energies

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Development of a Hydrogen Valley for Exploitation of Green Hydrogen in Central Italy

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Abstract: Green hydrogen exploitation plays a crucial role in achieving carbon neutrality by 2050. Hydrogen, in fact, provides a number of key benefits for the energy system, due to its integrability with other clean technologies for energy production and consumption. This paper is aimed at presenting the project of recovery of an abandoned industrial area located in central Italy by developing a site for the production of green hydrogen. To this aim, the analysis of the territorial and industrial context of the area allowed us to design the project phases and to define the sizing criteria of the hydrogen production plant. The results of a preliminary cost–benefit analysis show that a huge initial investment is required and that, in the short term, the project is sustainable only with a very large public grant. On the other hand, in the long term, the project is sustainable, and the benefits significantly overcome the costs.

Keywords: natural gas; hydrogen; transmission network; electrolyzer; decarbonization; hydrogen valley

Citation: Ficco, G.; Arpino, F.; Dell'Isola, M.; Grimaldi, M.; Lisi, S. Development of a Hydrogen Valley for Exploitation of Green Hydrogen in Central Italy. *Energies* **2022**, *15*, 8072. https://doi.org/10.3390/en15218072

Received: 18 September 2022
Accepted: 28 October 2022
Published: 30 October 2022

1. Introduction

In 2021, the COP26 conference of Glasgow recognized the urgent need to limit global warming to 1.5 °C by 2100, calling on countries to strengthen the global response to the climate change threat. Achieving this ambitious target will require a rapid, deep and sustained reduction in global emissions of CO_2 coming from fossil fuels, in all sectors of the economy.

Renewable energy sources (RES) are the keystone of the EU energy policy to replace fossil fuels and, consequently, to guarantee the goal of a carbon-neutral economy by 2050. RES allow, in fact, to reduce the overall greenhouse gas (GHG) emissions without the need to capture the CO_2 produced. In this sense, Europe is facing a substantial change in its energy system, promoting and incentivizing the transition from conversion systems based on fossil energy sources to systems based on the widespread use of RES.

However, achieving carbon neutrality by 2050 is a very challenging goal, especially for the energy-intensive industrial and the heavy transport sectors, i.e., the so-called hard-to-abate sectors, which annually are responsible for the emission in the atmosphere of about 10 Gton of CO_2, equal to 30% of total emissions [1]. Furthermore, the emissions from energy-intensive industries have rapidly increased as a consequence of the demand for basic materials, driven in turn by the increase in global well-being and inhabitants and in the related infrastructures [2]. The iron and steel industry, for example, was responsible for about 2.1×10^{10} GJ of energy consumed worldwide in 2019, of which about 40% is attributable to coal, whereas the remaining share is roughly divided between other fossil fuels and electricity. Moreover, the demand for basic materials is currently increasing, due to global economic growth [3]. Facing this trend and tuning industrial emissions under strict environmental objectives of the climate crisis is therefore an urgent and demanding task.

Reducing GHG emissions in the hard-to-abate sectors is very challenging due to several issues, such as: (i) the limited recovery of materials after use, (ii) the increase in efficiency of crucial thermodynamic processes without a parallel increase in GHG emissions reduction and (iii) the low availability of ready-to-use electric alternatives [4]. The decarbonization of these sectors can be pursued exclusively through a diversified approach. Circular economy, energy efficiency, use of green fuels (i.e., hydrogen and biomethane), CO_2 capture and electrification represent a set of solutions that can significantly reduce emissions in energy-intensive industrial sectors if implemented together.

In such a scenario, green hydrogen exploitation plays a crucial role since it provides a number of key benefits for the whole energy system, due to its intrinsic characteristics—first of all, its adaptability and integrability with RES and other green energy technologies. Specifically, hydrogen offers the possibility of decarbonizing the final uses of energy on a large scale, since CO_2 is not produced when hydrogen is used and chemical pollutants are not emitted into the atmosphere due to its combustion. The exploitation of green hydrogen, as well as carbon capture and storage (CCS) technologies, is expected to significantly reduce the carbon footprint of energy-intensive industries, especially of the steel and chemical sectors. Furthermore, the cost of RES is expected to decrease in the long term, becoming a cost-effective feedstock to produce ammonia, methanol and other chemicals. As known, hydrogen is already an essential component of these products, and thus the integration of green hydrogen is obtainable through limited modifications, based only on changing the process for hydrogen production from fossil fuels reforming or electrolysis from water [3]. In such a manner, hydrogen can accelerate the decarbonization process in the sectors for which electrification is not an efficient solution, such as heavy industry, long-distance and heavy goods transport, non-electrified rail transport and the residential sector, taking advantage of the flexibility and competitiveness of hydrogen transport and storage to meet the challenges of electrification. Hydrogen can also ensure the storage capacities required to guarantee the stability and flexibility of the electrical energy system by the application of power-to-gas (PtG) technologies. In fact, the injection into the NG pipeline system of the hydrogen produced from surplus renewable energy represents a real opportunity, providing at the same time the balancing of the electricity grid, as well as supporting the sector coupling between the NG and electricity grids. By exploiting the NG infrastructure, hydrogen allows for connecting production sites and demand across long distances, thus reducing the supply costs and guaranteeing the necessary security and continuity of the service by developing an international market. Finally, it is expected that in the next years, the production costs of hydrogen will decrease reaching competitiveness, due to the development of more efficient green hydrogen production technologies and the increasing availability of electric energy from RES.

As well known, the hydrogen blending into the NG leads to significant variations in the thermo-physical properties of the resulting H_2NG mixture. The changes in thermodynamic properties, in turn, result in a change in combustion and energy properties. In particular, hydrogen enrichment induces highly non-linear effects on the combustion rate and flame development, causing potential explosive behavior [5,6]. Therefore, the injection of hydrogen into the NG could lead to safety issues depending on the volumetric content of hydrogen (e.g., larger fugitive emissions and higher flammability). As a matter of fact, only minor criticalities occur with H_2 content within 5–15%, depending on specific conditions. For higher hydrogen content in the H_2NG mixture, in the scientific literature, it is agreed to carry out targeted investigations. As far as the evaluation of physical and thermodynamic properties of H_2NG mixtures is concerned, widespread scientific literature on the subject is available [7–10], as well as numerous regulatory technical documents, such as the ISO 6976:2017 standard [11] (i.e., to calculate the density and the calorific value) and the ISO 12213 standards for the calculation of the compressibility factor [12,13] (whose applicability is limited to 10%vol. of hydrogen).

The Italian strategy, in line with the EU one, aims at increasing investments for the production and use of hydrogen, with a twofold horizon. In the short-term (2030), the goal is to make green hydrogen progressively competitive in specific industrial sectors, laying the foundations for a national ecosystem based on this energy vector. In the long-term (2050), on the other hand, the goal is to help decarbonize the hard-to-abate sectors through the use of green hydrogen. The green hydrogen demand is expected to be approximately 0.7 Mton/year by 2030, requiring the installation of 5 GW of electrolyzers by the end of the decade.

This paper deals with the development of a green hydrogen exploitation plant in central Italy aiming at: (i) promoting and developing the use of green hydrogen in the industrial and public transport sectors; (ii) reducing GHG emissions and pollutants deriving from the use of fossil fuels; (iii) favoring the employment in the territory; and (iv) supporting the research, technology development and innovation relating to the hydrogen supply chain. The project aims to be carried out in the context of the Italian Recovery and Resilience Plan (PNRR) in the framework of the Next Generation EU recovery plan. Specifically, after the analysis of the territorial and industrial context, the project phases and the sizing criteria of the hydrogen production plant are described. Furthermore, a preliminary cost–benefit analysis is presented and discussed. The novelty of this research is twofold. On one hand, the project aims at developing a sort of technological demonstrator laboratory of the various forms of exploitation of hydrogen (e.g., electrolyzer, methanator, injection into the gas network, public transport) both for researchers and companies. On the other hand, the sizing of the project is based not only on the performance of the available applicable technologies but also on the characteristics of the area in which the intervention is planned and on the punctual NG consumption data of the industries operating there, together with the forecasts of the energy demand in a short-medium and long-term scenario. Moreover, with respect to similar studies, this paper presents a narrower scope, focusing on the recovery of an abandoned industrial area. Finally, this paper first addresses a relevant gap in knowledge, i.e., the lack of studies reporting a cost–benefit analysis about the development of a hydrogen valley for the exploitation of green hydrogen. More in general, examples of monetary evaluation of avoided CO_2 emissions are still scarce in the scientific literature. In this regard, this paper leverages the social carbon value (SCV) to quantify the environmental benefits deriving from the avoided CO_2 emissions, thus representing a sort of benchmark also for further similar studies. These aspects differentiate our study with respect to more traditional studies with significantly higher investment and several different applications.

2. Materials and Methods

Following the methodology in depth described in [10], the higher heat values (HHVs) and the density (d) of NG (the one typical of the investigated area), pure hydrogen and H_2NG mixtures with 10% and 20% hydrogen were calculated and are reported in Table 1. From the analysis of Table 1, it can be easily pointed out that considering the same amount of energy, larger volumes are needed as the hydrogen content increases in the H_2NG.

Table 1. High heating values and density of NG, pure hydrogen and H2NG mixtures with 10% and 20%vol H_2.

Mixture	HHV (MJ/Sm^3)	HHV (MWh/Sm^3)	HHV (MWh/kg)	d (kg/Sm^3)
100% NG	39.5391	0.0110	0.0146	0.7527
90% NG + 10% H_2	36.7799	0.0102	0.0149	0.6856
80% NG + 20% H_2	34.0254	0.0095	0.0153	0.6186
100% H_2	12.1023	0.0034	0.0396	0.0850

For the appropriate sizing of the intervention, the calculation of specific conversion coefficients at different H_2 content in the H_2NG mixture was performed, aiming at maintaining the same amount of energy related to the fixed volume of 10^6 Sm^3 of NG. The total volume of the mixture was then obtained by multiplying the NG volume by the ratio between the HHV of NG (i.e., the mixture without H_2) and the HHV of the mixture with the considered H_2 content. Consequently, the H_2 volume and mass needed were easily obtained by multiplying the H_2NG volume by the H_2 content and by the H_2 density, respectively. Finally, in Table 2, the calculated H_2NG mixture volume conversion coefficients together with the hydrogen needed (both in mass and volumes) and the avoided CO_2 emissions are reported.

Table 2. H_2NG mixture volumes, hydrogen needed and avoided CO_2 emissions at different H_2 contents.

Mixture	NG Volume (Sm^3 10^6)	Mix Volume (Sm^3 10^6)	H_2 Volume (Sm^3 10^6)	H_2 Mass (ton)	CO_2 Produced (ton 10^3)	CO_2 Avoided (ton 10^3)
100% NG	1	-	-	-	2.03	-
90% NG + 10% H_2	-	1.075	0.108	9.1	1.83	0.20
80% NG + 20% H_2	-	1.162	0.232	19.8	1.62	0.41
100% H_2	-	3.267	3.267	277.6	-	2.03

It is worth underlining that the amounts of the produced and avoided CO_2 in Table 2 were calculated through the SW tool available at [14] on the basis of actual natural gas composition. Furthermore, the avoided CO_2 in Table 2 only considers greenhouse gas emissions from natural gas consumption, whereas the potential CO_2 emission saving is evaluated considering total renewable energy produced by PV plants and not consumed by electrolyzers, leading to an additional potential CO_2 saving of about 4.59 ton for each million Sm^3 of NG.

The industrial area involved in the project is located in the territory of Frosinone and Ferentino municipalities, Central Italy. The transmission NG network in use consists of the following so-called stretches (see Figure 1): (i) former ASI network, pipeline diameters 6–8 inches; (ii) right side Sacco river, pipeline diameters 4–6 inches; (iii) left side Sacco river, pipeline diameters 4–6 inches.

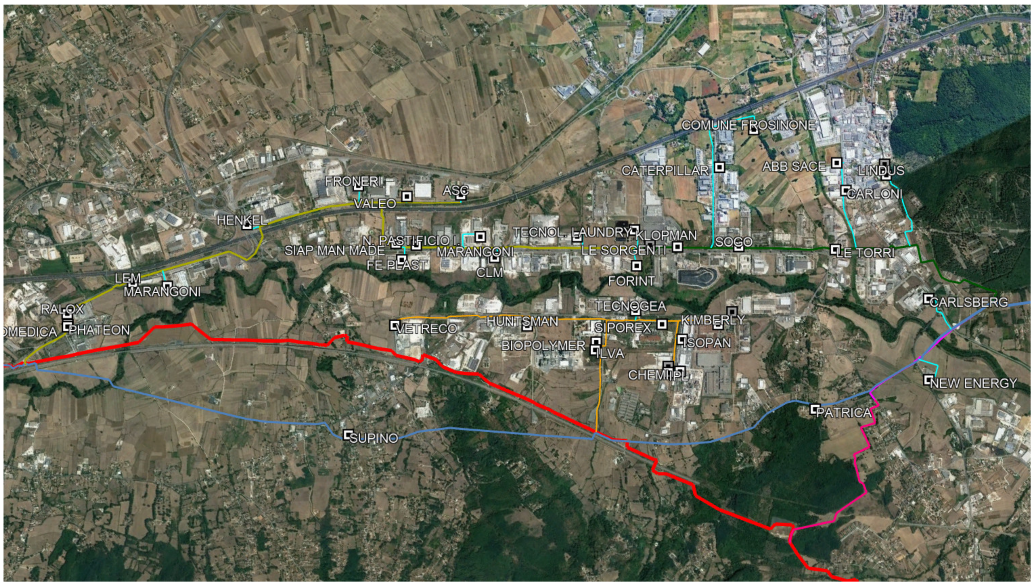

Figure 1. Frosinone–Ferentino industrial area view.

NG consumption of the supplied industries in the area over the last 6 years, from 2016 to 2021, was analyzed. Specifically, the consumption weighted average was calculated for each supplied industry to consider more significantly the consumption of recent years. From the analysis carried out, it was observed that the NG consumption trend in the area has increased in the last 3 years. In addition, more than 90% of NG consumption in the area is attributable to only 8 industries.

Aiming at assessing the NG demand forecast in the area, an NG demand multiplicative factor was estimated as the ratio of the calculated consumption of the analyzed year to the consumption of 2020, in reference to SNAM and Terna forecast (i.e., the major TSOs of the gas and electricity sectors in Italy). Two scenarios [15] were considered: (i) National Trend Italy [16] and (ii) Global Ambition EU [17]. In Table 3, the NG demand forecast for the time period 2022–2040 is summarized.

Table 3. NG demand forecast in Italy [15].

Scenario	2020	2025	2030	2035	2040
National NG consumption (billions Sm^3)					
Global Ambition	71.3	72.2	74.9	72.6	70.3
National Trend Italia	71.3	72.2	62.4	63.5	64.5
Average consumption	71.3	72.2	68.7	68.0	67.4
NG demand multiplicative factor					
Global Ambition	1.000	1.013	1.050	1.018	0.986
National Trend Italia	1.000	1.013	0.875	0.890	0.905
Average multiplicative factor	1.000	1.013	0.963	0.954	0.945

The phases of the project implementation were then hypothesized. In particular, two main phases were planned on the basis of the following principles:

- Phase 1: up to 9 companies involved, up to 10%vol of H_2 injection into NG mixture, about 500 tons of H_2 production through a 10 MW electrolyzer nominal power, H_2 storage capacity up to 10–14 tons and methanation reactor capacity of about 500 kW; finally, H_2 for transport sector is at initial stage;
- Phase 2: up to 20 companies involved, up to 20%vol of H_2 injection into NG mixture, more than 1000 tons of H_2 production through a 20 MW electrolyzer nominal power, H_2 storage capacity up to 30–35 tons and methanation reactor capacity of about 500 kW; finally, H_2 for transport sector is at development stage.

It is believed that the hydrogen content injected into NG mixture gradually increases starting from 2030 until the complete replacement of NG with hydrogen in the area by 2040, as well as the involvement of the nearby industrial areas (e.g., Cassino, Piedimonte, Ceprano and Anagni) and other companies located in the Frosinone–Ferentino area.

In order to correctly size the technical plants, the following parameters and hypotheses were assumed:

- The electrolyzer nominal capacity was evaluated using the following relation:

$$P_{el} = \frac{E_{H_2}}{h_{el}} = \frac{Q_{H_2} \cdot E_{un,H_2}}{h_{el}} \quad (1)$$

where P_{el} is the electrolyzer nominal capacity, (kWh); Q_{H_2} is the amount of H_2 needed per year, (kg); E_{un,H_2} is the electrolyzer energy consumption per unit of H_2 produced, assumed to be equal to 60 kWh/kg; and h_{el} is the number of functioning hours of the electrolyzer per year, assumed to be equal to 3000 h/year, considering the instability and intermittency of PV generation. Thus, the P_{PV}, i.e., the PV peak power (kWh) needed to guarantee the electric energy consumption needed by the electrolyzer, was evaluated by employing a multiplicative factor equal to 5.

- Considering the calculated PV system power, the annual electric energy production of the PV system was evaluated through the following equation:

$$E_{PV} = P_{PV} \cdot E_{PV,local} \quad (2)$$

where E_{PV} is the annual electric energy production, (kWh); $E_{PV,local}$ is the PV annual production relative to the area per kW of the PV system power installed, assumed equal to 1368 kWh and estimated through the EU PV GIS tool [18].

- Finally, the surface required to install the PV system was calculated as follows:

$$S_{PV} = P_{PV} \cdot \gamma_{S,P_{PV}} \tag{3}$$

where S_{PV} is the total surface occupied by the PV system (ha); and $\gamma_{S,P_{PV}}$ is the surface per kW of the PV system power, assumed equal to 1.5 ha/MW.

3. Results and Discussion

3.1. Sizing of the Intervention

The authors first estimated the amount of hydrogen needed to guarantee the energy demand in the area, according to the above-reported H_2 content of single phases. Each phase was designed following a progressive development of the connecting pipelines from the hydrogen production and storage site (both located in the abandoned industrial sites) to the delivery point at the industries' premises.

On the basis of the NG demand forecast, the nominal capacity electrolyzer of the hydrogen production unit was sized. Three main electrolysis technologies are available for the PtG system: (i) alkaline (AEL), (ii) proton exchange membrane (PEMEL) and (iii) solid oxide (SOEL). In Table 4, the main characteristics of the above-mentioned electrolyzer technologies are summarized.

Table 4. Main characteristics of the electrolysis technologies [19–23].

	AEL	PEMEL	SOEL
Operative temperature (°C)	20 ÷ 80	20 ÷ 200	500 ÷ 1000
Efficiency (HHV, %)	59 ÷ 70	65 ÷ 82	40 ÷ 60
Nominal production (Nm^3/h)	100 ÷ 103	100 ÷ 102	-
Nominal power (kW)	100 ÷ 103	100 ÷ 102	-
Water consumption (L/kg_{H2})	9 ÷ 11 [22]	9 ÷ 11 [22]	9 ÷ 11 [22]
	-	18.04 [23]	9.1 [23]
Specific energy consumption (kWh/kg_{H2})	50 ÷ 83	65 ÷ 81	33
Cold start time	10 min—h	s—min	-
Restarting time	30 ÷ 60 min	not necessary	-
Rangeability (% P)	25 ÷ 100%	5 ÷ 100%	-
System costs (EUR/kW)	1000	>2000	-

In the present study, the alkaline technology was considered as a first choice, since it is currently the most commercially mature one. The main advantages of this solution are represented by the lower investment costs (thanks to the use of non-noble metals for the electrodes) and the long-term stability [18].

As described above, the authors considered a growing H_2 content in the mixture (i.e., from 10%Vol in 2026 to 100%vol in 2035) and an energy demand multiplier as per Table 3 (for the period 2026–2029, a linear trend was considered) to get the amount of H_2 needed in tons. Thus, the demand for energy at the electrolyzer was obtained by multiplying the H_2 tons by the electrolyzer efficiency which can reasonably increase from 2030 onward from 60 to 50 kWh/kg (i.e., from 66% to 79%). Finally, the necessary electrolyzer power, electric energy and PV surface were obtained through Equations (1)–(3), respectively. In Table 5, the results of the analyses carried out in the mid-term (i.e., up to 2040) are summarized.

Table 5. Results of the project design phase.

	2026	2027	2028	2029	2030	2035	2040
Mix NG/H_2 (%)	10	10	10	20	20	100	100
Demand multiplier	1.003	0.993	0.983	0.973	0.963	0.954	0.945
H_2 needed (ton)	80	282	425	480	518	827	1303
Electrolyzer efficiency (kWh/kg)	60	60	60	60	60	50	50
Electrolyzer efficiency (%)	66	66	66	66	66	79	79
Demand for energy (MWh)	4818	16,914	25,519	28,803	31,109	41,328	65,163
Electrolyzer operation hours (h/a)	3000	3000	3000	3000	3000	3000	3000
Electrolyzer power, P_{el} (MW)	1.6	5.6	8.5	9.6	10.4	13.8	21.7
PV power, P_{PV} (MW)	8.0	28.2	42.5	48.0	51.8	68.9	108.6
Electric energy, E_{PV} (MWh/y)	10,984	38,564	58,184	65,670	70,929	94,227	148,572
Surface, S_{PV} (ha)	12	42	64	72	78	103	163

3.2. Cost–Benefit Analysis

The cost–benefit analysis carried out by the authors allows performing the evaluation of a project through the quantification of the present value of the related costs ($C_{tot,att}$) and benefits ($B_{tot,att}$). If the costs–benefits ratio is greater than 1, the project can be considered economically sustainable [24].

Costs can be classified into three main categories: (i) Capital Expenditure (CAPEX); (ii) Operating Expenditure (OPEX), calculated up to 2040 as a percentage of CAPEX; (iii) Mixed Costs (MIXED), which presents both the variable and fixed costs characteristics (e.g., H_2 storage and compression from 2035 onward).

In Table 6, the estimated cost relating to the project is summarized.

Table 6. Cost analysis results.

Description	CAPEX, M EUR			OPEX, M EUR			Mixed, M EUR		
	2023 2030	2031 2035	2036 2040	2023 2030	2031 2035	2036 2040	2023 2030	2031 2035	2036 2040
NG network	5.1	1.4	1	0.6	2.5	3.8			
PV	100	0	0	6.9	7.5	7.5			
Electrolyzer	12	288	150	2.2	15.5	37.9			
Compressor	11.4	0	0	3.3	2.7	0		0.9	5.3
Storage	15	0	0	2	1.8	0		63.2	352.3
Blending	1.6	0	0						
Safety factor	10	0	0						
Total	155.1	307.4	151	15	30	49.2		64.1	357.6

The investigated benefits include the following contributions: (i) environmental, i.e., benefits deriving from avoided CO_2 (SCV); (ii) socio-economic; i.e., benefits deriving from new employees (BSL); (iii) benefits deriving from the storage of hydrogen (BSI).

To quantify the monetary value of the environmental benefits deriving from avoided CO_2, the social carbon value (SCV) was estimated as follows [25]. SCV provides a maximum threshold of the costs that a company should be willing to incur to limit climate change.

$$SCV = CO_{2,av} * C_{CO_2} \tag{4}$$

where $CO_{2,av}$ is the avoided CO_2 emissions, and C_{CO_2} is the carbon cost, whose value can be obtained considering a worst-case scenario (WCS) and a best-case scenario (BCS) with values of C_{CO_2} estimated, respectively, equal to 57/114 EUR/ton until 2030 and 66/180 EUR/ton from 2030 to 2040 [26].

To quantify the socio-economic benefit deriving from new employees (BSL), an estimation of the added value per employee equal to EUR 58,683 in the area of Frosinone was quoted [27]. Furthermore, the number of new employees generated from a million euro investment (in terms of CAPEX and/or mixed costs) in environmentally sustainable projects ranges from 10 (WCS) to 15 (BCS) [28].

A further benefit is the difference between the cost of hydrogen storage BSI, foreseen in this study starting from 2035, and the cost of electricity storage. BSI was evaluated as follows:

$$BSI = \left(C_{storage,el} - C_{storage,H2}\right) H_2 \tag{5}$$

where $C_{storage,el}$ and $C_{storage,H2}$ are the storage cost of electricity and hydrogen (EUR/MWh), respectively. In this paper, $C_{storage,el}$ was assumed equal to 114.8 EUR/MWh, whereas $C_{storage,H2}$ was assumed variable between 51 EUR/MWh [29] (WCS) and 76 EUR/MWh (BCS) [30], in the case of hydrogen stored in a depleted NG field. In Table 7, the evaluated benefits are summarized.

Table 7. Benefit analysis results.

Benefit, M EUR	2023–2030	2031–2035	2036–2040
SCV WCS—BCS	4.7–9.3	18.9–37.8	67.9–150.9
BSL WCS—BCS	91–136.5	218–327	298.5–444.7
BSI WCS—BCS	0	38.6–63.5	215.2–353.9
Total Benefit WCS—BCS	95.7–145.8	275.5–428.3	581.6–949.5

For the evaluation of the costs–benefits ratio, given the wide variability of the WCS/BCS scenarios, the minimum and maximum values were calculated as follows:

$$\frac{B_{tot,att}}{C_{tot,att}} = \frac{\sum_t (SCV_t + BSL_t + BSI_t)\ FA_t}{\sum_t (CAPEX_t + OPEX_t + MIXED_t)\ FA_t} \tag{6}$$

$$FA_t = \frac{1}{(1+r)^t} \tag{7}$$

where FA_t is the discount factor, r is the social discount rate assumed equal to 4%, and t is the number of years considered in the analysis. In particular, the benefits–costs analysis was carried out considering a time period up to 2040. However, the analysis was extended until 2070 since the project is expected to show significant benefits in the period after 2040 (in terms of avoided CO_2 emissions, new employees and benefits deriving from storage).

The analysis carried out shows that a very large initial investment is required and that, in the short term, this is sustainable only with a relevant public grant. On the other hand, in the long term (i.e., after 2051, which is the year when the quantitative estimation of the benefits overcomes the costs), the project is sustainable, and the benefits significantly overcome the costs. In this case (i.e., in 2070), in fact, a benefits/costs ratio is equal to 1.1 and 1.9 in the WCS and BCS, respectively. In terms of avoided CO_2 emissions, the project presents limited yearly savings until 2035 (e.g., 31,298 tons in 2034), while the yearly saving significantly increases after 2035 (i.e., 206,596 tons per year from 2035 until 2039 and 315,210 tons per year from 2040 until 2070). For the sake of truth, a limitation of the obtained results is that the estimations of the cost items as well as the benefits are presented without the related uncertainty, i.e., as fixed values obtained from the best actualized estimations. In the next years, in fact, due to the actual economic and political scenario, energy costs (as well as materials and plant components) are expected to rapidly change in a very unpredictable way leading to the difficulty of setting appropriate uncertainty values in the medium-long-term scenario.

4. Conclusions

In this paper, the project of recovery of an abandoned industrial site located in central Italy for the production, distribution and consumption on a local scale of green hydrogen was presented and discussed. The project is aimed at promoting hydrogen use in the industrial and public transport sectors, as well as supporting the research, technology development and innovation relating to the hydrogen supply chain.

The analysis carried out highlighted that:

- Several companies in the industrial area are ready to be supplied by an H2NG mixture with a hydrogen content equal to 10% by 2028 since limited modification to their production systems is required;
- According to the energy demand forecast in the area, a 5 MW electrolyzer will be sufficient up to 2030, whereas, according to the development phases of the project, the electrolyzer power will necessarily increase up to 20 MW, capable to produce about 1000 ton/year of green hydrogen;
- In the long-term scenario, a reduction in CO_2 produced is expected up to 31,298 tons/year by 2030.

Finally, the results of a cost–benefit analysis show that a very large initial investment is required and that, in the short term, this is sustainable only with a relevant public grant. On the other hand, in the long term (i.e., up to 2070), the project turns sustainable since the benefits significantly overcome the costs. Future development of this study can extend the cost–benefit analysis considering also the uncertainty of the economic estimations, especially in the medium and long term (i.e., after 2031), even in a rapidly changing economic and political scenario.

Author Contributions: Conceptualization, G.F., F.A. and M.D.; methodology, G.F., F.A., M.D. and M.G.; software, G.F., F.A. and M.G.; validation, F.A. and M.G.; formal analysis, G.F., F.A., M.G. and S.L.; investigation, G.F., F.A. and S.L.; resources, M.D.; data curation, G.F., F.A. and M.G.; writing—original draft preparation, G.F. and S.L.; writing—review and editing, G.F. and S.L.; visualization, G.F. and S.L.; supervision, G.F., F.A. and M.D. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Data Availability Statement: Data available on request due to restrictions, e.g., privacy or ethical.

Acknowledgments: The authors wish to acknowledge Società Gasdotti Italia (SGI) Spa and Consorzio Industriale del Lazio for the useful support in the development of this manuscript. In particular, the authors thank Federico Frassi and Carmelo Fallone for the useful technical and economic discussions.

Conflicts of Interest: The authors declare no conflict of interest.

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