity prices (20–100 €/MWh). Superchi et al. (2023) explored wind-powered green hydrogen for direct reduced iron, reporting hydrogen costs of 4.95–5.26 €/kg. Other studies on renewable power-to-hydrogen systems (Marocco et al., 2023; Stolte et al., 2024) show that feasibility strongly depends on renewable energy availability, electricity carbon intensity, and hydrogen production costs.

These studies indicate that hydrogen adoption in industrial applications offers substantial emissions reduction potential but requires careful consideration of process integration, techno-economic factors, and policy measures to ensure competitiveness and environmental sustainability.

1.2. *A focus on the paper mill decarbonization*

The paper mill is among the largest industrial energy users, as its production process requires substantial electricity, gas, and steam. The sector contributes to 6% of global industrial energy consumption and 2% of direct CO_2 emissions (Furszyfer Del Rio et al., 2022). Life Cycle Assessment studies of 45 paper mills and 18 pulp plants show that 1 kg of paper generates on average 950 kg CO_2 equivalent, mainly due to energy use in production processes (Sun et al., 2018). With global pulp and paper demand projected to increase significantly by 2050 (Szabó et al., 2009), energy demand and associated emissions are expected to rise, making decarbonization critical to achieving net-zero CO_2 targets.

Five primary pathways are considered for reducing emissions in this sector: (1) energy efficiency measures, (2) electrification of heat supply, (3) paper recycling, (4) carbon capture and storage, and (5) switching to carbon-neutral fuels such as hydrogen (Joyo et al., 2025). Among these, hydrogen adoption has attracted significant interest due to its ability to replace fossil fuels where direct electrification is not feasible, enabling the storage and flexible use of renewable energy.

Despite growing interest, few studies have analyzed hydrogen applications in paper mills. Mati et al. (2023) investigated the feasibility of meeting thermal and electrical energy demand using green hydrogen blended with natural gas in a gas turbine. Their study focused on sizing renewable power and electrolysis systems and performed a sensitivity analysis to optimize economic performance, reporting a levelized cost of hydrogen of 6.41 €/kg. At the project level, Hyflexpower (2020) demonstrated a 12 MW gas turbine cogeneration plant capable of operating with up to 100% hydrogen for pulp and paper production. In Germany, Papierfabrik Adolf Jass Schwarza GmbH, in collaboration with TWS and the transmission system operator Ferngas, converted a combined heat and power (CHP) plant to run on 100% hydrogen, with the heat utilized for paper production, and built 70 km of hydrogen transport infrastructure (Wire Düsseldorf, 2023).

The limited number of studies and industrial projects highlights the need for detailed analyses to define practical decarbonization strategies. Future work should focus on demonstrating the environmental benefits of hydrogen switching, addressing economic challenges such as high capital and operational costs, and supporting policy measures and stakeholder collaboration to accelerate the adoption of hydrogen technologies in the paper sector.

1.3. Novelty and objectives of this work

In light of the existing literature, the introduction of hydrogen in hard-to-abate sectors raises critical questions regarding its technical feasibility, environmental performance, and economic sustainability. However, most existing studies address these dimensions separately, often focusing on individual aspects and lacking a comprehensive framework that integrates hydrogen supply chain optimization with real industrial energy demand and the assessment of hydrogen's competitiveness under different policy scenarios. As a result, studies that simultaneously consider technical system design, environmental benefits, and policy-dependent economic conditions remain limited, largely due to the complexity of combining system-level optimization, real industrial data, and policy-driven economic analysis.

This work addresses this gap by proposing an integrated and replicable methodological framework for the decarbonization of hard-to-abate industries, applied to a representative paper mill case study. The proposed approach combines:

- A detailed numerical model to determine the optimal configuration and sizing of a hydrogen supply chain capable of meeting both thermal and electrical energy demands, together with an environmental assessment of avoided CO_2 emissions.
- A comprehensive economic evaluation, including the levelized cost of hydrogen (LCOH) and a break-even analysis, explicitly assessing the role of policy instruments, such as green hydrogen incentives and carbon pricing mechanisms, in ensuring competitiveness and long-term sustainability.

The novelty of this study lies in its interdisciplinary and fully integrated approach, which, unlike previous work, simultaneously optimizes supply chain design, quantifies environmental benefits, and incorporates policy-driven economic scenarios. By providing quantitative evidence on the combined effects of system design, economic factors, and policy support, the proposed methodology offers actionable insights for stakeholders and decision-makers and can be readily adapted to other hard-to-abate sectors. Moreover, the analysis highlights potential economic challenges associated with European climate and energy policies, emphasizing the importance of well-designed incentives to support hydrogen adoption while preserving industrial competitiveness and resilience.

2. Methodological approach

The goal of this study is to propose a methodological approach to evaluate the technical feasibility, the environmental benefits, and the economic sustainability linked to the production and use of hydrogen to decarbonize energy-intensive industries.

The workflow of the proposed methodological approach is depicted in Fig. 1, which highlights the main steps of the technical, environmental, and economic assessment.

Starting from the data related to the selected case study (energy requirements of the end-user and the characteristics of the installation site in terms of renewable source availability), the technical assessment is based on the design and sizing of an on-site and grid-connected hydrogen supply chain, consisting of an electrolysis unit powered by a renewable power plant and a compression/storage unit. To this end, a properly developed numerical model is applied alongside an appropriate energy management strategy. The results of this technical assessment are used to estimate the environmental benefits in terms of CO_2 avoided and the economic feasibility of the hydrogen supply chain in terms of the levelized cost of hydrogen and the economic incentives required to ensure a sustainable use of hydrogen.

2.1. Case study: the paper mill

As a case study, a typical paper mill located in southern Italy, has been selected, and a PV system has been considered as a renewable plant to be installed on the industrial site. The solar data have been obtained from the PVGIS web-based calculation tool implemented by the European Commission (Photovoltaic Geographical Information System, PVGIS). In this installation site (40.6 Lat, 14.9 Lon), the average irradiation on the optimal slope angle ranges from 2.73 kWh m^{-2}/day (in December) to 7.35 kWh m^{-2}/day (in July), and the annual average

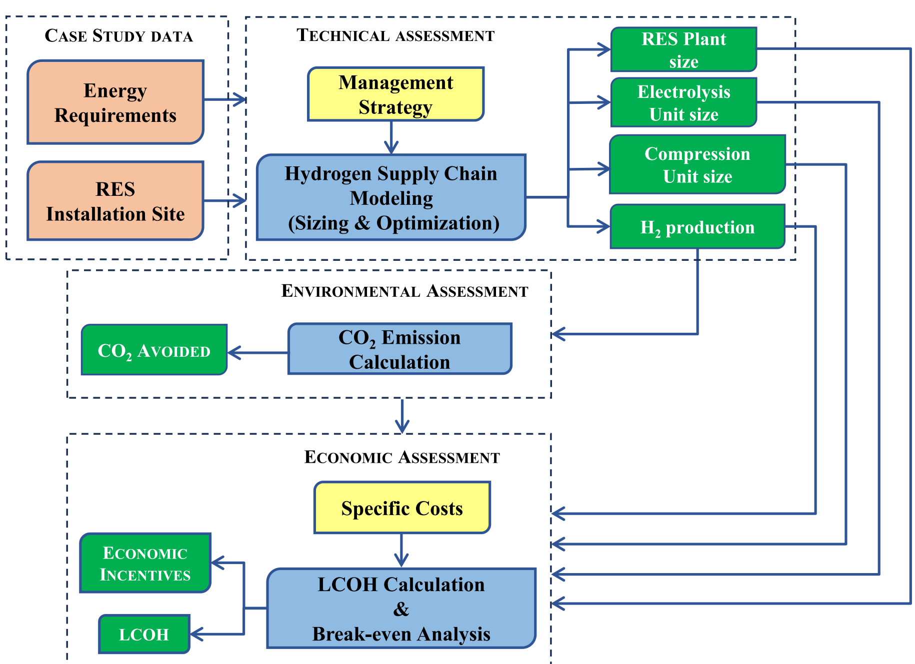


Fig. 1. Workflow of the methodological approach.

temperature varies from 8.9 to 25.6°C. The calculated PV plant capacity factor is 24.0%, corresponding to 2104 kWh/kW$_p$.

In terms of energy requirements, the thermal and electrical demands consist of heat supplied as saturated steam for the drying process of semi-finished products, along with electricity to operate the machinery. These data have been obtained from Mati et al. (2023). In particular, since the weekly patterns of steam consumption and electricity remain largely consistent throughout the year, a weekly profile was selected as a representative sample for the entire year. The electricity demand is almost constant, varying between 3.7 and 5.3 MWh, while the thermal energy demand varies more significantly from 6.7 to 12.6 MWh. The heat-to-electricity ratio, calculated over the week, is equal to 1.9. The thermal demand is in the form of process saturated steam at 20 bar (212°C), whose mass flow rate ranges from 9 t/h (2.5 kg/s) to 16.9 t/h (4.7 kg/s). The thermal and electric demands are met by a gas turbine-based combined heat and power (CHP) plant. The gas turbine is a Siemens GT-100, whose operating data can be found in Appendix (Kalina, 2012), and is available within the range of electric power ratings from 4.35 MW up to 5.4 MW. The Siemens GT-100, as declared by the manufacturer, can currently work with a hydrogen blending up to 65 vol.%. and turbines capable of running on 100% hydrogen are still under development.

In order to calculate the hydrogen demand, which is the main input needed to size the hydrogen supply chain, a numerical model of the CHP plant has been developed in Aspen Plus environment (see Appendix).

2.2. Technical assessment: hydrogen supply chain modeling

The hydrogen supply chain (HSC), depicted in Fig. 2, is designed to produce electrolytic hydrogen, blended with natural gas to fuel a gas turbine-based CHP plant supplying energy for paper production. The HSC follows a Power-to-Hydrogen approach, integrating a PV power

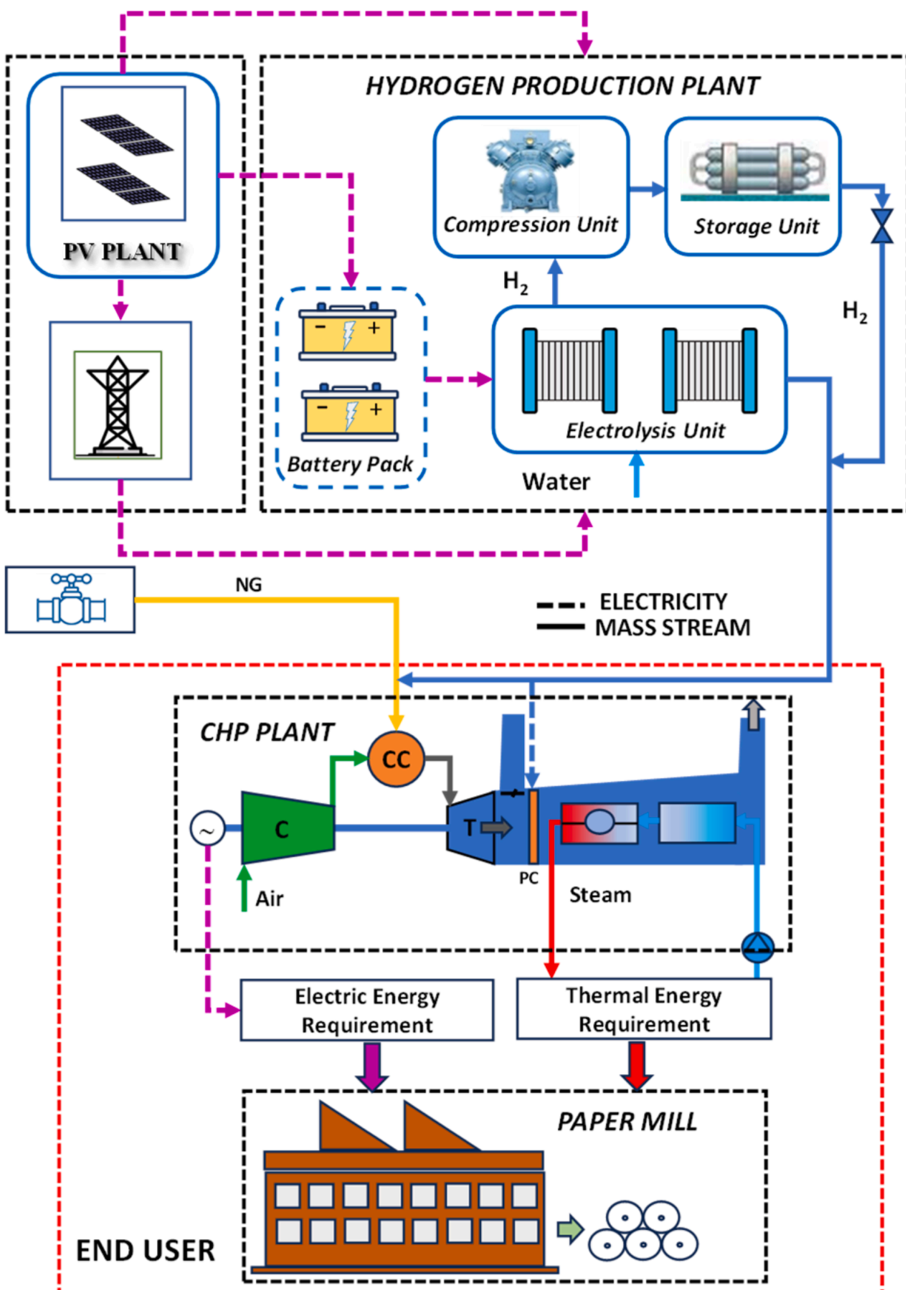


Fig. 2. Conceptual scheme of the hydrogen supply chain.

plant with an electrolysis unit, a compression unit, and storage systems. Three configurations are considered: HSC_1 with a small hydrogen buffer tank to compensate for demand fluctuations; HSC_2 with a large storage tank to increase renewable electricity utilization; and HSC_3, which also includes a battery pack to further maximize renewable electricity use.

The core of the system is a proton exchange membrane electrolyzer (PEMEL), valued in power-to-gas applications for its flexibility and fast response under dynamic conditions (Boudellal, 2018; Peter et al., 2022; Lanni et al., 2023). In this study, 1 MW PEMEL modules operating at 20 bar and 55°C were adopted (Lanni et al., 2023). Nominal cell conditions are set at 2.99 A/cm^2 and 2.17 V (Perna et al., 2020; Lanni et al., 2023), with auxiliary modules consuming 2.8% of rated power. Each module produces 16.8 kg H_2/h with a specific energy consumption of 59 kWh/kg, corresponding to a nominal efficiency (η_{EL}, LHV) of 56.5%.

The PV plant powering the electrolysis unit uses crystalline silicon modules with 16%–22% efficiency. A 560 W (44.3 V@12.6 A) Jinko Solar module with 20.5% efficiency under standard test conditions was selected, and tilt/azimuth angles were optimized based on local climatic data. Hydrogen is compressed using a reciprocating compressor to 200 bar. The battery system employs lithium-ion cells with 85%–95% efficiency, long cycle life (1000–10000 cycles), and energy density of 200–400 kWh/m^3. A Tesla Megapack module with 90% round-trip efficiency and 741.2 kW/2964.8 kWh power-to-energy ratio was adopted (Chen et al., 2020; Perna et al., 2023).

The electrolysis unit generates hydrogen by taking into account both the demand and the capacity of the storage unit; the grid connection allows to balance the electricity deficit (when the electricity generated by the PV plant is less than that required, it is compensated by the battery pack, if installed, or by the grid) or surplus (when the electricity generated by the PV plant is more than that required, it is diverted to the battery pack, if installed, or to the grid).

A properly developed numerical model for assessing the mass and energy balances and the size of the hydrogen supply chain components has been developed in the MATLAB environment. The model flowchart is illustrated in Fig. 3. The key parameters are the input data, the assumptions, and the constraints.

The input data are: i) the hourly hydrogen demand; ii) the PV load factor ($f_{PV,t}$), which is the hourly electrical energy produced by a 1 kW PV plant, according to the solar irradiation data of the installation site. Moreover, the algorithm is based on the assumption that the electrolysis unit must be sized to satisfy the maximum hourly hydrogen requirement, as well as on the constraint that the PV plant must be sized to meet the annual electricity demand of the electrolysis and compression units.

The size of the electrolyzer $\left(W_{EL,rated}\right)$ is calculated as follows:

$$W_{EL,rated} = m_{H_2,\ max} \cdot \mathrm{LHV}_{H_2} \cdot \eta_{EL} \tag{1}$$

where $m_{H_2,\ max}$ is the maximum hourly hydrogen mass flow rate, LHV_{H_2} is hydrogen's low heating value, equal to 120 MJ/kg (Shiva Kumar and Lim, 2022), and η_{EL} is the efficiency of the selected electrolysis unit at rated power. When the electrolysis unit operates under partial-load conditions according to the hydrogen demand, the efficiency varies as detailed in ref. (Perna et al., 2020).

$W_{COMP,rated}$ is the size of the compressor unit, estimated as:

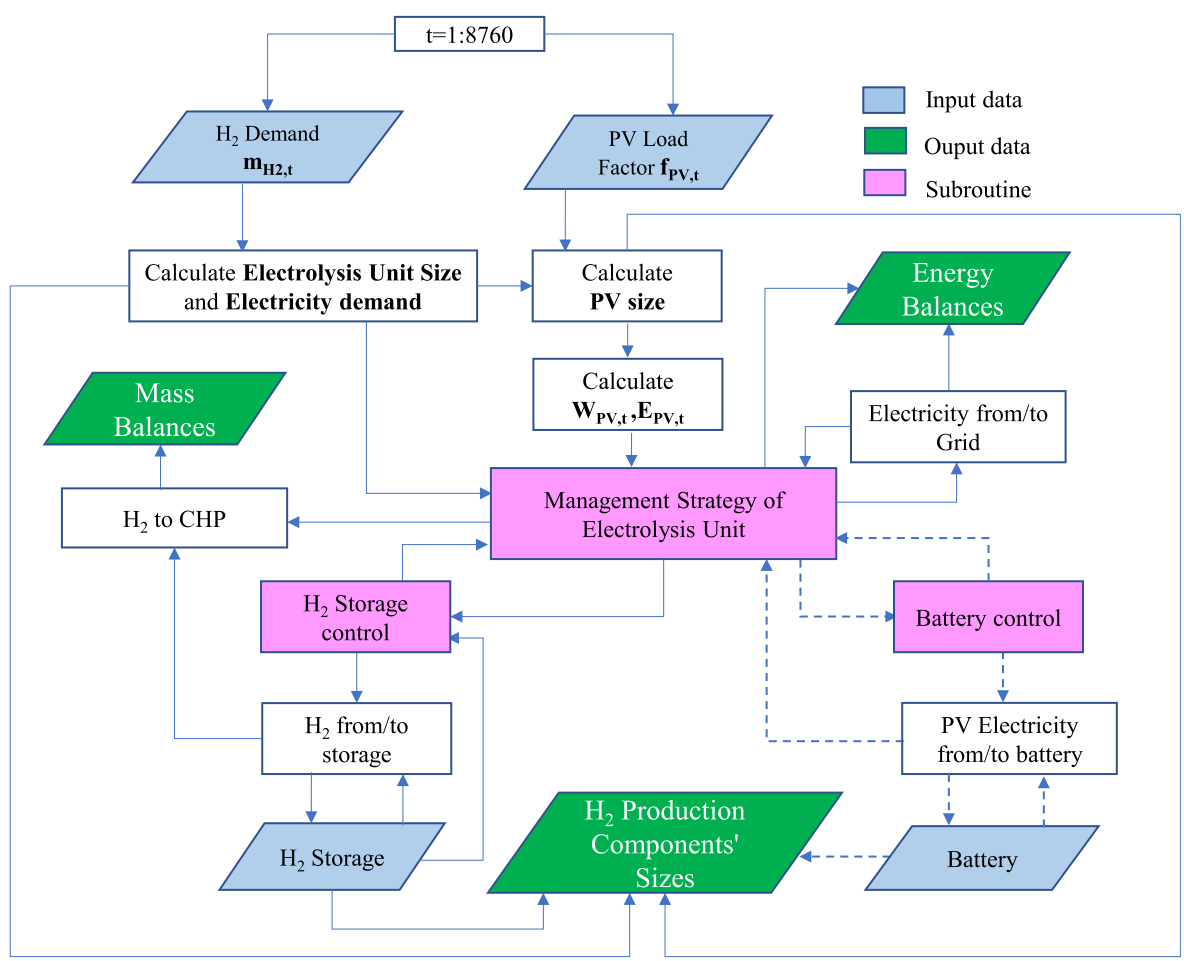


Fig. 3. Flowchart of the hydrogen supply chain.

$$W_{COMP,rated} = C_{s,COMP} \cdot m_{H_2,max} \tag{2}$$

where $C_{s,COMP}$ is the specific consumption of the compression unit (1.21 kWh/kg) and $m_{H_2,max}$ is the maximum hydrogen consumption (kg/h).

Consequently, the annual energy demands of the electrolyzer and of the compressor unit are estimated by considering the sum of their hourly power consumption ($W_{EL,t}$, $W_{COMP,t}$) as follows:

$$E_{EL} = \sum_{t=1}^{8760} W_{EL,t} \tag{3}$$

$$E_{COMP} = \sum_{t=1}^{8760} W_{COMP,t} \tag{4}$$

Finally, the size of the PV ($W_{PV,rated}$) is calculated taking into account the annual electricity demand that must be satisfied (corresponding to the electricity requirements of electrolyzer and compression unit, $E_d = E_{EL} + E_{COMP}$), and the total electricity generated from 1 kW PV plant (that is the sum of the plant hourly load factors in one year), according to the following equation:

$$W_{PV,rated} = \frac{E_d}{\sum_{t=1}^{8760} f_{PV,t}} \tag{5}$$

Based on the renewable energy source availability, a management strategy is applied to the electrolysis unit to regulate hydrogen production and its distribution between the CHP plant and the storage unit.

The strategy, based on the hourly operation (t) is guided by the following criteria:

i) if the PV electrical power ($W_{PV,t}$) exceeds the electrolyzer's electrical demand (according to the hydrogen demand), the electrolysis unit is set to operate at rated power $\left(W_{EL,rated,t}\right)$; the required hydrogen is supplied to the utility while any hydrogen surplus is stored in the storage tank (until it is full); at the same time, the electricity surplus is used to recharge the battery or, if the battery is already fully charged, it is diverted to the grid $\left(E_{to\_grid,t}\right)$.
ii) if the PV electrical power ($W_{PV,t}$) is lower than electrolyzer's electrical demand, the electricity deficit is supplied by the battery if installed, or by the electrical grid $\left(E_{from\_grid,t}\right)$.

Thus, the grid connection (and the battery pack, if installed) ensures continued operation of the electrolysis unit when the renewable energy is not sufficient to meet the electricity demand of the hydrogen production plant; on the other hand, any electricity surplus is either diverted to the grid or used to recharge the battery pack.

In addition, two control checks on filling/emptying of the hydrogen storage system (maximum and minimum capacity) and charging/discharging of the battery pack (maximum and minimum state of charge) have been established.

The variable parameters used for the sensitivity analysis, aimed at estimating the optimal configuration from an economic perspective, are the size of the hydrogen storage (300 kg in HSC_1 and 2000 kg in HSC_2 and HSC_3) and the size of the battery pack (in HSC_3); this size is calculated to ensure the full load operation of the electrolyzer for 4 h (H). By assuming the discharge efficiency (η_{BD}) equal to 0.94 and the minimum state of charge equal to 10% of the stored electricity, the battery size (E_B) is equal to:

$$E_B = \frac{H \cdot W_{EL}}{\eta_{BD}} \cdot 1.1 \tag{6}$$

2.3. Environmental assessment

The environmental analysis is based on the estimation of the avoided CO_2. To this end, CO_2 emissions in CHP conventional configuration and in CHP with hydrogen blending configuration have been calculated (Eq. (7)), using the natural gas emission factor (f_{NG}), which represents the tonnes of CO_2 emitted per tonnes of natural gas burned. This value is 2.75.

$$CO_{2,\text{avoided}} = \left(m_{NG,CHP} - m_{NG,CHP_{H2blend}}\right) \cdot f_{NG} \tag{7}$$

2.4. Economic assessment

The economic feasibility of the hydrogen supply chain, installed to satisfy the CHP hydrogen demand, has been assessed by estimating the main economic parameters, such as the investment (C_{Inv}), operating and maintenance ($C_{O\&M}$) and the replacement (C_{Rep}) costs, as well as the revenue R_{EGRID} from the sale of the electricity surplus produced by the PV plant and exported to the grid. A detailed description of these costs is summarized in Table 1.

These economic parameters must be calculated considering the plant operation throughout its lifetime (N); thus, it is important to take into account the real interest rate (I_r), and the Capital Recovery Factor (CRF), which are defined as:

$$I_r = \frac{i - f}{1 + f} \tag{8}$$

$$CRF = \frac{I_r \cdot (1 + I_r)^N}{(1 + I_r N)^N - 1} \tag{9}$$

where (i) and (f) are the nominal discount rate and the expected inflation rate, respectively. The plant lifetime, the nominal interest rate, and the expected inflation rate are assumed equal to 20 years, 3%, and 2%, respectively (Vandewalle et al., 2015).

As a consequence, all costs and the revenues are calculated by considering their annualization at a fixed year (n), according to the following equations:

$$C_{O\&M,n} = \frac{C_{Operating} + C_{maintenance}}{(1 + I_r)^n} \tag{10}$$

Table 1
Cost items description.

Investment cost	$C_{Inv} = C_{PV} + C_{EL} + C_{COMP} + C_S$	This cost item takes into account the costs of the hydrogen production plant's components: PV unit, electrolyzer, compressor unit and storage unit.
Operating and Maintenance costs	$C_{O\&M} = C_{Operating} + C_{Maintenance} = (C_{water} \cdot m_{water}) + E_{from\_grid} \cdot C_{E,in} + \left[\sum_i f_i \cdot C_{Inv,i}\right]$	This cost item is related to the plant operation, and it refers to a specific year (n); in particular: • the operating costs are calculated by considering the annual cost due to the annual H_2O consumption (m_{water}) times its cost (C_{water}), and the expenditure due to the electric energy (E_{from_grid}) purchased from the grid. • the maintenance costs are estimated as a percentage of the total investment cost; the term f_i refers to the percentage assumed for the maintenance cost estimation that depends on the type of component and ranges from 1% to 8% according to the values suggested in the literature.
Replacement cost	$C_{Rep} = C_{Rep,EL} + C_{Rep,COMP}$	This cost item refers to the replacement of components (electrolyzer stacks and compressor) at the specific year at which they must be substituted.

$$C_{Rep,n=n_{rep}} = \frac{C_{rep}}{(1+I_r)^{n_{rep}}} \tag{11}$$

where n_{rep} is the year at which the component must be replaced.

Similarly, the obtained revenues from selling the PV plant's surplus electricity to the grid $R_{E_{to\_grid}}$ are annualized over the plant's lifetime, according to the following equation:

$$R_{E_{to\_grid},n} = \frac{R_{E_{to\_grid}}}{(1+I_r)^{n}} \tag{12}$$

The estimation of these economic data allows for the calculation of the levelized cost of hydrogen with respect to the plant lifetime (N) by applying the following equation:

$$\text{LCOH} = \frac{\left(\sum_{n=1}^{N} C_{Inv,n,a} + \sum_{n=1}^{N} C_{Rep,n,a}\right) CRF + \sum_{n=1}^{N} C_{O\&M,n,a} - \sum_{n=1}^{N} R_{E_{to\_grid},n,a}}{\sum_{n=1}^{N} m_{H_2,n}} \tag{13}$$

where $m_{H_2,n}$ is the annual hydrogen production.

The economic data of the components used for the economic assessment are summarized in Table 2.

To evaluate the need for economic and financial instruments, such as incentives for green hydrogen production or other measures to support the reduction of CO_2 emissions, a break-even analysis has been carried out, allocating all the benefits of the investments to the final product (hydrogen) and assuming that the PV plant and hydrogen production plant operate as one unit.

This break-even analysis aims to estimate the economic value of the avoided CO_2, based on EU Emission Trading System carbon prices, and to identify the incentives required to achieve the same operating costs (in terms of fuel expenditure) in both the conventional and hydrogen blending configurations.

The fuel expenditure ($FExp, a$) in the case of economic valorization of the avoided CO_2 by means of a carbon price mechanism (p_{CO_2}) is calculated as:

$$FExp, a = m_{NG} \cdot p_{NG} + m_{H_2} \cdot LCOH - m_{CO_2,avoided} \cdot p_{CO_2} \tag{14}$$

The fuel expenditure ($FExp, b$) in the case of further economic incentives due to the on-site hydrogen production ($p^*_{H_2}$ is the price at which the hydrogen is valued if produced in a dedicated plant), is calculated as:

$$FExp, b = m_{NG} \cdot p_{NG} + m_{H_2} \cdot LCOH - m_{CO_2,avoided} \cdot p_{CO_2} - m_{H_2} \cdot p^*_{H_2} \tag{15}$$

A sensitivity analysis of these two prices has been performed to find the break event points in comparison to the conventional solution based solely on fossil fuels.

3. Results

The results of this study provide a comprehensive assessment of the technical, environmental, and economic performance of the proposed hydrogen supply chain, illustrating the effective approach of the methodological framework and highlithing the critical challenges and opportunities associated with hydrogen deployment. From a technical perspective, the study presents the optimal sizing of the hydrogen production system, designed to fully satisfy the hydrogen demand of the selected paper mill, using a modelling approach that is generalizable to other industrial applications. From an economic standpoint, the analysis focuses on the determination of the Levelized Cost of Hydrogen (LCOH), a key parameter for informed decision-making regarding the implementation of hydrogen within the energy market. From an environmental perspective, the study quantifies the CO_2 emissions avoided through the substitution of natural gas with hydrogen, highlighting the potential contribution of the proposed system to the decarbonization of the sector. Finally, the break-even analysis provides an additional and significant contribution, as it quantifies the level of incentives required to achieve economic sustainability for the proposed technological solution, offering concrete and practical guidance to industry stakeholders to support the planning and implementation of hydrogen-based decarbonization strategies.

3.1. Technical and environmental results

From a technical point of view, the analysis's focus has been on evaluating the operating conditions and the performance of the CHP plant in the blending configuration, as well as on estimating the size and the operating conditions of the hydrogen supply chains based on different plant configurations. On the other hand, from an environmental perspective, the analysis has allowed for the calculation of the avoided CO_2 resulting from the proposed blending configurations.

3.1.1. Combined heat and power plant operation

The thermochemical model developed in Aspen Plus (see Appendix A) has allowed to estimate the hydrogen demand of the CHP plant according to the electrical and thermal demands of the paper production process. Table 3 summarizes the calculated operating conditions and the performance of the plant in the blending configuration by considering the maximum power production (GT load at 100%).

The “thermal load following scenario” has been applied as management strategy of the CHP plant; this means that the GT load is managed in order to guarantee the demand for thermal energy (steam demand), while the demand for electricity is balanced by the electricity grid. The thermal power needed for the steam production is obtained by recovering heat from the exhaust gasses sent to the Heat Recovery Steam Generator (HRSG). Post-combustion is achieved using hydrogen in order to increase the amount of steam required for the drying process of semi-finished products.

Fig. 4(a)–(c) illustrate the weekly energy demand of the paper mill, the weekly natural gas consumption, both in GT blending configuration (NG 35 vol.%, H_2 65 vol.%) and conventional configuration (NG only feeding the CHP plant), and the weekly hydrogen consumption calculated for the GT blending configuration.

It is observed that, in the proposed blending configuration, the minimum and maximum natural gas consumptions are 591 and 952 kg/h, respectively (Fig. 4(b)). These values are approximately 35% lower than those associated with the conventional configuration (914 and

Table 2
Input data for the economic analysis.

	Unit	Investment Cost (C_{Inv})	Operating and Maintenance Cost ($C_{O\&M}$)	Replacement Cost (C_{Rep})	Revenues ($R_{E_{to\_grid}}$)
PV Plant (Lanni et al., 2025b)	€/kW	405.5	1.58%· C_{Inv}	-	-
Electrolyzer (Lanni et al., 2025c)	€/kW	1678	3%· C_{Inv}	40%· C_{Inv}	-
Compressor (Lanni et al., 2025b)	€	$36079 \cdot P^{0.6038*}$	8%· C_{Inv}	C_{Inv}	-
Tank (Lanni et al., 2025b)	€/kg	490	3%· C_{Inv}	-	-
Li-ion Battery cost (Electrek, 2021)	€/kWh	308	5%· C_{Inv}	C_{Inv}	
Electricity from the grid	€/kWh	-	0.1	-	-
Electricity to the grid	€/kWh	-	-	-	0.046
Deionized Water	€/kg	-	0.01	-	-

*P is the compressor's size expressed in kW.

Table 3
Operating conditions and performance of the GT in the blending configuration.

Data	Unit	Values
Operating conditions		
Air mass flow rate	kg/s	20.6
Turbine outlet temperature	°C	549.0
Compression Ratio	-	15.6
Natural gas consumption	kg/h	835.2
Hydrogen consumption	kg/h	194.4
Performance		
Electric Power	MW	5.5
Thermal power	MW	10.6
Fuel input	MW	18.1
Heat rate	MJ/kWh	11.8
Efficiency (LHV)	%	30.5
Cogeneration efficiency (LHV)	%	89.0

1413 kg/h).The hydrogen consumption in the gas turbine (blue line in Fig. 4(c)) varies between 137 and 221 kg/h. The additional hydrogen required by the HRSG post-combustor is very small (the maximum value is 50 kg/h); it accounts for only about 1.3% (383 kg) of the total weekly hydrogen consumption, which amounts to 29.8 t (the CHP plant demand is the total consumption shown in red in Fig. 4(c)).

3.1.2. *Hydrogen supply chain configurations: size and operation*

By applying the developed hydrogen supply chain model, the size of each component, and the energy and mass balances have been evaluated for the three plant configurations (HSC_1 employs a small hydrogen buffer to mitigate short-term demand fluctuations. HSC_2 utilizes a large hydrogen storage tank to enhance renewable electricity utilization. HSC_3 additionally incorporates a battery pack to further increase renewable electricity use), differing in terms of the sizes of the hydrogen storage unit and battery pack. Results of this analysis are summarized and compared in Table 4.

In all configurations, the size of the PV plant, which has to satisfy the annual electricity required by the hydrogen production plant, is 45.6 MW, and the size of the electrolysis unit, that has to produce the maximum hydrogen demand (271 kg/h), is 16.1 MW; in addition, the calculated size of the compression unit is 331 kW. It can be observed that a high hydrogen storage capacity and the use of a battery pack allow for an increase in the renewable energy utilization from 43.4% up to 57.1% and 77.7%, respectively. The total annual hydrogen production amounts to 1553 t. For the three configurations, the share of hydrogen generated by the renewable plant is 45%, 60%, and 78%, respectively, with the latter (HSC_3) encompassing both the direct contribution from the PV plant and the indirect contribution supplied via the battery pack.

These results are illustrated with respect to the monthly production, in terms of percentages, in Fig. 5(a) and (b). In Fig. 5(a), it is important to note that in HSC_1, the electricity generated from PV to power the electrolysis and compression units covers a percentage that ranges from 25% (in December) to 59% (in July).

The utilization of 2000 kg of hydrogen storage (configuration HSC_2) allows for an increase in the monthly percentages of electricity from PV to the electrolysis and compression units; these values range from 30% (in December) to 83% (in July). In the final configuration (HSC_3), the battery pack enables maximum utilization of renewable energy sources (RES). Specifically, in July, the utilization of PV energy to meet the electricity demand for the hydrogen production system is at its peak. During this month, 83% of the electricity demand is met directly by the PV system, while the remaining 15% is supplied by the battery pack. The annual energy contribution of the battery pack varies between 13% (in December) to 21% (in January, March, and September). Referring to the electricity diverted to the grid (see Fig. 5(b)), the monthly distribution ranges from 48% (in December) to 60% (in July) in the HSC_1; these percentages are reduced to 38% and 44% in HSC_2, and to 7% and 32% in HSC_3, confirming an increase in renewable energy source utilization.

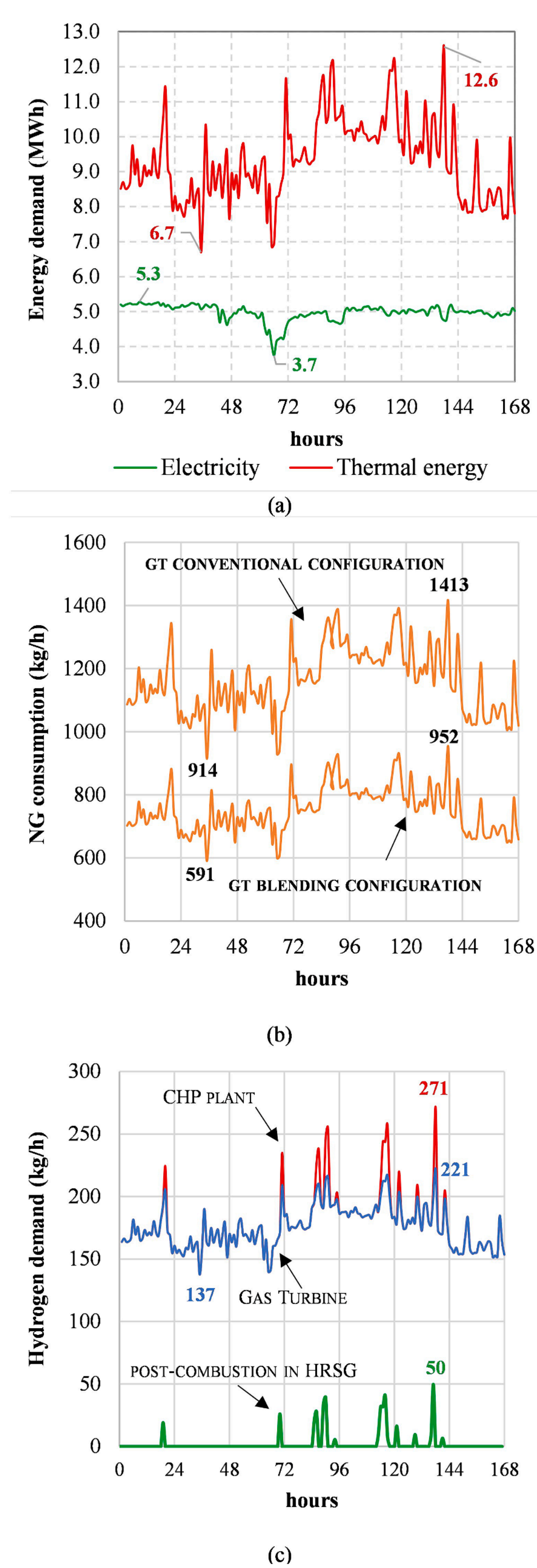


Fig. 4. Weekly energy demand and fuel consumption profiles of the paper mill and CHP system. (a) Weekly energy demands of the paper mill; (b) Weekly NG consumptions in the GT blending configuration; (c) Weekly H_2 demand in the GT blending configuration.

Table 4
Sizes and energy, and mass balances for different configurations of the hydrogen supply chain.

	HSC_1	HSC_2	HSC_3
Component size			
PV (MW)	45.6	45.6	45.6
Electrolysis Unit (MW)	16.1	16.1	16.1
Compression unit (kW)	331	331	331
Storage Unit (kg)	300	2000	2000
Battery pack (MWh)	-	-	75.4
Energy balances per year (MWh)			
Electricity from PV	95975	95975	95975
Electricity from PV to PEMEL	41595	54459	54459
Electricity from Grid to PEMEL	52098	38699	20792
Electricity from the Battery pack to PEMEL	-	-	17190
Electricity from PV to grid	54272	41133	21327
Electricity from PV to the Compression unit	108	383	383
Electricity from PV to Battery pack	-	-	19806
Renewable energy utilization factor (%)	43.4	57.1	77.7
Mass balances per year (t)			
Hydrogen from PV	705.2	923.2	923.2
Hydrogen from Grid	847.8	629.8	338.4
Hydrogen from Battery	-	-	291.4

3.1.3. *Environmental benefits*

The environmental benefits due to the introduction of hydrogen in the paper mill have been estimated in terms of avoided CO_2 emissions. In this assessment, the grid emission factor (which varies from country to country) has been neglected, as it has been assumed that the grid electricity is fully renewable. By analysing the results, it can be stated that the proposed hydrogen-based solution can achieve a reduction of 188.4 t CO_2 per week at the considered paper mill, corresponding to a 35% decrease compared to the emissions of the natural gas-based configuration. This finding is consistent with previous studies, such as Pashchenko (2023), which reported that the use of a 50% hydrogen blend in gas turbines can reduce greenhouse gas emissions by more than 23% compared to methane-only operation. The results of the environmental assessment could be further contextualized at a larger scale by considering the potential impact across the entire sector. At the annual scale, this reduction corresponds to approximately 9.8 kt CO_2 per year for a single paper mill. If the proposed hydrogen technology were implemented across all 151 paper mills in Italy, the cumulative reduction could reach approximately 1.48 Mt CO_2 per year, equivalent to around 32% of the sector's total emissions, c.a 4.66 Mt CO_2 in 2020, (ISPRA, 2022). These results underscore the substantial decarbonization potential of hydrogen deployment in the Hard-to-Abate paper sector, highlighting both the environmental benefits and the strategic relevance of scaling up this technology.

3.2. *Economic feasibility*

The economic evaluation of the hydrogen supply chain, and consequently the identification of its optimal configuration, has been carried out by estimating the minimum value of the LCOH. This evaluation has been carried out by considering that the calculated Levelized Cost of Electricity (LCOE) for the proposed PV plant, estimated as in (Mati et al., 2023), is 12.5 €/MWh, in accordance with data reported in (Fraunhofer Institute for Solar Energy Systems, 2024). Fig. 6 shows the LCOH for the three configurations as well as the incidence of each item cost on these values.

It can be noted that the lowest LCOH, equal to 4.24 €/kg, is achieved with the HSC_2 configuration, characterized by a larger hydrogen storage (2000 kg) and a renewable energy utilization factor of 57.1%. In contrast, HSC_3 shows the highest LCOH due to the increased investment and replacement costs associated with the battery pack, even if the renewable energy utilization factor is at its highest (77.7%), and, as a consequence, the electricity purchased from the grid (operating and maintenance costs) is the lowest.

Fig. 7(a)–(c) details the contribution of each component to the specific cost item for HSC_2, which, having an LCOH of 4.24 €/kg, is the optimal configuration. It is important to note that the electrolysis unit accounts for the largest share (56.7%) of the investment costs (47.7 M€), followed by the PV plant, which contributes 38.8%.

As expected, the most significant contributor to operating and maintenance costs (equal to 5.22 M€/year) is the cost of electricity purchased from the grid (at an assumed price of 0.1 €/kWh). This cost accounts for 74.2% of the total operating and maintenance costs. The maintenance costs (1.21 M€/year) account for 23.2% of the operating and maintenance costs: the electrolysis unit shows the highest value (67.1%), followed by the PV plant (24.1%).

Referring to the replacement costs, the electrolysis unit has the greatest impact (21.6 M€), since the stacks must be replaced 2 times (the stack lifetime is kept equal to 60000 h) during the plant lifetime. Based on this cost analysis, and taking into account the calculated revenue (33.2 M€) from selling the electricity surplus during the plant lifetime (Eq. (12)), the calculated LCOH (Eq. (13)) is equal to 4.24 €/kg.

3.2.1. *Break-even analysis*

The break-even analysis has been performed to identify the incentives needed to enhance hydrogen's competitiveness compared to fossil fuels in paper mills. Results of this analysis, related to the optimal configuration (HSC_2) are illustrated in Fig. 8.

Fig. 8(a) presents the weekly fuel expenditure $FExp, a$ (Eq. (14)) evaluated using the calculated LCOH of 4.24 €/kg and obtained by varying the NG (p_{NG}) and carbon prices (p_{CO_2}).

The intersection points between the NG curve, representing the fuel expenditure of the conventional configuration, and the corresponding curves for the blending configuration at various carbon prices (ranging from 100 to 290 €/ton, reflecting current and projected EU Emissions Trading System conditions) identify the breakeven thresholds. Under the current natural gas price of 1.3 €/kg, the proposed CHP blending configuration consistently exhibits lower fuel expenditure compared with the conventional configuration, provided that the carbon price remains at or above 290 €/ton.

Fig. 8(b) depicts the weekly fuel expenditure trend $FExp, b$ (Eq. (15)) obtained by considering the LCOH equal to 4.24 €/kg and the p_{NG} equal to 1.3 €/kg (current value). Moreover, both the carbon price p_{CO_2} and the economic incentive for the hydrogen production (p^*_{H2}) have been parametrically varied: the former across the range 100–290 €/ton and the latter within the interval 0.2–1.7 €/kg.

It is worth noting that the intersection points of the NG curve with the curves, which are the break-even points, represent the values of the incentives that allow the same fuel expenditure to be achieved in both CHP configurations (without or with hydrogen blending). It can be highlighted that if the CO_2 price is very high (290 €/ton), the blending configuration is always the best solution.

It is therefore possible to conclude that it is necessary to provide economic incentives to ensure financial sustainability.

4. Discussion and current outlook

The results of this study align with recent findings in this area of research. In fact, as reported in the literature review (Section 2) of this paper, the calculated LCOH (4.24 €/kg) is consistent with the values estimated in other studies, whose values range from 3 to 9 €/kg. This wide range depends on many factors, such as the size of the plant, the combination of different renewable energy sources, the geographical location of the plants, and the cost of electricity from the grid (which can vary from country to country). In any case, in all the published works, the LCOH is higher than the current price of the fossil fuels that it should replace (i.e., the price of natural gas in Italy is 1.3 €/kg), so it is clear that the introduction of hydrogen in the Hard-to-Abate sectors is not competitive from an economic point of view. Thus, the approach

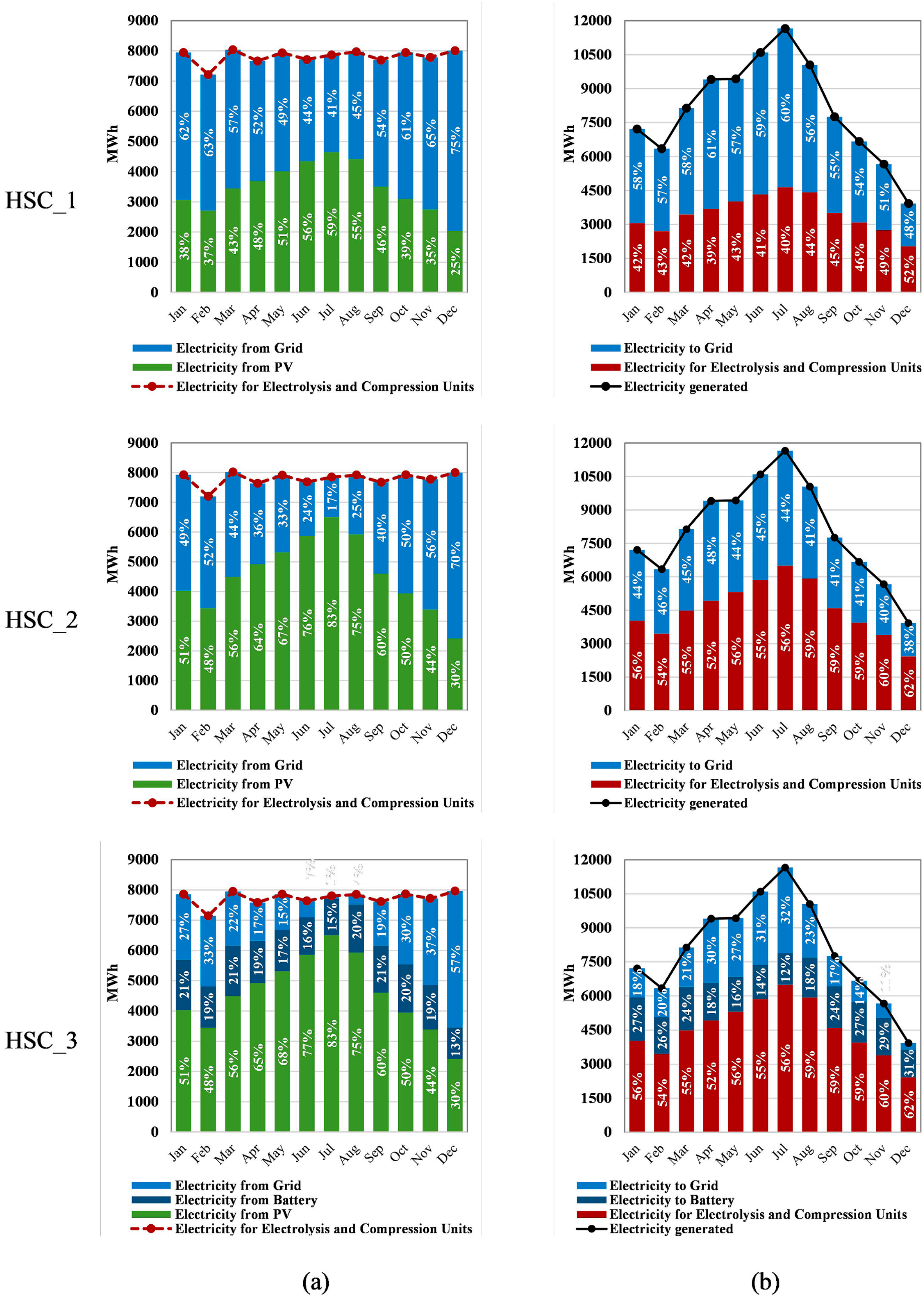


Fig. 5. Monthly electricity balance and renewable energy utilization of the hydrogen supply chain in the three configurations. (a) Monthly electricity balance of the hydrogen supply chain, and (b) Monthly electricity balance of the PV plant.

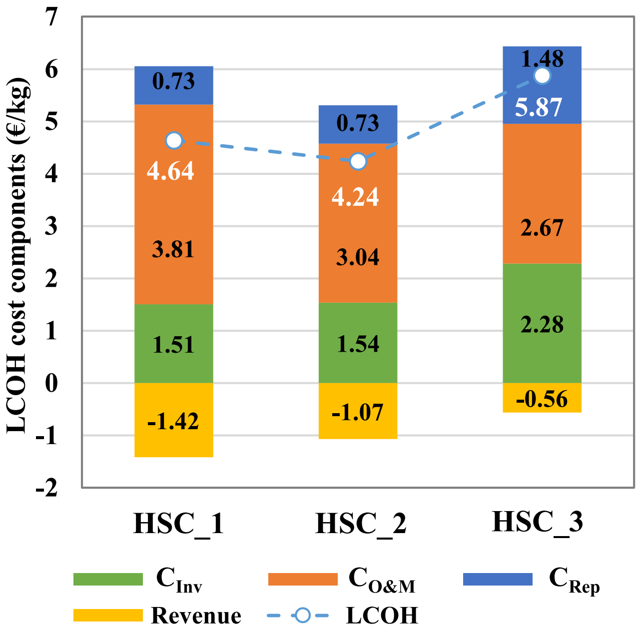


Fig. 6. Breakdown of the levelized cost of hydrogen for the proposed configurations. The figure compares total LCOH values and the contribution of investment, operation and maintenance, and replacement costs, as well as the contribution of revenues from surplus electricity sold to the grid.

proposed in this study aims to find strategies for introducing incentives, as has been done in a few studies published by other authors (see section 1.3).

In this context, it is clear that the technical feasibility and cost-effectiveness of fossil fuel substitution with hydrogen in the Hard-to-Abate sectors are not yet fully within reach; it is therefore worth mentioning that alternative routes to green hydrogen are currently being investigated in support of the decarbonization of energy-intensive industries. These alternative routes primarily focus on electrification, which, despite being an interesting and useful strategy, introduces challenges such as difficulty in forecasting demand profiles, controlling voltage and frequency, transmission congestion, and the need for robust storage systems. Therefore, once the barrier of higher costs is breached, hydrogen remains the most suitable technical solution, considering its numerous fields of application.

5. Conclusions

This work presents a methodological approach to estimate the technical, economic, and environmental performance of a hydrogen supply chain for Hard-to-Abate sectors. The approach is applied to a paper mill case study, where a CHP plant (Siemens GT-100) meets electrical and thermal demands. Hydrogen is blended with natural gas (65 vol.%), and the required hydrogen amount is determined. The optimal hydrogen supply chain, consisting of a PV plant, an electrolysis unit, compression and storage units, is identified by minimizing the LCOH.

The findings of this study indicate that, from a technical perspective, the optimal configuration for meeting the annual hydrogen demand of 1553 t is HSC_2. This configuration entails the installation of a 45.6 MW PV plant, a 16.1 MW electrolysis unit, and a hydrogen storage system with a capacity of 2000 kg. The environmental benefits are estimated at 9797 tonnes of avoided CO_2 emissions. Although the assumption that imported grid electricity is entirely renewable represents a limitation, it also provides an upper-bound estimate consistent with future scenarios in which full renewable penetration is expected by

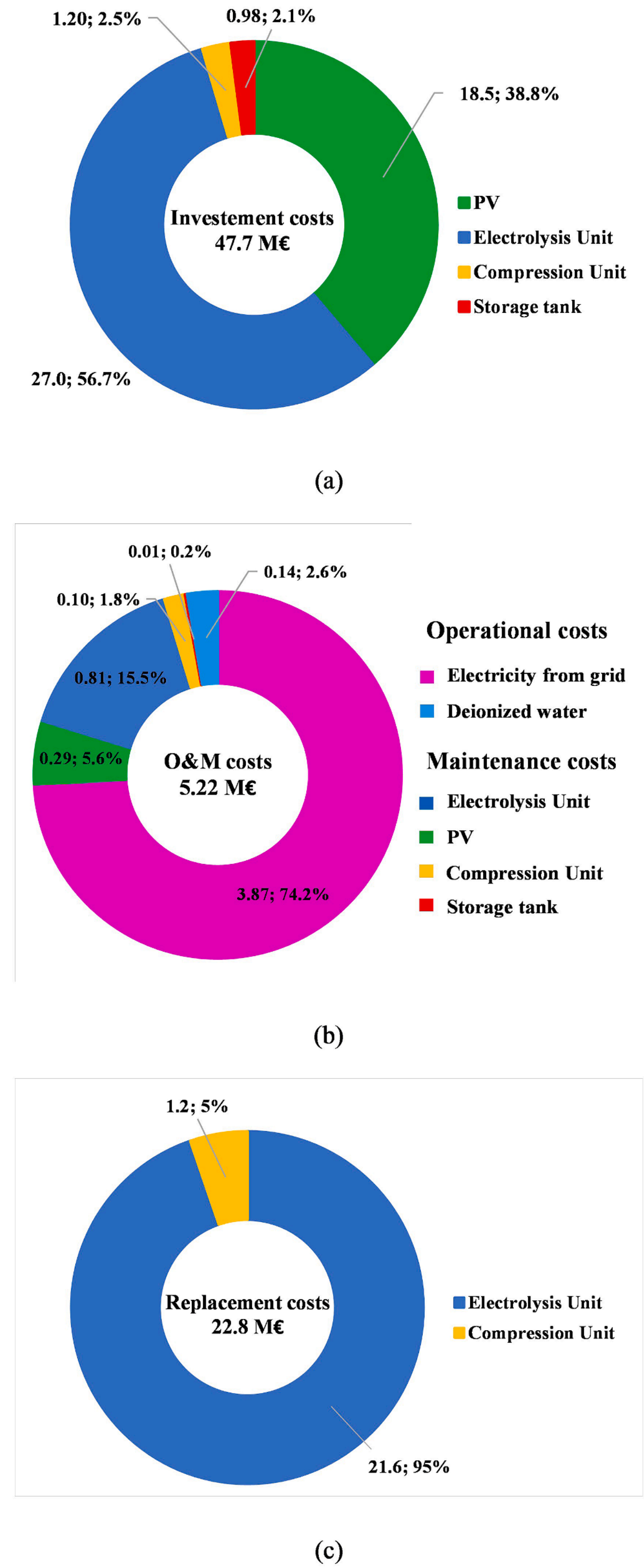
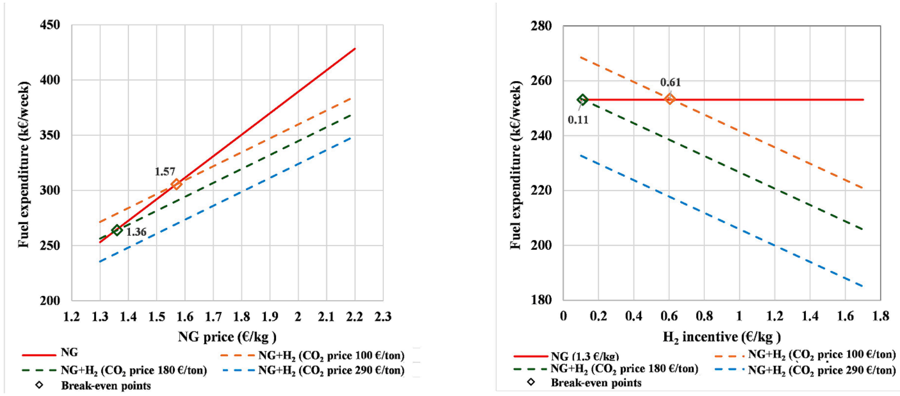


Fig. 7. Detailed contribution of system components to the main cost categories for the optimal configuration (HSC_2). (a) Investment costs; (b) operation and maintenance costs; (c) replacement costs.

2050. Nevertheless, future assessments should account for variations in grid carbon intensity to provide a more comprehensive evaluation of the system's performance. From an economic point of view, the cost of the



(a) (b)

Fig. 8. Break-even analysis of fuel expenditure under different economic scenarios. (a) Fuel expenditure as a function of natural gas and carbon prices (LCOH equal to 4.24 €/kg), (b) fuel expenditure as a function of hydrogen incentives and carbon prices (LCOH equal to 4.24 €/kg.

hydrogen produced is 4.24 €/kg, which can be reduced with specific incentives to become competitive with fossil fuels. Therefore, even if hydrogen is a viable and efficient solution for the decarbonization of the Hard-to-Abate sectors, economic policies and instruments need to be put in place to ensure the green transition of these sectors.

In conclusion, although the results presented are based on a specific case study with defined assumptions and constraints, the proposed methodological approach can be applied to a wide range of Hard-to-Abate industrial contexts. Its structured framework allows for a systematic evaluation of energy integration and emission-reduction benefits, while remaining flexible to account for sector-specific characteristics. When applied to other industries, only some operating parameters, such as fuel composition, process heat demand, emission factors, and technology-specific conditions, need to be adjusted. This ensures the methodology can effectively capture process variability and provide reliable estimates of both integration potential and decarbonization benefits.

CRediT authorship contribution statement

A. Perna: Writing – review & editing, Writing – original draft, Supervision, Software, Methodology, Investigation, Conceptualization. **G. Di Cicco:** Writing – review & editing, Writing – original draft, Investigation, Formal analysis, Data curation. **E. Jannelli:** Writing – review & editing, Supervision, Project administration, Funding acquisition. **C. Bassano:** Writing – review & editing, Supervision, Project administration, Funding acquisition, Conceptualization. **D. Lanni:** Writing – review & editing, Writing – original draft, Software, Formal analysis, Data curation. **M. Minutillo:** Writing – review & editing, Writing – original draft, Supervision, Software, Methodology, Investigation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A

A1. Siemens GT-100 in combined heat and power configuration: modelling with hydrogen blending

The SGT-100 installed in the paper mill to satisfy the electrical and thermal energy demands consists of 10 compressor stages, 6 burners in the combustion chamber, and two expander stages. The first stage nozzle and rotor blades are cooled by compressor discharge air. The compressor is equipped with variable guide vanes in order to optimize the operation of the machine. Table A1 summarizes the nominal operating parameters (Siemens Energy, 2017)

Table A1
STG-100 nominal operating parameters (Siemens Energy, 2017)

Parameter	Unit	Values
Pressure Ratio	-	15.6
Turbine inlet temperature	°C	1158
Turbine outlet temperature	°C	549
Air mass flow rate	kg/s	20.6
NG flow rate at rated power	kg/s	0.388
Exhaust Gases mass flow rate	kg/s	21
Rated Net Power	MW	5.42
Heat Rate	kJ/kWh	11913
Net Electric Efficiency (LHV)	%	30.2

The gas turbine (GT) cogeneration system was modeled in Aspen Plus. Figure A1 shows the model flowsheet, illustrating the main simulation results under nominal conditions (with the post-combustor switched off). The GT consists of the compressor (COMP), combustor (CC), and turbine (TURBINE), with a WORK MIXER (WTG) used to close the power balance between compressor consumption and turbine output.

The Heat Recovery Steam Generator (HRSG) recovers thermal energy from GT exhaust gases to generate single-pressure steam at 20 bar for the paper mill. Feedwater at 30°C and atmospheric pressure is pumped and preheated in the economizer (ECO). When the steam demand exceeds the GT's unfired capacity, a hydrogen-fired post-combustion chamber (PC) increases exhaust-gas temperature and enables additional steam production, resulting in fired (off-design) HRSG operation.

HRSG design is governed by the evaporator pinch point, economizer approach temperature, and exhaust stack temperature. The pinch point determines the required heat-transfer surface area and thus the capital cost; the approach temperature ensures subcooled water entry into the economizer; the stack temperature controls heat recovery while avoiding acid dew-point corrosion. These parameters are defined under unfired design conditions.

The following design values are adopted:

- $\Delta T_{EVA,pp}$: the evaporator pinch temperature difference is assumed equal to 5°C.
- $\Delta T_{ECO,ap}$: the economizer approach temperature difference is set at 10°C.
- $T_{exh,stack}$: the exhaust stack temperature is assumed equal to 85°C.

In post-combustion mode, the off-design operations involve different values of the economizer approach point difference temperature ($\Delta T_{ECO,ap} = 25$°C) and of the exhaust stack temperature (72°C), with respect to the design conditions.

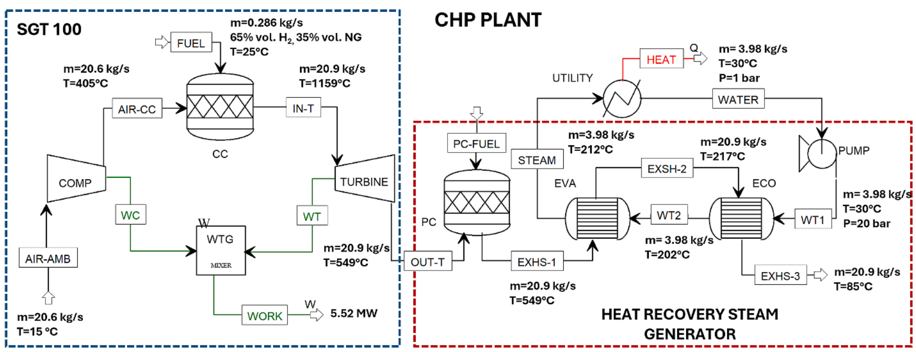

Fig. A1. Aspen Plus flowsheet of the CHP plant model. The scheme represents the main components of the gas turbine and HRSG system, including compressor, combustor, turbine, post-combustor, and heat recovery sections.

A2. Challenges and critical parameters of hydrogen blending in gas turbines

The conversion of existing or newly designed gas turbines to operate on hydrogen or hydrogen–natural gas blends is being actively pursued by major manufacturers such as Siemens, Rolls-Royce, and Kawasaki. The primary technical challenges concern the durability of hot-section materials, which face elevated risks of high-temperature oxidation, corrosion, and hydrogen embrittlement due to the combined presence of hydrogen and steam (Stefan et al., 2022). Moreover, hydrogen-rich combustion can accelerate long-term degradation mechanisms associated with flame-diffusion behavior (O'Connor et al., 2025).

From an emissions standpoint, research shows that hydrogen contents above 20 vol.% in CH_4–H_2 mixtures can increase NO_x formation to more than three times that of pure natural gas, largely due to enhanced radical-driven nitric oxide pathways (Mustafa et al., 2024). Although small hydrogen fractions may improve flame stability and reduce CO emissions, a recurring drawback is elevated NO_x unless mitigation strategies, such as advanced combustor architectures or dilution techniques, are employed (Kondor, 2025).

Overall, the literature underscores the need for dedicated component-level investigations into the long-term operational impacts of hydrogen enrichment in gas turbines, particularly concerning material integrity and NO_x control, topics that warrant further exploration in future studies.

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