

Techno-Economic Analysis of Hydrogen Blending and Injection in Portugal's Gas Grid

Masters in Economics and Environmental Management

Daniela Flor Leal Louback

Advisor: Susana Silva, PhD (2012) in Economics by the
Faculty of Economics of Porto

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ABSTRACT

Within the European context of the ambitious targets to integrate hydrogen into existing energy systems to allow for a more accelerated and efficient strategy towards carbon neutrality, the current investigation developed a techno-economic model of small-scale Hydrogen Production Units (HPUs) for blending and injection into the national gas network in Portugal. The regulatory and historical considerations regarding the natural gas and the approaching introduction of hydrogen into this system are outlined. The methodology is divided in three main phases, (1) collection and organization of data based on nominal and historic capacities of Gas Regulation and Measurement Stations (GRMS) in the National Transport Grid (RNTGN), (2) development of the HPU model (3) techno-economic analysis to determine the strategic injection points in the national gas grid and examination of the resulting investment and decarbonization impact. Out of the total 83 GRMS analysed, 33 were identified as economically and technically feasible injection points, resulting in annual emissions savings of 57.6 million tonnes of CO₂e. This work also performs a sensitivity analysis of the key modelling assumptions and evaluates how current regulatory proposals impact the economic viability of hydrogen production.

KEY WORDS

hydrogen blending; hydrogen injection; hydrogen economy; hydrogen model;

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ABBREVIATIONS

CCS – Carbon Capture and Sequestration

DGEG – Directorate-General for Energy and Geology

ERSE – Regulatory Agency of Energy Services

EU ETS – European Union Emissions Trading Scheme

GHG – Greenhouse gases

GRMS – Gas Regulating and Metering Station

H₂-NG – Hydrogen and Natural Gas

HPU – Hydrogen Production Unit

LCOH – Levelized cost of hydrogen

NSNG – National System of Natural Gas

PEM – Proton Exchange Membrane

PPAs – Power purchase agreements

PV – Photovoltaic

RES – Renewable Energy Sources

RDGN – Natural Gas Distribution Network

RNTGN – Natural Gas Transport Network

SMR – Steam Methane Reforming

1. INTRODUCTION

Portugal has committed to ensuring the neutrality of its emissions by the end of 2050, outlining a clear vision regarding the decarbonization of the national economy, as a contribution to the Paris agreement and in line with the more ambitious targets set forth in the Governance of the Energy Union and Climate Action (EU Regulation, 2018/1999). In this context, by 2030, a level of emissions reduction over 45% in relation to 2005 must be achieved in order to ensure compliance with the path towards carbon neutrality (PNEC, 2019).

Considering its key characteristics of storage capacity and flexibility, the role of natural gas will gradually be that of stability and security of the electrical system, acting as a backup for intermittent renewable energy sources. This will reduce its importance in the production of electricity, while prolonging its permanence in a system increasingly based on renewable and decarbonized energy. In the short and medium term, energy balancing of large grids will continue to depend on thermoelectric or nuclear plants to guarantee security of supply (Daan Peters et al. 2020).

According to the National Energy and Climate Strategy (2019), Portugal is highly dependent on energy imports, mainly of crude oil and natural gas, negatively impacting the country's trade balance. Hydrogen enables sector coupling, through the integration of electricity and natural gas systems, which accelerates the decarbonization of the energy system, allowing for a more efficient strategy towards carbon neutrality. In the foreseen context of the need for thermoelectric plants to guarantee security of supply until 2040, the decarbonization of natural gas must be a priority (PNEC, 2019). Portugal's Hydrogen Strategy (2020), focuses on the specific role hydrogen will play in the country's objectives of decarbonizing the natural gas network, electric power plants and industry sectors. In the transport sector, the strategy envisages an increase of hydrogen powered vehicles and the development of 50 to 100 hydrogen refuelling stations. To meet the increased demand, hydrogen production must increase accordingly, and the strategy forecasts domestic electrolyser installed capacity will be between 2 GW to 2.5 GW by 2030 (PNEC, 2019).

The current infrastructures for reception, storage, transport and distribution of natural gas will play a fundamental role in allowing the introduction, distribution and consumption of hydrogen, in the various sectors of the economy, allowing to achieve higher levels of incorporation of renewable sources in the final consumption of energy. To ensure the demand side, it is important to set ambitious but realistic targets for the incorporation of hydrogen in the various sectors of the

economy, which are compatible with the energy transition, with the current and future investment capacity, and with the availability of technological solutions (IRENA, 2022b).

This study outlines the regulatory and historical considerations regarding the natural gas network and the approaching introduction of hydrogen into this system. At the level of Public Administration in Portugal there are papers evaluating technologies and the role of hydrogen in the national energy system. The current study will refer to the publications “Roadmap and Action Plan for Hydrogen in Portugal” (DGEG, 2019) and “Hydrogen in the Portuguese Energy System: Integration Challenges” (DGEG, 2018). In addition, this work examines the main legislative milestones of implementation for both natural gas and hydrogen in Portugal, these documents provide insight on the regulatory point of view, within the scope of this investigation.

This investigation is guided by 4 main objectives:

- 1) Identify the factors that make Portugal a favourable candidate for implementing hydrogen blending in its natural gas networks.
- 2) Create a technoeconomic model and perform a mapping of the natural gas grid.
- 3) Determine the feasibility of implementing Hydrogen Production Units (HPUs) at strategic injection points in the natural gas grid.
- 4) Identify the level of investment and estimated reduction in greenhouse gas emissions that could result from deploying all the HPUs identified as feasible.

In addition to the investigation of these overarching premises, this work performs a sensitivity analysis of the key modelling assumptions and also evaluates how current regulatory proposals impact the economic viability of hydrogen production.

This investigation takes into account the regulatory principals and technical constraints of hydrogen blending in gas grids, examining the economic efficiency of large-scale production in face of the market competition and innovation brought on by small-scale decentralized production. This study aims to determine the optimal sizing of hydrogen production units that would be implemented in strategic injection points throughout the natural gas pipeline. This would enable a large share of Hydrogen in the global grid volume, while avoiding centralized investment, production and injection that lead to market control and stagnation.

To be able to perform the mapping of the natural gas grid, the current study benefited from information provided by the National Energy Regulator (REN). The methodology is divided in three main phases, (1) organization and analysis of data to determine the strategic injection points in the national gas grid based on nominal capacities and historic flow rates of Gas Regulation and

Measurement Stations (GRMS) in the National Transport Grid (RNTGN), (2) development of the techno-economic model of the HPU (3) techno-economic analysis of wide scale implementation of the HPUs in the GRMS identified as optimal and examination of the resulting decarbonization impact.

The current work was structured in 6 chapters. Following this introduction, chapter 2 contains the literature review, where this study references authors and works on the subjects of Hydrogen production technologies, their economic feasibility and environmental sustainability as well as the technical considerations for the application of hydrogen blending and injection in the NG grid. Chapter 3 provides a comprehensive analysis of the regulatory frameworks of natural gas and hydrogen and the emerging concept of hydrogen blending in NG pipelines in the EU and in Portugal specifically. Chapter 4 contains the methodology, where the natural gas grid data is analysed and economic modelling is performed. The results and discussion are addressed in chapter 5, where the main findings are examined and limitations are identified. Finally, chapter 6 contains the conclusions of this work.

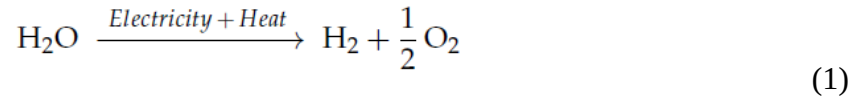
2. LITERATURE REVIEW

2.1 Production Technology

"Grey hydrogen" has been widely produced through steam methane reforming (SMR), reforming of oil and naphtha, and coal gasification. These are carbon-intensive processes that use finite resources as feedstock, oil, natural gas, and coal. Today over 90% of hydrogen volumes produced globally are from SMR, coal gasification or as a by-product of naphtha production, and are consequently the most cost-efficient methods, at an average \$3.50/kg (Ahmed et al., 2021). In the event that the grey hydrogen production process captures the carbon dioxide, the hydrogen produced is labelled as "blue hydrogen", i.e., minimizing the associated emissions by implementing a carbon capture and sequestration (CCS) system. This is only more sustainable than grey hydrogen if the storage of CO₂ is indefinite and fail proof, and would never be released back into the atmosphere. Even so, authors Howarth and Jakobson demonstrated that the emissions inherent to the upstream exploitation of NG and associated to the SMR and CCS process themselves, lead to very limited sustainability potential: "*total emissions from producing blue hydrogen are only 9% to 12% less than for grey hydrogen, 135 or 139 g CO₂eq per MJ compared with 153 g CO₂eq per MJ*" (2021, p. 7).

The sustainable alternative to grey and blue hydrogen is “green hydrogen”. Ahmed et al. (2021), made a comprehensive review on the available state-of-the-art technologies for green hydrogen production, taking into account not only technical efficiency but the economic and long-term feasibility of the techniques. The investigation makes an in-depth comparison between all the existing fossil fuel and renewable production routes, concluding that water electrolysis powered by wind and solar energy *“is the only pathway considered feasible at the present stage to deliver the amounts of hydrogen needed at an acceptable price”* (Ahmed et al. 2021, p. 37250).

This process is very energy intensive, and the high cost of large quantities of electricity from renewable sources presents challenges to wide scale implementation. Although electrolysis technology has existed for over a hundred years, it has recently undergone critical development and efficiency improvements as a result of the regulatory, political and economic incentives that are boosting demand for green hydrogen (Schmidt et al., 2017). When powered by renewable energy, water electrolysis enables the production of green hydrogen and oxygen as a by-product, as can be seen in the basic representation of the process (1):



In the electrolysis process, water molecules are the reactant, which under the influence of electricity and heat dissociate into hydrogen and oxygen in an oxidation-reduction process. There are three main types of electrolyzers, they can be classified based on their operating conditions, the ionic agent and the electrolyte used: alkaline electrolysis, proton exchange membrane (PEM) electrolysis and solid oxide electrolysis (SOE) (Wang et al., 2022).

Alkaline electrolysis is a well-established technology, it has reached commercial maturity with industrial applications since 1920 (Zhang et al., 2015). The electrolyser is characterized by having two electrodes operating in alkaline liquid electrolyte solution, usually potassium or sodium hydroxide. Among the commercially available technologies, alkaline is the most cost-efficient, it stands to benefit from economies of scale, with megawatt capacity stacks readily available and also presents the longest system durability of 20 – 30 years (David et al., 2019). However, the low current density and low operating pressures present limits to the system’s efficiency, and are the parameters where improvements in performance can be achieved (Schmidt et al., 2017).

Proton exchange membrane (PEM) electrolysis consists of solid polysulfated membranes used as an electrolyte, through which the ionic agents pass during the process. Protons and electrons

recombine on the side of the cathode to produce hydrogen (Wang et al., 2022). PEM systems are commonly used in small-scale applications, the technology is less mature than Alkaline, first introduced by General Electric in 1966 (Zhang et al., 2015). PEM electrolyzers present high proton conductivity and potential to operate at higher pressures, higher current density resulting in slightly higher efficiency, faster start-up time and compact design when compared to alkaline systems. However, the electrocatalysts used are noble metals such as platinum or palladium for the cathode and iridium ruthenium oxide for the anode, which makes this technology more costly compared to alkaline. The durability is also inferior compared to alkaline, with a system lifetime of 10-20 years (David et al., 2019).

Solid oxide electrolysis (SOE) operates at high pressures and temperatures, with an innovative element: the use of water in the form of steam. Currently, some proton-conducting ceramic materials have been studied to replace regular ionic agents in solid oxide fuel cells, due to their higher thermodynamic efficiency and superior optical conductivity at operating temperatures (Wang et al., 2022). SOE presents advantages in efficiency, although it must overcome some obstacles to achieve commercial scale, notably related to lack of stability and high level of degradation due to high temperature requirements. This is also why it is not especially suitable for coupling with intermittent power sources, but more so with nuclear or combined-cycle plants (Schmidt et al., 2017).

Compared to PEM, the advantages of alkaline water electrolysis are mainly: lower costs; greater durability; lower pressure operation; well-known safety aspects; higher level of maturity. Lastly, in a study performed by Zhao et al. (2020), a comparative analysis of the life cycle impact of the three water electrolysis systems found that the manufacturing of PEM systems resulted in significantly higher environmental impacts than SOE and Alkaline. Therefore, the current study will consider an alkaline electrolyser in the HPU model developed in Chapter 4.

2.2 Technical considerations

A study performed by Omoniyi et al., (2021) investigated hydrogen quality for injection into natural gas pipelines. Sampling and analysis of hydrogen produced from SMR, PEM and alkaline electrolysis were carried out by the National Physical Laboratory. The results of the analysis indicated that the presence of contaminants and particles were at levels below or at the threshold

limits set by ISO 14687 Grade D¹, thus indicating that these methods produce hydrogen with a purity level suitable for blending and injection in NG pipelines, as well as for fuel cell electric vehicles.

Many authors discuss the potential benefits and challenges of blending hydrogen into natural gas networks. It clearly offers opportunities to leverage existing infrastructure to achieve decarbonization goals. However, there are technical obstacles to widespread hydrogen blending, including variations in network composition, material and operational impacts, as well as the energy content implications. Erdener et al. (2023) highlights that blending hydrogen with natural gas can impact various components and systems within the gas network, including downstream end-use applications. The technical properties of hydrogen differ significantly from natural gas, posing compatibility concerns for system components.

The lower volumetric energy density of hydrogen requires a larger volume of blended gas to meet the same energy demand, potentially necessitating increased transmission and storage capacity. Mechanical reliability is another concern, as hydrogen exposure can lead to embrittlement in pipeline materials. Increasing hydrogen content can affect compressor stations due to pressure drops, which significantly decrease the energy line-pack and cause changes in flow capacity. Pressure losses when blending higher levels of hydrogen require the inlet pressure to be correspondingly increased, requiring improvements in existing networks to accommodate the additional power demands (Wang et al., 2023).

These technical limitations and requirements need to be carefully managed to enable the safe utilization of blended hydrogen in natural gas systems. Shirvill et al. (2019) found that when the H₂-NG mixture contained a hydrogen content of up to 25%, the risk of explosions resulting from overpressure would not be significantly greater than those already generated by natural gas alone. Addressing these challenges is crucial for the successful integration of blended hydrogen into natural gas systems. Considerations that system operators must take into account include harmonizing gas quality, monitoring flow and metering stations, ensuring pipeline compatibility, managing pressure drop and overpressure, and addressing mechanical reliability concerns (Erdener et al., 2023).

Exploring the potential to transition from fossil fuels using hydrogen blends in existing natural gas networks, Mahajan et al. (2022) provides an updated perspective on the most advanced

¹ ISO 14687:2019 Hydrogen fuel quality — Product specification

implementations in the areas of transportation and end-use of H₂-NG mixtures. 22 active demonstration projects in Europe, North America and Australia are testing blends, mostly ranging from 1% to 30% hydrogen content in NG distribution networks, with some aiming to make the necessary modifications to be able to reach 100% hydrogen content. Pressure reduction and increased energy requirements for transporting blended gas are challenges that can be mitigated through pressure and flow rate modifications. Four key challenges identified included design modifications for end-use appliances when hydrogen content is superior to 25%, additional compressors (consequently additional power requirement) for lower mass flow rates, new safety codes for higher hydrogen content blends, and mitigating the risk of hydrogen-induced corrosion and embrittlement (Mahajan et al., 2022).

A very interesting study by Silvestre et al. (2023), developed a computational tool to model H₂-NG blends supplied to major industrial consumers in Portugal and calculated power losses in the high-pressure network for different hydrogen contents. Higher percentages of H₂ content led to increased power losses in transmission, demonstrating a linear relationship. Higher percentages of hydrogen content caused greater power losses due to reduced gas density and pressure drops. The study developed a correlation to estimate the power losses as a function of the hydrogen content in and NG transmission system, that can be applied in a case-by-case scenario.

2.3 Economic considerations

According to the International Energy Agency reports on *Hydrogen* (2022) and *Electrolysers* (2022), the commercial operation of electrolysers for dedicated hydrogen production has only recently begun to accelerate. In 2020 the global installed capacity of water electrolysis systems was approximately 300 MW, with an increase of almost 70% in 2021 as an additional 200 MW came into operation. Electrolyser CapEx requirements are currently in the ranges of (all values in USD) 500 – 1400 \$/kW for alkaline electrolysers, 1100 – 1800 \$/kW for PEM electrolysers, and 2800 – 5600 \$/kW for SOE systems. Costs of all systems should decrease with the growth of manufacturing capacity, having already reached 8 GW/year in 2021, which is currently underutilized. Projects in pipeline will need to materialize to further incentivize expansion of manufacturing capacity. Forecasts predict that by 2030 global installed electrolyser capacity will reach 134 - 240 GW and manufacturing capacity will be 65 GW/year (IEA, 2022b).

The levelized cost of hydrogen (LCOH) is a metric used to evaluate the cost of producing hydrogen over the lifetime of a project, taking into account various factors. The calculation of LCOH typically includes the following elements (Yates et al., 2020):

- a. **CapEx (Capital Expenditures):** Costs associated with constructing the hydrogen production facility, such as equipment, infrastructure, and land. It encompasses the costs of electrolyzers, reformers, storage tanks, compressors, and other necessary components.
- b. **O&M (Operation and Maintenance):** Ongoing expenses required to operate and maintain the hydrogen production facility. O&M costs include labour, electricity, water, maintenance, and any other recurring costs associated with the operation.
- c. **Efficiency:** The energy efficiency of the technology employed for the hydrogen production process affects the overall cost. Efficiency in this case refers to the amount of energy input required to produce a given amount of hydrogen. Higher efficiency leads to lower energy costs and can result in a lower LCOH.
- d. **Capacity Factor:** The capacity factor represents the actual operating hours of the hydrogen production facility compared to its maximum potential, accounting for maintenance downtime or intermittent power supply. The higher the capacity factor, the lower the LCOH.
- e. **Lifetime and Discount Rate:** The lifetime of the production facility influences the LCOH calculation, as the longer the facility operates, the more it can spread the initial capital costs over the hydrogen production and resulting revenues. Additionally, a discount rate is applied to future costs and revenues to account for the time value of money.
- f. **Revenue Streams:** LCOH calculations can take into consideration any potential revenue streams generated from the hydrogen production facility, such as the sale of by-products (oxygen) or revenue from carbon credits or other incentives.

Yates et al. (2020) studied the LCOH of alkaline electrolysis powered by off-grid PV, performing a multifactor uncertainty analysis using the Monte Carlo method, looking to enable the optimisation of hydrogen production systems with the aim of reaching profitable conditions. The authors explore prior works on determining the LCOH in different regions around the world and the impact of different production factors. One of the main factors is the source of electricity, that could be grid connected (considering a renewable energy mix) or stand-alone dedicated PV or wind power, or a combination of both, dedicated renewable power complemented by a grid connection. Some key takeaways from the study are: 1) LCOH values found in the literature present a very wide range, that vary based on different configurations, assumptions and input parameters; 2) grid-powered systems that can operate at high-capacity factors present a clear advantage; 3) optimal system configuration is highly dependent on specific location and circumstances; 4) systems powered by

off-grid PV are feasible in cases of larger system sizes, lower PV capital costs, and high grid electricity prices (Yates et al., 2020).

Research performed by Muñoz Díaz et al, (2023) focused on the optimization of green hydrogen production in Chile, using AIMMS software to conduct an optimization considering various scenarios of electrolyser capacity and CapEx levels, combined with varying grid power prices and different capacities of an integrated photovoltaic plant. The sensitivity analysis concluded that the LCOH is primarily influenced by the cost of the electricity (60%), followed by the CapEx of the electrolyser (20%), other installation factors (15%), and operation and maintenance (5%).

Povacz et al. (2023) examines the potential for decentralized renewable hydrogen production in Austria using wind power and PV electricity sources. The study finds that the minimum LCOH is estimated to be 3.08 €/kg, while the maximum is 13.12 €/kg. Feasible levelized cost of electricity (LCOE) values range from 40 to 70 €/MWh for wind and from 50 to 70 €/MWh for PV. The analysis highlights that the LCOH is greatly influenced by the capacity factor of the renewable electricity sources and corresponding sizing of system components. The study suggests that balancing the electricity supply is a key element in driving down the LCOH. In the case of off-grid production, systems presenting the lowest LCOH are the ones that effectively combine both wind and PV capacities, enabling higher load factors due to the complementary nature of their power production profiles.

A study by Tang et al. (2022), examined the cost components of hydrogen production in Sweden, considering the combination of PV and wind as renewable inputs and the options of on-grid and off-grid production. All findings demonstrated the clear advantage of grid connected systems, as this produces more affordable hydrogen and allows excess renewable electricity to be sold back to the grid, balancing the amount of electricity purchased and enabling the supply of more renewable electricity and green hydrogen to the energy system overall. The results indicated that in off-grid scenarios, the LCOH ranges from 7.1 to 15.3 €/kg, while in on-grid cases, it ranges from 3.5 to 7.2 €/kg. The initial investment plays a significant role in determining the cost level, making the optimisation of the capacity factor of the electrolyser critical.

Further in the study performed by Silvestre et al. (2023), an economic assessment from the perspective of the H₂ producer revealed a LCOH of 4.99 EUR/kg. A sensitivity analysis on the production NPV highlighted the significant impact of electricity prices and H₂ sale prices. An assessment of impacts on the consumer side was made using a specific ceramics industry in Portugal, results showed that burning the NG-H₂ mixture reduces CO₂ emissions by 1.54%, 3.19%,

and 6.90%; for 5%, 10%, and 20% H₂ contents, respectively (p. 9). However, the savings in CO₂ license cost at €67/ton, did not compensate the increase in fuel cost for all H₂ percentages, when compared to a pure NG scenario at €120/MWh, indicating an economic disadvantage for the industry. However, the study suggests that if: NG prices exceed €136.92/MWh; or H₂ prices fall below €133.2/MWh; or CO₂ license prices exceed €152.68/tonCO₂; using the NG-H₂ blend would become advantageous for the end user without the need for subsidies.

3. NATURAL GAS AND HYDROGEN IN PORTUGAL

The National Hydrogen Strategy establishes the grid can take up to 22% blending of hydrogen with natural gas, the driving parameter for this maximum volumetric ratio is the calorific value of the gas, which remains within the limits currently imposed by regulations and does not require modifications in end-use applications (EN-H₂, 2020). This chapter provides a comprehensive analysis of the regulatory frameworks of natural gas and hydrogen and the emerging concept of hydrogen injection in pipelines in the EU and in Portugal specifically. Furthermore, this chapter examines the structure of the NG market in Portugal, shedding light on historic and current market dynamics, addressing the infrastructure available and offering insights into the potential impact of hydrogen injection into NG pipelines on Portugal's energy landscape.

3.1 Regulatory Frameworks

3.1.1 Natural Gas

In 1989, Decree-Law no. 374/89 established the rules for introducing natural gas (NG) in Portugal, covering importation, storage, treatment, transportation, and regional distribution of liquefied natural gas (LNG). In 1996, NG supply in Portugal began through the Campo Maior pipeline. The EU Directive (EC) 98/30 was issued in 1998, creating the Internal Market of Natural Gas and providing rules for the organization and operation of the NG sector, with a 10-year derogation granted to Portugal. ERSE's authority was extended to the NG sector in 2002, marking the start of sector regulation in Portugal.

The EU Directive (EC) 2003/55, established the organization and functioning of the sector, as well as the access to the market. It also defined the criteria and mechanisms for the concession of authorization for the transport, distribution, supply, storage and utilization of the grid. The Regulation (EC) 2005/1775 of the European Parliament and of the Council, established non-discriminatory rules on conditions of equal access to natural gas transmission networks. The EU

Directive (EC) 2019/692 was introduced in 2019, amending (EC) 2009/73 and focusing on common rules for the internal natural gas market and energy supply unbundling. Figure 1 contains a timeline summary of the regulatory measures and the implementation of NG in Portugal.

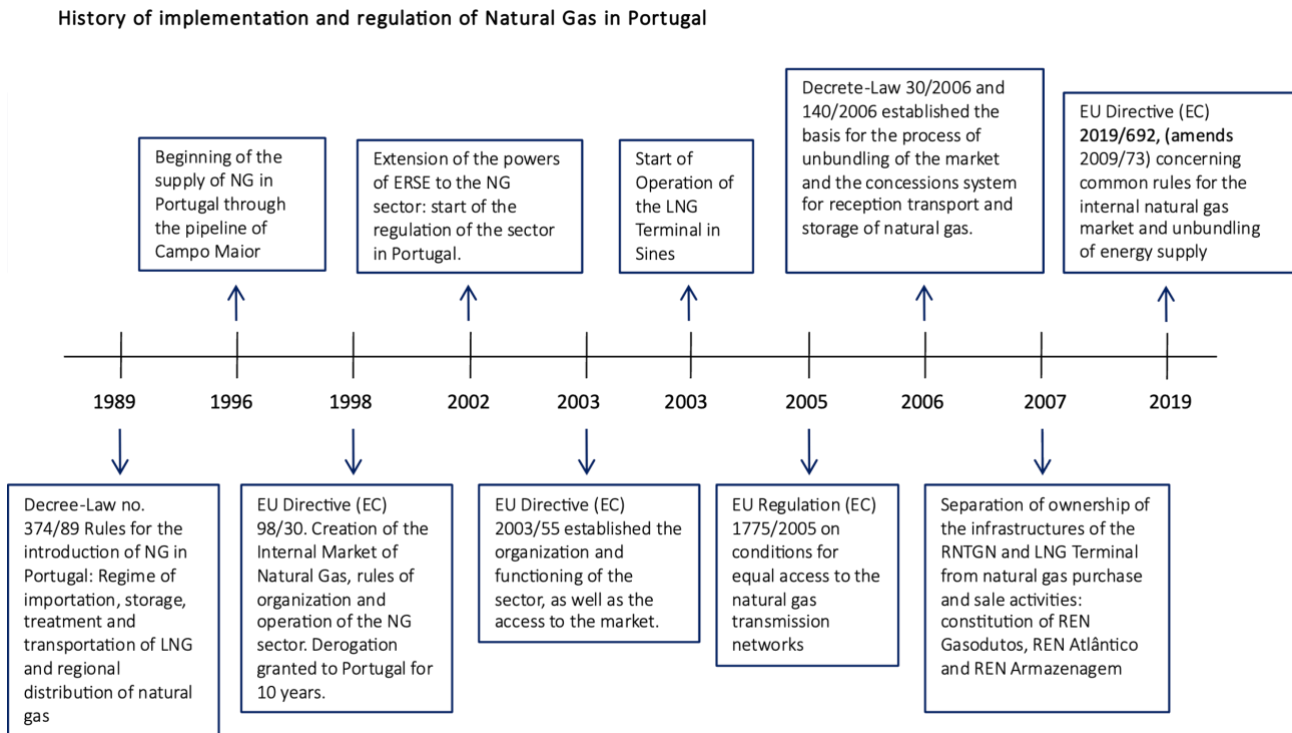


Figure 1: Timeline of implementation and regulation of Natural Gas in Portugal. (Source: own elaboration)

The Decree-Law No. 30/2006, which transposes Directive 2003/55/EC into Portuguese law, established the general bases for the functioning and organization of the National System of Natural Gas (NSNG) and the Decree-Law No. 140/2006, of July 26th, established the legal regime for activities carried out in the NSNG, the gradual liberalization of the natural gas market was carried out, as well as the revision of the Transgás concession contract, setting the dates of implementation of the liberalized gas market and extinguishing the model of exclusivity of a single importer supplying natural gas in Portugal (Decree-law 374/89). In 2007, ownership of RNTGN and the LNG Terminal infrastructure was separated into purchase, transport and storage activities, resulting in the establishment of REN Gasodutos, REN Atlântico, and REN Armazenagem.

The directives and regulations for EU gas markets established very clearly the importance of unbundling to foster competition and non-discrimination and equal access to the market, so consequently it can flourish, attracting investments and stimulating innovation, ultimately generating more energy efficiency and thus bringing greater benefit to end-consumers and society at large. The green hydrogen industry is still in early development, and there is an opportunity for

policymakers to lay the foundation for a robust and efficient green hydrogen market by taking into account the principles of energy markets unbundling.

3.1.2 Hydrogen

According to a report by IRENA (2022a) hydrogen production will grow by a factor of more than six from 2020 to 2050. In the 1.5°C scenario, about one quarter of the global hydrogen demand in 2050 (equivalent to about 150 Mt of hydrogen per year) will be satisfied through international markets. This is similar to today's gas market, where 33% of global production is traded internationally. Regarding the role of pipeline transport of hydrogen volumes in the trade across borders:

“Around 55% would travel by pipeline, and most of the hydrogen network would be based on existing natural gas pipelines that would be retrofitted to transport pure hydrogen, drastically reducing the transport costs. [...] This pipeline-enabled trade would be concentrated in Europe (85%) and Latin America.” (IRENA, 2022a, p. 7)

The energy cost differential analysis in the IRENA (2022b) report compares different pathway efficiencies of both hydrogen and fossil fuel transport costs. Liquid hydrogen presents the most expensive form in \$/MWh/km, and hydrogen pipeline transport is one of the most efficient, only falling behind oil pipelines and shipments. This is because regions with existing natural gas pipelines can be used to transport hydrogen, either through blending or if the pipelines are repurposed for pure hydrogen. According to Navigant (2019, p. 5), “The European gas transmission and distribution (T&D) networks combined consist of approximately 260,000 km of high-pressure network [...], plus approximately 1.4 million km of medium and low-pressure pipelines operated by distribution system operators (DSOs)” which presents a massive existing infrastructure that can potentially serve for the transport and trade of hydrogen throughout the whole EU.

The European Hydrogen Backbone (EHB, 2022) initiative estimates that the trans-European network of hydrogen will be made up of about 28,000 km in 2030. Portugal integrates this European vision with the contribution of their current national gas system for this objective. The EHB, of which REN is a member together with more than 30 operators of European transport networks, made an assessment of the potential to anticipate the development of transnational hydrogen corridors based on the possibility of adapting some existing gas infrastructure combined with the construction of dedicated infrastructure. This evaluation falls within the scope of the European strategy to reduce energy dependence and increase security of supply. By 2040, EHB estimates that the backbone will have a total of 53,000 km, composed of up to 60% conversion of NG pipelines.

In the Proposal for an EU Directive² on common rules for the internal markets in renewable and natural gases and in hydrogen, the word “unbundling” appears 47 times, emphasizing the vital implications this can have on the hydrogen industry (EC Proposal, 2021). Below is a brief summary of the principles of unbundling and their application in the green hydrogen sector:

- a. Separation of activities: effective separation of network operators from activities of production and supply prevents conflicts of interest, promotes fair market access, and encourages competition among different actors in the value chain.
- b. Transparent market rules: to ensure equal access to infrastructure, grid connections, and fair pricing mechanisms. Transparent market rules encourage investment, foster innovation, and promote the deployment of green hydrogen technologies.
- c. Effective regulatory oversight: to enforce unbundling rules and prevent anti-competitive practices. It also enhances market integrity, investor confidence, and long-term sustainability in the green hydrogen sector.
- d. Incentives for innovation: Incentives encourage technological advancements, research and development, demonstration projects, and infrastructure development.
- e. Collaboration and standardization: Unbundling should be accompanied by collaboration and standardization efforts across the industry. Cooperation between stakeholders, including governments, energy companies, and research institutions, can facilitate the development of common standards, best practices, and knowledge sharing. This will drive efficiency, market harmonization and security of supply in the green hydrogen sector.

Integrating these principles into policy making and incentives can create an enabling environment for sustainable and accelerated growth in renewable energy and green hydrogen production. The proposal also underlines that the production of gases from renewable sources should be developed as a liberalized activity, with low administrative requirements and adequate regulation to guarantee the security of supply.

“The simplification and streamlining of administrative permit granting processes and clear time limits for decisions to be taken by the authorities competent for issuing an authorisation should ensure that the deployment of hydrogen production facilities and system infrastructure can occur at an adequate pace.” (EU Commission, 2021, p. 25)

² <https://data.consilium.europa.eu/doc/document/ST-7911-2023-INIT/en/pdf>

In 2009, the EU Renewable Energy Directive was implemented, providing a legal framework for the development of renewable energy across all sectors of the EU economy. In 2014, Directive 2014/94/EU was enacted, establishing a framework and requirements for the deployment of alternative fuels, including refuelling stations for hydrogen. The EU Revised Renewable Energy Directive 2018/2001, set a binding target of 32% renewable energy by 2030, with hydrogen being included in the calculation of the energy share from renewable sources. In 2022, the REPowerEU Plan set a target of producing 10 million tonnes of domestic renewable hydrogen and importing another 10 million tonnes by 2030. In 2022, Portugal approved Ordinance 98-A/2022, which regulates the incentive system to support the production of green hydrogen and other renewable gases. Figure 2 recaps these milestones in a timeline.

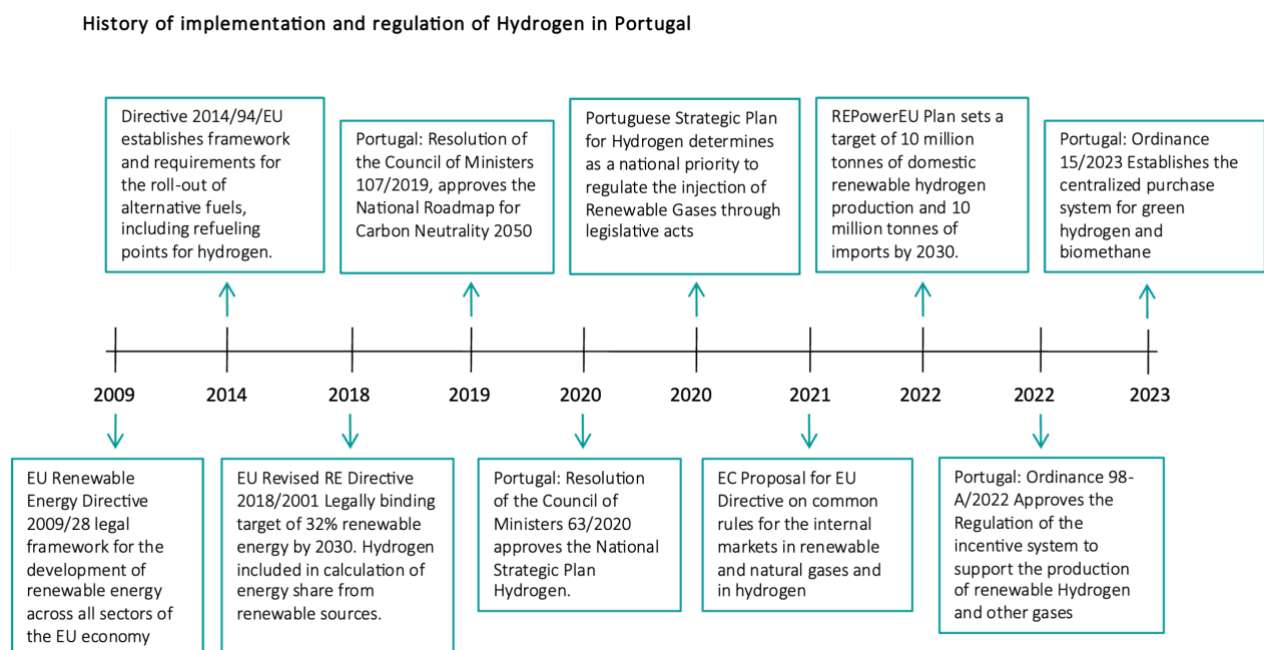


Figure 2: Timeline of implementation and regulation of Hydrogen in Portugal. (Source: own elaboration)

Article 27 Delegated Act (2023), supplementing the EU Directive on renewable energy (RED II, 2018), determined the rules for production of renewable fuels. On the matter of *additionality*, the regulation determined that from 2028 onward, the electricity powering green hydrogen production must be sourced from installations that came into operation in the last 36 months. Hydrogen installations commissioned before 2028 are exempt from additionality rules until 2038. Notably, producers located in bidding zones where the grid electricity has a carbon intensity lower than 65g CO₂e/kWh do not have to comply with this requirement. The regulation has considered nuclear power to be green, which has resulted in some countries' full grids to be classified as "green", which is the case of France and Sweden, both presenting power emissions below the regulated threshold of 65g CO₂e/kWh. On the matter of *temporal correlation*, renewable hydrogen production must be matched to the contracted renewable energy supply on a monthly basis, this stands until 2030, after

which the correlation will be an hourly basis. On the matter of *geographical correlation*, hydrogen production that is grid connected and supported by green power purchase agreements (PPAs) must be located in the same (or interconnected) bidding zones as the corresponding renewable energy installation. The delay in implementing the stricter rules is intended to allow markets and infrastructure to further develop, in order to meet the required synchronisation of new green electricity generation with H₂ production. Once the rules enter into force, new hydrogen projects will be faced with significant challenges that will restrict market growth.

On the subject of hydrogen producers supplementing their revenues by trading carbon allowances in the EU Emissions Trading Scheme (EU ETS), current legislation is undergoing changes in order to sanction this incentive. According to EU Regulation 2019/331 on *transitional Union-wide rules for harmonised free allocation of emission allowances*, the production methods of hydrogen that are eligible for free allocation of carbon allowances, are limited to reforming or partial oxidation with a production capacity exceeding 25 tonnes per day. The following extracts are taken from the amendments recommended by the European Parliament in June 2022 for the Proposal 2021/0211 amending (EC) 2003/87, which would establish the free allocation of emission allowance to green hydrogen producers.

The EU ETS should incentivize production from installations that partly or fully reduce GHG emissions. Therefore, [...] free allocation for the production of a product should be independent of the nature of the production process. It is therefore necessary to modify the definition of the products and of the processes and emissions covered for some benchmarks to ensure a level playing field for new and existing technologies. It is also necessary to decouple the update of the benchmark values for refineries and for hydrogen to reflect the increasing importance of production of *green* hydrogen outside the refineries sector. (Amendment 419 to EU Directive (EC) 2003/87)

[Free allocation of emissions allowances will apply to:] Production of hydrogen and synthesis gas with a capacity exceeding 25 tonnes per day and production of hydrogen and synthesis gas where the energy content is derived from renewable energy sources with a capacity exceeding 5 tonnes per day. (Amendment 624 to EU Directive (EC) 2003/87)

According to the EU Delegated Decision (EC) 2019/708 sectors and subsectors which are deemed to be at risk of carbon leakage will receive 100% of emissions allocation for the period 2021 to 2030, to then be gradually phased out. The production of hydrogen is included in a listed sector “*Manufacture of industrial gases*” (NACE code 2011). The allocation of free allowances is calculated based on the product benchmarks. EU Regulation 2019/331 set the hydrogen benchmark

value at 8,85 (emissions allowance/tonne H₂). The product benchmarks were revised and updated by EU Regulation 2021/447, the hydrogen value is now set at 6,84. Although free allocation of allowances is set to end in 2034, the methodology of how it will be phased out for sectors at risk of carbon leakage is yet to be determined.

In 2020, Portugal established the National Hydrogen Strategy (EN-H2, 2020) that is an annex to the Resolution of the Council of Ministers No. 63/2020. This strategy aims to contribute to national and European decarbonization objectives, introducing an element of incentive and stability for the energy sector, promoting the gradual introduction of hydrogen as a sustainable and integrated pillar in a more comprehensive strategy of transition not only for the internal economy, but also exploring the opportunity for the sector/country to play a key role in international markets. The objective of the strategy is to guarantee, by 2050, the decarbonization of the entire network of Natural Gas and Electric Power Plants and to contribute significantly to the decarbonization of the transport and industry sectors. In addition to the goals of incorporating hydrogen in the NG network, the strategy also establishes its ambition for 2030, such as the commercial penetration of hydrogen powered vehicles in the mobility sector, served by the implementation of 50 to 100 hydrogen refuelling stations, and an installed capacity of up to 2.5 GW in electrolyzers to meet the growing demand for hydrogen.

The EN-H2 (2020) established a target of elaborating the legislation, regulation and normative structure to allow the promotion and injection of renewable gases, namely hydrogen and biomethane to decarbonize the NG grid and as a renewable energy vector for export to all the EU. To this end, the Government is promoting an industrial policy around hydrogen and renewable gases, which is based on the definition of a set of public policies that guide, coordinate and mobilize public and private investments in the areas of production, storage, transport and end-use applications of Renewable gases in Portugal.

The “Roadmap and Action Plan for Hydrogen in Portugal” (DGEG, 2019) outlines clear objectives to create a normative framework for the wide scale implementation of hydrogen in the short term, applicable to different sectors. One of the driving principles is to provide competition between alternatives on an energy-efficient, cost-effective basis and minimize environmental impacts. The roadmap specifically identifies only three configurations in the hydrogen value chain with the greatest potential for immediate applicability, injection to natural gas pipelines is among them. The action plan highlights the importance of promoting the transition of existing pipeline infrastructure to support a hydrogen distribution network, as well as underground storage solutions and retrofitting of burners for H₂-NG mixtures (DGEG, 2019).

On January 4th 2023, Ordinance 15/2023³ was published, which establishes the centralized purchase system of biomethane and hydrogen produced by electrolysis from water, using electricity from renewable energy sources, for injection into the national gas grid. The regulation determines the target volumes for acquisition and respective maximum prices (higher calorific value PCS base): Biomethane – 150 GWh/year at a price of €62/MWh; and Hydrogen – 120 GWh/year at a price of €127/MWh. The referred ordinance determines the volumes are contracted by a competitive electronic auction procedure organized by the Directorate-General for Energy and Geology (DGEG). The successful bids would result in PPA contracts between producers and “last-resort wholesale commercial distributors” (*Comercializadores de último recurso grossista - CURg*) with a duration of 10 years from the date of the first supply. The CURg are then subsidised for the difference between the costs of acquiring the biomethane and hydrogen from producers and the selling price obtained, as well as the associated guarantees of origin. The CURg assumes the costs of tariffs for accessing the transport and distribution networks, in particular those for the injection of renewable gases that may apply.

3.2 Implementation of NG in Portugal

The introduction of NG in Portugal began with the Decree-law 374/89 and the celebration of a concession contract, between the Portuguese State and Transgás, under the exclusive public service regime, for importation, transportation, storage, and supply. In parallel, concessions were held, also under the exclusive public service regime for the regional distribution of natural gas. Within the scope of these contracts, the import of natural gas to Portugal was assured by Transgás with the celebration of long-term take or pay contracts⁴, with a duration equal to or greater than 20 years. The first contract of this nature was entered into with the Algerian company Sonatrach in 1994, with the start of supply in 1996 and which continued in effect until 2020.

In parallel, coal power plants implemented a natural gas combined cycle aiming to consume a minimum level of natural gas that would satisfy the economic feasibility of implementing NG infrastructures. From 2010 to 2012 the evolution of the procurement of NG suffered from a substantial reduction in the production volumes of the natural gas combined cycle plants – in large part motivated by the increase in production from renewable sources, as well as an economic retraction that led to lower consumption in the industrial segment. In this context, the initial forecast

³ <https://diariodarepublica.pt/dr/detalhe/portaria/15-2023-205689383>

⁴ Contracts in which the supplier is guaranteed a payment in reference to base volumes defined contractually.

of NG volumes in supply contracts under the take or pay regime were excessive for the effective market conditions, impacting gas and electricity consumer prices (ERSE, 2019).

3.3 Structure of the NG Market

This section of the research is based on the publication “Functioning of the Natural Gas Market, Analysis from a Competitive Perspective” (ERSE, 2019). Portugal is not a producer of natural gas, therefore acquisitions constitute the first segment of the sector's value chain. All NG consumed in Portugal is imported and the supply is carried out through entries in the system via transport pipeline through Spain, Campo Maior and Valença, and the LNG terminal in the Port of Sines. In Figure 3, we can observe the evolution of imported volumes of natural gas in Portugal. Although the cross-border pipeline with Spain began as the main entryway, LNG shipments gradually entered the mix and since 2019 have become the primary import route.

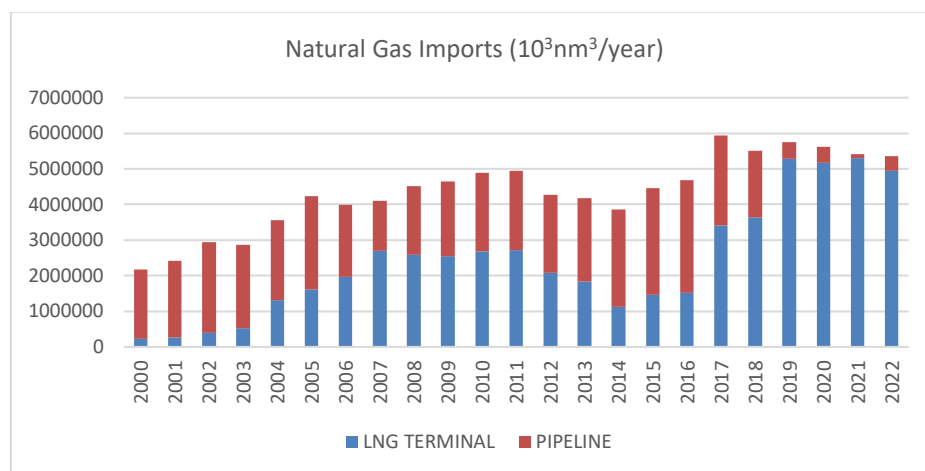


Figure 3: NG imported volumes by year and transport route. (Source: own elaboration based on historic data provided in the DGEG website⁵)

The activities of reception, storage and regasification of LNG, underground storage and transport of natural gas are carried out under concession contracts of 40 years. More specifically, REN Atlântico holds the concession for the reception, storage and regasification of LNG at the Sines LNG terminal and REN Armazenagem holds a concession for the underground storage of natural gas located in the Municipality of Pombal.

REN Gasodutos operates the National Natural Gas Transport Network (RNTGN) which receives natural gas at the Spanish border, at the exit of storage facilities (REN Armazenagem) or at the regasification terminal (REN Atlântico) and delivers it to distributors or high-pressure end

⁵ <https://www.dgeg.gov.pt/pt/estatistica/energia/gas-natural/importacoes-exportacoes/>

customers. REN Gasodutos holds the concession for the transport and technical management of the RNTGN through which it ensures the coordination of the natural gas distribution and proper functioning of transport infrastructures that guarantee the continuity and security of supply. The entity is also responsible for proposals to expand or improve the RNTGN. The national gas distribution network (RNDG) is made up of 11 operators that hold concessions for the distribution of natural gas to end customers, in medium and low pressure, two of which are REN Portugal Distribuição and Sonorgás, the remaining 9 operators belong to the holding Floene S.A. (formerly GGND – Galp Gás Natural Distribuição): Duriensegás, Beiragás, Lusitaniagás, Tagusgás, LisboaGás GDL, Setgás, Dianagás, Medigás and Paxgás.

According to EUROSTAT⁶, within the European Union, Portugal is currently the country with the 7th highest rate of incorporation of renewable energy sources in its energy mix, with over 30 % of its gross final energy consumption from clean sources. Gil et al., (2022) poses that renewable gases have the potential to reverse the energy dependence Portugal has experienced historically, importing over 80% of its energy until 2009.

Two of the main objectives of the national energy policy is to reduce imports dependence to 65% by 2030, with renewables taking on a share greater than 47% of the energy mix (PNEC, 2019). The production of renewable gases has an obvious potential to build on these targets, not

only to reduce imports but possibly play a role in energy exports, given the forecasts of growing external demand for these gases in central and northern Europe. It will be some time before countries like Portugal can fully move away from NG, blending hydrogen in the existing gas grid can be an effective solution to increase H₂ production and enable the reduction of emissions, while limiting the immediate need for the construction of costly new hydrogen pipelines and end-user investments (Daan Peters et al, 2020).

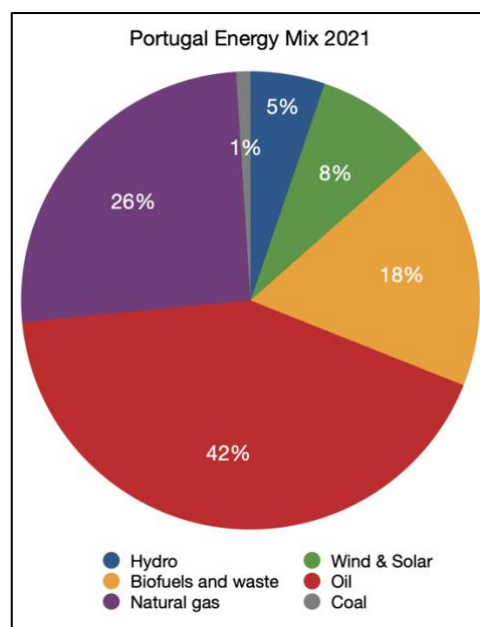


Figure 4: Portugal gross final consumption energy mix 2021. Source: own elaboration based on data from EUROSTAT.

⁶ Share of energy from renewable sources, 2021

4. METHODOLOGY

The hypothesis of this investigation takes into account that there are technical constraints related to the ratio of hydrogen blended into the grid. Although economies of scale point to greater economic efficiency achieved when employing large-scale production, the natural gas flow would limit the volumes of hydrogen injected in each access point. Therefore, this study aims to determine the optimal sizing of hydrogen production units that would be implemented in strategic injection points throughout the natural gas pipeline, which would enable a larger share of Hydrogen in the global grid volume, while circumventing the problem faced by greater volumes injected into single access points. In addition, this study estimates the decarbonization impact resulting from full deployment of all HPUs that were determined to be feasible.

The methodology was divided into three phases: Phase 1 – Basic mapping of the gas network and initial organization of data provided by REN; Phase 2 – Definition of base economic and technical assumptions of the Hydrogen production units (HPUs) which are applied in an economic model and sensitivity analysis. Phase 3 – Based on results of Phase 1 & 2, further analysis of data to determine strategic injection points and optimal capacities of hydrogen production and injection. Phase 4 – Perform a wider economic analysis to determine the overall investment requirement to deploy HPUs at all injection points and the decarbonization impact on the national gas network.

4.1 Mapping of the Gas Grid

In Portugal the national gas transportation network (RNTG) receives natural gas from the Sines LNG terminal or from the Spanish gas system. The RNTG is made up of 1375 km of large diameter transmission lines operated at high pressure (ranging from 70 up to 100 bar) which supply approximately 19 000 km of medium pressure pipelines (between 8 and 20 bar) and the low-pressure distribution grid (4 to 8 bar). There are some large industrial consumers directly connected to the high-pressure network, domestic consumers are supplied by the gas distribution network. The scope of the current study is focused on the RNTG and does not include the distribution grid.

The Sines liquefied natural gas terminal integrates the set of infrastructures for the reception and dispatch of methane tankers, storage and regasification of LNG that feeds the RNTG, as well as for the loading of LNG in tanker trucks. In the underground storage facilities of Carriço, Pombal municipality, the gas is stored at high pressure in caverns created inside a saline mass, at depths greater than a thousand meters. Currently there are six cavities in operation that use the same surface gas station, which allows the bidirectional flow, i.e., the injection from the transport network into

the caverns and the extraction of gas from the caverns to the transport network.

RNTG network is made up of the following main components (ERSE, 2019):

- 1375 km – High-pressure main pipeline and branches with diameters ranging from 150 to 800 mm, intended for the transportation of natural gas;
- 88 – Gas regulation and measurement stations (GRMS), which are intended for pressure regulation and subsequent measurement of natural gas delivered to distribution networks and high-pressure customers;
- 62 – Junction stations, which are destined to the section of the main transportation gas pipeline and/or the respective branch of derivation;
- 43 – Block valve stations, for the sectioning of the main transportation gas pipeline;
- 5 – T-interconnection stations, which are intended for derivation in T of the main transportation gas pipeline;
- 2 – Custody transfer stations, intended for measurement and custody transfer with the interconnected network of Spain.

The distribution networks are made of polyethylene (non-reactive to H₂); while the transport network is made up of API X57 steel (high tolerance to H₂); The hydrogen injection points must be implemented near gas regulation and measurement stations (GRMS), these are the transition points from (70 bar) to (20 bar). There are 88 GRMS within the national grid, that are represented in the map in Figure 5.

4.1.1 Data collection considerations

Through a formal request to the National Energy Regulator (REN) of Portugal, and upon the signing of an NDA, this investigation gained access to the standard nominal capacities and hourly flow rates of the GRMS in the transmission network. As the information provided by REN contains confidential data relevant to the security of the grid and gas supply, the current study will not disclose any specific location or make any correlation that could enable the identification of the GRMS in question. The data provided consisted of the hourly flow rates during a full year from 01/01/2022 to 01/01/2023 of the 88 GRMS. With the objective of identifying the optimum hydrogen injection capacities, the analysis of this data took into account: a) average historic volumes; b) intraday and seasonal fluctuations; c) % of capacity utilisation; d) grouped into capacity ranges for H₂ injection.

First an analysis of intraday consumption of the overall network was performed as can be seen in figures 6 and 7. It was possible to observe the average daily flow rate maintains a relatively stable behaviour, with the lowest rate at 500 10³Nm³/h in the early morning hours and highest at 662 10³Nm³/h at the end of the day. Additionally, the flow rates on Saturday and Sunday were sectioned out to verify if there are significant changes of behaviour during the weekends. It was possible to observe a very similar fluctuation pattern, with the weekends in a slightly lower range, 422 10³Nm³/h in the early morning and 508 10³Nm³/h in the evenings. These observations are positive for a scenario of hydrogen injection, as large fluctuations in flow rate would implicate the ramping up and down of production and/or larger H₂ storage buffers, which can be cumbersome from a technical and economic perspective.

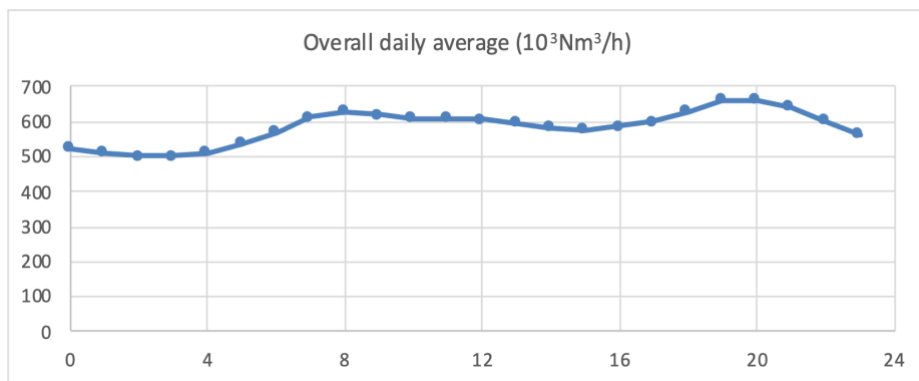


Figure 6: Intraday flow rate analysis of daily average in 2022, Y axis is NG flow rate in 10³Nm³ and X axis is hours in a day. Source: own elaboration based on REN data.

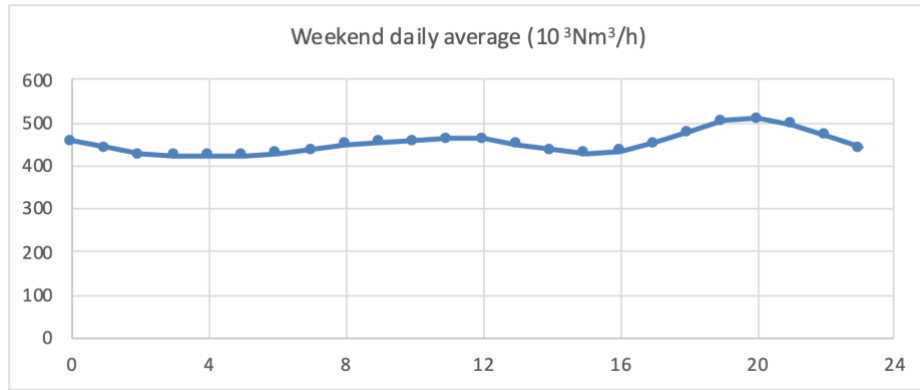


Figure 7: Intraday flow rate analysis of weekend average in 2022, Y axis is NG flow rate in 103Nm³ and X axis is hours in a day. Source: own elaboration

From the analysis of seasonal consumption during 2022 demonstrated in Figure 8, it was possible to observe there are no major differences in NG flow rates between the colder and warmer periods of the year, as is commonly seen in northern climates due to increased consumption for heating purposes. To the contrary, most of the summer months ranked higher than winter months, which could be linked to the high influx of tourists during the summer in Portugal. Thus, seasonal variations will not be taken into account in the assumptions for hydrogen injection.

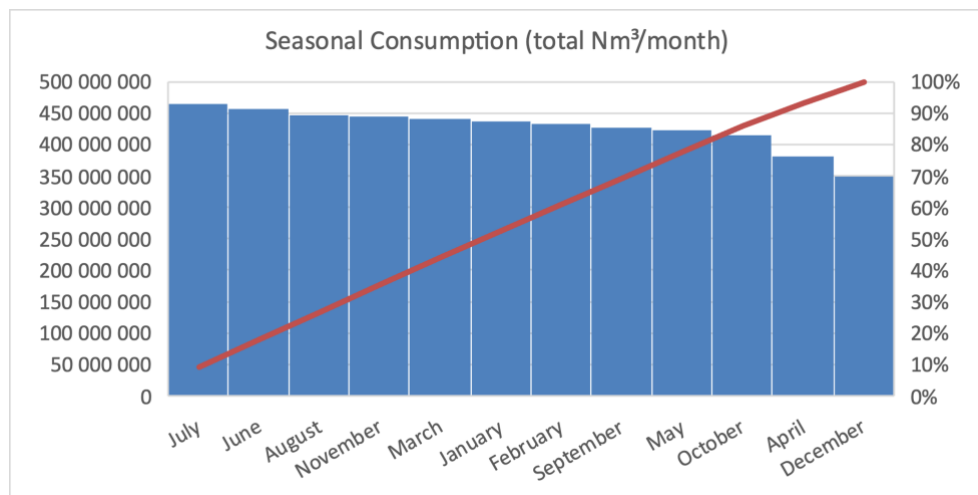


Figure 8: Seasonal consumption analysis, left Y axis is total volume in Nm³, right Y axis is accumulated percentages and X axis is months of the year. Source: own elaboration based on REN data.

4.2 Development of the Hydrogen Model

The base case assumes an alkaline electrolyser, with 1 MW stacks that can be modularly combined to increase capacity, with an efficiency of 4.7 kWh/m³ H₂. The CapEx cost was estimated at €1600/kW, which encompassed the EPC, electrolyser, water purification system, H₂ buffer storage and the H₂-NG blending, odorization and injection station. The power supply assumption is a baseload green PPA (hydro, wind and PV energy mix) at a cost of €55/MWh, and system operation at a 90% load factor. The model also considers an OpEx cost (O&M, staff, land lease)

approx. 3% of CapEx, and a water cost of €1,60/m³. The project life is 20 years with the H₂ production taking into account a yearly stack degradation of 0.87%. The model also assumes a 70/30 debt and equity financing ratio with 5% loan interest, and a 7% discount rate.

The only revenue considered aside from hydrogen sales is from carbon credits. The assumptions were defined according to the recent legislative landscape that is currently undergoing amendments (detailed in chapter 3.1.2, p. 18-19 of this study). The model considers free allocation of allowances until 2034, emissions benchmark value set at 6,84 (allowance/tonne H₂) with a yearly rate of decrease of 1,51% (EU Commission, 2021, p. 57⁷). Each allowance is equivalent to 1 tonne of CO₂e and can be traded in the EU ETS market. Assuming a price of €80/tCO₂ indexed to the inflation, this is a conservative average that aims to encompass market fluctuations, as the EU-ETS carbon prices have risen consistently above €60/tCO₂ since 2021 and reached over €100/tCO₂ in 2023⁸. The oxygen produced as a by-product is assumed to be safely released back into the atmosphere. Its sale was not considered due to data uncertainty related to both offtake terms and CapEx for purification and storage. Table 1 summarises the model assumptions:

Assumptions	Value	Unit	Reference
Electrolyser efficiency	4,7	kWh / m ³ H ₂	Technical assumption
Conversion m ³ to Kg H ₂	0,089	m ³ / kgH ₂	Technical data
Conversion kWh/Kg H ₂	52,8	kWh / kgH ₂	Technical data
Yearly system degradation	0,87	% / year	(David et al., 2019)
CAPEX	1 600	kEUR / MW H ₂	(IRENA, 2022a)
Load factor (operational hours)	90	%	Technical assumption
Electricity price	55,00	EUR / MWh	Economic assumption
Emission Allowance Price (EU ETS)	80,00	EUR / tCO ₂ e	See footnote 8
Emission Allowance Benchmark	6,84	tCO ₂ e / tH ₂	See footnote 7
Allowance free allocation ending	2034	year	See footnote 7
Benchmark Rate of decrease	1,51	% / year	See footnote 7
O&M (% of CapEx)	1,5	%	Economic assumption
Average Fixed OpEx (staff and land lease)	166	kEUR / year	Economic assumption
Discount rate (WACC)	7,0	%	(IRENA, 2022a)
Domestic inflation rate (on costs)	1,5	%	Economic assumption
Debt Ratio	70	%	Economic assumption
Loan Interest	5	%	Economic assumption
Depreciation Period	20	years	Economic assumption
Project Life	20	years	(IRENA, 2022a)
H ₂ max sale price (fixed)	5,00	EUR/kg	(Ordinance 15/2023)

Table 1: Summary of technical and economic assumptions utilised in the hydrogen production model

Based on the previous technical and economic assumptions, the sensitivity analysis first worked to determine the smallest electrolyser capacity that resulted in a positive NPV (net present value)⁹ in the optimal base case scenario: 90% load factor, power cost of €55/MWh and H₂ sale price of

⁷ https://climate.ec.europa.eu/system/files/2021-10/policy_ets_allowances_bm_curve_factsheets_en.pdf

⁸ <https://tradingeconomics.com/commodity/carbon>

⁹ Net present value is used to calculate current value of future revenues during the life of a project, in this case 20 years. It indicates if a project is economically feasible based on the assumed discount rate.

€5.00/kgH₂. That is the maximum H₂ price established in the current regulation for a centralized purchase system in Portugal (see Ordinance 15/2023 in chapter 3.1.2). Thus, a lower capacity boundary of 2MW was identified for economic feasibility purposes, which results in an LCOH of €4.75/kgH₂. In addition, the sensitivity to the load factor was assessed, and the lower boundary of 85% load factor was identified, as can be seen in Table 2. A maximum load factor of 95% is considered, due to maintenance or other possible downtime.

Capacity 2MW		
Load Factor	H ₂ (Nm ³ /h)	NPV ('000 €)
95%	404	447
90%	383	252
85%	362	52
80%	340	-152
75%	319	-360

Table 2: Load factor sensitivity analysis at 2 MW capacity.

It is important to note that the above modelling outcomes take into account the revenue from carbon allowances until 2034. Current legislation undergoing approval (see chapter 3.1.2, p.19 of this study) would set the free allocation threshold of eligible green hydrogen production at a minimum 5 tonnes a day. Although that is an improvement from the previous 25 tonnes threshold (production scale of refineries) it is of no benefit to smaller scale projects. Within the model developed for this study, only systems above 12MW would produce over 5 tonnes of H₂ per day. If carbon allowance revenue is removed from the model, the lower capacity boundary would come to be 4 MW at 90% load factor (see Table 3), with an LCOH of €4.83/kgH₂.

Capacity 4MW		
Load Factor	H ₂ (Nm ³ /h)	NPV ('000 €)
95%	809	491
90%	766	180
85%	723	-139
80%	681	-466
75%	638	-800

Table 3: Load factor sensitivity analysis at 4 MW, without CO₂e allowance revenue.

This difference might seem small, but in the next section of this study, we can observe that setting the lower capacity boundary at 766 Nm³/h instead of 362 Nm³/h excludes 18 GRMS from being viable hydrogen injection points. For this reason, the decision was made to include the carbon allowance revenues in all modelled system capacities. If the previously mentioned legislation is sanctioned, this revenue would have to be replaced with other forms of government subsidy for projects below 4 MW to remain feasible.

The sensitivity analysis goes on to determine the impact of varying PPA prices or H₂ sale prices on economic feasibility, illustrated in Figures 9 and 10. Considering the lower capacity boundary of 2 MW, project NPV remains positive as long as the electricity cost is below €57/MWh, or the H₂

sale price is above €4.30/kgH₂. The same exercise was performed for system capacities of 5, 10, 20 and 40 MW. Initially, as the system capacity increases, the boundaries of economic feasibility become more flexible, tolerating higher electricity costs and lower H₂ sales prices. With a 5 MW system capacity the project NPV remains positive with electricity prices of up to €63/MWh, or H₂ prices as low as €4.00/kgH₂. However, it was possible to observe that this flexibility in price tolerance was progressively smaller as system capacities increase further. With a 10 MW capacity the project NPV stays positive with electricity prices of up to €65/MWh, or hydrogen prices of at least €3.90/kg H₂. To keep a positive NPV for a 20 MW system, the electricity price cannot be over €66/MWh, and hydrogen prices cannot go below €3.80/kgH₂. The exact same boundaries were found for a 40 MW system, only with higher corresponding NPV values. For further information on the sensitivity analysis, see Annex 1.

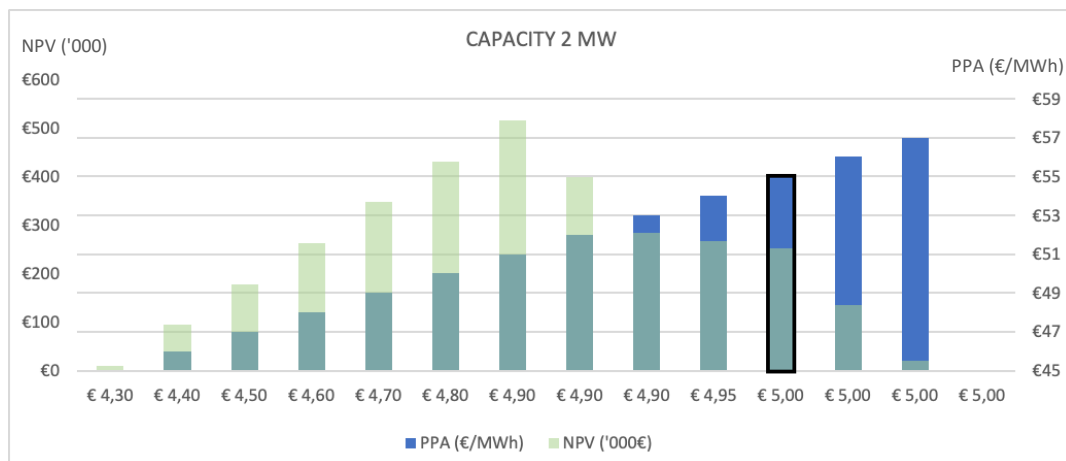


Figure 9: Sensitivity analysis of 2 MW system. The left Y axis represents project NPV, the right Y axis represents electricity prices and the X axis represent the H₂ sales price. The base case is outlined to stand out. (Note the darker green is an overlap of the blue and light green, not a third indicator.)

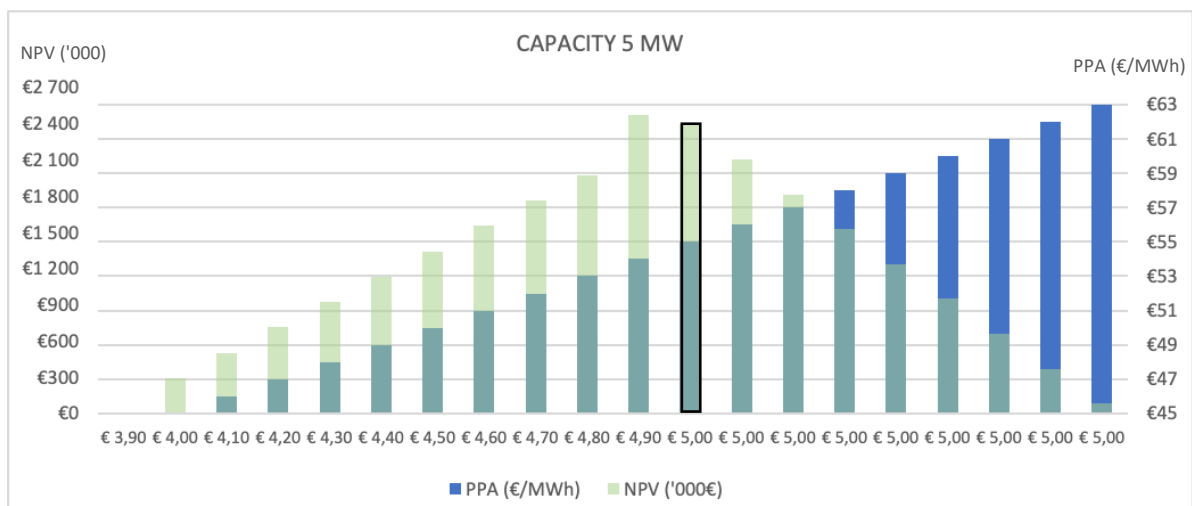


Figure 10: Sensitivity analysis of 5 MW system. The left Y axis represents project NPV, the right Y axis represents electricity prices and the X axis represent the H₂ sales price. The base case is outlined to stand out. (Note the darker green is an overlap of the blue and light green, not a third indicator.)

In terms of economic outcome, the increase of system capacities brought the expected gains of economies of scale, shown in Table 4. The NPV values and corresponding internal rate of return (IRR)¹⁰ were identified in two scenarios, with and without CO2e allowance revenues within the base case (€55/MWh and €5.00/kgH2) and the lower boundary case (€45/MWh and €4.30/kgH2) identified for the smallest system (2 MW). This confirms that smaller systems would benefit more from emissions allowance revenues or alternative subsidy programs. Whereas larger systems can more easily meet investor requirements on a purely commercial basis.

With CO2e Revenue		LOWER BOUNDARY		BASE CASE	
Capacity	CapEx (k€)	NPV (k€)	IRR	NPV (k€)	IRR
2 MW	3 040	10	7,1%	252	8,8%
5 MW	7 600	1 791	11,4%	2 394	12,9%
10 MW	15 200	4 795	12,7%	5 965	14,1%
20 MW	30 400	10 694	13,3%	13 206	14,7%
40 MW	60 800	22 565	13,6%	27 389	15,0%

Without CO2e Revenue		LOWER BOUNDARY		BASE CASE	
Capacity	CapEx (k€)	NPV (k€)	IRR	NPV (k€)	IRR
2 MW	3 040	-739	1,6%	-498	3,4%
5 MW	7 600	-83	6,8%	520	8,3%
10 MW	15 200	1 010	8,2%	2 216	9,6%
20 MW	30 400	3 197	8,8%	5 608	10,2%
40 MW	60 800	7 570	9,1%	12 393	10,5%

Table 4: Analysis of scale in two scenarios, with and without CO2e revenues, lower boundary: €45/MWh and €4.30/kgH2; base case: €55/MWh and €5.00/kgH2.

Annex 1 provides further insight on the results of the sensitivity analysis, upon which the tables and charts in this chapter, and table 6 in the following chapter, were based on.

4.3 Hydrogen injection analysis

Out of the 88 existing GRMS, 5 were inactive during the year of 2022, thus a total of 83 stations were considered in the following analysis. Table 5 below of GRMS data took into account: (a.) nominal capacity, (b.) maximum NG flow rate, (c.) average NG flow rate. Assuming that out of the 20% H2 blending limit that is permitted by current regulation, 10% would be allocated to the distribution grid and the other 10% to the transport grid, which is the object of this analysis, the potential (d.) maximum H2 injection and (e.) average H2 injection capacities were calculated. Additionally, the GRMS were grouped according to 6 different (f.) ranges of average flow rate, and lastly the (g.) utilisation rate was calculated by the difference between nominal capacity and average flow rate of each GRMS in the year 2022.

The largest group was in the lowest range, with 24 GRMS that presented an average NG flow rate under 1000 Nm³/h, which corresponded to a very low average H2 injection capacity between 3

¹⁰ Metric that indicates the annual rate of return of a financial investment.

- 97.6 Nm³/h. 18 out of the 24 GRMS in Group 1 had a utilisation rate below 10%, although this demonstrates potential for growth of transported NG volumes, the majority of the nominal capacities in this group are low, with the exception of 3 stations with capacities above 10 000 Nm³/h. Also notably, in Group 1 there are significant differences between the average NG flow rate versus maximum, indicating volatile behaviours that can be challenging for H2 injection. Group 2 contains a total of 19 GRMS with average NG flow rates ranging from 1000-2000 Nm³/h. This group begins to exhibit a smaller gap between the registered maximum and average flows, with the exception of station “41” with a significantly higher maximum flow rate compared to the average. Group 2 also presents strong potential for volume growth, with utilisation rates ranging from 5 - 33%. Groups 3, 4 and 5 present the most stable behaviour, with maximum flows never exceeding in more than 3x average flow rates, with the exception of one outlier, station “51”, which has a utilisation rate of only 4% and nominal capacity of 100 000 Nm³/h. The final group, although containing only 7 stations presents the largest total volume in combined average NG flow rates, as well as the highest utilisation percentages. Groups 3, 4, 5 and 6 present more reasonable conditions for H2 injection, with average NG flow rates ranging from 2 250 – 92 721 Nm³/h.

	GRMS	a. NOMINAL NG (Nm ³ /h)	b. MAX NG (Nm ³ /h)	c. AVERAGE NG (Nm ³ /h)	d. MAX H2 (Nm ³ /h)	e. AVERAGE H2 (Nm ³ /h)	f. RANGE Average NG	g. % utilisation (Aver./Nom. NG)
GROUP 1	1	2 500	2 033,0	30,3	203,3	3,0	< 1k	1%
	2	2 500	2 082,0	42,9	208,2	4,3	< 1k	2%
	3	4 200	685,0	59,4	68,5	5,9	< 1k	1%
	4	4 200	210,0	62,8	21,0	6,3	< 1k	1%
	5	4 200	351,0	83,8	35,1	8,4	< 1k	2%
	6	2 500	267,0	91,5	26,7	9,1	< 1k	4%
	7	4 200	614,0	98,4	61,4	9,8	< 1k	2%
	8	4 200	925,0	102,9	92,5	10,3	< 1k	2%
	9	1 500	231,0	119,3	23,1	11,9	< 1k	8%
	10	4 200	3 639,0	128,3	363,9	12,8	< 1k	3%
	11	4 200	2 498,0	134,9	249,8	13,5	< 1k	3%
	12	1 500	682,0	144,5	68,2	14,4	< 1k	10%
	13	4 200	700,0	293,2	70,0	29,3	< 1k	7%
	14	11 000	925,0	300,4	92,5	30,0	< 1k	3%
	15	4 200	1 046,0	311,0	104,6	31,1	< 1k	7%
	16	4 200	964,0	423,9	96,4	42,4	< 1k	10%
	17	4 200	1 128,0	425,9	112,8	42,6	< 1k	10%
	18	7 000	2 190,0	489,6	219,0	49,0	< 1k	7%
	19	4 200	1 431,0	500,2	143,1	50,0	< 1k	12%
	20	7 000	2 083,0	609,1	208,3	60,9	< 1k	9%
	21	11 000	2 292,0	723,7	229,2	72,4	< 1k	7%
	22	25 000	1 894,0	788,3	189,4	78,8	< 1k	3%
	23	4 200	3 882,0	935,9	388,2	93,6	< 1k	22%
	24	7 000	2 952,0	975,6	295,2	97,6	< 1k	14%
GROUP 2	25	17 000	2 218,0	1 021,6	221,8	102,2	1k to 2k	6%
	26	11 000	2 849,0	1 048,7	284,9	104,9	1k to 2k	10%
	27	7 000	1 958,0	1 107,3	195,8	110,7	1k to 2k	16%
	28	17 000	3 257,0	1 153,8	325,7	115,4	1k to 2k	7%
	29	17 000	2 812,0	1 160,3	281,2	116,0	1k to 2k	7%
	30	17 000	2 711,0	1 191,5	271,1	119,2	1k to 2k	7%
	31	11 000	2 382,0	1 274,7	238,2	127,5	1k to 2k	12%
	32	11 000	6 903,0	1 376,6	690,3	137,7	1k to 2k	13%
	33	4 200	4 334,0	1 377,9	433,4	137,8	1k to 2k	33%
	34	11 000	3 757,0	1 403,4	375,7	140,3	1k to 2k	13%
	35	11 000	3 072,0	1 444,2	307,2	144,4	1k to 2k	13%
	36	11 000	3 383,0	1 446,9	338,3	144,7	1k to 2k	13%
	37	11 000	3 566,0	1 508,1	356,6	150,8	1k to 2k	14%

	38	11 000	4 895,0	1 760,8	489,5	176,1	1k to 2k	16%
	39	11 000	5 845,0	1 832,2	584,5	183,2	1k to 2k	17%
	40	7 000	4 135,0	1 859,5	413,5	185,9	1k to 2k	27%
	41	40 000	24 662,0	1 918,7	2 466,2	191,9	1k to 2k	5%
	42	7 000	5 253,0	1 932,3	525,3	193,2	1k to 2k	28%
	43	17 000	9 734,0	1 962,1	973,4	196,2	1k to 2k	12%
GROUP 3	44	25 000	4 467,0	2 250,9	446,7	225,1	2k to 5k	9%
	45	17 000	6 214,0	2 320,0	621,4	232,0	2k to 5k	14%
	46	7 000	6 733,0	2 527,6	673,3	252,8	2k to 5k	36%
	47	7 000	4 775,0	2 577,9	477,5	257,8	2k to 5k	37%
	48	11 000	9 122,0	3 019,1	912,2	301,9	2k to 5k	27%
	49	17 000	5 799,0	3 463,3	579,9	346,3	2k to 5k	20%
	50	17 000	6 810,0	3 554,3	681,0	355,4	2k to 5k	21%
	51	100 000	70 400,0	3 700,8	7 040,0	370,1	2k to 5k	4%
	52	11 000	6 460,0	4 078,2	646,0	407,8	2k to 5k	37%
	53	17 000	6 394,0	4 139,7	639,4	414,0	2k to 5k	24%
	54	17 000	9 070,0	4 198,3	907,0	419,8	2k to 5k	25%
	55	17 000	10 300,0	4 489,5	1 030,0	449,0	2k to 5k	26%
	56	25 000	17 025,0	4 638,8	1 702,5	463,9	2k to 5k	19%
	57	7 000	9 189,0	4 889,8	918,9	489,0	2k to 5k	70%
	58	7 000	9 905,0	4 924,5	990,5	492,4	2k to 5k	70%
GROUP 4	59	16 000	11 469,0	5 027,9	1 146,9	502,8	5k to 10k	31%
	60	50 000	12 845,0	5 338,0	1 284,5	533,8	5k to 10k	11%
	61	25 000	10 328,0	5 688,7	1 032,8	568,9	5k to 10k	23%
	62	25 000	13 185,0	5 731,5	1 318,5	573,1	5k to 10k	23%
	63	16 000	14 255,0	6 124,9	1 425,5	612,5	5k to 10k	38%
	64	22 000	13 276,0	6 564,1	1 327,6	656,4	5k to 10k	30%
	65	25 000	12 895,0	6 676,8	1 289,5	667,7	5k to 10k	27%
	66	65 000	16 090,0	6 947,4	1 609,0	694,7	5k to 10k	11%
	67	17 000	13 870,0	7 140,7	1 387,0	714,1	5k to 10k	42%
	68	22 000	15 922,0	7 581,7	1 592,2	758,2	5k to 10k	34%
	69	25 000	17 856,0	7 776,2	1 785,6	777,6	5k to 10k	31%
	70	72 000	19 842,0	8 593,4	1 984,2	859,3	5k to 10k	12%
GROUP 5	71	65 000	23 487,0	10 229,3	2 348,7	1 022,9	10k to 15k	16%
	72	50 000	24 136,0	10 502,5	2 413,6	1 050,3	10k to 15k	21%
	73	100 000	34 311,0	11 198,3	3 431,1	1 119,8	10k to 15k	11%
	74	25 000	19 625,0	11 950,9	1 962,5	1 195,1	10k to 15k	48%
	75	25 000	30 956,0	13 004,3	3 095,6	1 300,4	10k to 15k	52%
	76	40 000	30 499,0	14 066,7	3 049,9	1 406,7	10k to 15k	35%
GROUP 6	77	50 000	44 337,0	19 581,1	4 433,7	1 958,1	> 15k	39%
	78	95 000	61 709,0	26 280,8	6 170,9	2 628,1	> 15k	28%
	79	100 000	73 980,0	28 523,8	7 398,0	2 852,4	> 15k	29%
	80	100 000	113 012,0	35 523,1	11 301,2	3 552,3	> 15k	36%
	81	210 000	189 043,0	64 032,3	18 904,3	6 403,2	> 15k	30%
	82	195 000	172 420,0	78 016,2	17 242,0	7 801,6	> 15k	40%
	83	160 000	133 320,0	92 721,9	13 332,0	9 272,2	> 15k	58%

Table 5: Flow rates of 83 GRMS stations during the year of 2023, (a.) NG Nominal capacity, (b.) Maximum NG flow rate, (c.) Average NG flow rate, (d.) theoretical Maximum H2 injection, (e.) theoretical Average H2 injection (f.) Ranges of NG average flow rate, (g.) % of utilisation based on NG average flow rate versus nominal capacity. Source: own elaboration based on REN data.

Now based on the technical and economic assumptions of the HPU model in the previous section of this chapter, this work proceeded to determine the GRMS that are optimal for hydrogen injection. According to the NPV sensitivity analysis, the lower capacity boundary for economic feasibility was identified as a 2MW electrolyser at 85% load factor, which results in a production of ~362 Nm³/h of hydrogen. Based on this assumption and the analysis of potential average H2 injection during 2022, in column e. of Table 5, the first 50 stations presented flow rates that are below this threshold. Considering HPUs would be deployed at the remaining 33 GRMS, and with the aim of determining at what flow rate it is economically advantageous to increase the system capacity, the load factor sensitivity analysis was performed for different system capacities assuming 1 MW increments, considering the base case scenario assumptions (€55/MWh and €5.00/kgH2).

The analysis aimed to identify at what point each increment presented an advantage compared to the highest production scenario of the previous system capacity. For example, at 95% load factor a 2MW system produces 404 Nm³/h and presents an NPV of 447 k€, a 3MW system at 85% load factor results in a higher NPV, thus the H₂ injection flow rate of 543 Nm³/h is the point at which the system capacity should be increased from 2 to 3 MW. As can be seen in Table 6, the point where increasing the capacity resulted in a higher NPV was at load factors of 85% for capacities of 3 and 4 MW, and 90% for capacities 5, 6, 7 and 8 MW. The analysis found that any increase equal to or above 9MW system capacity, the tipping point remained at 95% load factor. Thus, the respective production factors will be considered when determining the HPU capacity for each GRMS, i.e., the electrolyser system will be increased when potential H₂ injection flow rates match the production at each economic tipping point.

Load Factor	2 MW Capacity		3 MW Capacity		4 MW Capacity		5 MW Capacity	
% operational hours in a year	H2 (Nm ³ /h)	NPV ('000 €)	H2 (Nm ³ /h)	NPV ('000 €)	H2 (Nm ³ /h)	NPV ('000 €)	H2 (Nm ³ /h)	NPV ('000 €)
95%	404	447	606	1259	809	2071	1011	2883
90%	383	252	574	966	766	1680	957	2394
85%	362	52	543	666	723	1281	904	1895
80%	340	-152	511	361	681	873	851	1386
75%	319	-360	479	49	638	457	798	866
70%	298	-572	447	-269	596	33	745	336
65%	277	-788	415	-594	553	-399	691	-205
60%	255	-1036	383	-925	511	-841	638	-757
Load Factor	6 MW Capacity		7 MW Capacity		8 MW Capacity		9 MW Capacity	
% operational hours in a year	H2 (Nm ³ /h)	NPV ('000 €)	H2 (Nm ³ /h)	NPV ('000 €)	H2 (Nm ³ /h)	NPV ('000 €)	H2 (Nm ³ /h)	NPV ('000 €)
95%	1213	3694	1415	4506	1617	5318	1819	6130
90%	1149	3108	1340	3822	1532	4536	1723	5250
85%	1085	2509	1266	3124	1447	3738	1628	4352
80%	1021	1898	1191	2411	1362	2923	1532	3436
75%	957	1275	1117	1683	1277	2092	1436	2500
70%	894	638	1043	941	1191	1243	1340	1546
65%	830	-11	968	183	1106	378	1245	572
60%	766	-673	894	-589	1021	-505	1149	-421

Table 6: Load factor sensitivity analysis, identifying the economic tipping point to increase system capacity.

4.4 Investment and Decarbonization Impact

Based on the results of the analyses performed thus far, this section of the study determines the HPU capacities at each injection point and the related investment and decarbonization impact. As can be seen in Table 7 below, to deploy HPUs at the 33 GRMS that were identified as economically and technically feasible injection points, with a volumetric blending ratio of 10% hydrogen content, the total investment required would be 392 million EUR. This would result in a total volume of 41,3 thousand tonnes of hydrogen injected every year in the national gas grid. The equivalent annual emissions savings¹¹ are over 1,1 million tons (Mt) of CO₂e. This hydrogen volume and decarbonisation impact would be doubled if the remaining 10% H₂ blending were also achieved in

¹¹ Calculated according to lower calorific values and emission factors for fuels published by DGEG (*Despacho n.º 17313/2008, Diário da República, 2.ª série — N.º 122 — 26 de Junho de 2008*)

the NG distribution grid.

GRMS	a. NOMINAL (Nm ³ /h)	b. AVERAGE NG (Nm ³ /h)	c. AVERAGE H ₂ (Nm ³ /h)	d. HPU Capacity (MW)	e. utilisation rate	f. Investment ('000 €)	g. Emmisions Savings (tCO ₂ e/year)
51	100 000	3 700,8	370,1	2	4%	3 200	7 876
52	11 000	4 078,2	407,8	2	37%	3 200	8 679
53	17 000	4 139,7	414,0	2	24%	3 200	8 810
54	17 000	4 198,3	419,8	2	25%	3 200	8 935
55	17 000	4 489,5	449,0	2	26%	3 200	9 555
56	25 000	4 638,8	463,9	2	19%	3 200	9 873
57	7 000	4 889,8	489,0	2	70%	3 200	10 407
58	7 000	4 924,5	492,4	2	70%	3 200	10 481
59	16 000	5 027,9	502,8	2	31%	3 200	10 701
60	50 000	5 338,0	533,8	2	11%	3 200	11 361
61	25 000	5 688,7	568,9	3	23%	4 800	12 107
62	25 000	5 731,5	573,1	3	23%	4 800	12 198
63	16 000	6 124,9	612,5	3	38%	4 800	13 035
64	22 000	6 564,1	656,4	3	30%	4 800	13 970
65	25 000	6 676,8	667,7	3	27%	4 800	14 210
66	65 000	6 947,4	694,7	3	11%	4 800	14 786
67	17 000	7 140,7	714,1	3	42%	4 800	15 197
68	22 000	7 581,7	758,2	4	34%	6 400	16 136
69	25 000	7 776,2	777,6	4	31%	6 400	16 550
70	72 000	8 593,4	859,3	4	12%	6 400	18 289
71	65 000	10 229,3	1 022,9	5	16%	8 000	21 771
72	50 000	10 502,5	1 050,3	5	21%	8 000	22 352
73	100 000	11 198,3	1 119,8	5	11%	8 000	23 833
74	25 000	11 950,9	1 195,1	6	48%	9 600	25 435
75	25 000	13 004,3	1 300,4	6	52%	9 600	27 677
76	40 000	14 066,7	1 406,7	7	35%	11 200	29 938
77	50 000	19 581,1	1 958,1	9	39%	14 400	41 674
78	95 000	26 280,8	2 628,1	13	28%	20 800	55 932
79	100 000	28 523,8	2 852,4	14	29%	22 400	60 706
80	100 000	35 523,1	3 552,3	16	36%	25 600	75 602
81	210 000	64 032,3	6 403,2	29	30%	46 400	136 277
82	195 000	78 016,2	7 801,6	35	40%	56 000	166 039
83	160 000	92 721,9	9 272,2	42	58%	67 200	197 336

Table 7: Analysis to determine the (e.) HPU optimal capacity, (f.) corresponding CapEx investment and (g.) approx. equivalent emissions saved by injecting 10% hydrogen in the identified GRMS.

A more granular analysis of each GRMS should be performed to confirm technical and financial parameters, as well as identify where HPUs should take into account future potential increases in consumption and consequently greater injected hydrogen volumes. As can be seen from the utilisation rates in column e. of Table 7, there is plenty of leeway for flow rate growth and consequent expansion of hydrogen production and injection.

5 RESULTS AND DISCUSSION

The emissions savings resulting from the deployment of all the HPUs analysed in this study would represent a reduction of almost 2% of the country's total emissions considering GHG data from the year 2020, which amounted to 57.6 million tonnes of CO₂e according to the National

Emissions Inventory (APA, 2022). One could argue that this impact is small in face of the challenge of reaching Net Zero by 2050. However, many authors point to the importance of gradually implementing hydrogen in the natural gas networks to enable the gathering of data, so both industry and legislators can gain the necessary experience to deploy hydrogen on a wider scale. In addition, these relatively small steps cause a ripple effect in other sector of the value chain, generating innovation and cost efficiencies upstream and downstream. The impact might seem small initially, but will lead to increased production and end-use applications in mobility and industry, as technical know-how grows stronger and regulators find their footing.

Portugal presents optimal conditions to be a first mover in the implementation of hydrogen blending, this study identified the regulatory landscape is advancing quickly and setting the groundwork to enable a competitive and dynamic market. The country has established the national centralized purchase system of biomethane and hydrogen for injection into the national gas grid (see Ordinance 15/2023 in chapter 3.1.2). This regulation also determined a price that was used in the base case modelling of the HPU. Under base case assumptions, with a 90 % load factor, power cost of €55/MWh and H₂ sale price of €5.00/kgH₂, the LCOH for capacities 2MW, 5MW, 10MW, 20MW, 40MW were €4.75/kgH₂, €4.39/kgH₂, €4.28/kgH₂, €4.22/kgH₂ and €4.19/kgH₂, respectively. This clearly demonstrates the economy of scale effect and the ability for larger projects to be more economically feasible, whereas smaller projects would be more challenging to undertake.

Yet, this study poses that small-scale projects have an important part to play in the upcoming hydrogen industry, not only because a large number of GRMS present lower flow rates but also to promote decentralized and competitive growth, fostering innovation and free access to market. As was discussed in chapters 3.1.2 and 4.2, the regulation of free allocation of emissions allowances has major potential to improve project feasibility, particularly for smaller scale systems. If the current proposal (Amendment 624 to EU Directive (EC) 2003/87) to set a minimum production threshold of 5 tonnes a day is sanctioned, free allowances would only benefit hydrogen projects that could very well be viable without this additional revenue. Table 4 in chapter 4.2 demonstrates that capacities above 10 MW would remain economically attractive even without CO₂e revenues. This should be re-examined by legislators, to assure these incentives are serving the best purpose.

Within the assumptions used in this study, the sensitivity analysis identified a lower capacity boundary of 2 MW at 85% load. Increasing this capacity created cost efficiencies that made the HPU more tolerant to fluctuating electricity costs and H₂ sale prices. This study confirmed findings in the literature with respect to the results of the sensitivity analysis, which demonstrated the

significant impact of electricity costs and load factor on economic feasibility. When analysing production and load factor to determine when the system should be increased for each NG flow rate, the study found the economic tipping point that revealed the optimal system sizing to meet average injection capacities.

When considering the limitations of this study, there are opportunities for further detailing and optimisation, as the results of this analysis are highly sensitive to the underlying economic and technical assumptions. One aspect that is not explored, is how stand-alone hydrogen production systems powered by dedicated PV and/or wind with lower capacity factors would perform against the base case grid connected scenario. This could be investigated on a location basis for each GRMS, identifying when the local condition would meet the footprint requirements of developing PV near the HPU. Also, the economic modelling did not consider stack replacements to mitigate electrolyser performance degradation, this might improve the business case and result in a longer project life. This and other variables such as, fixed costs variables at different capacities and CapEx variations should be considered in a more in-depth sensitivity analysis.

6 CONCLUSIONS

In conclusion, hydrogen blending shows promise in reducing CO₂ emissions from the gas industry in the short term, but it has limitations as a decarbonization strategy. The success of blending depends on striking a balance between implementation ease and emission impact. Operational experience and research are crucial for addressing technical challenges and informing policy decisions. Blending and injection of hydrogen in the NG grid presents an actionable and imminent opportunity to gain the necessary knowledge and further motivate other sectors to adopt hydrogen. System planners and policymakers need to carefully evaluate the role of blending in integrated gas and electricity networks while considering potential lock-in effects or delays in transitioning away from natural gas. The scientific community and industry alike expect increases in CO₂ license prices, lower H₂ production costs with evolving technology, and rising NG prices as regulatory and financial incentives continue to be directed towards renewables.

The “Roadmap and Action Plan for Hydrogen in Portugal” (DGEG, 2019) states the importance of promoting demonstration projects to solidify hydrogen’s critical role in the National Energy and Climate Plan until 2030 (PNEC, 2019), which will be a crucial step towards cost-effective scaling of the integration of hydrogen into the Portuguese and European energy systems. The pipeline injection projects from the current investigation present an opportunity for this implementation with

an existing distribution infrastructure and consumer market, combining and creating synergies between sectors. Once the current cap of 20% volumetric blending ratio is fulfilled, industries and domestic consumers connected to the gas grid will be able to measure and gain an understanding of actual tolerance and applicability of hydrogen in each type of end-use. This will provide valuable insight on the question of whether hydrogen has the potential to increasingly replace natural gas.

From the literature and from the development of the HPU model, it is possible to conclude that to reduce the LCOH it is crucial to stabilize the electricity supply. In countries with strong hydropower and nuclear baseloads, such as France and Sweden, grid connected electrolysis that can maintain a stable operation is ideal, and guarantees the ‘green’ quality of the H₂. Nonetheless, countries lacking clean electricity in their energy mix can equally benefit from renewable power developed for the purpose of hydrogen production. If these power plants inject excess renewable electricity into the grid, it will offset the purchase of non-renewable electricity from the grid when wind or PV power production are insufficient. Even if not ideal, this enables the much-needed higher capacity factor for H₂ production, and results in overall greater quantities of hydrogen and green electrons in energy systems as a whole.

From the regulatory point of view, this investigation found that the hypothesis of implementing a large number of HPUs throughout the gas grid is in line with EU directives of liberalization and unbundling of energy markets. One could argue that the most efficient way to decarbonize the Portuguese gas grid would be to implement a large production unit at the LNG terminal in Sines where over 90% of the national gas supply enters the country according to the 2022 ERSE bulletin¹². If hydrogen were to be produced and blended at the maximum capacity at the “gateway” of the main transport grid, this surely would present efficiencies in terms of cost and logistics. It would also undoubtedly concentrate the hydrogen injection under one operation, owned and operated by one entity or joint venture, leading to a monopoly of production and losses of efficiencies that can only be achieved by way of free competition. This clearly would jeopardize end consumers and preclude the entrance of new companies in this niche of the upcoming hydrogen industry. There is an opportunity here to inhibit a centralized logic from the outset, laying the groundwork for more competitive energy markets.

¹² <https://www.erse.pt/media/c2hj4h3k/boletim-erse-infra-g-3%C2%BA-t-2022.pdf>

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ANNEX 1 - SENSITIVITY ANALYSIS - ELECTRICITY PRICES AND HYDROGEN SALE PRICES

Techno-Economic Analysis of Hydrogen Blending and Injection in Portugal's Gas Grid

Daniela Louback

Outputs of data tables: NPV (€000E)

2023

Capacity 2MW	PPA (€/MWh)	€	4.00	€ 4.10	€ 4.15	€ 4.20	€ 4.25	€ 4.30	€ 4.35	€ 4.40	€ 4.45	€ 4.50	€ 4.55	€ 4.60	€ 4.65	€ 4.70	€ 4.75	€ 4.80	€ 4.85	€ 4.90	€ 4.95	€ 5.00
H2 Price (€/kg)		€45.00	-589	-389	-289	-189	-99	10	110	210	310	410	510	610	710	809	909	1009	1109	1209	1309	1409
		€46.00	-714	-505	-405	-305	-205	-105	-5	94	194	294	394	494	594	694	794	893	993	1093	1193	1293
		€47.00	-858	-621	-521	-421	-321	-221	-121	-21	79	178	278	378	478	578	678	778	878	977	1077	1177
		€48.00	-990	-760	-636	-536	-437	-337	-237	-137	-37	63	163	263	362	462	562	662	762	862	962	1062
		€49.00	-1123	-891	-776	-662	-552	-452	-353	-253	-153	53	153	253	352	452	546	646	746	846	946	1046
		€50.00	-1258	-1024	-908	-792	-678	-568	-468	-368	-269	-169	31	131	231	331	431	530	630	730	830	930
		€51.00	-1395	-1157	-1040	-924	-809	-694	-584	-484	-384	-284	-184	85	15	115	215	315	415	515	615	714
		€52.00	-1517	-1293	-1175	-1057	-941	-825	-724	-600	-500	-400	-300	-200	-100	-1	99	199	299	399	499	599
		€53.00	-1656	-1430	-1310	-1192	-1074	-957	-856	-740	-626	-516	-416	-316	-216	-116	-16	83	183	283	383	483
		€54.00	-1797	-1568	-1447	-1328	-1209	-1091	-989	-872	-757	-642	-532	-432	-332	-232	-132	-32	68	168	267	367
		€55.00	-1939	-1692	-1586	-1465	-1345	-1226	-1123	-1005	-889	-773	-658	-547	-448	-348	-248	-148	48	52	152	252
		€56.00	-2065	-1833	-1726	-1604	-1482	-1362	-1243	-1140	-1022	-905	-789	-674	-563	-463	-364	-264	-164	-64	36	136
		€57.00	-2197	-1975	-1851	-1744	-1622	-1500	-1380	-1276	-1157	-1039	-922	-806	-705	-579	-479	-379	-279	-180	-80	20
		€58.00	-2342	-2102	-1994	-1869	-1762	-1639	-1518	-1413	-1293	-1174	-1056	-939	-837	-721	-606	-495	-395	-295	-195	-96
		€59.00	-2483	-2240	-2120	-2012	-1904	-1780	-1657	-1535	-1430	-1310	-1191	-1073	-970	-854	-737	-622	-511	-411	-311	-211
		€60.00	-2623	-2380	-2259	-2138	-2030	-1922	-1798	-1675	-1553	-1448	-1328	-1208	-1090	-987	-870	-754	-638	-527	-427	-327
		€61.00	-2768	-2522	-2399	-2277	-2156	-2048	-1940	-1817	-1693	-1587	-1466	-1345	-1225	-1122	-1004	-887	-770	-654	-543	-443
		€62.00	-2913	-2664	-2541	-2418	-2296	-2180	-2066	-1959	-1834	-1710	-1605	-1483	-1362	-1242	-1139	-1021	-903	-787	-685	-558
		€63.00	-3059	-2807	-2684	-2560	-2437	-2320	-2199	-2085	-1977	-1852	-1728	-1623	-1501	-1380	-1276	-1156	-1038	-920	-818	-702
		€64.00	-3206	-2953	-2827	-2704	-2580	-2460	-2338	-2217	-2103	-1995	-1870	-1763	-1640	-1518	-1397	-1293	-1173	-1055	-937	-835
		€65.00	-3352	-3099	-2973	-2847	-2723	-2599	-2479	-2357	-2236	-2121	-2013	-1888	-1781	-1658	-1536	-1431	-1310	-1191	-1071	-969

Capacity 5 MW	PPA (€/MWh)	€	3.10	€ 3.20	€ 3.30	€ 3.40	€ 3.50	€ 3.60	€ 3.70	€ 3.80	€ 3.90	€ 4.00	€ 4.10	€ 4.20	€ 4.30	€ 4.40	€ 4.50	€ 4.60	€ 4.70	€ 4.80	€ 4.90	€ 5.00
€45.00		-4618	-4008	-3447	-2862	-2289	-1705	-1205	-706	-206	293	792	1292	1791	2290	2790	3289	3789	4288	4787	5287	
€46.00		-4933	-4356	-3789	-3197	-2616	-2046	-1458	-895	-496	4	503	1002	1502	2001	2501	3000	3499	3999	4498	4997	
€47.00		-5247	-4709	-4134	-3535	-2948	-2372	-1805	-1248	-781	284	783	1282	1781	2280	2779	3278	3777	4276	4775	5274	
€48.00		-5628	-5024	-4485	-3878	-3283	-2701	-2128	-1574	-1074	-575	-75	424	923	1423	1922	2421	2921	3420	3919	4419	
€49.00		-5986	-5376	-4800	-4225	-3623	-3033	-2455	-1916	-1363	-864	-365	135	634	1133	1633	2132	2631	3131	3630	4130	
€50.00		-6343	-5724	-5127	-4576	-3966	-3370	-2818	-2242	-1653	-1153	-654	-155	345	844	1343	1843	2342	2842	3341	3840	
€51.00		-6709	-6084	-5470	-4891	-4315	-3711	-3153	-2571	-1988	-1443	-943	-444	55	555	1054	1554	2053	2552	3052	3551	
€52.00		-7075	-6443	-5827	-5219	-4647	-4055	-3492	-2904	-2325	-1755	-1233	-733	234	734	1234	1734	2233	2732	3232		
€53.00		-7441	-6809	-6183	-5573	-4982	-4405	-3836	-3240	-2655	-2080	-1522	-1022	-523	-24	476	975	1474	1974	2473	2972	
€54.00		-7807	-7175	-6544	-5924	-5322	-4758	-4183	-3580	-2989	-2408	-1868	-1312	-812	-313	186	686	1185	1684	2184	2683	
€55.00		-8173	-7541	-6910	-6283	-5668	-5073	-4495	-3924	-3327	-2739	-2195	-1601	-1102	-602	-103	396	896	1395	1895	2394	
€56.00		-8539	-7907	-7275	-6644	-6026	-5415	-4849	-4273	-3688	-3075	-2526	-1950	-1391	-892	-392	107	607	1106	1605	2105	
€57.00		-8904	-8273	-7641	-7010	-6383	-5761	-5164	-4625	-4013	-3413	-2859	-2278	-1705	-1181	-681	-182	317	817	1316	1815	
€58.00		-9270	-8639	-8007	-7376	-6744	-6124	-5519	-4940	-4363	-3756	-3197	-2610	-2032	-1470	-911	-471	28	527	1027	1526	
€59.00		-9636	-8995	-8373	-7741	-7110	-6482	-5867	-5268	-4716	-4102	-3538	-2945	-2361	-1820	-1260	-761	-261	238	738	1237	
€60.00		-10002	-9371	-8739	-8107	-7476	-6844	-6221	-5612	-5031	-4453	-3883	-3284	-2694	-2148	-1549	-1050	-550	-51	448	948	
€61.00		-10368	-9736	-9104	-8473	-7842	-7210	-6581	-5963	-5360	-4807	-4191	-3626	-3030	-2480	-1902	-1359	-840	-340	159	658	
€62.00		-10734	-10102	-9471	-8839	-8208	-7576	-6944	-6323	-5706	-5122	-4543	-3971	-3370	-2815	-2231	-1655	-1129	-630	-130	369	
€63.00		-11100	-10468	-9837	-9205	-8573	-7942	-7310	-6680	-6056	-5464	-4898	-4321	-3714	-3116	-2564	-1983	-1418	-919	-420	80	
€64.00		-11466	-10834	-10202	-9571	-8939	-8308	-7676	-7045	-6421	-5811	-5213	-4633	-4060	-3457	-2901	-2314	-1772	-1208	-709	-209	
€65.00		-11832	-11200	-10568	-9937	-9305	-8674	-8042	-7410	-6779	-6163	-5557	-4989	-4411	-3801	-3240	-2649	-2102	-1525	-998	-499	

Capacity 10 MW	PPA (€/MWh)																							
H2 Price (€/kg)	€	3.10	3.20	3.30	3.40	3.50	3.60	3.70	3.80	3.90	4.00	4.10	4.20	4.30	4.40	4.50	4.60	4.70	4.80	4.90	5.00			
€45.00		-7814	-6629	-5470	-4332	-3231	-2232	-1234	-235	1763	2761	3760	4759	5758	6756	7755	8754	9752	10751	11750				
€46.00		-8507	-7306	-6132	-5042	-3909	-2811	-1812	-813	784	1783	2782	3781	4780	5779	6778	7775	8775	9774	10773	11771			
€47.00		-9209	-7992	-6870	-5702	-4556	-3391	-2391	-1392	392	1391	2390	3389	4388	5387	6386	7385	8384	9383	10382	11381			
€48.00		-9940	-8687	-7552	-6369	-5210	-4072	-2969	-1970	-972	27	1026	2024	3023	4022	5021	6019	7018	8017	9016	10014			
€49.00		-10517	-9339	-8243	-7045	-5873	-4722	-3591	-2549	-1550	-552	447	1446	2445	3444	4442	5441	6440	7438	8437	9436			
€50.00		-11027	-9822	-8743	-7543	-6343	-5193	-4063	-3128	-2239	-1389	-539	867	1866	2865	3864	4863	5862	6860	7859	8857			
€51.00		-11493	-10723	-9574	-8423	-7221	-6044	-4888	-3812	-2707	-1709	-710	789	1288	2286	3285	4284	5283	6281	7280	8279			
€52.00		-12662	-11432	-10226	-9125	-7908	-6716	-5513	-4462	-3386	-2287	-1288	-290	709	1708	2707	3705	4704	5703	6701	7700			
€53.00		-13393	-12140	-10910	-9756	-8603	-7397	-6283	-5120	-3976	-2866	-1867	-868	311	1129	2128	3127	4125	5124	6123	7122			
€54.00		-14125	-12862	-11625	-10410	-9207	-8086	-6961	-5784	-4628	-3491	-2445	-1447	-448	551	1549	2548	3547	4546	5544	6543			
€55.00		-14857	-13594	-12336	-11117	-9938	-8793	-7646	-6456	-5288	-4139	-3024	-2025	-1027	-28	971	1968	2967	3967	4966	5965			
€56.00		-15589	-14326	-13062	-11818	-10615	-9489	-8264	-7136	-5955	-4794	-3716	-2604	-1605	-606	392	1391	2390	3389	4387	5386			
€57.00		-16320	-15057	-13794	-12539	-11306	-10120	-8963	-7824	-6630	-5457	-4369	-3182	-2184	-1185	-186	813	1811	2810	3809	4808			
€58.00		-17052	-15789	-14526	-13263	-12023	-10801	-9671	-8519	-7312	-6126	-5029	-3879	-2762	-1763	-765	234	1233	2232	3231	4229			
€59.00		-17784	-16521	-15258	-13995	-12738	-11513	-10302	-9223	-8002	-6803	-5696	-4535	-3391	-2342	-1343	-344	654	1653	2652	3650			
€60.00		-18516	-17253	-15989	-14726	-13463	-12238	-11008	-9859	-8679	-7488	-6317	-5197	-4042	-2922	-1923	-893	766	2755	3754	4753			
€61.00		-19248	-17984	-16721	-15458	-14195	-12936	-11704	-10508	-9405	-8180	-7051	-5867	-4701	-3619	-2500	-1502	-503	496	1495	2493			
€62.00		-19979	-18716	-17453	-16190	-14927	-13663	-12413	-11195	-10035	-8879	-7653	-6543	-5366	-4275	-3079	-2080	-1081	-83	916	1915			
€63.00		-20711	-19448	-18186	-16922	-15658	-14395	-13134	-11895	-10692	-9587	-8358	-7227	-6038	-4938	-3782	-2659	-1600	-661	338	1336			
€64.00		-21443	-20180	-18918	-17653	-16389	-15127	-13868	-12629	-11418	-10216	-9013	-7810	-6607	-5404	-4201	-3039	-1918	-124	241	740			
€65.00		-22175	-20911	-19648	-18385	-17122	-15859	-14596	-13332	-12103	-10899	-9699	-8498	-7297	-6096	-4897	-3741	-2617	-1818	-818	179			
€66.00		-22906	-21643	-20380	-19117	-17854	-16591	-15327	-14064	-12814	-11592	-10399	-9240	-8096	-6899	-5779	-4607	-3522	-2397	-1798	-399			
€67.00		-23638	-22375	-21112	-19849	-18585	-17322	-16059	-14796	-13533	-12296	-11085	-9951	-8796	-7687	-6547	-5275	-4109	-2975	-1976	-998			
€68.00		-24370	-23107	-21844	-20580	-19317	-18054	-16791	-15528	-14265	-13011	-11761	-10582	-9503	-8274	-7142	-5950	-4777	-3686	-2555	-1355			
€69.00	-25013.57847	-24858.4	-22575.3	-21232.1	-20048.9	-18785.8	-17522.6	-16259.5	-14996.3	-13733.1	-12489.1	-11270.5	-10133.7	-8975.7	-7754.15	-6530.53	-5443.75	-4347.19	-3190.72	-2134.82				
€70.00	-25813.36764	-23580.2	-23307	-22032.9	-20780.7	-19517.5	-18252.4	-16991.2	-15728.1	-14463.9	-13213.6	-11990.1	-10789.7	-9684.62	-8517.31	-7317.89	-6120.56	-5016.11	-3849.27	-2713.33				