



## 1 **1 Introduction**

2 The upcoming decade appears to be crucial for what concerns the efforts towards the energy transition  
3 and the achievement of long-term sustainability goals, especially for Europe. Even though the 2030 climate  
4 and energy framework was adopted in its final version in 2018, setting the collective target of cutting the  
5 greenhouse gas emissions at 40 % [1], the new European Green Deal [2] pushed the commitment forward.  
6 Consistently with these plans and thanks to the significant investment pulse from the Next Generation EU  
7 recovery plan [3], new strategy for energy system integration [4] and for hydrogen uptake [5] have been  
8 formally adopted. According to [6], hydrogen can play a major role in decarbonizing the energy system thanks  
9 to its versatility of use in transportation, electricity and heating provision, storage and grid services and as a  
10 commodity for industrial applications, provided that it is produced from low-emission sources. At present, all  
11 of the hydrogen produced (which is mainly used as feedstock) comes from fossil origin: 76% comes from  
12 steam reforming of natural gas and the rest from coal, thus producing 830 MtCO<sub>2</sub>/yr [7]. Usually, these CO<sub>2</sub>  
13 emissions are not captured thus this production pathway originates the so-called “grey hydrogen”, which is the  
14 cheapest one. This already existent value chain of hydrogen may be transitioned towards sustainability by  
15 capturing and storing the carbon emissions thus originating the so-called “blue hydrogen”. But when talking  
16 about the crucial role of hydrogen within the energy system, it is the “green hydrogen” that is mainly addressed,  
17 which is the one produced via electrolysis powered by electricity from renewables. A comparison in terms of  
18 greenhouse gas emission of the different hydrogen production alternatives is given in [8].

19 Hydrogen from renewables can thus have a prominent role not only for the decarbonization of fuel system  
20 (natural gas in particular) but also as a cross-sectorial link. As an energy vector, crucial is the opportunity that  
21 hydrogen offers to avoid the requirements for instantaneous supply-demand balancing thanks to the many  
22 possibilities to store it easily at large scale [9] with promising environmental outcomes if the electricity source  
23 would be renewable [10].

24 The role of hydrogen and other renewable gases (biomethane, syngas) for the long-term deep  
25 decarbonization of the energy system has been widely recognized in recent years. In a matter of two years,  
26 between 2018 and 2020, the role of renewable gases and hydrogen have changed from marginal [11] to the  
27 core of the gas industry strategy for the future [12]. European scenarios at 2050 show that their uptake may  
28 offer decarbonization options which are cheaper than deep electrification by between 94 [13] and 138 [14]  
29 billion € per year. Savings from choosing the deployment of hydrogen in 100% renewable cities are obtained  
30 also in [15]. The limits of the electrification are highlighted in [16] and [17]: starting from the current situation  
31 in which electricity use in final consumption is about 20%, scenarios at 2050 foresee an increase of its share up  
32 to, respectively, 29% (current policy) or 50% (in order to meet climate goals). According to IRENA, in order  
33 to achieve the Paris Agreement goals, the 8% of the global energy consumption should be provided by  
34 hydrogen at 2050 [18]. Interestingly, the renewable gases have been modeled in details for the first time in  
35 2019 World Energy Outlook by IEA [19] which also dedicated an special insight on the role of gas  
36 infrastructure and its greenen for the energy transition. The IEA finds a very limited uptake of them under the  
37 “Stated Policy Scenario” where renewable gases will contribute only for the 1.6 % to the global gas demand

1 at 2040. On the contrary, the "Sustainable Development Scenarios" shows that this share could be as high as  
2 6.5% in order to meet the climate goals.

3 The role of gas infrastructure appears to be fundamental in the evaluation of the economic advantage of  
4 investing in renewable gases. Avoiding a potential stranded asset by repurposing or retooling the European  
5 gas infrastructure can generate 217 billion € savings per year, according to [20]. However, the conversion  
6 towards renewable gases of the entire gas infrastructure would affect the whole natural gas value chain,  
7 especially if hydrogen will take the prominent role. There is in fact a wide consensus that the first phase for  
8 the hydrogen penetration into the gas market will be both through the creation of the so-called "Hydrogen  
9 Valleys" and the hydrogen blending within the gas infrastructure.

10 A number of previous studies have reviewed the readiness of the gas system towards the presence of  
11 hydrogen blends within the natural gas. An extensive review of the opportunities and the criticalities of  
12 hydrogen admixture within the current gas infrastructure is given in [21]. In [22] maximum values of  
13 admissible hydrogen concentrations are given for a number of different areas of the overall gas system  
14 concluding that no major issues should be met up to a concentration of 15% - 20%. However, in the presence of  
15 Compressed Natural Gas (CNG) fuelling stations or gas turbines the limit may need to be 1% or lower due to  
16 the current standards for vehicle tanks. What is more, underground storage systems other than salt caverns  
17 require further investigation. A comprehensive overview of the available test results has been presented by  
18 Marcogaz in [23]. Some limitations may derive from material limits [24] or from the high sensitivity towards  
19 gas quality. This stands especially for turbines, gas burners and boilers for which the variation of gas quality  
20 may affect the stability of the combustion with potentially detrimental consequences in terms of the increase  
21 of pollutant emissions [25] and safety risks [26]. Even though these results call for the need of more  
22 experimental trials and the definition of new hydrogen blends oriented testing methodologies, results from  
23 Siemens [27] and more recently from Baker-Huges [28] show no major issue emerged in powering gas turbines  
24 and turbocompressors with 10% hydrogen blends. However, in order for the hydrogen economy to be uptake by  
25 means of the hydrogen blending, it is urgent that the natural gas quality standards at European level will be  
26 harmonized as soon as possible. In this sense, the European Commission delegated the mandate M/400 EN  
27 [29] to the European Committee for Standardization (CEN). The publication of the norm EN 16726:2019 [30]  
28 on standardisation of gas quality (group H) was an outcome of it. Here the case of hydrogen injection is  
29 mentioned in an informative annex, reporting the results already presented in [22] and concluding with the  
30 impossibility of setting a common limiting value for hydrogen in the European infrastructure and  
31 recommending a case-by-case analysis.

32 The need for a significant pulse from decision makers towards a hydrogen economy is thus clear given  
33 the vast implications on the gas sector and end users. The hydrogen strategy for a climate-neutral Europe [5] is  
34 specifically devoted to the definition of a precise roadmap towards 2030 and 2050 for the creation of a complete  
35 hydrogen ecosystem. By means of the creation of the Clean Hydrogen Alliance, the EU intends to put in  
36 practice a strategic roadmap consisting in the realization of large-scale projects and the creation of a suitable  
37 investment agenda. At present, the first phase foresees the realization of at least 6 GW of electrolyzers in the

1 EU by 2024, mostly devoted to the decarbonization of the already existing hydrogen production. A second  
2 phase to 2030, known as “the 2x40 GW” initiative, sets the goal of installing at least 40 GW of electrolyzers  
3 within Europe and additional 40 GW of electrolyzers capacity in North-Africa and Ukraine [31]. Along with  
4 these policy statements, a report by several European natural gas TSOs aimed at providing the first proposal  
5 of a roadmap to a fully developed continental hydrogen infrastructure [32]. While the goal is to build up a  
6 100% hydrogen infrastructure by late 2040s – 2050, the hydrogen blending is considered an earlier option  
7 (already for the 2020s) to deploy hydrogen in the pipeline. While in [32] the focus is on the infrastructure and  
8 on the domestic production, in report [33] the possibility to produce green hydrogen from the solar and wind  
9 resource of North Africa is considered. This area is both rich in renewable resources and connected through  
10 natural gas pipelines to southern Europe as highlighted in [34].

11 In this context, this paper aims to simulate the transport of hydrogen from North Africa to Europe through  
12 the existing gas transport infrastructure, setting its focus in particular on the Greenstream, connecting southern  
13 Italy to Libya. The hydrogen is assumed to be mixed with the extracted natural gas so that it is transported as  
14 a blend. Differently from [35], the fluid-dynamic model of the gas network is a transient one. Previous works  
15 on the modelling of hydrogen blending in which transient model of the gas networks are used are [36] and  
16 [37]. In [36] the hydrogen injection is performed along a pipeline and follows a given pattern, so to result in  
17 a H<sub>2</sub>-NG blend with varying concentration; in [37], a detailed multi-component, thermal and fluid-dynamic  
18 model is applied to a pipeline in order to simulate the propagation of gas quality perturbations when hydrogen  
19 is injected. These works aimed at modelling the impact of hydrogen blending as a form of renewable energy  
20 storage within the gas pipelines. The only constraint that is considered is the hydrogen availability (depending  
21 on the renewable electricity excess). On the contrary, in this work, the constraints imposed by the natural gas  
22 infrastructure are considered first. The share of hydrogen blended within the natural gas is kept constant (as in  
23 [38]) in view of the importance that gas quality stability may have for the final appliances. The infrastructure  
24 is modelled by means of a fluid-dynamic gas network solver as described in [39], which includes a model for  
25 the gas compression stations. Unlike [39], the gas flowing within the pipelines is modelled by means of a more  
26 sophisticated equation of state (the GERG-2008 [40]) thus the whole model is sensitive to the different  
27 composition of the hydrogen-natural gas blends.

28 The fluid-dynamic simulations consist in four blending scenarios under increasing hydrogen fraction (5%,  
29 10%, 15% and 20%) with the twofold goal of estimating the impact of the hydrogen presence on the gas  
30 transport and of evaluating the patterns of hydrogen acceptability. The impact on transport is quantified in  
31 terms of variation of the compression work at the compression stations. As for the hydrogen acceptability  
32 patterns, they are the outcome of the gas pipeline and gas compressor modelling which is based on the available  
33 data on natural gas imports at the gas terminal of Gela (Sicily, Italy). These patterns are then used, together  
34 with the solar irradiation curve, to evaluate the mismatch between hydrogen production from photovoltaic  
35 source and hydrogen acceptability by the gas infrastructure. Finally, a design is proposed for the photovoltaic  
36 fields based on the minimization of the hydrogen storage needs.

1 With respect to the existing literature (e.g. [34]), the novelty of this work lies on the modelling oriented  
2 approach aimed at determine the impact of hydrogen blends on the gas pipeline operations resulting in higher  
3 operation costs in terms of energy, a different duty cycle and the failure in maintaining the required pressure  
4 level in some extreme cases. What is more, the question of mismatch between pipeline availability to accept  
5 hydrogen and solar hydrogen production is addressed, assuming that the gas quality is to be maintained  
6 constant. This operational hypothesis (it is not a real physical constrain on infrastructure or final appliances)  
7 offers a new point of view for the evaluation of potential and challenges of the electricity-gas sectorial  
8 integration.

9 The paper is structured as follows: in the next section, Paragraph 2, a detailed description of the gas  
10 network model is given, focusing on the assumptions made on the compressor station equation and on its  
11 control strategies. The case study is presented in the Paragraph 3, where a description of the technical features  
12 of the Greenstream are given and four hydrogen injection scenarios are described. The results of the  
13 simulations are given in the Paragraph 4 where they are compared with the base case scenario (non-injection  
14 scenario). Based on the results of the hydrogen injection profiles and the solar profile, a design procedure is  
15 then set-up in order to size the photovoltaic plants needed for providing a constant share of hydrogen. The  
16 procedure aims at minimize the need for hydrogen storage which is assumed to be in pressurized form, this is  
17 shown in Paragraph 5. Finally, a discussion of the results leading to the conclusions are performed in Paragraph  
18 6.

## 19 **2 Methodology**

20 In order to evaluate the impact that the different levels of hydrogen blending cause on the fluid-dynamic  
21 of the gas pipeline and, consequently, to the operations of the gas compressor, a fluid-dynamic model of the  
22 infrastructure, including the pipelines and the compression stations is used. The expected outcomes of the  
23 simulations are the pressure level and the gas flows throughout the whole infrastructure which result from the  
24 boundary conditions applied. In this case, the outlet gas flows (i.e. the gas required at users' side) are known  
25 thus the profile of the gas at the infrastructure inlet is calculated. These profiles depend also on the compression  
26 stations operations which, in turn, depend on the calculated pressure level at the end of the pipeline. The  
27 resulting operation cycle of the compressors is evaluated in terms of the compression energy required and the  
28 gas consumption profile, which will be different across the four blending cases, allowing the calculation of the  
29 number of operative hours, the total gas consumption and the transport efficiency. The resulting gas profiles  
30 at the gas infrastructure inlet allow calculating the corresponding hydrogen injection profile which is needed  
31 to form the hydrogen share in the corresponding blending case. This hydrogen pattern is compared to the  
32 nominal potential hydrogen production profile from a photovoltaic power plant to highlight possible  
33 mismatches between hydrogen production and the pipeline availability to accept it. A sizing procedure of the  
34 photovoltaic plants at the gas infrastructure inlet locations is proposed. The mismatch calls for the need of a  
35 certain storage capacity thus the sizing procedure is based on the minimization of the hydrogen storage  
36 capacity. It is assumed that hydrogen is stored in compressed form.

## 1 2.1 Pipeline model

2 The motion of a fluid within a pipeline is governed by a system of three partial differential equations  
3 (PDEs): the conservation of mass, momentum and energy. In case of iso-thermal fluid-flow simplification (as  
4 in the model here described), the system of PDEs is reduced to the mass and momentum equation as follows:

### 5 Conservation of Mass

$$\frac{\partial \rho}{\partial t} + \frac{\partial(\rho v)}{\partial x} = 0 \quad (1)$$

6

### 7 Conservation of Momentum

$$\frac{\partial(\rho v)}{\partial t} + \frac{\partial(\rho v^2)}{\partial x} + \frac{\partial p}{\partial x} + \frac{\lambda \rho v |v|}{2D} + \rho g \sin \alpha = 0 \quad (2)$$

8

9 where  $\rho$  is density,  $v$  is velocity,  $p$  is pressure,  $\lambda$  is friction factor,  $D$  is the pipeline diameter,  $g$  the gravitational  
10 acceleration and  $\alpha$  the pipeline inclination angle.

11 As the modelled network regards a compressible fluid, Eq. (1) cannot be further simplified while the second  
12 term of Eq. (2) (the convective term) can be neglected, as the maximum velocity of gas within pipelines does  
13 not exceed  $10 \div 25$  m/s.

14 The system of equation is characterized by two equations in three unknowns thus a closure equation is  
15 required, this being the Equation of State

$$\frac{p}{\rho} = c^2 = Z R T \quad (3)$$

16 where  $c$  is the isothermal speed of sound and  $Z = Z(p, T, [y])$  is the compressibility factor, a function of  
17 pressure, temperature and gas composition  $[y]$ . The way the compressibility factor is determined defines which  
18 equation of state is chosen to solve the problem. In this case, the GERG-2008 equation of state [40] has been  
19 chosen, being one of the most recent developed, wide-range, multi-component equation of state. In fact, it is  
20 sensitive to the composition of the natural gas considered, being able to account for 21 different chemical  
21 species within the natural gas, including hydrogen.

22 In order to derive a proper pipeline equation, it is convenient to substitute the velocity  $v$  with the mass  
23 flow rate  $\dot{m}$  by means of the following relation:

$$\dot{m} = \rho v A \quad (4)$$

24 In this way, the pipeline equation relates the main operational variables of a duct: pressure and gas flow. By  
25 substituting Eq. (3) and (4) in Eq. (2) and rearranging the terms, it is possible to obtain a differential expression  
26 of the pressure drops along a pipeline:

$$\frac{\partial p}{\partial x} = -\frac{1}{A} \frac{\partial \dot{m}}{\partial t} - \frac{\lambda c^2}{2DA^2 p} \dot{m} |\dot{m}| - \frac{g \sin \alpha}{c^2} p \quad (5)$$

1 which results in a composition of several terms such as:

- 2 • inertia, related to the time derivative of the mass flow, accounting for the forces which oppose the flow
- 3 acceleration direction;
- 4 • hydraulic resistance accounting for the friction which is quadratically proportional to the mass flow
- 5 and it oppose the mass flow direction;
- 6 • gravitational resistance accounting for the pressure losses due to gravity if the pipeline has an
- 7 inclination  $\alpha$ .

8 In the form of Eq.(5), the pressure drops equation displays non-linearity both on mass flow and on  
9 pressure. Some further elaborations are required to get to a linearized form, which is suitable for network  
10 modelling purpose.

11 First, the non-linearity associated with the pressure can be avoided by performing a substitution of variable  
12 such as  $P = p^2$ , thus referring to the quadratic pressure, obtaining:

$$\frac{\partial P}{\partial x} + \frac{2g \sin \alpha}{c^2} P = -\frac{2p}{A} \frac{\partial \dot{m}}{\partial t} - \frac{\lambda c^2}{DA^2} \dot{m} |\dot{m}| \quad (6)$$

13 The presence of the time and spatial derivatives requires the adoption of integration strategies. Regarding  
14 the integration of the spatial derivative, Eq. (6) can be considered as a linear and non-homogeneous differential  
15 equation of first order provided that the coefficients of the right-hand side are averaged over the pipe  
16 section  $\Delta x = l$ , so to be constant with respect to the  $x$ . Assuming this approximation, the equation is solved  
17 analytically yielding to the following pipeline equation:

$$P_{in} - P_{out} e^{s_j} = \frac{2 \bar{p}_j l_{e_j}}{A_j} \frac{\partial \dot{m}_j}{\partial t} + \frac{\lambda_j \bar{c}_j^2 l_{e_j}}{D_j A_j^2} \dot{m}_j |\dot{m}_j| \quad (7)$$

18 with:

$$l_{e_j} = \begin{cases} l_j, & h_{in} = h_{out} \\ \frac{e^{s_j} - 1}{s_j} l_j, & h_{in} \neq h_{out} \end{cases} \quad s_j = \frac{2g(h_{out} - h_{in})}{\bar{c}_j^2}$$

19 Where subscripts *in* and *out* stand for the inlet and the outlet sections of the generic  $j^{th}$  pipe. In order to  
20 account for the gravitational contribution, the “effective length”  $l_e$  is defined as the corrected length of the  
21 pipeline section in case of non-horizontal pipelines (whose slope is defined by the elevation difference  
22  $(h_{out} - h_{in})$  of their ends.

23 The averaged quantities, which make the analytical solution possible, are calculated starting from the  
24 computed value of the average pressure  $\bar{p}$  as expressed in [41] and here reported:

$$\bar{p} = \frac{p_{in}^2 + p_{in} p_{out} + p_{out}^2}{p_{in} + p_{out}}$$

25 And in turn:

$$\overline{c^2} = Z(\overline{p}, T, [y])RT$$

Eq. (7) has now the form of an ordinary differential equation in which the time derivative can be treated by means of an implicit finite different scheme for the approximation of the inertia term, leading to the following expression:

$$P_{in}^{n+1} - P_{out}^{n+1} e^s = \frac{2 \overline{p}^{n+1} l_e}{A \Delta t} (\dot{m}^{n+1} - \dot{m}^n) + \frac{\lambda \overline{c^2} l_e}{DA^2} \dot{m}^{n+1} |\dot{m}^{n+1}| \quad (8)$$

This scheme is a single-step backward differentiation formula also known as backward Euler method. It is one of the most common and basic numerical method for the solution of ordinary differential equations with first-order convergence and fully implicit feature, so to guarantee stability for large timesteps, as reported in [42] and in [43].

The integrated form of the pipeline equation is finally given in a more concise form as follows

$$\Delta P^{n+1} = R_I \cdot (\dot{m}^{n+1} - \dot{m}^n) + R_F \cdot \dot{m}^{n+1} |\dot{m}^{n+1}| \quad (9)$$

with  $\Delta P$  representing the corrected and quadratic pressure drop as defined here

$$\Delta P^{n+1} = P_{in}^{n+1} - P_{out}^{n+1} e^s ;$$

and the coefficients of the right-hand side grouped in two resistance coefficients

$$R_I = \frac{2 \overline{p}^{n+1} l_e}{A \Delta t} ; \quad R_F = \frac{\lambda \overline{c^2} l_e}{DA^2} = \frac{16 \lambda \overline{c^2} l_e}{\pi^2 D^5} ;$$

The two terms in the right-hand side of the Eq. (9) represent the two physical phenomena contributing to the pressure variation along the pipeline: The inertia contribution (subscript  $I$ ) and the fluid-dynamic friction (subscript  $F$ )

The quadratic pressure-drop equation as expressed in Eq. (9) is a parabolic function of the mass flow. In order to be included in an algorithm for the network simulation, it has to be linearized. Considering the generic pipe  $j$  and assuming the linearization point as  $(\Delta P_j^{n+1}, \dot{m}_j^{n+1})$ , the application of the linearization formula leads to the following expression:

$$\Delta P_j^{n+1(k+1)} - \Delta P_j^{n+1(k)} = \left. \frac{d\Delta P_j^{n+1(k)}}{d\dot{m}_j^{n+1(k)}} \right|^{(k)} (\dot{m}_j^{n+1(k+1)} - \dot{m}_j^{n+1(k)})$$

from which, solving the derivative of the pressure drop Eq. (9), it is possible to obtain the final expression:

$$\begin{aligned} \Delta P_j^{n+1(k+1)} - (2R_F \cdot |\dot{m}_j^{n+1(k)}| + R_I) \dot{m}_j^{n+1(k+1)} = \\ = -R_F \cdot |\dot{m}_j^{n+1(k)}| \dot{m}_j^{n+1(k)} - R_I \dot{m}_j^{n(k)} \end{aligned} \quad (10)$$

1 This method was presented in [44] for the steady state case and generalized for the application to the  
 2 transient equation in [39].

3 In the end, in order to refer to the normal pressure drop  $\Delta p$  rather than the corrected-square pressure drop  
 4  $\Delta P$ , the Eq. (9) and its linearized version (10) which are generally applied to the pipeline  $j$ , shall be divided by  
 5  $(p_{in} + p_{out} e^{s/2})$ .

## 6 2.2 Compression Station Model

7 Within the gas network infrastructure, the compressor stations are active, non-pipeline elements that are  
 8 fundamental to guarantee the gas transport along the pipelines. They usually consist in a number of centrifugal  
 9 compressors, powered by gas turbines, which consume a fraction of the natural gas from the grid. The  
 10 compression units may be in a series or parallel configuration. Usually series (or multistage) configurations  
 11 allow higher compression ratios, while parallel ones allow higher flow rates. Additionally, a gas compression  
 12 station is equipped with gas coolers in order to cool down the gas which has heated up after the compression  
 13 far higher than the acceptable pipeline temperature.

14 In this modelling framework, the compression station is considered as a black box which contains the  
 15 combination of all the installed compressors and the gas coolers. In this way, the outlet gas temperature can be  
 16 assumed as the same as the one assumed throughout the system. The general form of the gas compressor  
 17 equation, referred to the mechanical shaft power ( $P_{mech\_shaft}$ ) required by the compressor to the gas turbine  
 18 driver, results in:

$$P_{mech\_shaft} = \frac{1}{\eta_{is} \eta_{mecc}} \frac{\gamma}{\gamma - 1} Z_{in} T_{in} R_{in} \left( \beta^{\frac{\gamma-1}{\gamma}} - 1 \right) \dot{m}_j \quad (11)$$

19 with  $\eta_{is}$  the isentropic efficiency of compression,  $\eta_{mecc}$  the mechanical efficiency of the compressor (set equal  
 20 to 80%),  $\gamma$  the adiabatic exponent and  $\beta$  the compression ratio which is the ratio between outlet and inlet  
 21 pressure.

22 The fuel offtake required to power the whole gas compression station may be derived as follows:

$$\dot{m}_{consumption} = \frac{P_{mech\_shaft}}{\eta_{turb} HHV} \quad (12)$$

23 with  $\eta_{turb}$  the turbine efficiency (which includes the expansion efficiency and the combustion efficiency) and  
 24  $HHV$  the higher heating value of the natural gas (or H<sub>2</sub>-NG blends).

25 Typical ranges for  $\eta_{is}$ ,  $\eta_{turb}$  and  $\beta$  are given in the following table:

26 Table 1 – Typical ranges for isentropic efficiency, mechanical drive efficiency and compression ratio for a gas  
 27 network compressors [45], [41]

$\eta_{is}$	$\eta_{turb}$	$\beta$
[%]	[%]	[-]
75 ÷ 84	28 ÷ 38	< 2

1 In order for the compressor equation to be integrated within the complete linear set of equation of the gas  
 2 infrastructure model, a linearized version of the compressor equation is obtained as Eq. (13). In this form, the  
 3 amount of the extracted fuel from the network to power the turbo compressor is also accounted and it is  
 4 assigned to the gas compressor inlet node. In this way it is possible to calculate the amount of gas consumed  
 5 by the compressor itself.

$$- \frac{K_i \dot{m}_j}{p_i} \beta^{\frac{\gamma-1}{\gamma}} \cdot p_i + \frac{K_i \dot{m}_j}{p_o} \beta^{\frac{\gamma-1}{\gamma}} \cdot p_o + \frac{K_i \gamma}{\gamma-1} \left( \beta^{\frac{\gamma-1}{\gamma}} - 1 \right) \cdot \dot{m}_j + \dot{m}_{consumption} = 0 \quad (13)$$

6 with:

$$K_i = \varphi \frac{Z_i T_i R}{\eta_{ad} \eta_{mecc} \eta_{turb} HHV} ;$$

7 Where  $K_i$  is the fraction of the total installed power of the compression station.

8 The compressor may assume a number of different operational modes, depending on the choice of the  
 9 control variable. In this work two possible control modes are considered: the compressor working at assigned  
 10  $\beta$  and the compressor controlled by the assigned shaft power. The compressor will work at assigned  
 11 compression ratio when a minimum  $\beta$  is to be guaranteed or to comply with the limit of  $\beta_{max}$ . Otherwise, the  
 12 compressor is controlled by the assigned shaft power. The compression station can either be by-passed or shut-  
 13 down. In case of by-pass, the inlet and outlet pressure will be required to be equal. In case of shut-downs, the  
 14 mass flow rate within the compressor will be set to zero. More details and assumptions on the operation of the  
 15 gas compression station in this study are given in the ‘‘Assumptions and Simplifications’’ section.

### 16 2.3 Algebraic model of the gas infrastructure

17 In order to have a complete algebraic model of the gas infrastructure, the mass conservation equation has  
 18 to be applied to each node of the network (i.e. joints between two pipeline sections). Having defined a control  
 19 volume around each node, the integral form of the continuity equation may be obtained as follows:

$$\frac{V_i}{c^2} \frac{dp_i}{dt} = - \sum_j a_{i,j} \dot{m}_j - \dot{m}_{ext_i} \quad (14)$$

20  
21  
22

23 with:

$$V_i = \frac{\pi}{8} \sum_j D_j^2 \Delta x_j ;$$

24 that is the geometrical volume of the  $i^{\text{th}}$  node.

25 Introducing the concept of incidence matrix defined as follows:

$$\mathbf{A} = [a_{i,j}]^{n \times b}, \quad a_{i,j} = \begin{cases} +1, & \text{node } i \text{ is the inlet of edge } j \\ -1, & \text{node } i \text{ is the outlet of edge } j \\ 0, & \text{node } i \text{ and edge } j \text{ have no connections} \end{cases} \quad (15)$$

1 where  $n$  is the number of nodes (connection between pipes) and  $b$  is the number of edges (pipes or other non-  
 2 pipe elements such as compression station) as a way to express any network topology in matrix form, it is  
 3 possible to express Eq (10) , Eq (13) and Eq (14) in matrix form as follows:

$$\mathbf{A}_g^t \mathbf{p}^{n+1(k+1)} - \mathbf{R} \dot{\mathbf{m}}^{n+1(k+1)} = -\mathbf{R}_F(|\dot{\mathbf{m}}^{n+1(k)}| \circ \dot{\mathbf{m}}^{n+1(k)}) - \mathbf{R}_I \dot{\mathbf{m}}^n \quad (16)$$

4

$$\mathbf{C}_{NP P} \mathbf{p}^{n+1} + \mathbf{C}_{NP M} \dot{\mathbf{m}}^{n+1} + \mathbf{C}_{NP} \dot{\mathbf{m}}_{ext}^{n+1} = \mathbf{0} \quad (17)$$

5

7

$$\Phi \mathbf{p}^{n+1} + \mathbf{A} \dot{\mathbf{m}}^{n+1} + \mathbf{I} \dot{\mathbf{m}}_{ext}^{n+1} = \Phi \mathbf{p}^n \quad (18)$$

8

10

11 This set of equations are to be solved simultaneously for each time step of the simulation period, provided that  
 12 suitable boundary conditions at the gas pipeline inlet and outlet are assigned. Because of the linearization of  
 13 the pipeline equation, for each timestep the fluid-dynamic problem will be solved iteratively until the residue  
 14 of the pipeline equation will be smaller than a given tolerance (usually  $10^{-4}$ ).

### 15 3 Case study description

#### 16 3.1 Technical description of the Greenstream and the West Libyan gas infrastructure.

17 The European natural gas market heavily relies on imports. According to Eurostat [46], between 2017 and  
 18 2018 the share of annual imported natural gas grew from 74.4 % to 77.9 %, with Russian gas playing the  
 19 prominent role, accounting for about 47 % of the imports, followed by Norway (about 30 %) and North-Africa  
 20 (around 12 %). The latter region is connected to Southern Europe by means of four corridors, commissioned  
 21 between 1983 and 2010 with an overall capacity of 61.2 bcm/y of natural gas. About the 67 % of this capacity  
 22 is connected to the European system by means of the Italian natural gas transmission system, which is reached  
 23 by the Trans-Mediterranean Pipeline (Transmed) and the Greenstream Pipeline in Sicily. This work will focus  
 24 on the Greenstream corridor.

25 The Greenstream pipeline is the corridor carrying Libyan gas to the European market. It starts from the  
 26 Libyan coast at Mellitah Complex where the gas compression station is located and it landfalls at Gela gas  
 27 receiving terminal (Sicily, IT). It ends at Enna gas compression station where it connects to the Transmed  
 28 route. Greenstream is the longest and the deeper submarine gasduct of the Mediterranean Sea, running about  
 29 520 km subsea and reaching a maximum depth of about 1150 m [47]. It is composed of a single pipe with a  
 30 nominal diameter of 32 inches. The onshore section in Sicily is 67.3 km long [48].

31 Greenstream is a part of the Western Libyan Gas Project (WLGP), a joint venture between the Italian Eni  
 32 and the Libyan National Oil Corporation (NOC), which had the goal of developing the oil and gas sector in  
 33 Western Libya. The project had covered the development of two main extraction areas, the gas hub of Mellitah

1 and the entire connecting infrastructure along with the Greenstream. Today, Western Libyan natural gas is  
 2 extracted from the Wafa oil and gas field, located onshore in the Sahara Desert near to the Tunisian border,  
 3 about 520 km south-west far from Mellitah and the Bahr Es Salam offshore field, located 110 km far from the  
 4 Libyan coast. Extracted oil and gas are both sent to the Mellitah Gas Processing plant where treatment facilities  
 5 are located as well as the gas compression station of Greenstream and the local market gas reduction station.

6 Table 2 – Main technical features of the gas pipelines infrastructure of Western Libyan Project (in which  
 7 Greenstream gas corridor is included)

Segment					Length	# Pipes × Diameter	DN
From		To			[km]		[mm]
	Wafa Field	Mellitah Hub	Libya	Onshore	520	1 × 32"	800
	Bahr Es Salam field	Mellitah Hub	Libya	Offshore	110	1 × 24"	600
Greenstream	Mellitah Hub	Gela Receiving Terminal	Sicilian Channel	Offshore	520	1 × 32"	800
	Gela Receiving Terminal	Enna compression station	Italy	Onshore	67.3	1 × 36"	900

8  
 9 As it can be noted, the Mellitah Hub is a crucial point of both the Greenstream and the Western Libya oil and  
 10 gas infrastructure. As for the natural gas sector, it receives the sales-ready natural gas from the Wafa field and  
 11 the raw natural gas extracted from the offshore Bahr Es Salam field, coming from the Sabrata Platform. This  
 12 stream of gas is treated at Mellitah Gas Treatment Plant and then it is integrated to the natural gas transmission  
 13 system. The total amount of gas collected at Mellitah Complex is allocated between the export and the domestic  
 14 market by means of the gas compression station and the gas reduction and metering station that are both located  
 15 at the Mellitah Complex. The Mellitah Gas Compression Station is composed of 5 turbo-compressor trains.  
 16 For each of the train, the gas turbine drives 2 barrel type centrifugal compressor in a tandem configuration  
 17 through a speed increasing gear box [49]. The gas turbines are of the type MS5002D-DLN, with a rated power  
 18 of 32.58 MW and an overall efficiency  $\eta_{turb} = 29.4\%$  [50]. The turbo compressor total installed power of the  
 19 site is 160 MW. The gas station is devoted to compress the gas for export purposes, up to a maximum operating  
 20 pressure of 212 bar. At present, the annual maximum transmission capacity of the Greenstream pipeline is 11  
 21 billion Sm<sup>3</sup>, which corresponds to about 30 MSm<sup>3</sup>/d on average. The Mellitah gas reduction and metering  
 22 station is instead designed to deliver up to 15 MSm<sup>3</sup>/d for the domestic consumption by means of the 44 bar  
 23 coastal line, operated by the Sirte Oil Company (S.O.C.) [47].  
 24 As for the production fields, the production capacity of the Wafa field is up to 2.8 MSm<sup>3</sup>/d after the installation  
 25 of four new gas compressors [51] and the production capacity of Bahr Es Salam field is up to 28.2 MSm<sup>3</sup>/d  
 26 [52].

### 1 3.2 Blending scenarios

2 Four blending scenario have been considered, ranging from 5% of hydrogen within natural gas on volume  
 3 basis, up to 20%, with an increment of 5% for each scenario. Each blending case study is compared with the  
 4 base case scenario consisting in a simulation of the current gas system operation. Given that the increase of  
 5 the hydrogen molar fraction causes a decrease of the calorific value of the natural gas-hydrogen admixture, the  
 6 simulations have been conducted considering the same amount of energy flow carried along the pipeline as the  
 7 energy transported in the reference case of 0% hydrogen. This implies an increase of the volume flow rate of  
 8 the natural gas and hydrogen blends. Under this assumptions, the hydrogen share is meant to substitute a  
 9 portion of the fossil gas. Concerning the modelling strategy, the constraints on the outlet gas flow will be given  
 10 in terms of chemical energy released.

11 The hydrogen-natural gas mixture has been assumed to be formed upstream the modelled gas  
 12 infrastructure, at the two inlets of the network: Wafa Field and Mellitah hub. As the admixture process is out  
 13 of the modelling domain, the gas quality throughout the infrastructure is then homogeneous throughout all the  
 14 infrastructure and constant during the whole considered time interval for each scenario. The natural gas quality  
 15 for the base case scenario is set equal to the composition of the Libyan gas for the thermal year 2017-2018 as  
 16 specified by Snam at [53] and reported in Table 3. The composition will be re-proportioned accordingly as the  
 17 hydrogen is mixed to the natural gas.

18 Table 3 – Typical natural gas composition and gas quality parameter for the Libyan gas for the thermal year 17-18  
 19 [53].

Chemical species		Libyan Gas [% mol/mol]
	Methane	85.306
	Ethane	6.486
	Propane	2.058
	Iso Butane	0.280
	Normal Butane	0.437
	Iso Pentane	0.099
	Normal Pentane	0.063
	Hexane +	0.015
	Nitrogen	3.882
	Carbon Dioxide	1.268
	Helium	0.106
	Oxygen	-
Gas quality parameter	units	
Higher Heating Value	[MJ/Sm <sup>3</sup> ]	39.586
Wobbe Index	[MJ/Sm <sup>3</sup> ]	49.158

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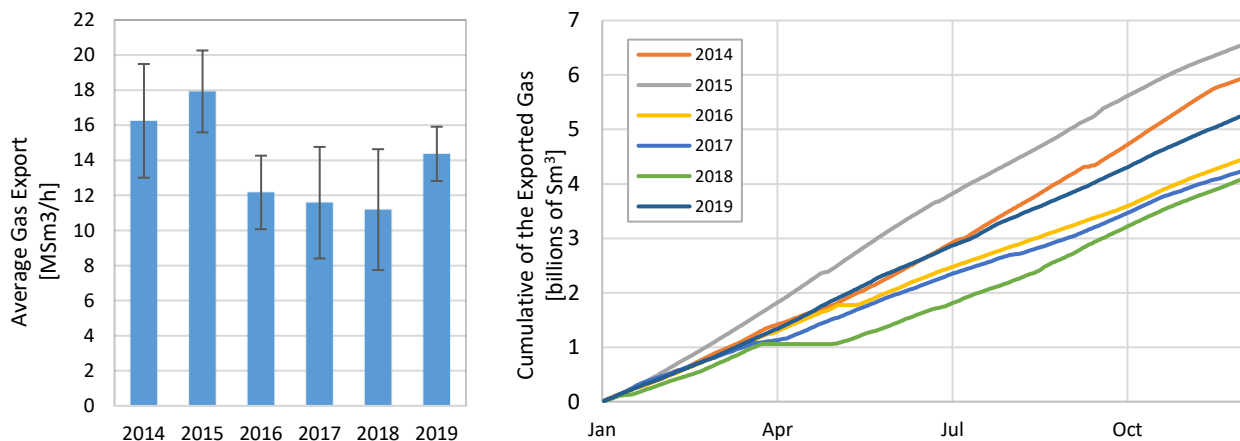
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## 4 Assumptions and simplifications

### 5 4.1 Gas production and delivery

6 According to the data on the natural gas imports available on the transparency platform of ENTSOG [54],  
7 the annual import of natural gas from Libya to Italy varied between 4 and 6.5 billion Sm<sup>3</sup> during the years  
8 2013-2019. These data show that the infrastructure is currently running at the half of its capacity. Figure 1  
9 shows the average gas flow rates together with the standard deviation for each year. Even though the variations  
10 may be as high as 25%, the cumulative curves in Figure 1.b show that the imports are not affected by a  
11 summer/winter seasonality as the rate of increase is more or less constant throughout the year. This observed  
12 behaviour justifies the choice of the simulation time interval, corresponding to 10 days between November 7<sup>th</sup>  
13 and November 17<sup>th</sup>.

14



15

16 Figure 1 – Left: average daily gas export through Greenstream. Right: cumulative of the daily gas export through  
17 Greenstream.

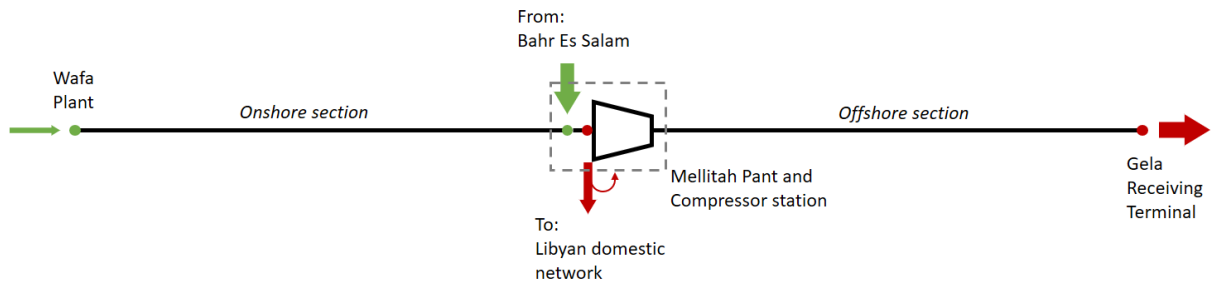
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19 The gas export data towards Italy is the only set of data of the Western Libya infrastructure that are  
20 available with a daily or hourly time resolution. No detailed information about production rate at the production  
21 fields or about the amount of gas delivered to the domestic market are available. Thus, the following  
22 assumptions have been made based on the information about the capacities of the production or delivery points  
23 cited in the previous paragraph. As for the delivery to the internal Libyan market, the gas exiting the Mellitah  
24 hub towards the coastal line has been assumed to be equal to the half of the gas sent to the export. Regarding  
25 the production field, the Wafa one has a throughput capacity of 1/11 of the one of Bahr Es Salam. Thus, for

1 the sake of the simulations, it has been assumed that the allocation of the overall gas flow rate among the two  
 2 fields will constantly follow these proportions.

### 3 4.2 Infrastructure

4 In order to model the effect of increasing molar fraction of hydrogen within the Libyan gas system, the  
 5 western Libyan gas infrastructure has been simplified as reported in Figure 2.



6

7 Figure 2 – Schematic of the modeled portion of Western Libya gas infrastructure including the onshore section from  
 8 Wafa to Mellitah, the Mellitah plant and compression station and the submarine section of Greenstream until the Italian  
 9 coasts.

10 The modelled infrastructure corresponds to a series of two pipelines connected by the Mellitah gas hub  
 11 where the natural gas from the offshore platform of Bahr Es Salam is added to the stream from Wafa and a  
 12 portion of the natural gas is delivered to the local market. Thus, the 110 km long pipeline between the offshore  
 13 platform and the Mellitah Gas Processing Plant has been excluded from the study because it carries sour gas  
 14 that is treated at the Mellitah plant. The treated gas resulting from the plant is integrated to the modelling  
 15 framework considering an injection node at the end of the first section of the pipeline system. Similarly, the  
 16 coastline domestic infrastructure is not modelled thus, for the sake of the simulations, a withdrawal node is  
 17 considered upstream the gas compressor in which both the assumed amount of gas delivered to the local market  
 18 and the gas consumption of the compressor are withdrawn.

19 The two pipes in series are both 520 km long with a nominal diameter equal to 800 mm. The first section  
 20 is the onshore ducts running from Wafa Plant to Mellitah while the second section is the Greenstream offshore  
 21 section from Mellitah Compressor station to the Receiving Terminal at Gela in Sicily. Both sections have been  
 22 discretized with a 10 km long mesh. In Table 4 the technical details of the two pipeline sections are given.

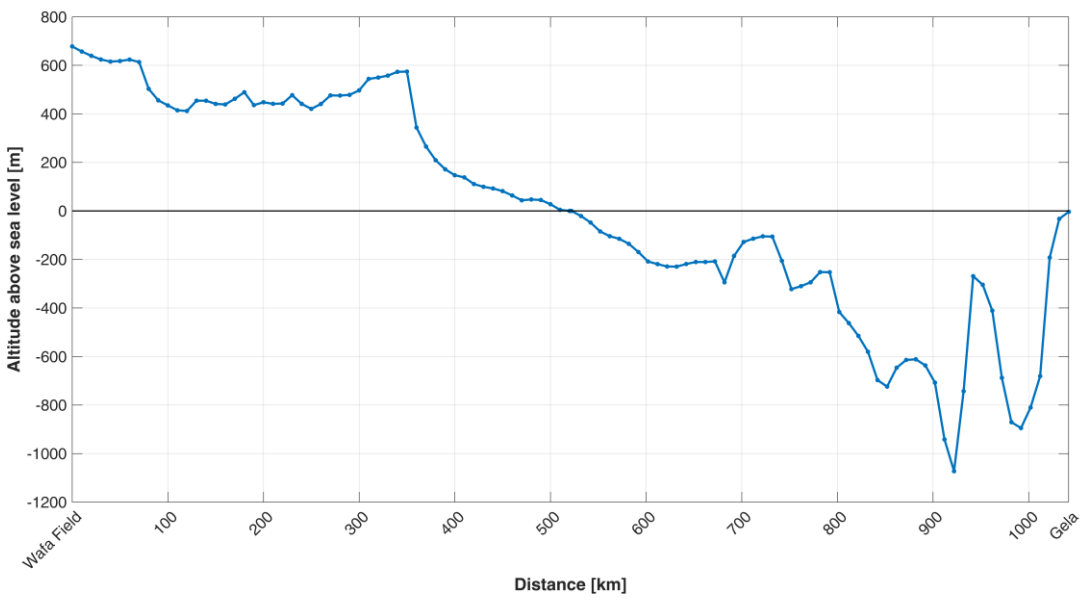
23 Table 4 – Technical features of the modeled portion of the Western Libyan Infrastructure (wall thickness data from  
 24 [55]).

Segment			Length	# Pipes × Diameter	DN	Outer diameter	Wall thickness	Inner diameter	Roughness
			[km]		[mm]	[mm]	[mm]	[mm]	[μm]
Wafa Field – Mellitah Hub	Libya	Onshore	520	1 × 32"	800	812.8	30.2	752.4	14

Greenstream	Mellitah	Sicilian Channel	Offshore	520	1 × 32"	800	812.8	30.2	752.4	14
	Hub – Gela Receiving Terminal									

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Given that the Greenstream is known to be the Mediterranean gas duct that reaches the deepest seafloor, the elevation of the entire path of the pipelines have been considered so to account for the gravitational terms of the momentum equation. The elevation profile have been obtained from [56] for what concerns the offshore section and reconstructing the pipeline path on Google Earth for the onshore section. In Figure 3 the overall profile is given.



7  
8  
9

Figure 3 – Elevation profile of the modelled infrastructure.

10 *4.3 Assumptions on the compressor station and its control strategy*

11 According to [41], the typical compression ratio for a centrifugal compressor is lower than 2. Thus, it is  
 12 assumed that the compression ratio range for the compressor in this model is  $\beta = [1.2 - 1.8]$ . The Mellitah Gas  
 13 Compression station is assumed to have all the 5 turbo-compressors in parallel so that higher amount of flow  
 14 rates may be elaborated while keeping the compression ratio within the range.

15 Concerning the compressor control strategy, each time the gas pressure at the inlet node is higher than the  
 16 outlet node pressure, the compressor is by-passed and the entire infrastructure is operated under free-flow  
 17 condition. Conversely, whenever the outlet pressure is higher than the inlet one, the “off mode” is applied so  
 18 than no flow rate is passing through the compressor’s branch. The compressor is turned-on depending on the  
 19 resulting pressure at the end of the Greenstream pipeline, at the Gela Gas Receiving Station. In fact, according  
 20 to [57], the minimum contractual pressure at the Gela entry point must be 70 bar<sub>g</sub>. In order to comply with this  
 21 contractual requirement, it was assumed that whenever the pressure at Gela drops below 95 bar<sub>g</sub>, the

1 compressor station is turned on. Depending on the value of the pressure ratio between the outlet and the inlet  
2 nodes of the compressor, the compression station may be operated in two alternative modes:

- 3 1) Compression ratio controlled: if the ratio between outlet and inlet pressure is less than  $\beta_{\min} = 1.2$ , the  
4 value of  $\beta_{\min} = 1.2$  is imposed as a constraint on the compressor equation;
- 5 2) Shaft Power assigned: if the compression ratio  $\beta$  is within the range, the shaft power is imposed as a  
6 constraint on the compressor equation.

7 When the compression station is operated according to the shaft power, the range of variation of the assigned  
8 power is  $P_{\text{shaft}} = [0 - 128]$  MW, following the redundancy principle mentioned in [57], for which a stand-by  
9 compressor having a rated power higher or equal to the rated power of each single active units is to be  
10 guaranteed. A compressor start-up rate has also been considered: a linear ramp of 6.5 MW every 10 min has  
11 been assumed, which is coherent with other compressor operation modes in gas transmission systems. The  
12 assigned shaft power increase continues as long as a drop of the gas pressure at the Gela receiving station is  
13 observed provided that the compression ratio  $\beta$  is within the ranges. Whenever the compression ratio exceeds  
14  $\beta_{\max} = 1.8$ , the gas station control mode changes again to the case of assigned compression ratio, which will be  
15 set equal to  $\beta_{\max}$ .

16

## 17 **5 Simulations and results**

18 A time interval of 264 hours (11 days from gas day November 7<sup>th</sup> to gas day November 18<sup>th</sup>) has been  
19 considered to run the following simulations, with a time discretization of 600 s. The two 520 km long pipeline  
20 sections have been spatially discretized in 52 subsections of 10 km each. For what concerns the boundary  
21 conditions of the pipeline system, the real profile of gas export towards Italy have been applied to the Gela  
22 Receiving Terminal while the same profile but halved in magnitude have been applied to the gas outlet towards  
23 domestic market. To be noted that data from [54] are available with an hourly time resolution. In order to lower  
24 it at 10 minutes (600 s), a linear interpolation procedure was been applied. The gas flow boundary condition  
25 at Gela gas receiving station is given in Figure 4.

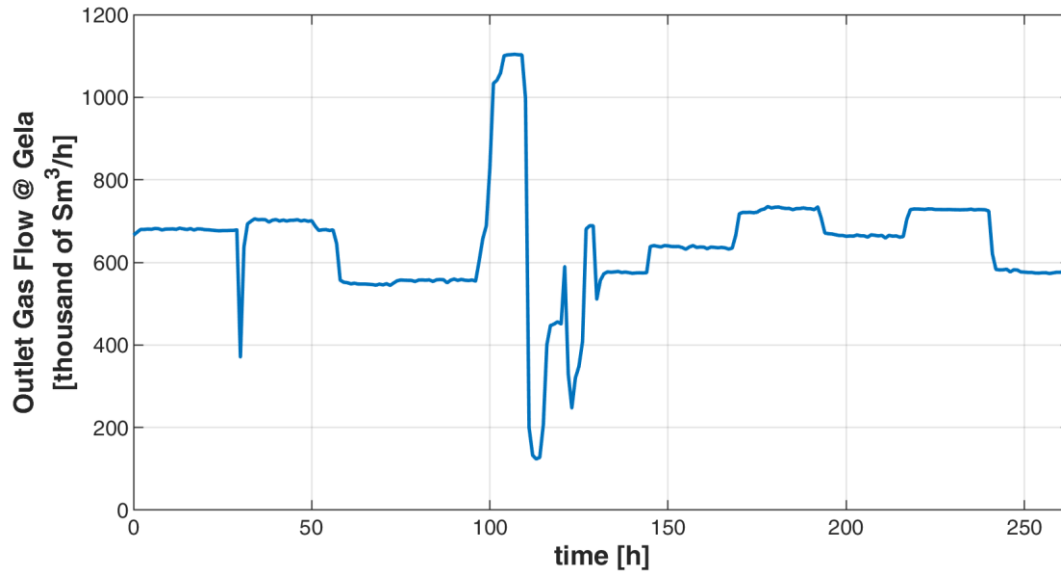


Figure 4 – Outlet gas flow rate set at Gela gas receiving station as a boundary condition Data for the period Nov.7<sup>th</sup> – Nov.17<sup>th</sup> 2017 from [54].

As for the gas inlet points, the Wafa field is assumed to be a pressure-controlled node (as it is a gas well output) set to a constant value of 75 bar<sub>g</sub>, while for the gas inlet from the offshore fields, the condition on the gas flow allocation described in the previous section is assigned.

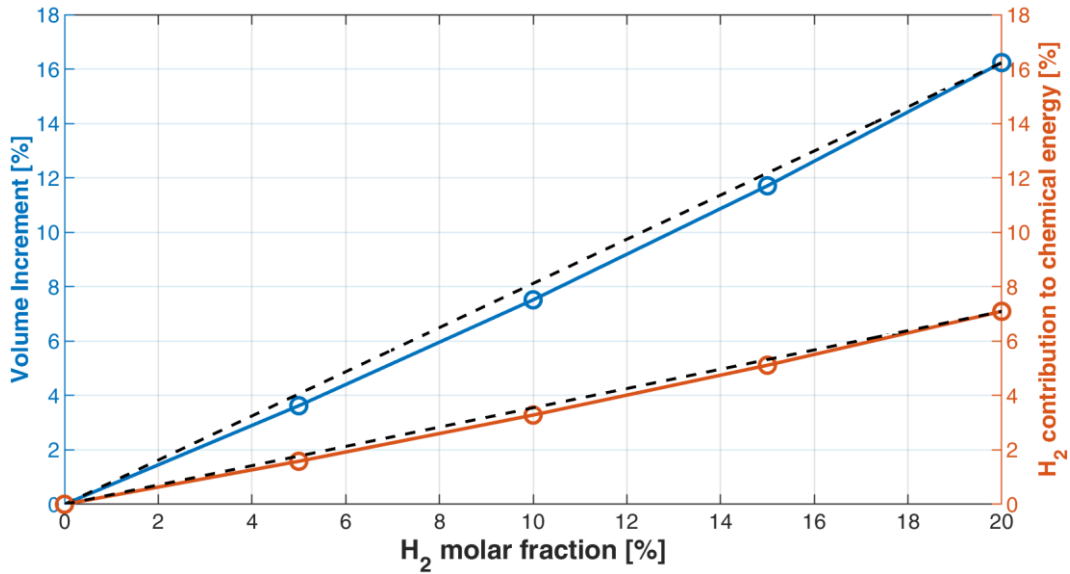
For each of the following simulations, a steady-state initial condition of the gas network is assumed, with the outlet pressure of the compression station set to 110 bar<sub>g</sub>.

The alteration of the gas quality of the transported gas is expected to affect the gas fluxes and the operations of the gas compression station. The objective of the simulations is to quantify these effects.

### 5.1 Fluid-dynamic impacts of hydrogen blending

If the amount of chemical energy delivered at the outlet is kept constant, the amount of gas flow increases because the volume-based heating value of the blend decreases as the hydrogen molar fraction increases.

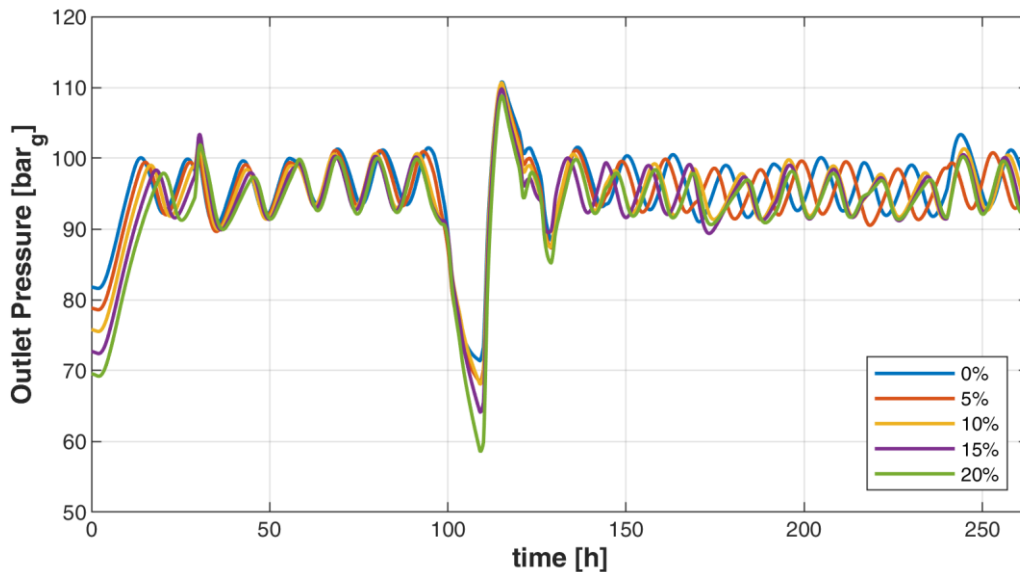
The blue line in Figure 5 shows the relation between the volume increment rates with respect to the increase of the hydrogen amount in the natural gas blend, under the hypothesis of supplying the same amount of energy. When 10% hydrogen is present within the natural gas, the gas volumetric flow is increased by 7.5% while at 20% of hydrogen, the gas volumetric flow is increased of 16.2 %. The relation is slightly less than linear (the dashed line marks the linear relation). The orange line represents the relation between the hydrogen molar fraction and its contribution to the energy content of the gas flow. It is worth to note that the 20% of the hydrogen fraction substitutes only the 7% of the energy content of the initial 100% fossil natural gas flow.



1

2 Figure 5 – Relation between the hydrogen molar fraction within the natural gas blend, the volume increment of the gas  
 3 flow and the hydrogen energy contribution to the gas flow, under the hypothesis of constant energy output at the outlet  
 4 nodes of the network.

5 The increase of the volume gas flow rate is the main cause of the increment of the pressure drop along the  
 6 pipeline system. This results in a lower pressure at the outlet nodes. In Figure 6, the pressure profile at Gela  
 7 gas receiving terminal is given for the whole simulation interval and for the five hydrogen blending cases. It  
 8 is possible to see that the higher is the hydrogen fraction, the lower is the outlet pressure. At the initial time,  
 9 the outlet pressure variation is as high as  $-15\%$  for the case of 20% hydrogen. It gets to  $-17.9\%$  at time  $t = 109$   
 10 h when the lowest pressure value can be observed (corresponding to the maximum withdrawal interval). It is  
 11 worth noting that the outlet pressures of all the cases with hydrogen injection drops below the minimum  
 12 contractual pressure that should be guaranteed at Gela receiving station (i.e.  $p = 70 \text{ bar}_g$ ). This implies that a  
 13 change in the compressors' control strategy would be required.

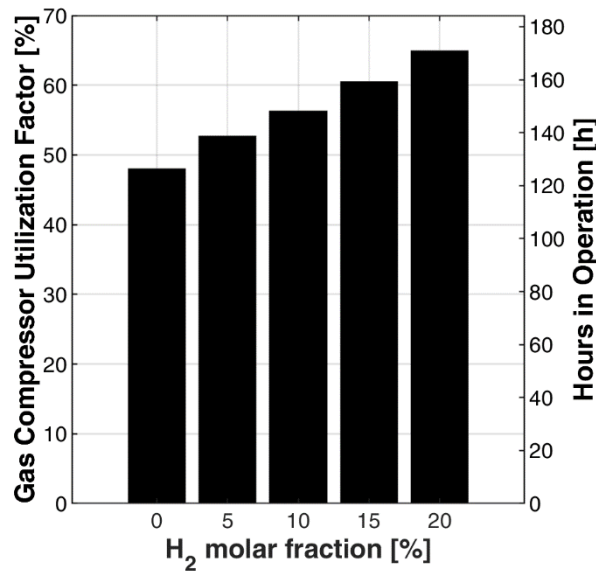


14

15 Figure 6 – Pressure profiles at the Gela gas receiving station under different molar fraction of hydrogen.

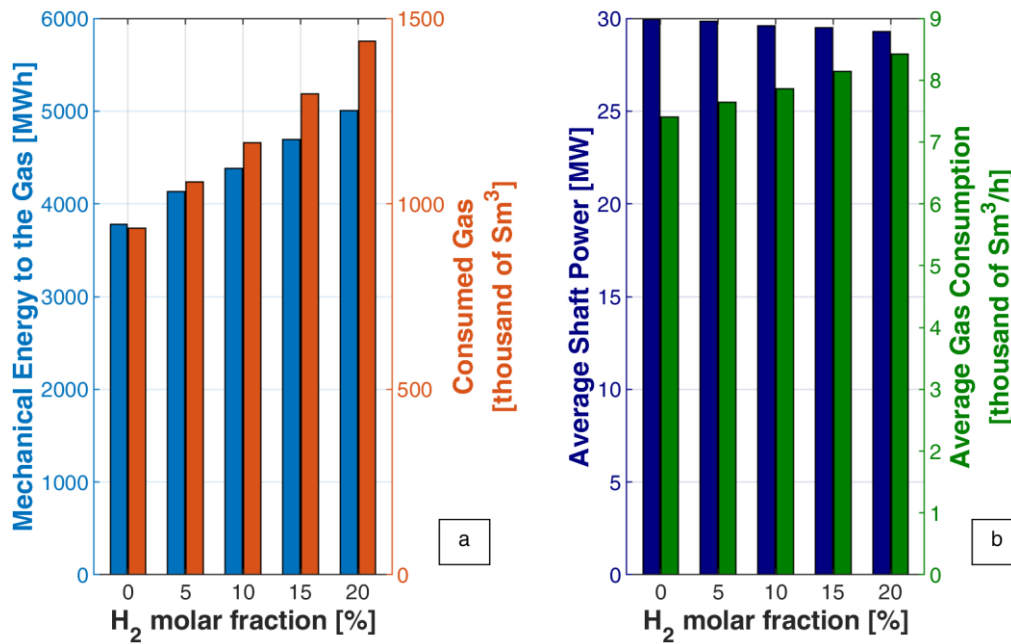
1 The second part of Figure 67 (for times higher than 120-150 h) shows the different pressure profiles going  
2 out of phase with respect to each other. This is a consequence of the variation in the gas station operation, as  
3 it will be clearer from the next figures.

4 Figure 7 shows both the number of hours in which the gas compression station is active and the  
5 compressors utilization factor, calculated as the ratio between the operating hours and the overall simulation  
6 hours. It is possible to see that as the hydrogen molar fraction increases, the number of operating hours of the  
7 compressor increases too, under the assumption that the compressor control strategy is maintained unvaried  
8 for all the five simulation cases. The results mean that in order to reach the outlet pressure set point the  
9 compressor needs to work longer. More specifically, the increment in the overall operating time interval with  
10 respect to the previous simulation scenario is between 9.5 and 12.3 hours. As it has been already commented  
11 for Figure 6, the longer operating time does not prevent the compression station to fail from keeping the  
12 pressure level higher than the minimum set point value in case of sudden increase of gas withdrawal.



13  
14 Figure 7 – Gas Compressor utilization factor and overall operating hours.  
15

16 The bar plots of Figure 8 aim at giving aggregated values to summarize the variations in the behaviour of  
17 the gas compression station. Figure 8.a (left) depicts the overall mechanical energy released to the gas during  
18 the simulation timeframe and the corresponding overall gas consumption. It is worth noting that the overall  
19 compression work required in the case of 5% hydrogen is around 10% higher than the benchmark case while  
20 for the case of 10% hydrogen is 16%, 25% with 15% hydrogen blending, this increment grows to 32.5% with  
21 20% hydrogen concentration. Figure 8.b (right) depicts instead the average values of the shaft power and of  
22 the gas consumption of the compressor, obtained by dividing the overall values of mechanical energy and gas  
23 consumption by the number of operating hours. In this case it is possible to note that the average shaft power  
24 required by the compressor slightly decreases as the hydrogen molar fraction increases (because of the increase  
25 of the compressor operating time and lower pressure at Gela terminal) while the average gas consumption rate  
26 increase as an effect of the lower volumetric heating value of the hydrogen-natural gas blends.



1

2 Figure 8 – a) overall mechanical energy provided to the gas for its compression and corresponding overall consumed  
 3 gas for the five hydrogen blending cases; b) average shaft power and average gas consumption rate for the five hydrogen  
 4 blending cases.

5 In relative value, compression work accounts for around 0.5% of total energy transported by the  
 6 transmission infrastructure that increases at 0.7% when 20% hydrogen blend is transported.

7

## 8 5.2 Sizing of the solar hydrogen production facilities.

9 A further objective of the simulation of the portion of the Western Libyan infrastructure is to determine  
 10 the patterns of admissible hydrogen at the injection points. The aim is to evaluate the renewables storage  
 11 potential of the infrastructure under real case working condition and to size possible future renewable hydrogen  
 12 facilities whose production is to be matched to the gas network receiving capability.

13 According to the assumption made, the modelled gas network has been constrained on gas flows only at  
 14 the outlet nodes of Gela and of the domestic gas market. Thus, the inlet gas flows at Wafa field and at the  
 15 Mellitah Gas Processing plant are the results of the interplay between gas withdrawals, gas station operation  
 16 and the fluid-dynamic of the pipelines. Having assumed that the hydrogen is blended at the two injection points  
 17 so to guarantee a fixed and constant molar fraction, the pattern of hydrogen injected for the two nodes is the  
 18 one depicted in Figure .

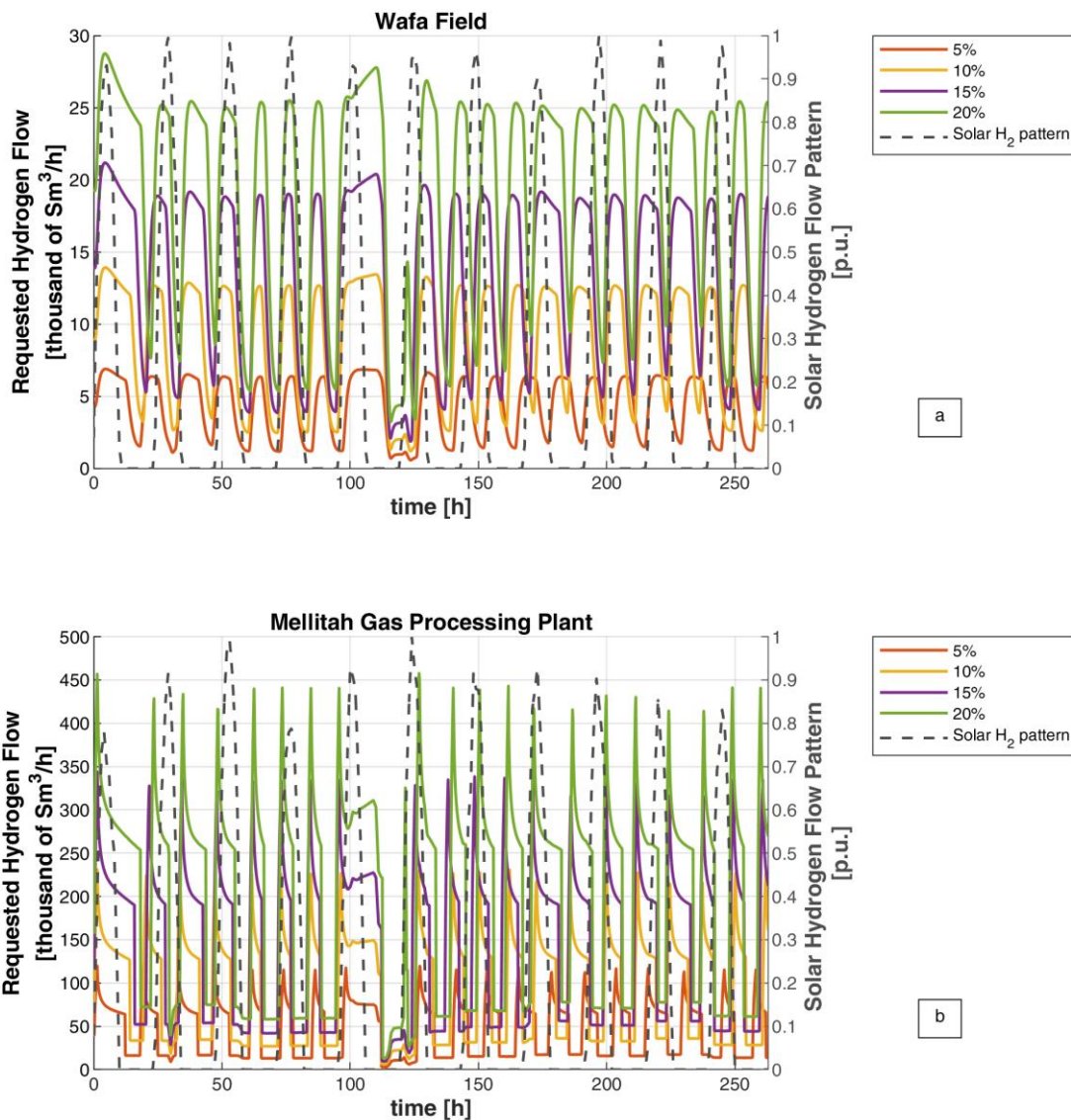


Figure 9 – Hydrogen injection pattern at the inlet nodes of the modeled gas infrastructure for the four injection scenarios superimposed to the nominal possible hydrogen pattern generated from electricity from a dedicated photovoltaic plant (in p.u. , referred to the right axis). Figure a refers to the Wafa Field area; figure b to the Mellitah Gas Processing Plant

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As it is possible to see, not only the magnitude of the maximum injectable hydrogen, but also the injection pattern is significantly different between the two locations. It is interesting to note that, for both the locations, the cycling pattern is related to the compression station operating mode, with the hydrogen injection profile at the Mellitah Gas Processing Plant being closely linked to the compressor operating status. This is caused by the proximity of this injection point to the compression station. In Figure 9 a and b the possible hydrogen pattern generated from an electrolyzer exclusively powered by a photovoltaic plant is also superimposed. It is expressed in “per unit” i.e. as a fraction of the maximum production rate within the considered timeframe, so to give emphasis to the profile. As it is possible to note, the frequency of the oscillations of the hydrogen

1 acceptability by the gas network is higher than the one of the solar hydrogen production, leading to mismatches  
 2 between hydrogen production and the gas network receiving capacity. What is more, the hydrogen production  
 3 from photovoltaic drops to zero during the night time while the receiving capacity of the gas pipelines never  
 4 goes to zero as the gas flow never stops along the main transmission infrastructure (unless critical events  
 5 happen).

6 The mismatch between the hydrogen production and the pipeline receiving capacity and the discontinuous  
 7 production from solar source call for the need of a suitable storage system if a constant share of hydrogen over  
 8 time is to be guaranteed. The size of photovoltaic field that is dedicated to power the electrolyzers depends on  
 9 the size of the related hydrogen storage.

10 As for the electrolyzers, the hydrogen conversion efficiency was assumed to be equal to  $65\%_{HHV}$ , that is  
 11 an average value within the common range of alkaline and proton-exchange-membrane (PEM) type [58],[59].  
 12 Alkaline and PEM electrolyzers are also the most suitable technology for a coupling with variable renewable  
 13 energy sources according to the abundant literature [60],[61] and the several projects on these systems  
 14 [62],[63]. Their nominal power will follow the actual solar power production, so to be able to convert  
 15 completely the renewable power to a hydrogen flow without the need of any battery pack for electricity storage.  
 16 Since the pressure level of the natural gas pipeline ranges between  $75 \div 80 \text{ bar}_g$ , the hydrogen needs to be  
 17 compressed up to the required pressure for injection or storage. The most suitable electrolyzers able to provide  
 18 hydrogen at higher pressure are PEM ones, reaching pressures up to  $30 \text{ bar}_g$  [64]. A further compression stage  
 19 is, in general, required. A possible option for hydrogen storage may be given by pipes storage [9],[65][66]

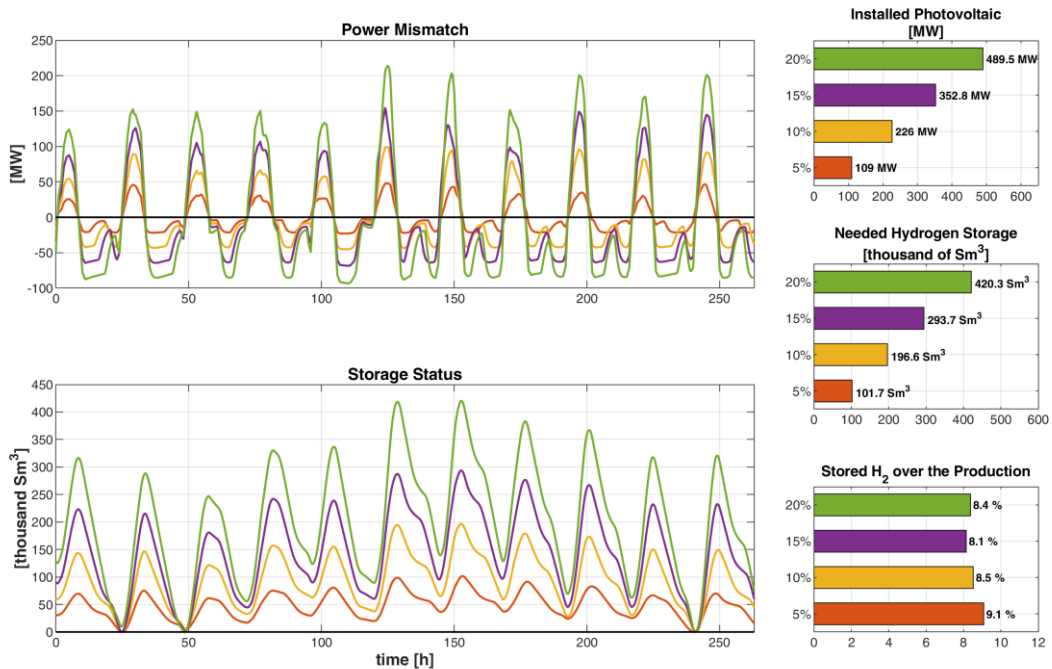
20 For both locations, the photovoltaic hourly plant production has been obtained using the PV-GIS web tool  
 21 by JRC [67]. A fixed axis, crystalline silicon,  $1 \text{ MW}_p$  photovoltaic plant with 14% of system losses has been  
 22 considered for the tilt and azimuth angles optimization evaluating the overall production over the full PV-GIS  
 23 weather database (2005-2016). The main technical specifications for both the locations are summarized in  
 24 Table 5.

25 Table 5 – Technical specification of the photovoltaic unit plants as obtained from the optimization tool by PV-GIS  
 26 [67].

Location	Nominal Power [p.u.]	Installation type	Module type	System losses [%]	Tilt angle [°]	Azimuth angle [°]
Wafa	1	Fixed	Crystalline Silicon	14	30	0
Mellitah Gas Processing Plant	1	Fixed	Crystalline Silicon	14	31	4

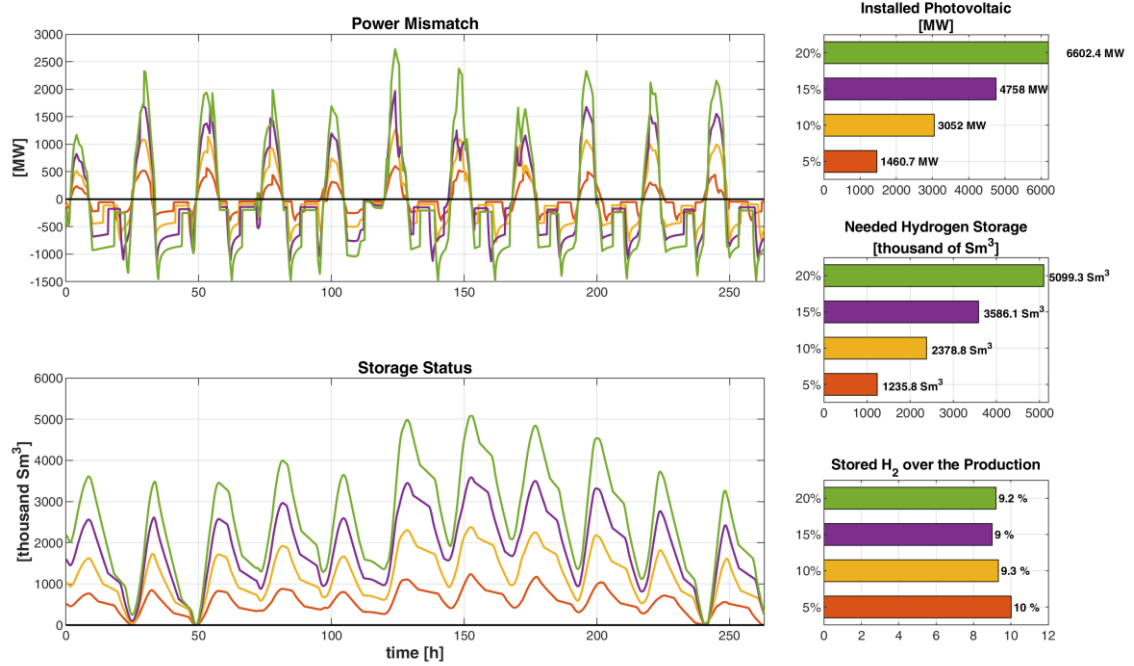
27  
 28 The hourly plant production for the period 2005-2016 has been obtained from the PV- GIS tool and it has  
 29 been used to generate a typical solar production year by averaging the hourly solar production over the whole  
 30 period. The optimal sizing of the two photovoltaic plants has been based on the averaged values and restricted  
 31 to the 11-day timeframe for which the gas network simulations have been obtained. The objective function  
 32 consisted in the amount of hydrogen that needs to be stored in order to compensate the mismatch between the

1 production and the pipeline receiving capacity. The size of the storage depends on the nominal installed power  
 2 of photovoltaic. The optimization procedure aims at determine the solar plant size which minimizes the storage  
 3 volume needed within the 11-day timeframe considered before. Figure 10 and Figure 11 give the main results  
 4 of this procedure for the four hydrogen blending cases and for the two locations considered (Wafa field and  
 5 the Mellitah Gas Processing Plant respectively). In both figures, the mismatch between the hydrogen  
 6 production and the hydrogen receiving capacity is given in terms of hydrogen chemical power with positive  
 7 values indicating an overproduction of hydrogen. The temporal profile of the amount of hydrogen stored within  
 8 the storage facility is given accordingly depicting the status of the storage that is varied in order to keep the  
 9 hydrogen share of the blend constant. The maximum value of each curve represents the storage required for  
 10 each case and it is reported for the sake of comparison in the middle bar plot at the side.



11

12 Figure 10 – Results of the Wafa photovoltaic plant optimal sizing procedure consisting in the minimization of the  
 13 hydrogen storage needs. The two line graphs represents (top) the hydrogen production-injection mismatch (in chemical  
 14 power terms) and (bottom) the temporal profile of the amount of hydrogen stored within the storage system. The side  
 15 bar plots indicates (from top to the bottom): the optimal photovoltaic plant size, the amount of hydrogen that needs  
 16 to be stored and the percentage of the size of the hydrogen storage over the overall hydrogen production within the  
 17 considered timeframe of 11 days.



1

2 Figure 11 – Results of the Mellitah photovoltaic plant optimal sizing procedure consisting in the minimization of the  
 3 hydrogen storage needs. The two line graphs represents (top) the hydrogen production-injection mismatch (in chemical  
 4 power terms) and (bottom) the temporal profile of the amount of hydrogen stored within the storage system. The side  
 5 bar plots indicates (from top to the bottom): the optimal photovoltaic plant size, the amount of hydrogen that needs to  
 6 be stored and the percentage of the size of the hydrogen storage over the overall hydrogen production within the  
 7 considered timeframe of 11 days.

8

9 The value of the storage, for each of the four blending cases, is the result of the storage minimization  
 10 procedure described before that carried to the determination of the optimal power of the photovoltaic plants.  
 11 For what concerns the Wafa case, the sizes range from 109 MW to 489.5 MW as the hydrogen blending target  
 12 grows from 5 to 20% (upper bar plot of Figure 10) while for the Mellitah location, the sizes exceed the gigawatt  
 13 scale, ranging from 1.5 GW to 6.6 GW (upper bar plot of Figure 1).

14 As a final indicator, the ratio between the size of the required hydrogen storage over the total hydrogen  
 15 produced within the considered 11 days is given in percentage terms in the lower bar plot of the figures, in  
 16 order to indicate the importance of the storage on the production. For Wafa site it ranges between 8.1 and 9.1%  
 17 while for the Mellitah one these values are slightly higher, ranging between 9 and 10 %. These numbers give  
 18 a measure of the minimum storage size required to overcome the mismatches between solar energy availability  
 19 and the pipeline flow management.

20 Concerning the electrolyzers, following the sizing assumption aforementioned that aimed at avoiding any  
 21 electrical storage devices, the results of the sizing process are given in

22

23

24 Table 6.

Table 6 – Electrolyzers rated power

Location		Cases			
		5 %	10 %	15 %	20 %
Wafa	[MW]	81.0	167.9	262.1	363.6
Mellitah Gas Processing Plant	[MW]	968.1	2022.7	3153.3	4375.7

## 6 Discussion

The fluid dynamic modelling of the portion of the Libyan gas infrastructure shows a non-negligible impact of the hydrogen blending already in the range [0% – 20%]. The increase of volume caused by the decrease of the volumetric higher heating value as the hydrogen fraction grows causes an increase of the work of compression up to 32.5% during the time interval addressed by the simulation. What is more, the results of the fluid-dynamic simulations show that the usual control strategy of the compression station adopted for the 100% natural gas case is not suitable anymore already if the 5% of hydrogen is blended within the natural gas. In fact, the contractual constraint on the pressure at Gela Station is not respected anymore. This aspect, together with the potentially detrimental effect that the hydrogen-natural gas blends may have on the combustion efficiency at the turbo-compressor (that has not been considered in this work), may amplify the overall increasing operational costs. However, the increase of the compressor station consumption has a very little impact on the efficiency of the gas transport system: by losing less than 0.2 % point of transport efficiency (at maximum), the gas transport network is able to provide an energy flux that is up to 7% from renewables.

As for the gas quality parameters, the impact of the hydrogen blending on the relative density, on the higher heating value and on the Wobbe Index of the gas can be evaluated with respect to the composition of the Libya natural gas and compared with the upper and lower limits of each parameter as set by the Italian national regulation [68]. It is interesting to note that, in the case of Libyan natural gas the hydrogen acceptability is up to 15% and the limiting parameter is the Wobbe Index<sup>1</sup>. It is important to underline that these quality indicators are not exhaustive nor comprehensive in order to decree the acceptability of the hydrogen blending. However, these are the most widely used among the TSOs in order to monitor the acceptability of natural gas from different origins. What is more, most of the gas network value chain is ready to accept up to 15 – 20 % of hydrogen according to [23].

<sup>1</sup> The Wobbe Index is defined as the ratio between the fuel gas heating value (higher or lower) and the square root of its relative density

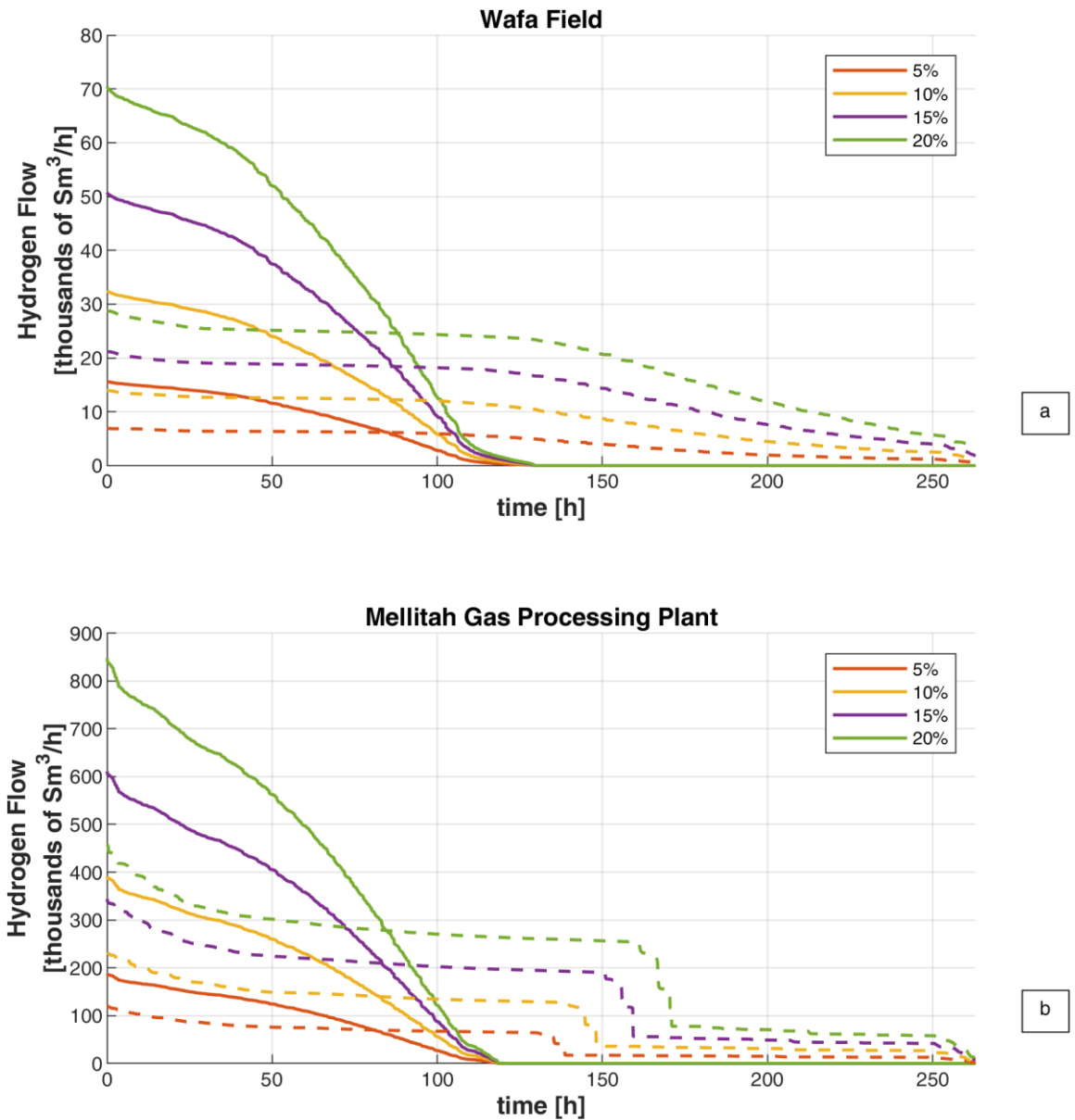
$$WI = HHV / \sqrt{RD}$$

Where the relative density of a gas is the ratio of the density of the gas to the density of the air both calculated at standard pressure and temperature conditions.

In this work: normal conditions [  $T_n = 273.15 \text{ K}$ ,  $p_n = 101,325 \text{ Pa}$  ];

Standard conditions [  $T_{STD} = 288.15 \text{ K}$ ,  $p_{STD} = 101,325 \text{ Pa}$  ];

1 A superposition of the solar hydrogen production duration curves resulting from the optimal sizing process  
 2 with the duration curves of the hydrogen receiving potential are given in Figure 12 for both the considered  
 3 locations. The solid curves represent the hydrogen production from solar source while the dashed lines  
 4 represent the pipeline receiving capacity. The role of the storage is fundamental in order to store the  
 5 overproduction to be shifted whenever the solar source is missing or non-sufficient (from about time, 120 h in  
 6 the figures).



7

8 Figure 12 – Duration curves of the hydrogen production from solar source (solid lines) and hydrogen acceptability  
 9 within the natural gas stream (dashed lines).

1 According to the assumption made this duration curves represent also the output of the electrolyzers and  
2 show a low capacity factor operation of 26.8% for the Wafa case and of 23.9% for the Mellitah installation.  
3 Indeed, the electrolyzers only operate for about 120 h and modulate over their full operational range.

## 4 **7 Conclusions**

5 In this work, the impact of the practice of hydrogen blending within one of the European gas import stream  
6 from North Africa, the Greenstream, was assessed by means of the application of a gas network fluid-dynamic  
7 model.

8 The goal was first to evaluate the additional costs in terms of energy consumption at compressor stations.  
9 Four blending scenarios have been considered, with hydrogen share constantly fixed at 5%, 10%, 15% and  
10 20%. It has been assumed that the hydrogen would have substituted a share of natural gas thus realizing a H<sub>2</sub>-  
11 NG mixture with the same energy content as in the base case, without any hydrogen blending. This resulted in  
12 a higher overall volume of gas transported, as the volume-based higher heating value of the hydrogen is lower  
13 than the one of the natural gas.

14 The simulation was conducted without varying the assumed control mode of the gas compression station,  
15 which was preliminary verified to be suitable for the infrastructure requirements under no hydrogen scenario.  
16 It has been observed that already at 5% blends, the pressure level at the end of the infrastructure fails at reaching  
17 the minimum requested value under a peculiar moment of the simulation. As for the additional compression  
18 costs, the presence of hydrogen increases the number of hours of activity of the compressor and the overall gas  
19 consumption increases accordingly. However, in terms of transport efficiency, the amount of energy that is  
20 transported through pipeline is so high that the increment of the gas compression costs (which may be as high  
21 as 32.5%) impacts in a negligible way (an incremental increase of 0.2%) on the transport efficiency.

22 As final outcome of this work, a sizing procedure for a hydrogen production dedicated photovoltaic plant  
23 have been proposed, based on the minimization of the hydrogen storage. The results show that a considerable  
24 amount of hydrogen needs to be stored because of the pipeline availability is not always in phase with the  
25 hydrogen production profiles, even at lower hydrogen blends. It is also to be underlined that the case study  
26 under consideration consists in an intercontinental gas import pipeline thus even at lower share of hydrogen,  
27 the renewable power which is required is very high. In this sense, these case studies may help framing the 2x40  
28 GW initiative from EU [31].

29 The key messages that this work aim to provide are the following:

- 30 1) The amount of renewable that can be conveyed through hydrogen blending is considerable (considering  
31 the high capacity transnational pipeline) and it is available at rather low additional operational costs in  
32 terms of energy;
- 33 2) However, the pipeline availability in accepting hydrogen may not be infinite. Requiring a constant share  
34 of hydrogen within the natural gas blend limits the flexibility of the natural gas system thus imposing  
35 some barriers to the opportunities offered by the system integration.

36 In this case, the hydrogen storage needs have emerged as potential barriers.

1 Future works may be headed to the opportunities offered by some variations in the gas compressor  
2 management system so to increase the hydrogen acceptability within the gas infrastructure or to reduce  
3 mismatches by phasing gas fluxes to the hydrogen production profiles. In a broader context, the choice of the  
4 type of storage (either electrochemical or in gaseous form or both) and its optimal sizing, together with  
5 innovative infrastructure management strategies, should also be addressed in order to evaluate the realistic  
6 added-value of sectorial integration through green hydrogen from power-to-gas.

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