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Natural Gas–Hydrogen Blends to Power: Equipment Adaptation and Experimental Study

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Abstract: An experimental study was devised to assess the technical, environmental, and economic impact of incorporating hydrogen into natural gas. The experimental tests were conducted on a GUNT ET 792 demonstration unit, characterized by operating on a gas cycle in a twin-shaft configuration. The equipment was adapted to accommodate natural gas and mixtures of natural gas with hydrogen in volumetric fractions of 5%, 10%, and 20%. The tests carried out ensured the viability of using these mixtures from a safety perspective. On the other hand, it was possible to evaluate the main differences in the use of these fuel gases in terms of the temperatures and pressures that characterize the main points of the gas cycle, fuel injection pressures, air/fuel ratios, excess air, power output, overall cycle efficiencies, NO_X and CO_2 emissions, and operational cost.

Keywords: energy transition; gas cycle; gas turbine; hydrogen

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1. Introduction

The need to implement measures to mitigate climate change impacts towards the common goal of achieving carbon neutrality fosters energy transition. This necessity became clear in what is the most significant milestone in the shift towards a more sustainable future: the 2015 Paris Agreement, at the United Nations Climate Change Conference in Marrakech (COP22), where Portugal committed to achieving carbon neutrality by 2050. From this commitment, two plans emerged: the Roadmap for Carbon Neutrality 2050 (RNC2050), to be implemented in the long term, and the National Energy and Climate Plan 2021–2030 (PNEC 2030), an immediate action plan in line with the report of the Intergovernmental Panel on Climate Change (IPCC) [1]. In both plans, hydrogen is presented as a promising energy vector. It is expected to play a key role in electricity generation and in the transport sector, to the detriment of fossil fuel [2].

By the year 2050, it is expected that 4% of the final energy consumed will come from this source, and that 5% to 8% of the electricity produced will be through green hydrogen [1]. Considering the national decarbonization goals and the role hydrogen plays in them, it is essential to conduct studies that guide the application of this energy vector. The present work falls into this category, building on studies already conducted that highlight the limitations in the transportation area and in the use of natural gas–hydrogen mixtures.

In [3], the impact of incorporating hydrogen into a natural gas network characterized by a 322 km transmission network and a 10-kilometer distribution network is studied. The results predict that a volumetric fraction of 30% hydrogen (with a reduction in transmitted energy of around 49%) can be transported without modifications to the pipelines.

The HyDeploy project, developed in the United Kingdom, demonstrated, in its first phase, the feasibility of incorporating up to 20% hydrogen into networks originally designed to operate with natural gas. The study included a distribution network of 101 households, and it was shown that all network components approved in the natural gas tests also received positive results in the tests conducted with the mixture [4].

In Portugal, in the city of Seixal, a similar initiative is being carried out by Floene as part of the Green Pipeline project. This Natural Hydrogen Energy is the first project in Portugal to bring a mixture of green hydrogen and natural gas to a select group of 80 consumers of different types spread in several cities of Continental Portugal. The gas network where the project is being implemented is representative of 95% of the natural gas installations in Portugal and is currently being supplied with a mixture characterized by a volumetric hydrogen fraction of 12% [5].

Two studies conducted by researchers at Yildiz Technical University reveal that injecting 20% hydrogen into the gas supply for stoves leads to an 8% reduction in natural gas consumption and a 4% reduction in CO_2 emissions, at the cost of an increase in heating time of nearly 16%. With 30%, an increase in stove efficiency of over 3% is recorded, rising from 41% to 44.4%, along with a reduction of approximately 21% in CO_2 emissions [6,7].

In [8], a study is presented on the use of natural gas and hydrogen mixtures (up to a maximum of 30%) in a cogeneration plant equipped with a six-cylinder reciprocating engine. It was concluded that as the percentage of hydrogen increases, there is a rise in the maximum pressure within the combustion chamber. At the limit of 30% volumetric hydrogen fraction, an increase of 2.1% in the efficiency of the plant was observed, at the cost of an increase in NO_X emissions from 200 mg/Nm^3 to 1100 mg/Nm^3.

An experimental study conducted at the Turbomachinery Institute of the School of Mechanical Engineering at Shanghai Jiao Tong University demonstrated the effects of natural gas and hydrogen mixtures in a Dry Low Emission radial burner. Regarding emissions, a gradual increase in NO_X emissions was recorded with the increase in the incorporated hydrogen fraction, and no evident decrease or increase in CO emissions was observed [9,10].

The study by [11] focuses on the technical questions/challenges that must be addressed when applying H_2 or H_2/natural gas (NG) blends to advanced-class gas turbines, which have higher operating pressures and temperatures, namely, the raised concerns about the potential for leakages or fuel sequencing operations where flammable mixtures of fuel and air could auto-ignite.

The variable operating modes of a gas turbine unit with a capacity of 18 MW, depending on the percentage of H_2 in natural gas, is the theme of [12]. The traditional fuel for gas turbines is natural gas; the presented study considers adding up to 20% hydrogen to the original natural gas. The addition of hydrogen fuel affects the operating mode of the turbine. The operation of a gas turbine unit at various outside temperatures, operating at full and partial load in the conditions of the wholesale electricity market, is considered.

The authors of [13] implement a European power system model formulated as a stochastic program to address the questions of investments in green hydrogen as a flexibility source for the European power system by 2050. The authors use the model to compare various instances with hydrogen in the power system to a no-hydrogen instance.

The paper of [14] presents a real multi-component natural gas configuration, and the premixed flame and combustion characterization parameters of natural gas/H_2/air are obtained through experiment.

The research of [15] investigated hydrogen-enriched methane/air flames diluted with CO_2. The turbulent premixed flame was stabilized on a Bunsen-type burner and the two dimensional instantaneous OH profile was measured by Planar Laser-Induced Fluorescence (PLIF). The flame front structure characteristics were obtained by extracting the flame front from OH-PLIF images. And the turbulence–flame interaction was analyzed through the statistic parameters.

In the study by [16], the swirling flame characteristics of natural gas mixtures with H_2 are investigated in the current work using a numerical assessment of a single swirl burner, which is extensively employed in GT combustors.

Regarding the implemented commercial solutions operating on a mixture of natural gas and hydrogen, some examples are [17–19].

However, the use of hydrogen in existing gas transportation systems is not as smooth as described. For example, [20] identify numerous challenges and uncertainties that complicate this approach to natural gas decarbonization, however, and this review summarizes current research on the material, economic, and operational factors that must be considered for hydrogen blending, namely that the presence of hydrogen in the mixture, even in small quantities, can cause fatigue crack growth and fracture resistance. The authors of [21] recognize the advantages that hydrogen brings to the energy system, but bring concerns regarding the property differences between natural gas and methane–hydrogen mixtures (such as density, viscosity, phase interactions, and energy densities), which are also the primary reasons for major safety concerns, over-pressurization, and leakage in pipelines, of which there is a chance of incidence in hydrogen-blended gas pipelines.

Based on the state of the art, the present work aims to analyze the operating parameters of a gas cycle in a twin-shaft configuration for natural gas–hydrogen mixtures at volumetric fractions of 5%, 10%, and 20%. The selection of these specific hydrogen mixtures (5%, 10%, and 20%) was based on the European regulatory framework. There is no need to exceed a 20% hydrogen fraction, as most relevant studies on hydrogen–natural gas blends identify this as a “non-problematic” threshold. Additionally, 10% represents the maximum legally permitted hydrogen fraction for injection into natural gas grids in some European countries, such as Germany. The 5% blend served as an initial step to ensure a safe and controlled incorporation process.

2. Equipment and Experimental Procedure

This chapter presents to the reader the conditions under which the current work was conducted. It is divided into two sections: the first related to the equipment and the second to the procedure.

2.1. Experimental Equipment

The experimental test bed equipped with the ET 792 gas turbine is a teaching unit powered by propane that allows for the study of the behavior of a gas cycle with a twin-shaft arrangement. The equipment consists of eight main subsystems:

- Gas generator, composed of a compressor and a turbine that operate within a speed range of 60,000 to 120,000 revolutions per minute, along with the combustion chamber and a noise-attenuated air inlet;
- Power turbine characterized by operating speeds ranging from 10,000 to 40,000 revolutions per minute and delivering a maximum power of around 2 kW, equipped with an exhaust silencer and connected to the electric generator via a 1:11 belt transmission ratio;
- Fuel system, including a main valve, a quick shut-off valve, a pressure regulator, a control valve, and an injector;
- Ignition system, featuring a spark plug and an ignition transformer;
- Lubrication system, consisting of a tank, an oil filter, a pressure regulator that ensures operation between 2 and 4 bar, an oil cooler, and a pump;
- Electric generator, with an efficiency of 74% and a maximum electrical power of 1.5 kW, including a converter, ballast resistors, and a power indicator;

- Starting system, which includes a starter fan with a power of 1 kW, a speed of 30,000 rpm, and a maximum pressure of 10 kPa, along with the air flow regulation vanes;
- Instrumentation and control, equipped with measurement probes for temperature, flow, rotation speed, and pressure, as well as an automatic shutdown system that is activated whenever any of the following conditions are met:
    1. Gas generator turbine inlet temperature above 1100 °C or below 600 °C;
    2. Lubrication oil temperature above 100 °C;
    3. Oil circuit pressure below 2 bar;
    4. Gas generator speed exceeding 130,000 revolutions per minute.

Regarding the gas generator turbine inlet temperature, maintaining a fixed gas generator rotational speed ensures that the system operates under conditions similar to its original configuration, allowing for a fair comparison between tests. The phrase "Gas generator turbine inlet temperature above 1100 °C or below 600 °C" refers to the operational limits of the test bench. If the temperature drops below 600 °C, the turbine will not generate sufficient power to operate, while exceeding 1100 °C would result in overheating, triggering a system shutdown.

Figure 1 [22] presents the process diagram associated with the test bed where the experimental tests were conducted.

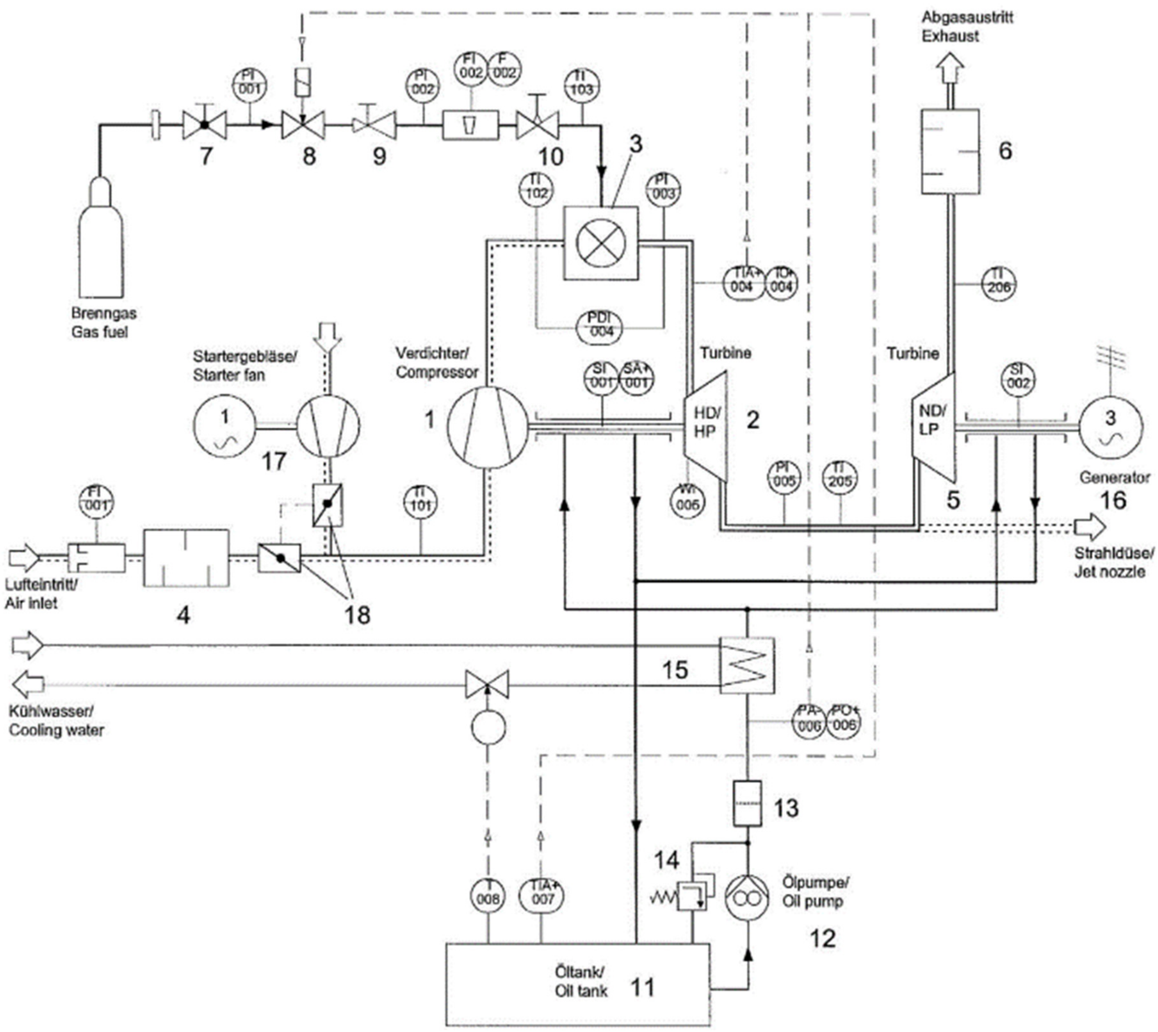

Figure 1. Process diagram of the ET 792 experimental test bed.

The gas supply was achieved through mixtures prepared in a laboratory, which ensure a fuel gas very similar to the natural gas used in Portugal, with the introduction of hydrogen in highly accurate percentages. Table 1 presents the compositions of the fuel mixtures used.

Table 1. Composition of gas mixtures.

Substance	Natural Gas	GN + 5% H_2	GN + 10% H_2	GN + 20% H_2
Methane (CH_4)	92.4%	87.8%	83.2%	73.9%
Ethane (C_2H_6)	4.8%	4.6%	4.3%	3.8%
Propane (C_3H_8)	2.1%	2.0%	1.9%	1.7%
Butane (C_4H_{10})	0.7%	0.6%	0.6%	0.6%
Hydrogen (H_2)	-	5.0%	10.0%	20.0%

The selection of these specific hydrogen mixtures (5%, 10%, and 20%) was based on the European regulatory framework. There is no need to exceed a 20% hydrogen fraction, as most relevant studies on hydrogen–natural gas blends identify this as a "non-problematic" threshold. Additionally, 10% represents the maximum legally permitted hydrogen fraction for injection into natural gas grids in some European countries, such as Germany. The 5% blend served as an initial step to ensure a safe and controlled incorporation process.

2.2. Procedure

The experimental tests, which began with natural gas and progressed towards increasing hydrogen content, were conducted as follows:

- Starting the turbine according to the manufacturer's instructions;
- Stabilizing the rotation speed of the gas generator at 80,000 revolutions per minute;
- Data collection, as indicated in Figure 2, where values were recorded for the following variables: air flow, fuel flow, gas temperature, compressor inlet temperature, compressor outlet temperature, pressure drop in the combustion chamber, injection pressure, turbine inlet temperature, turbine inlet pressure, power turbine inlet temperature, power turbine inlet pressure, power turbine outlet temperature, gas generator rotation speed, power produced, NOx concentration, and O_2 concentration;
- Repeating the second and third steps for speeds of 90,000, 100,000, 110,000, and 120,000 revolutions per minute. Stabilizing the gas generator speed and collecting the data on this last speed require maximum efficiency, as operating the bench for long periods with electrical outputs exceeding 1.5 kW is not recommended;
- The process is repeated for a new gas mixture, with the equipment being cooled between tests.

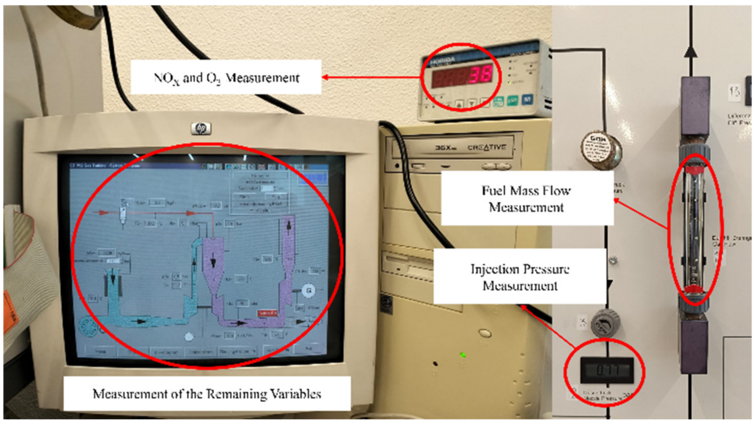

Figure 2. Data collection method.

2.3. General Description of the Mechanism of NOx Formation

The presence of oxygen in the exhaust gases and the high temperatures reached trigger a reaction between oxygen and nitrogen, leading to the formation of nitrogen oxides (NOx), the most common of which are NO and NO_2. These pollutants are mainly influenced by four factors: maximum combustion temperature, percentage of excess air, pressure, and exposure time to high temperatures. Among these factors, maximum temperature and excess air are the most notable, with the former tending to decrease as the latter increases. Consequently, the maximum temperature is reached under stoichiometric conditions; however, under these conditions, nitrogen oxides are formed in smaller amounts since the available oxygen for their formation is very limited. When combustion becomes lean but remains relatively close to stoichiometry, the optimal conditions for the formation of nitrogen oxides are met. Their concentration increases up to an excess air coefficient of approximately 1.3. Beyond this point, the cooling effects of the excess air override its contribution to NOx formation, and a decrease in the concentration of this pollutant is observed.

3. Results

3.1. Temperatures

In terms of cycle temperatures, the most relevant one to analyze is the inlet temperature to the gas generator turbine, measured in an area close to the outlet of the combustion chamber. It is in this temperature that the effects of hydrogen incorporation are most evident: in the other points of the cycle, the trend observed from the analysis of the outlet temperature of the combustion chamber is reduced or inexistent when analyzing the outlet temperature of the power turbine. The introduction of 5% hydrogen and 10% hydrogen led to average temperature increases of 0.75% and 1.14%. However, the natural gas mixture with 20% hydrogen shows a reduction of 0.30% in temperature at this point in the cycle. As mentioned earlier, this temperature is measured at the outlet of the combustion chamber. Therefore, the cooling effects promoted by the excess air and H_2O flow in the combustion products, which are significantly higher with the natural gas mixture containing 20% hydrogen, have an effect before the temperature measurement probe. Figure 3 shows the temperature evolution of the different mixtures.

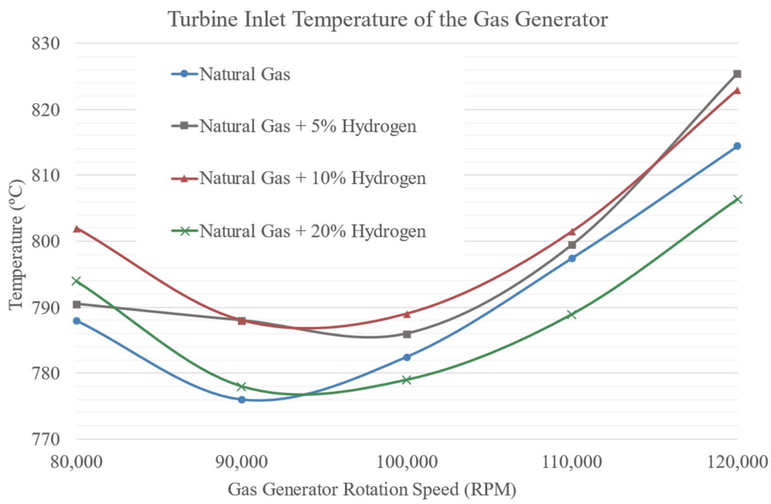

Figure 3. Turbine inlet temperature of the gas generator as a function of rotation speed and mixture used.

If one looks at the energy properties of natural gas mixed with hydrogen fuel, the heat of combustion, MJ/m^3 decreases with an increase in the proportion of hydrogen. On a volume basis, the heat of combustion (MJ/m^3) does indeed decrease as the hydrogen proportion increases. However, as the hydrogen fraction increases, the Lower Heating Value (LHV) in MJ/kg also increases. Additionally, hydrogen has a significantly higher adiabatic flame temperature compared to natural gas, so blending the two fuels naturally results in a higher burning temperature than pure natural gas.

3.2. Pressures

In terms of the pressures that characterize this gas cycle, there is no evidence that changes in the fuel composition led to variations in pressure. Due to the limited resolution of the pressure measurement scale at the turbine inlet of the gas generator (tenth of a bar), it was not possible to draw any conclusions regarding the influence of the different mixtures on this pressure. Regarding the outlet pressure, despite the scale allowing for it, no significant differences were recorded. According to what would be expected from the analysis of the Wobbe Index of the mixtures (lower as the hydrogen content in natural gas increases), a higher injection pressure (Figure 4) was identified with the mixture containing 20% hydrogen compared to the use of natural gas. This increment reached 1.78% when analyzing the average of the results obtained for the tests at different speeds, and it increased to 2.44% when exclusively analyzing the test at maximum speed. With the other mixtures, no evident increase in injection pressure was observed. In fact, a slight decrease was recorded compared to the use of natural gas.

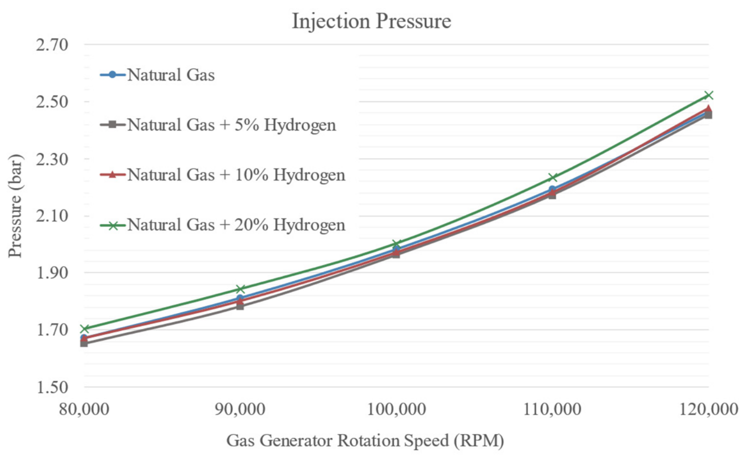

Figure 4. Injection pressure as a function of rotation speed and mixture used.

3.3. Combustion

From the measurement of the air and fuel flow rates, the air excess coefficient is indirectly obtained in an expedited manner by applying (1), where AFR is the air/fuel ratio, $\dot{m}_{air}$ is the mass flow of air, and $\dot{m}_{fuel}$ is the mass flow of fuel. Regarding (2), AFR_{sto} is the stoichiometric air/fuel ratio, and these expressions represent the calculation of the air/fuel ratio and the air excess coefficient, respectively. Calculation of the air/fuel ratio:

$$AFR = \frac{\dot{m}_{air}}{\dot{m}_{fuel}} \tag{1}$$

Calculation of the air excess coefficient:

$$\lambda = \frac{AFR}{AFR_{sto}} \tag{2}$$

As previously stated in the temperature analysis, the excess air of the mixture incorporating 20% hydrogen in natural gas surpasses all the others. On average, the tested fuel gases show air excess coefficients of 4.47, 4.52, 4.49, and 4.61, in increasing order of hydrogen incorporation. The results are presented in Figure 5.

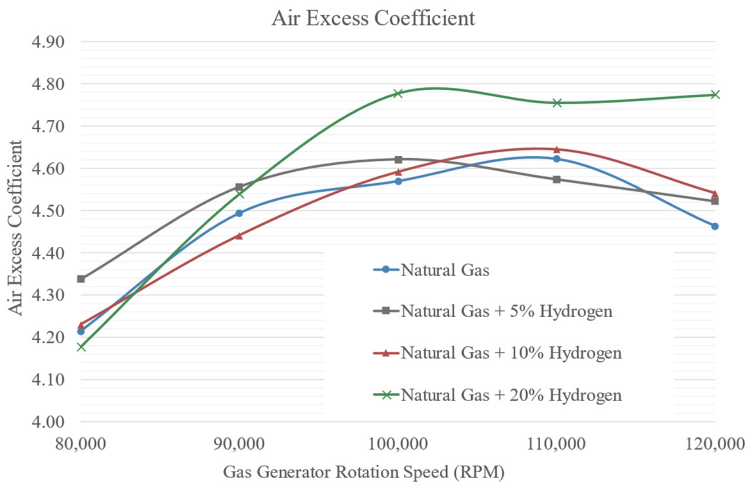

Figure 5. Air excess coefficient as a function of rotation speed and mixture used.

From the analysis of NO_X emissions (Figure 6), it was observed that the ideal mixture from the standpoint of reducing this pollutant's emissions is the one containing 5% hydrogen incorporated into natural gas. On average, this mixture shows a reduction of 21.25%, 22.38%, and 24.56%, compared to natural gas, natural gas +10% hydrogen, and natural gas +20% hydrogen, respectively. Likely due to a potentially higher flame temperature, the natural gas mixture with 20% hydrogen shows the highest average nitrogen oxide emissions: 57 ppm.

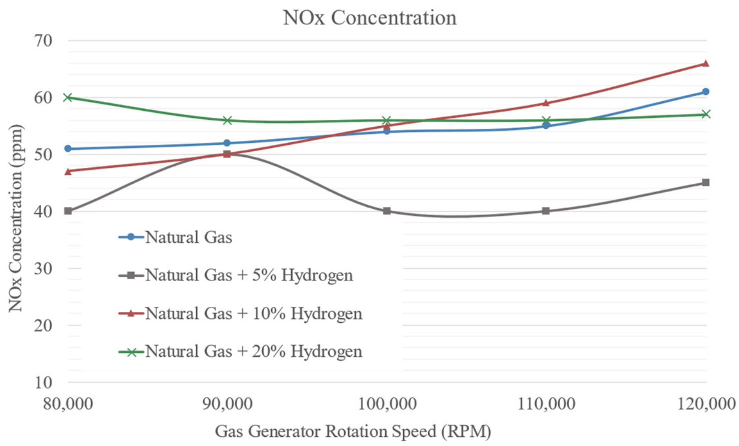

Figure 6. NOx concentration as a function of rotation speed and mixture used.

Given that the composition of the mixture is known, that the mass flow rates of air and fuel are also known, that nitrogen oxides and carbon monoxide emissions are negligible, and that combustion is complete, it is possible to write the composition of reactants and products in mass terms (5), where θ_i is the mass fraction, y is the molar fraction, and M is the molar mass. By using the relationship between the mass flow ($\dot{m}$) rate and molar flow rate ($\dot{m}$), through the molar mass of each substance (3), an estimate of CO_2 emissions in tons/year can be obtained.

$$\dot{x} = \frac{\dot{m}}{M} \tag{3}$$

This analysis showed that, on average, the incorporation of hydrogen into natural gas can lead to a reduction in CO_2 emissions by 2.14%, 2.94%, and 7.22% compared to operation with natural gas, for the 5%, 10%, and 20% mixtures, respectively. The absolute results are presented in Figure 7.

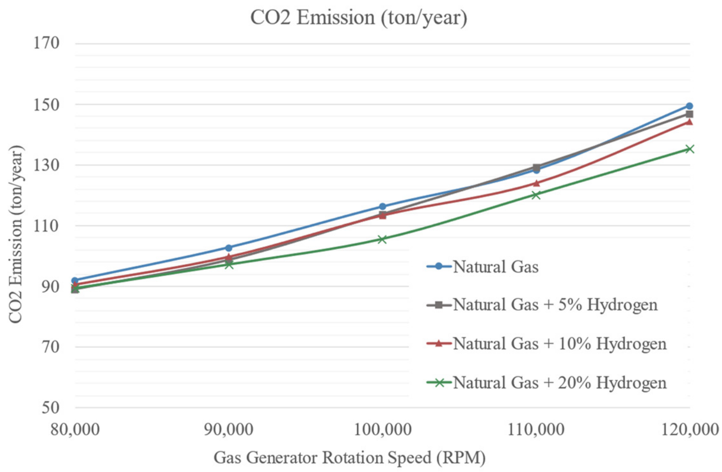

Figure 7. CO_2 emission as a function of rotation speed and mixture used.

3.4. Power and Efficiency

The analysis of power produced and cycle efficiency only allow to state that natural gas is not significantly affected by the incorporation of hydrogen. The efficiencies of the equipment in question (4), due to the equipment being a didactic unit, rarely exceed 2.5%, even in its original configuration. With natural gas, the maximum efficiency obtained was 2.60%, with the introduction of 5% hydrogen, 2.50%, with 10% hydrogen, 2.53%, and with 20%, it reached an efficiency of 2.56%.

$$\eta = \frac{P}{\dot{m}_{fuel} \cdot LHV \cdot 0.74} \quad (4)$$

3.5. Operational Costs

As one of the objectives of this work is to demonstrate the possibility of incorporating hydrogen into natural gas without changes to transportation infrastructure and terminal equipment, the operating cost is limited to the cost associated with the change in the fuel used. According to the REN Data Hub, the annual average market price of natural gas in Portugal in 2023 was EUR 36.97/MWh, decreasing to EUR 30.98/MWh in 2024 (annual average up to September 2024) [23–25]. This is equivalent to approximately EUR 0.419/kg. The European Hydrogen Observatory defines the cost of producing green hydrogen between EUR 4.18/kg and EUR 9.60/kg, based on actual production costs across Europe throughout 2022. Through the relationship between the mass fraction and molar fraction, presented in (5), and since the fuel flow rates are known, the costs associated with the consumption of natural gas and hydrogen can easily be devised using (6), where OC is the operational cost, C_{NG} is the cost of natural gas, C_{H2} is the cost of hydrogen, $\dot{m}_{NG}$ is the mass flow of natural gas, and $\dot{m}_{H2}$ is the mass flow of hydrogen, enabling the calculation of the operating cost.

$$\theta_i = \frac{y_i \cdot M_i}{\sum_{j=1}^{m} y_j \cdot M_j} \quad (5)$$

Calculation of total operational cost:

$$OC = C_{NG} \cdot \dot{m}_{NG} + C_{H2} \cdot \dot{m}_{H2} \quad (6)$$

From the cost analysis, it is possible to observe that the operating cost without the addition of any hydrogen will be around EUR 2.02/h. The introduction of 5% hydrogen into natural gas would, on average, increase the operating cost by between 3.83% and 11.48%. Using a mixture that contains 10% hydrogen will raise the cost by 9.48% to 25.49%, and using the maximum percentage studied, which is 20%, will lead to an expected increase of 19.53% to 53.94%. The absolute costs of transitioning from natural gas to natural gas with hydrogen can be found in Figure 8.

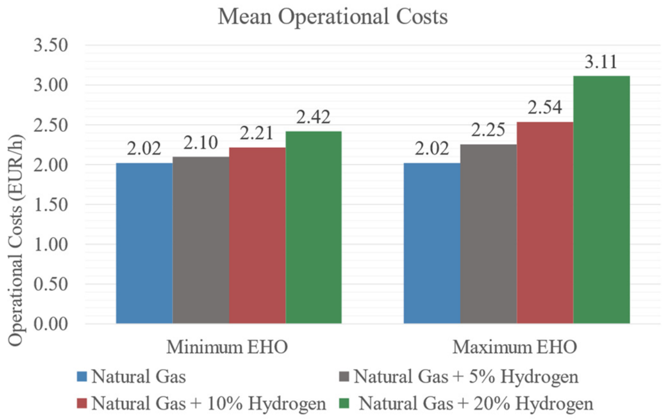

Figure 8. Operational costs as a function of the mixture used and the estimate of hydrogen production costs from the European Hydrogen Observatory.

4. Conclusions

With the progress of the experimental tests conducted, it is possible to conclude that the incorporation of hydrogen into natural gas is safe up to a percentage of 20%, as no gas leaks were recorded. It can also be concluded that the integrity of the equipment was never a concern, as none of the automatic protections were triggered (due to excessive temperature, for instance). From the analysis of the results, one can conclude that the incorporation of 5% hydrogen into natural gas leads to a reduction of 21.25% in nitrogen oxide emissions. It can also be concluded, regarding emissions, that with the incorporation of 20% hydrogen, a reduction of 7.22% in carbon dioxide emissions can be achieved. From the performance analysis, it is safe to say that the use of these mixtures does not harm the equipment from this standpoint. Despite the major advantages found, a significant increase in costs is expected, resulting from the fact that green hydrogen production is still a developing technology. The incorporation of 20% of this renewable gas into natural gas would lead to cost increases ranging from 19.53% to 53.84%.

Analyzing NOx production based solely on temperature variation is overly simplistic and can lead to inaccurate conclusions. While temperature plays a key role, several other factors influence NOx formation, including exposure time at high temperatures, pressure, and excess air levels in the exhaust gases. Excess air significantly affects NOx production. Within an excess air range of 1.1 to 1.3, excess air can act as a catalyst for NOx formation, but beyond this range (as is the case in our system), it leads to a reduction in NOx emissions. Additionally, the temperature probe does not measure the peak temperature within the combustion chamber; instead, it is positioned downstream in the flow, where cooling effects may lower the recorded temperature. This means the measured temperature does not fully reflect the conditions that influence NOx production inside the chamber.

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Data Availability Statement: The original contributions presented in the study are included in the article, further inquiries can be directed to the corresponding author.

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

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