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Blue sky mining: Strategy for a feasible transition in emerging countries from natural gas to hydrogen

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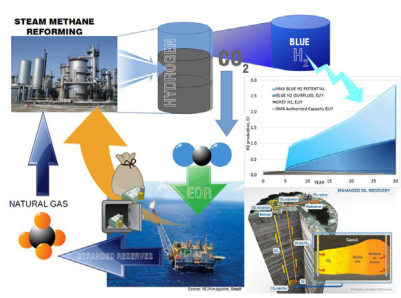
HIGHLIGHTS

- A strategy is defined for monetizing natural gas based on idle capacity in SMR units.
- Blue Hydrogen may be a feasible source of income for avoiding stranded gas reserves.
- Moderate Oil prices quickly pay investments in Blue H_2 by means of Enhanced Oil Recovery (EOR).
- This strategy can be replicated in other expanding markets.

GRAPHICAL ABSTRACT



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ABSTRACT

Natural gas is often considered a transition fuel to a deep decarbonized world. However, for this to happen, new technologies should be fostered, among which a natural gas-based H_2 industry can become a key-option. This study tests the hypothesis that the development of a natural gas-based H_2 industry equipped with CO_2 capture can monetize natural gas remaining resources, mitigate CO_2 emissions and facilitate the transition to the renewable energy-based H_2. To do that, this study evaluates a stepwise strategy for setting up the development of H2, departing from the idle capacity in the existing natural gas industry, to progressively create a H_2 independent supply. Findings indicated that this strategy can be feasible, according to the case study assessed at relatively moderate crude oil prices. Nevertheless, CO_2 storage can become a constraint to deal with the co-produced CO_2 from the steam methane reforming units. Therefore, it is worth developing storage options.

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Introduction

Upon transitioning from the intensive use of fossil fuels to renewable energies and ultimately to renewable hydrogen, the main actions are driven to the development of clean hydrogen production processes at scale, as most of the hydrogen currently produced has fossil origin. An eight-fold increase on the availability of hydrogen would be required up to 2050 [1]. Therefore, a variety of technological options, raw materials, and energy sources for hydrogen production must be made viable, taking into consideration that low environmental impact technologies will be preferred.[1]

Dincer and Acar [2] have made a thorough analysis of nineteen hydrogen production methods, which were compared based on energy and exergy efficiencies, production cost, global warming potential, acidification potential, and social cost of carbon.[2] They found that fossil fuel reforming has the highest (83%) energy efficiency and lowest cost, while biomass gasification has the highest (60%) exergy efficiency compared to other selected options. Navas-Anguita et al. [3] approached the specific case of road transportation decarbonization using hydrogen and considered different scenarios for banning the use of hydrogen from fossil-based origin (2030, 2035 and 2040) to conclude that hydrogen production by steam methane reforming with carbon capture and storage would satisfy the demand for road transport in the short-to-medium-term. The real cost-effectiveness use of fuels should consider externalities such as damage to forestry from acid rain, climate change as a result of greenhouse gas emissions, and health impacts from air pollution in cities, none of which are internalized in the form of levies, such as carbon taxes [4]. In this sense, Al-Qahtani et al. [5] presented a comprehensive assessment of the most promising ten hydrogen production technologies considering simultaneously their cost and externalities due to impacts on human health, ecosystem quality and resources depletion, by means of a correlation gathering those variables. The internalized cost of environmental externalities was combined with the levelized cost of hydrogen to generate estimates of the "real" total cost of hydrogen. The authors evaluated the influence of each variable on total cost of hydrogen, which was strongly impacted by the environmental externalities in fossil-based hydrogen, ranging from 57% to 76% in steam methane reform with and without carbon capture and storage, respectively; 62% in methane pyrolysis; 78% and 88% in coal gasification with and without carbon capture and storage, respectively. The steam methane reform with carbon capture and storage presented the lowest unabated total cost of hydrogen, US\$4.67/kgH_2, and was classified as the most effective hydrogen production route, while the levelized cost of hydrogen production was found to be US\$1.88/kgH_2 and US\$1.26/kgH_2 for steam methane reform with and without carbon capture and storage, respectively.[3] The same type of result highlighting the cost advantages of steam methane reform can be found in other studies. For instance, Muritala et al. [6] and Nazir et al. [7–9] compared the main technologies for producing hydrogen from fossil fuels and indicated that steam methane reform is the most mature and used technology worldwide and should maintain its place for producing hydrogen in the future.

Particularly, as for the hydrogen transportation and storage infrastructures, logistics might be one of the challenges for expanding hydrogen market under the energy transition [10]. Therefore, hydrogen deploying strategies often include the use of an existing natural gas infrastructure [10,11]. Injecting H_2 at low blend volumes (e.g. 15%) in natural gas pipelines is considered an attractive (lower cost) destination for near-term produced hydrogen [12–18].

Actually, Messaoudani et al. [19] reviewed main issues concerning hydrogen blending in natural gas transmission pipelines and point some key issues for attention concerning the Joule-Thompson effect, minimum ignition temperature and gas flammability. Despite these issues, the authors considered natural gas pipelines can transport hydrogen with minor changes, depending on the blending percentage applied.[4]

These findings create the basis to explore how the main and abundant present source of methane, natural gas reserves, and its industrial infrastructure may strategically contribute to the energy transition and to the design of a new hydrogen energy era.

Technically recoverable world natural gas (NG) resources amount 810 trillion cubic meters [20] and proved reserves 198.8 trillion cubic meters [21]. Such vast resources could supply world natural gas demand for the next two centuries [11]. In addition, many emerging countries rely on rich fossil fuels reserves to support development and generate economic growth. Latin America and the Caribbean, for instance, present a steadfast production increase [20], from traditional players like Venezuela, Bolivia, Trinidad & Tobago, Brazil and

[1] Presently, 96% of world H_2 comes from fossil fuels [38], being the steam methane reforming (SMR) the source of over 70% of global H_2 supply [14].

[2] Nazir et al. [7] classified the hydrogen production from fossil fuel methods according to two basic approaches, hydrocarbon reforming and hydrocarbon pyrolysis; while an early work from van der Burgt, Cantle and Boutkan [114] analyzed the synthesis gas via coal gasification, and applied both hydrogen and CO_2 for fueling combined cycle power facilities. More recently, Kaplan and Kopacz [110] assessed four variants of coal gasification to hydrogen with CCS in Poland, performing a sensitivity analysis for each case. The authors observed that coal reserves might be unexplored if there is no kind of stimulus to this technology.

[3] Alternative processes for generating blue hydrogen were also proposed in the scientific literature. For instance, Abbas, DuPont and Mahmud [47] evaluated Hydrogen production from methane decomposition into hydrogen and carbon as a possible fashion to reduce CO_2 emission and showed that thermal decomposition may become competitive to SMR Labanca [111] adopted a plasma pyrolysis process using natural gas as feedstock generating solid carbon black instead of CO_2. This process was proved to be environmentally promising. However, compared to the SMR process, it yields half the amount of conventional SMR and required high amounts of electricity.

[4] Blending was also considered for underground facilities. Reitenbach et al. [112] assessed the underground storage with blending of hydrogen in the natural gas. Le Duigou et al. [113] analyzed underground hydrogen storage (UHS) options in France, performing feasibility analysis for salt caverns and evaluating its applicability for other countries.

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Argentina [22], to newcomers like Guyana, which is preparing to explore its recently-discovered resources [23].

Natural gas has been often regarded as the transition fuel to a low carbon economy [24–28]. However, some authors disagree with addressing the transition required by the goals of the Paris Agreement via increasing natural gas direct combustion. As greenhouse gases – GHG – emissions have already reached high levels, some scenarios to comply with the Paris Agreement indicate the urgency to halt the use of fossil fuels [29]. According to Refs. [30,31] estimates, GHG emissions from the combustion of current global fossil fuel recoverable resources would emit around three times the 1100 Gt of carbon dioxide (CO2) remaining budget (between 2011 and 2100) to keep global warming below 2 °C with a 50% chance. Actually, a rapid fossil fuels phase-out is needed to meet environmental goals and avoid more aggressive climate change effects [32], meaning that natural gas unabated production should be reduced by 57% in 2050 compared to 2020 values. Moreover, a delay in responding to the rapid phase-out of fossil fuels may result in enormous economic losses, mainly in fossil fuels-based economies, and some authors consider the transition to a low-carbon economy inevitable [33].[5] Therefore, deploying a strategy to offer feasible alternatives to emerging countries to both explore their fossil resources and cut GHG emissions is important. If the Paris Agreement limits were fully applied, fossil fuel producers would have to curb their production creating a severe reduction in their wealth expectation that might reach US$ 100 trillion [34], mostly due to large volumes of stranded reserves,[6] while ambitious technical solutions like Direct Air Capture of CO_2 remain unconsolidated [35].

In sum, to define a strategy to minimize stranded reserves is paramount for fossil-fuel abundant and depending regions [36,37]. At the same time, hydrogen can become key in deep decarbonization scenarios [10,12,38–40], although its production mostly relies on steam methane reform, as of today. Therefore, the hypothesis of this study is that the blue H_2[7] may be an option to monetize natural gas resources, while bridging towards a low carbon economy [41]. CCS with Steam Methane Reforming (SMR) plants can reduce carbon emissions in up to 90%, if applied to process and energy CO_2 emission streams [42]. Moreover, a proposed hydrogen deploying strategy should include step-by-step the use of the existing natural gas infrastructure [10,11], both the hydrogen production units and the gas pipelines and storage sites, in order to create a market (the learning-by-doing and using) for the hydrogen.

This is the aim of this study: to propose a step-by-step strategy to foster the production and use of hydrogen, starting from the blue hydrogen. Such strategy departs from the conventional NG industry to progressively create a H_2 mass industry. In other words, benefiting from the idle capacity in existing conventional fossil fuel facilities to stablish and raise an independent H_2 industry.

To the best of our knowledge, no study has up to date delimited this type of stepwise strategy for setting up a blue H_2 development, departing from the idle capacity in the NG industry. A blue hydrogen production strategy remains a challenging universal issue. For instance, in the United States of America, information on national production is not easily gathered. Sun et al. [43] developed a methodology assessing H_2 production in SMR facilities. Furthermore, they estimated emitted CO_2 from those facilities in order to give subsides for future studies. Collodi et al. [44] evaluated the performance and cost of a green field modern SMR plant producing H_2 from natural gas as feedstock/fuel operating in merchant plant mode. The authors mention some projects in the area, including a pilot plant injecting CO_2 from SMR processes for EOR production in the USA, two in construction (Canada and United Emirates) and evaluate better capture techniques. Findings showed overall capture rate from 53 to 90%. Díaz-Herrera et al. [45] evaluated a Blue hydrogen SMR plant in Mexico and Anguita et al. [46] assessed SMR in Spain. While the latter identify the barriers for developing projects, the former indicate that SMR should meet the blue hydrogen market needs by 2040. Finally, Abbas et al. [47] developed SMR models for small scale and evaluated CO_2 emissions impact.

This study aims to close this gap by proposing a case study for Brazil, considering its near-future gas production expansion, the already existing H_2 production in the country's oil refineries and the existing NG pipelines. The case study illustrates a strategy and procedures that can be well replicated in other countries/regions where there is an already installed NG industry.

This study firstly describes in section Materials and methods the applied Materials and Methods, starting from its main premises and, then, detailing the proposed strategy and the methodology to assess it. Section Results and discussion presents and discusses the findings of the study, while section Conclusion concludes it by raising its main lessons. The Supplementary Material of this paper details the data from the case study and provides additional tables and figures of the results found.

Materials and methods

Premises

The Blue H_2 strategy herein proposed intends to comply with a steadfast environmental commitment and offers windows for reaching next maturity levels. The main premises that

[5] The COVID-19 pandemic did not change the urge for a transition to low-carbon economy [106], since CO_2 emissions decrease due to the economic crisis caused by the pandemic should not endure with economic recovery [20].

[6] Stranded assets will no longer be able to provide economic return as planned at some time prior to the end of their economic life due to changes associated with the transition to a low-carbon economy [104]. This unbalance would occur due to disruptive changes that yield lower internal rate of return for fossil fuels production in a lower demand and prices scenario than those conditions anticipated at the investment decision point [109].

[7] In this study, we apply the following definitions [13,41]: H_2 is classified as Grey, Blue and Green. Grey H_2 is gas produced by thermochemical conversion (such as steam methane reforming) of fossil fuels without carbon capture. Blue H_2 is also produced by thermochemical conversion of fossil fuels but now equipped with CCS. Green H_2 is a renewable gas produced mainly by water electrolysis using renewable electricity sources such as solar PV, wind and others, and also from biomasses.

support this strategy must deal with regulatory and technical assumptions.

Regulatory aspects

This work considers that countries and regions might possess poorly-developed markets for H_2, but may count on a minimum established infrastructure for natural gas, like pipelines and traditional H_2 production units (HPU) from natural gas. For countries or regions where H_2 regulatory maturity is yet to be established, we propose a minimum of two years lag time prior to defining a regulatory framework.

Natural gas infrastructure: pipelines, processing and H_2-NG blending

For the purpose of this study, transport networks include high-pressure pipelines (above 2 MPa) and distribution networks include medium and low-pressure pipelines (0.2–2 MPa). Natural Gas goes through processing in Natural Gas Processing Units (NGPU) prior to being transported and distributed to final users. Those units adjust NG composition to its quality regulation (CH_4% mol > 85) [48], separating methane and ethane from heavier fractions (the so-called C_{2+}). Simulated new NG processing facilities are similar Comperj,[8] presenting a capacity of 21 Mm^3/d of raw NG. Gas volumes are expressed in Normal cubic meters.[9]

Blending volumes limits of NG and H_2 in pipelines may vary [15,49]. However, most authors agree that 15% v/v is a safe value. This study applies this limit, considering pipelines maximum declared capacity. Embrittlement is one of the most present concerns in injecting H_2 in NG systems [49,50] and it could lead to leakage [1,15,51]. Therefore, H_2 blending would start in networks disposing of relatively new facilities (built after 2000), [52]. This study considers that investors might replace pipelines after 10 years or built H_2 dedicated networks. Blending might take place in both transport and distribution networks, but in this work we consider only blending in transport pipelines.

Hydrogen production and steam methane reforming (SMR)

Being focused on NG conversion, this study does not evaluate alternatives methods for producing H_2 in addition to the conventional SMR, whose feedstock is the processed (dry) Natural Gas. For this facility, this study assumes that by 2025 all authorized units will become operational, hence adding full Grey H_2 capacity for refining use. H_2 facilities planned according to the present strategy will produce according to the Steam Methane Reforming (SMR) process and sized for producing 5.76 MNm^3/d H_2.

Carbon capture and storage and Enhanced Oil Recovery

Carbon emissions related to the H_2 production process have to be captured. In this study, enhanced Oil Recovery (EOR) techniques are used to inject CO_2 in oilfields. CO_2-EOR is a proven technology used since mid-1980's in the USA [53] and for more than 20 years in Europe [54]. Several fluids may be used for oil recovery and Mechanical Vapor Recompression (MVR) is a suitable technology to increase recovery outputs [55,56]. It has been also used to store more than 260 million metric-tons of anthropogenic CO_2, being suitable for producing low-carbon H_2 [57]. EOR technologies meet 50% of the CO_2 storage projects in the world [56].

Planned CO_2 pipelines flowing supercritical fluid, in offshore operation, are 250 km long, with 25 MPa design pressure and built with API65XL type steel [58–60]. Revenues from oil production increase with CO_2-EOR provide monetary resources to expand infrastructure.

Basic strategy

The energy transition strategy from fossil fuels to low carbon economy through H_2 is divided into three steps: Fossil Fuel Domain (short term), Transition (medium term) and Green Energy (long term). Those steps describe a process where fading characteristics of the previous step give place to rising forms of the next. Therefore, blurred areas may appear, mainly in years between steps.

The stepwise strategy developed in this work focuses on the short and medium-term steps (first and second steps), addressing boundary conditions for these two steps rather than detailing the third one. The reason for this is that we consider whether an effective transition is feasible, a H_2 market independent from fossil fuel logistic chain would be reached. In such conditions, Green H_2 would become a natural choice, fostering independent producers to connect to a future and developed H_2 network. Therefore, along this 3-steps strategy, we take advantage of the existing infrastructure to comply with current and future energy demands. In addition, progressive milestones are landed for opening space to reach an independent H_2 market.

Short-term step – Fossil Domain

This first step benefits from the current H_2 idle production capacity, which also defines network injection points and the start-up time for mixing H_2 into NG networks until a maximum pre-defined blend, according to thermodynamic parameters (Wobbe Index, e.g.) and pipeline specification. Besides, H_2 investments are totally dependent on decision makers linked to fossil fuels companies. This step is effective as long as idle capacity is available, bearing in mind that new facilities should become available for producing Blue H_2.

Current H_2 production capacity is strongly related to oil refining capacity where Grey H_2 is produced for hydrotreating purposes or chemical use. Production idle capacities provide H_2 volumes that can be made available to be blended into natural gas networks. Since refineries are already connected to NG networks, H_2 would be injected in those city gates (delivery points) with minor engineering changes [15]. In such circumstances, NG traders might profit from carbon credits by selling a mix of NG and H_2 [41] and H_2 gains shares in NG markets. Meanwhile, investor will have time to develop EOR projects, processing, transporting and H_2 producing facilities. Fig. 1 shows how information is collected, addressing H_2 injection in the NG network.

The theoretical H_2 injection volume blends offers the possibility to evaluate a ramp up for H_2 injection in existing facilities. In Europe [61], estimates a blend up to 10% in NG

[8] Comperj is the most recent facility designed in Brazil, still under construction [108]. It includes SMR and NGPU units.

[9] Normal conditions are 20 °C and 101.3 MPa [48].

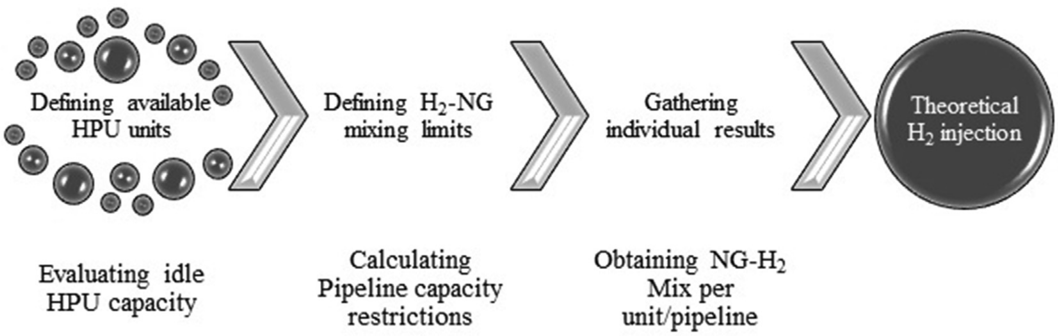

Fig. 1 – Stepwise method for obtaining reliable H_2 theoretical injection volumes – first step.

networks when preparing exclusive H_2 pipelines by retrofitting existing systems. In the USA [15], evaluates that within a range between 5 and 15% H_2 v/v no additional risk is added to deliver gas to households and other consumers. Some specialists go further to a blend up to 20%, depending on the local natural gas composition and the pipeline network, recalling that blended H_2 is an old technology, applied since mid-1800 in the USA in a blend varying from 30 to 60%, called "manufactured gas" or "town gas" [1]. According to the same authors, if infrastructure and appliances upgrades are done under control, pure H_2 networks are possible. Main adaptations would require leakage control improvements, retrofitting remaining steel pipelines against H_2 embrittlement or replacing them with noncorrosive and non-permeable materials, such as polyethylene or fiber-reinforced polymers.

To evaluate the energy delivered and estimate maximum H_2 volumetric blends the Wobbe index may be used so as to meet customer energy demands[10]. This index is obtained as follows [62]:

$$W = \frac{H_s}{\sqrt{\frac{\rho_g}{\rho_a}}}, \tag{1}$$

where: W = Wobbe index.

Hs = High heating value (HVV), J/m^3

$\rho_{g,a}$ = gas/air densities.

The Wobbe index is directly proportional to the quantity of combustion energy supplied through a nozzle for a burning process, and it depends on the gas composition [51]. In general, gross calorific values and densities are available in standard conditions. For Wobbe calculation, the standard condition must be the same for air and gas densities, so as for calorific value. In this study, a maximum of 15% v/v blend was applied considering pipelines maximum declared capacity and the Wobbe index was evaluated for a similar range.

Finally, in this first step, existing H_2 production units produce essentially Grey H_2. Blue H_2 starts from compensating emissions from existing H_2 production in Year 5 and not sooner. At least a pipeline or some infrastructure should be built for CO_2 transport to injection field and for CO_2 capture. Estimates indicate that pipeline design and construction time takes no less than 5 years, time that would be needed before starting emissions compensation [63].

[10] This study criteria keep existing consumption devices instead of installing or converting equipment.

Medium-term step – transition period

The second step aims at developing a Blue H_2 supply to support decision makers to meet decarbonization while monetizing it. It considers NG supply increase and requires both greenfield plants for increasing H_2 production capacity and CCS infrastructure deployment for storing CO_2, since planned facilities for H_2 production must be associated with CO_2 injection field and connected to the CO_2 pipeline. CO_2 from H_2 production increasingly fills export pipeline as oil production from CO_2-EOR increases. Facilities dedicated to H_2 production are built, notwithstanding refinery capacity, preferably next to Natural Gas Processing Units (NGPU). Collected CO_2 in these units are transported to a main pipeline next to the production zone. Market development allows building a relationship client–customer between H_2 producers and fossil fuels producers, increasing the independence of the latter from the former.

After developing a H_2 market for energy use, Grey H_2 decreases. Traditional producers are stimulated to neutralize H_2 emissions and regulation is assumed mature for both H_2 and CO_2 transport modals. Contractors build new pipelines and government launches bids for operators, who sale H_2 transport service for carriers meeting consumers demand. In the future, Green H_2 producers may also connect to the network, connecting medium and long term strategies and completing transition for green energy.

Pipeline sizing and cost estimation

Considering the preliminary approach of this study, CO_2 pipeline sizing was performed on a simplified flow for compressible fluids considering Darcy's formula. Churchill's correlation was chosen for calculating friction factor [64]. Complementary data for pipeline sizing like wall thickness were obtained from Brazilian Standard NBR-12712 [65]. Addressing adequate pipe sizing [66], indicated a practical rule of thumb including pressure losses between 15 and 25 kPa/km. This practical approach was applied in this work. Reference costs for CO_2 pipelines is given by Eq. (2). In spite of displaying values that might not be updated [67], brings a practical approach, allowing immediate evaluation of pipeline costs per tCO_2. This correlation was obtained from those values.

$$C = 9.3235M^{-0.596},\ R^2 = 0.9993 \tag{2}$$

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where, C = Cost US$/t$CO_2$/250 km.

M = Mass flow rate (MtCO_2/y).

Recent studies have addressed CO_2 pipeline costs. Kjärstad [68] shows that ship transporting is advantageous over pipelines in Nordic countries due to low volumes required. Eq. (3) approaches a correlation obtained from values found for a 730 km offshore pipeline in Norway [68].

$$C = 39.9M^{-0.596},\ R^2 = 0.9853 \quad (3)$$

where, C = Cost (€/tCO_2/250 km).

M = Mass flow rate (MtCO_2/y).

According to the authors, for volumes higher than 1.3 MtCO_2, pipelines become a less costly transport solution compared to ships. Knoope [69] found costs for a 300 km pipeline about 0.11–0.64 M€$_{2010}$/km for 0.30 m diameter and 1.5–13 M€$_{2010}$/km for 1.30 m diameter.

A detailed method for pipeline cost calculation is out of the scope of this work. However, it may be found in Refs. [69,70]. For some specific aspects, like CO_2 hub formation, Costa et al. [71] designed a model based on a Kernel density estimator for the Iberian Peninsula. Gathering lessons learnt from pipeline construction [72], summarizes key costs drivers for pipelines in the following items:

- Piping (type and grade of material)
- Equipment (such as compressors, booster stations, valves, crack arrestors, etc.)
- Trenching (i.e. earthworks, excavation, backfilling)
- Distance
- Diameter
- Terrain
- Labor
- Engineering (e.g. design, project management, regulatory/permitting activities)

Case study description

This study simulates the proposed strategy in the Brazilian NG infrastructure. Brazil is a potentially high-producing H_2 country, whose 1P and 3P Natural Gas reserves total 364.6×10^9 m^3 and 550.0×10^9 m^3, respectively [73], and the NG production is expected to increase up to 253 million m^3/day in 2029 [74] and 501.7 million m^3/day in 2050 [75].[11] These perspectives point towards an infrastructure development, similar to other Latin American and emerging countries with plenty NG remaining resources [20,21].

Existing infrastructure facilities

The Brazilian gas transport (interstate, high pressure) infrastructure has 9409 km of pipelines from 8 to 38 inches[12] [52] and the maximum operating pressure (MAOP) between 20 and 100 kgf/cm^2 [76].[13]

This network relies on 3 operating and 1 authorized Liquefied NG regasification terminals with total capacity of 62 Mm^3/d [52], 14 Natural Gas Processing Units (NGPU) totaling 107,210 Mm^3/d of nominal capacity [77], 36,290 km of distribution (intrastate, low pressure) pipelines and 4650 km of production flow pipelines [52].

IEA expects a growth in NG production in Central and South America (CSA) in the period from 2020 to 2040. Brazil does not diverge from this expectation [20]: In the "Stated Policies Scenario", IEA expects a production increase from 174 to 244 billion cubic meters in CSA between 2019 and 2040. In the same period, Brazilian NG production should double, going from 26 to 58 billion m^3. The Brazilian government [74,75,78] also forecasted growth scenarios for NG production in the next decades. Those projections indicate that by 2027 NG processing infrastructure might reach its full capacity.

Since H_2 blending should take place in networks possessing relatively new facilities and around 20% of the pipeline network length was built before 2000, it is likely that those pipelines would not be adequate for H_2 blending due to regular use wear. Therefore, initial H_2 production curve is smooth, considering currently grey H_2 production, and might not use all facilities in the beginning years.

CO_2 storage potential

Brazil's CO_2 storage potential is above 100 GtCO_2 [79]. Recently [80], estimated the CO_2 storage potential of 108 Mt of CO_2 in salt caverns built in ultra-deep Brazilian pre-salt layers. Rockett et al. [81] mentioned a total storage capacity of ca 2000 Gt CO_2 in Brazil, assessing specific storage capacities of 1800 Gt CO_2 and 167 MtCO_2 respectively for Campos and Santos basins, while calculated, in a more accurate approach, 950 Mt CO_2 for 17 specific fields in Campos' basin. Likewise [53], estimated for Campos' basin a 1.1 Gt CO_2 storage potential considering CO_2-EOR techniques.

Nevertheless, conservatively this study departs from forecasted oil production to estimate possible CO_2-EOR in the studied time frame. In Brazil, CO_2-EOR is a currently used technique [82]. Ravagnani [83] evaluates that 2.58 tCO_2 are injected for obtaining 1 m^3 of oil with EOR technique. Similar ratio can be obtained from values described in Ref. [84], around 2.45t CO_2/m^3 oil. Alternatively [53], estimates between 0.26 and 0.31 t CO_2 per incremental oil barrel produced.

EOR production factor increase depends on several factors, and [84] indicates values ranging between 7 and 23% of total oil in place (OIP), with an average of 13%. Other authors [85] corroborate that range for miscible mixtures between CO_2 and oil in EOR. Concerning Chinese oilfields, Hill [86] estimated 6%–10% of total oil in place (OIP) production increase. However, the authors highlight that China does not inject supercritical CO_2, which stimulates miscibility and increases productivity. More recent studies reported incremental oil recovery ranging from 6.09 to 22.83% OIP for techniques of CO_2-EOR [87].

Future oil production in Brazil is expected to increase. In fact, daily production should rise by 60% in 2050, compared to 2020. In this study, we consider that part of this growth production might be spurred by CO_2-EOR techniques. In this case study we consider this forecasted oil production for estimate CO_2-EOR storage availability and compare it to CO_2 storage

[11] From this point on, million m^3/day will be indicated as Mm^3/d and, for year, d will be replaced by "y".

[12] Pipelines are usually traded in diameters named in inches (nominal size). The above values range from 203.2 to 965.2 mm (SI units).

[13] 1961.33–9806.65 kPa.

needs from H_2 production. If expected CO_2-EOR storage availability is higher than CO_2 produced in H_2 plants, the maximum H_2 production generation is reached. Otherwise, it sets a curb for H_2 production, assumed to be Blue H_2 in this study. Future oil production in Brazil is expected to increase from 3.24 million bbl/d in 2020 to 5.30 million bbl/d in 2050 [74,78].

As premise, only part of this production growth will be based on CO_2-EOR. Based on previous studies [87], we considered technical learning would allow gains in EOR starting from 7% up to 23% daily production, in analogy to the above references.

A CO_2 pipeline is sized considering supercritical flow to convey captured gas to injection facilities. Such case is relevant when both H_2 and oil production sites lie close to each other. In Brazil, it occurs quite often, since production frontiers are offshore and several HPU facilities are installed close to the shore. Natural Gas Processing Unities (NGPU) are even closer to the shore, which means that those facilities may be feasible locations for future H_2 producers in an independent market.

Pipeline costs

For countries where CO_2 supercritical pipeline costs are not available, the analogy with natural gas pipelines is a usual approach, as proposed in Ref. [69], where the author highlights that traditional costs were based on superseded costs from North American natural gas pipelines, and further proposed a change in those models by an updated model. Since in Brazil most resources are deployed offshore, recently-built and projected production flow pipelines that connect offshore fields and processing units onshore might be a good approach for cost evaluation.

Values sources vary from 2012 to 2019 and were equaled in the same base date according to Refs. [88,89] for exchange rates and base date prices. These values were compared to those indicated in specific costs for CO_2 pipelines previously cited [67,68] and updated to base year 2019 according to Ref. [90].

H_2 production potential

As mentioned before, H_2 production requires mainly dry NG, free from heavier fractions and composed by lighter fractions, such as methane and a low portion of ethane [91]. Therefore, not all raw NG volumes are available for producing H_2. Processing factor in Brazilian NGPU may be obtained from historical data [77]. In 2019, 22,930 Mm^3 NG were processed in Brazil, generating 20,970 Mm^3 dry NG. This leads to a processing factor of 0.91, or 91% of the produced NG reaches the required qualification to produce H_2. Heavier fractions (rich gas) are sold as ethane, LGP (propane, butane) and naphtha (C_{5+}). For the purposes of this study, we apply this processing factor in all raw NG streams.

Not before 2 years blending actions in the NG networks should start, since in Brazil, as in other emerging countries, H_2 blending is not yet regulated. Currently valid regulation for NG does not mention H_2 [48] in transport pipelines.

Authorized refinery capacity totals 2411 million barrels/day of processed oil in 19 facilities. Nonetheless, H_2 generation capacity (HPU) is restricted to 11 refineries, all of them connected to NG network. Brazil's H_2 generation capacity (HPU) is located to 11 refineries connected to NG networks, totaling 25,838.44 kNm^3/d or 31,598.44 kNm^3/d. Average capacity use is 74.4%, and idle capacity is 25.6% [92–94].

Recently, the Brazilian government published forecasts revealing a vast production potential for natural gas [74,75,78]. Such optimistic forecast for natural gas production compares a business-*as*-usual production scenario to a "new gas market" scenario, featuring a surplus between those two scenarios departing from 53 Mm^3/d in 2020, reaching 245 Mm^3/d.

Under a conservative perspective that considers that the NG supply of the business-*as*-usual scenario would have a guaranteed market, this study expects that the Blue H_2 might spur the "New Gas Market", offering a low carbon option for monetizing these resources thus decreasing CO_2 emissions. Therefore, we suppose that the NG forecast in the reference scenario would be used in conventional application. However, NG surplus provided in the New Gas Market possibility could be employed in Blue H_2 generation, including new facilities and required infrastructure.

Likewise, in the current strategy we anticipate processing extra capacity from year 6 onwards. Therefore, Blue H_2 production will come from greenfield projects, increasing current H_2 production.

Therefore, the H_2 potential production related to this NG supply expansion, via SMR based Brazilian existing HPU, is obtained from Ref. [91] and corresponds to a weight ratio of 0.4208 kg H_2/kg NG. Potential H_2 may be found in Table 1.

HPU and NGPU capacity expansion

Processing units costs were obtained from Ref. [95]. This cost was updated to the base date[14] and converted to US$, obtaining a current value of US $395.58 million. For the H_2 production, Yan et al. [96], addressed Blue H_2 production obtaining capital costs ranging from £188.7 to 293.0 (US$ 232.42 to US$ 360.89) million and operational costs from £237.5 to 329.8 (US$ 292.53 to US$ 406.21) million, while Yan et al. [97] analyzed H_2 purification in Pressure Swing Adsorption (PSA) processes. Other studies, like [98] obtained operational cost for H_2 production for conventional SMR 0,130 €/Nm^3 (0.1444 US$/$Nm^3$). Considering Brazilian facilities, Labanca [99] evaluated costs ranging from 2080.0 to 2655.4 US$/t H_2. In the present study, we have adopted the following values to estimate production costs and required investments for evaluating Blue H_2: applied unitary costs were 2655.4 US$/t H_2 for SMR [99] and US $25.90 million/$m^3$d NG [95].

Results and discussion

According to the strategy proposed by this study, the short and medium-term steps (first and second steps) were essential for developing a H_2 market. This section will present global results for H_2 production and CO_2 emissions discussing each step, as previously expressed. The strategy refers to the proposed steps, rather to the time span between them. For instance, if regulatory framework is ready in a country or

[14] Base year in 2019, and obtained rates are available in Ref. [88].

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Table 1 – Potential H_2 (elaborated from Refs. [74,75]).

Year	Natural gas production, MNm^3/d			Hydrogen production, MNm^3/d	
	A	B	C	D	E
	Conventional use (Business as usual)	NG Surplus (available for new uses)	Maximum forecasted production (A + B),	Potential from NG surplus (B)	Max Potential H_2 (from A + B)
0	77.7	53.6	131.3	**1124.9**	**2755.8**
1	73.4	52.7	126.1	**1105.3**	**2645.6**
2	71.1	43.5	114.6	**912.8**	**2404.6**
3	70.0	44.1	114.1	**925.8**	**2395.2**
4	66.6	49.5	116.2	**1039.8**	**2438.1**
5	68.6	53.4	122.0	**1119.9**	**2559.3**
6	81.5	55.8	137.4	**1171.9**	**2883.0**
7	98.0	57.9	155.9	**1214.5**	**3270.8**
8	115.3	53.0	168.3	**1111.7**	**3530.8**
9	136.8	43.7	180.5	**917.1**	**3787.0**
10	136.8	43.7	180.5	**917.1**	**3787.0**
20	156.8	150.2	307.0	**3151.0**	**6441.5**
30	256.3	245.4	501.7	**5150.6**	**10,529.1**

region, this lag time could be leaped, and all strategy anticipated.

Short-term step – Fossil Domain

Currently, the installed capacity for producing H_2 is 25.8 MNm^3 H_2/d (0.112 EJ/y).[15] If authorized SMR facility starts up, it might reach 31.6 MNm^3 H_2/d (0.137 EJ/y). This first step benefits from the current H_2 idle production capacity, which also defines network injection points and the start-up time for mixing H_2 in NG networks until a maximum pre-defined blend, according to thermodynamic parameters (Wobbe Index, e.g.).

H_2 blending becomes possible from year 2 onwards and full installed capacity 25.8 MNm^3 H_2/d might be reached if main H_2 producers increase operation for injecting in the network. It is possible to see blending volumes in the left axis (Fig. 2a), increasing up to 5.4 MNm^3 H_2/d in Y10 (see Fig. 3).

Grey and Blue H_2 forecasts may be observed in (Fig. 2b). Total H_2 production might reach 0.40 EJ in 2030 (Y10). Grey H_2 would depart from the current production of 0.087 EJ and would peak (0.137 EJ) by year 7, after capacity increase. Therefore, within this step, Blue H_2 should depend on new SMR facilities. As a CO_2 pipeline should operate from year 5 onwards, Blue H_2 production will receive a strong push forward, flowing CO_2 captured from new SMR facilities.

Extra H_2 capacity production for Blue H_2 would be required from year 6 onwards. Two extra SMR units producing 5.76 MNm^3H_2/d would be required to meet NG estimated production. Likewise, considering that existing NG processing facilities might be equally busy, then two dedicated processing units of 21 MNm^3 H_2/d would be required for treating forecasted NG production up to Y10.

This first transition is not a rigid landmark, but it would occur when new H_2 production facilities become available. This strategy extends from year 6 to year 10, period in which Blue H_2 slowly displaces Grey H_2 and further increases.

This slow transition from installed Grey H_2 capacity to Blue H_2 should be explained. Firstly, it occurs slowly due to Grey H_2 facilities residual development. Secondly, it is likely that facilities designed for producing Grey H_2 take some time to compensate their emissions postponing their conversion prior to becoming Blue H_2 producers, since CO_2 capture and transport facilities are not originally in the scope of those facilities. At last, some of them may not be installed close enough to the CO_2 transport network. Fig. 2b displays this initial transition from Grey to Blue H_2. However, some compensation may be possible. Therefore, installed Grey H_2 loses some fraction, mostly linked to blended gas.

During the Fossil Domain, H_2 investments are totally dependent on decision makers linked to fossil fuels companies. Capacity use departs from average 74.4% in Y0. Most of the H_2 production capacity (0.11 EJ/y) is strongly related to oil refining capacity and mostly Grey H_2 is produced for refining purposes or chemical use. This step would take as long as new facilities become available for producing and trading H_2. However, during this period H_2 trading may find a constraint, which is the maximum installed capacity of H_2 conversion in Brazil in year 0. H_2 blending in the network for commissioning purposes starts in Y3 (grey H_2) in selected spots in the network, overall percentage of 0.41% in Y3, increasing up to close to global 15% in Y7. Yet, it is relevant to evaluate local blending should not overcome blending limits. Between Y5-10, it is possible to foresee at least one 100%-H_2 pipeline ramp up, which would influence overall H_2 use.

H_2 production reaches full capacity in year 6 when the authorized Comperj SMR facility starts operation. This new facility does not meaningfully change installed capacity use because its capacity is mostly committed to refining process. Surely, it implies that planners should prepare and design new SMR facilities previously. Simultaneously, Blue H_2 production begins in Y5, reaching 0.4 EJ in Y10. In the present strategy, two new SMR facilities would be required in year 6. Those units would meet H_2 generation requirements up to year 11.

H_2 production increases more than fourfold in the first ten years, 75% of this being Blue H_2, prior to develop internal

[15] Considering reference H_2 density value 0.0838 kg/m^3 @ 20 °C, 1 atm and High Heating Value 11.915 MJ/m^3 [107].

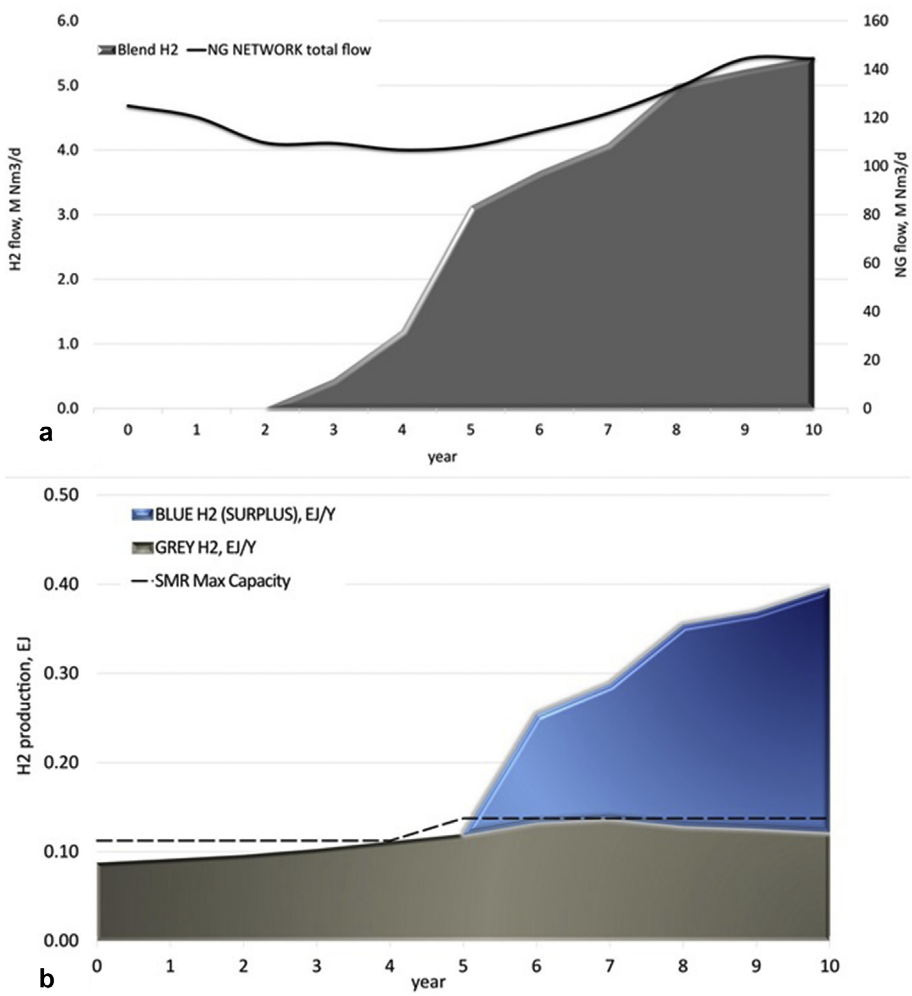

Fig. 2 – H_2 results during the Fossil Domain: (a) H_2 blending volumes in the network; (b) H_2 production.

market according to the current strategy. In Y10, Blue H_2 is 0.3 EJ, while Grey H2 reaches 0.1 EJ.

In order to avoid a constraint after Y5 due to a lack of CO_2 for EOR, the proposed strategy considers a CO_2 pipeline for making the production of Blue H_2 possible. Fig. 7a shows CO_2 emissions and oil production using the CO_2-EOR technique.

CO_2 emissions from the indicated SMR facilities would start at 3.0 Mt CO_2 in year 5, reaching 11.0 Mt CO_2 in year 10. In principle, these volumes are independent from CO_2 storage capacity for EOR production, since they are based on NG availability. But, if oil production requires less CO_2 than SMR supplies, Blue H_2 is curbed. For new facilities, only Blue H_2 is allowed in this strategy.

EOR presented an increasing pace, according to oil production. During this period, CO_2 use in EOR techniques is more than enough for the forecasted oil production, and EOR stands for 15% of overall oil production (Fig. 7b).

Blended Natural gas delivery depends on transport pipelines and requires specific analysis, since capacity sizing would involve locational aspects in order to investigate eventual bottlenecks in the network [63]. However, in this work some considerations are entailed related to energy delivery through blending. In Brazil, Wobbe index ranges from 46.5 to 53.5 MJ/m^3 in transport networks [48]. Calculated H_2 Wobbe index is 46.5 MJ/m^3 [100,101]. Although maximum allowed blend in this work is 15% v/v, we simulated energy losses per volume up to 21.2% v/v H_2/NG blending. Energy losses due to blending may be seen in Fig. 4.

Blending causes losses of 3.3% on delivered energy for 21% H_2 in blending, which means that if NG might be supplied in the maximum allowed Wobbe number, 53.5 MJ/m^3, blending H_2 to NG would supply energy equivalent to 51.0 MJ/m^3. For 15% blending it would represent less than 3%. Regulatory tolerance of 13.1% is much higher than variation caused by H_2 blending, indicating that H_2 blending would likely be absorbed by NG clients.

Medium-term step – transition period and forward

This second step happens after both greenfield plants for producing H_2 and CCS infrastructure operate reliably. Since market development allows building a relationship client–customer between H_2 producers and fossil fuels producers, NG pipelines may be replaced by H_2 pipelines, and full-H_2 networks become available. Households and industry adapt their equipment, turning them able to use H_2. After blended H_2 was spread, safety tests should guarantee those applications. New facilities for H_2 production are designed in

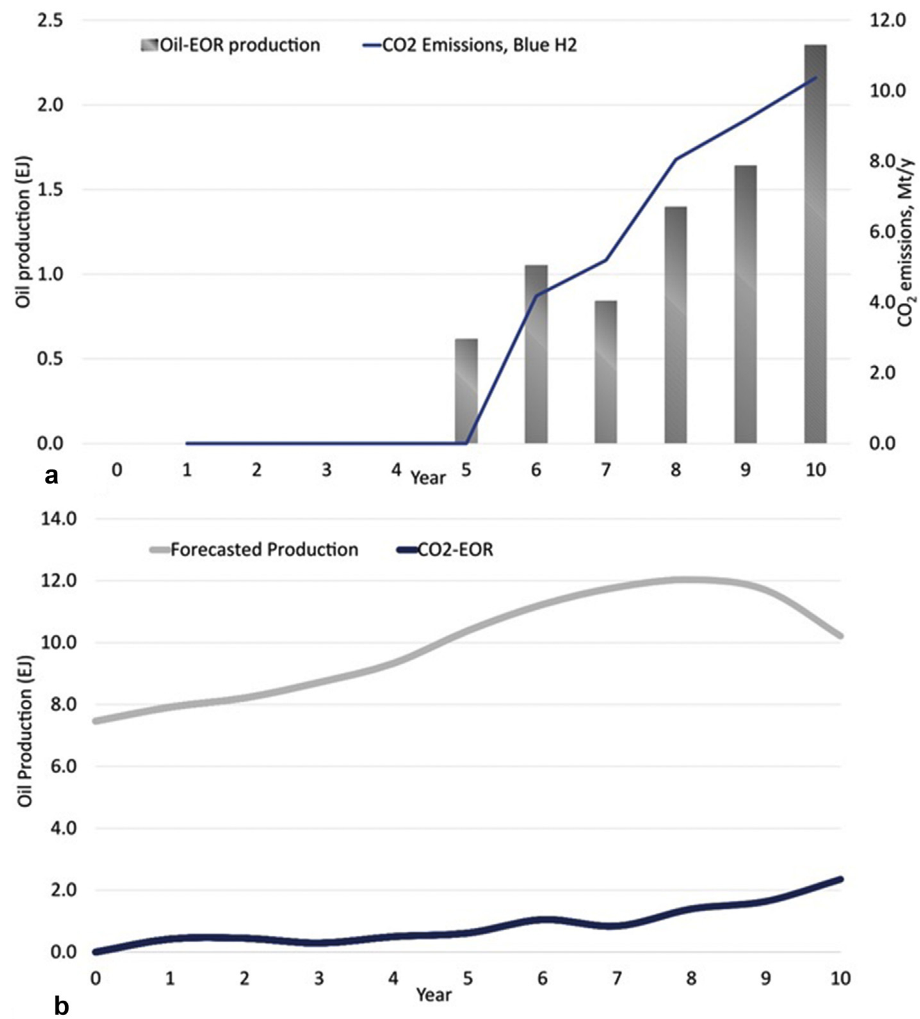

Fig. 3 – EOR Results in the first ten-year period: (a) additional oil production and injected CO_2; (b) total oil production (Y1–Y10), with EOR derived production highlighted in blue. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

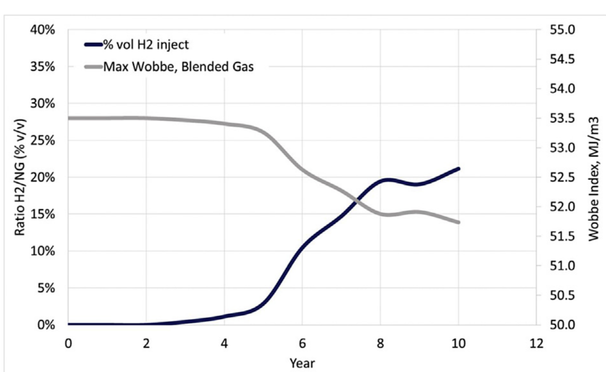

Fig. 4 – Wobbe index of different H2/NG blends.

association with CO_2 storage fields and turned available by connection through a structuring pipeline. Captured CO_2 from H_2 production increasingly fills export pipeline as oil production from CO_2-EOR increases. Fig. 5 shows obtained results.

During the transition domain, H_2 investments gain relative independence from decision makers linked to fossil fuels companies. Although it departs from a condition in which most of H_2 production capacity is still related to oil refining, Blue H_2 gains pace, attracting investors. SMR units' locations displace from refineries and may be installed close to NGPUs, thus injecting blended H_2 in the NG network or connecting to exclusive H_2 pipelines.

As a comparative standard, this study refers to the Europe Decarbonization pathway [41]. In this reference, two main scenarios are described, starting from a current H_2 demand of 329 TWh (1.2 EJ). The European "current policy scenario" previewed to reach 0.5 EJ in 2040 and 0.54 EJ in 2050. As for the "accelerated decarbonization pathway", 2270 TWh in 2050 (8.17 EJ) H_2 demand, 1600 TWh (5.76 EJ) of which green H_2. Blue H_2 would stand for 600 TWh (2.16 EJ) in 2050 in Europe. Thus, non-green H_2 use would reach 670 TWh (2.4 EJ) in 2050. Compared to this reference, Fig. 5 shows that total H_2 production might reach 0.8 EJ, in (Y20) and 1.13 EJ in (Y30), respectively 0.7 and 1.11 EJ corresponding to Blue H_2. Grey H_2 would go from the current

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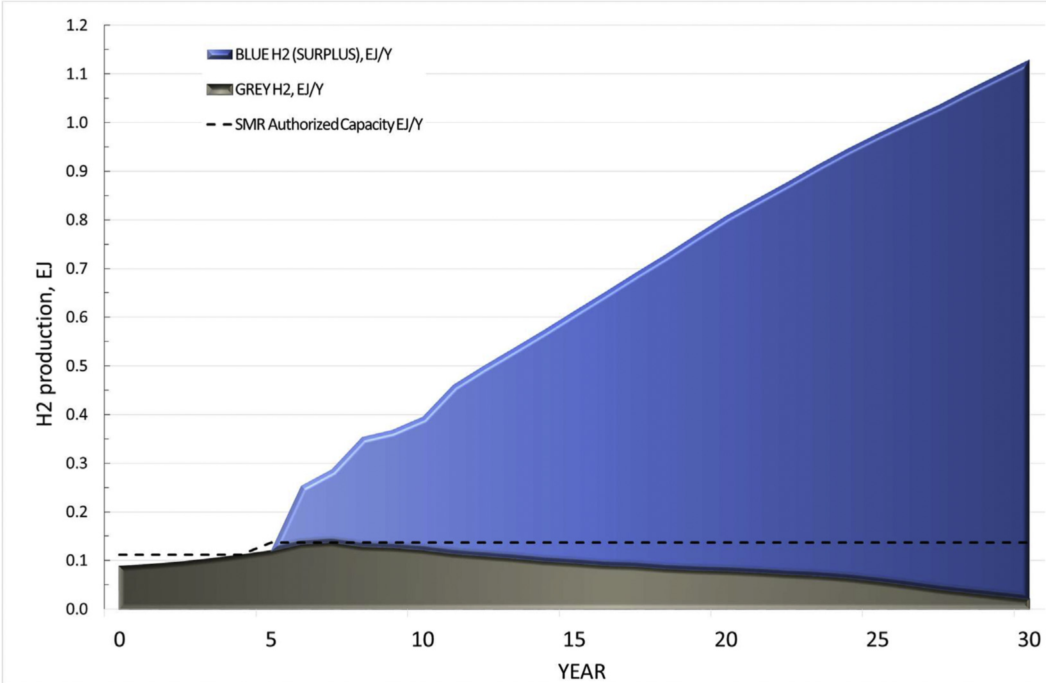

Fig. 5 — Blue and Grey H2 production in the first ten-year period. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

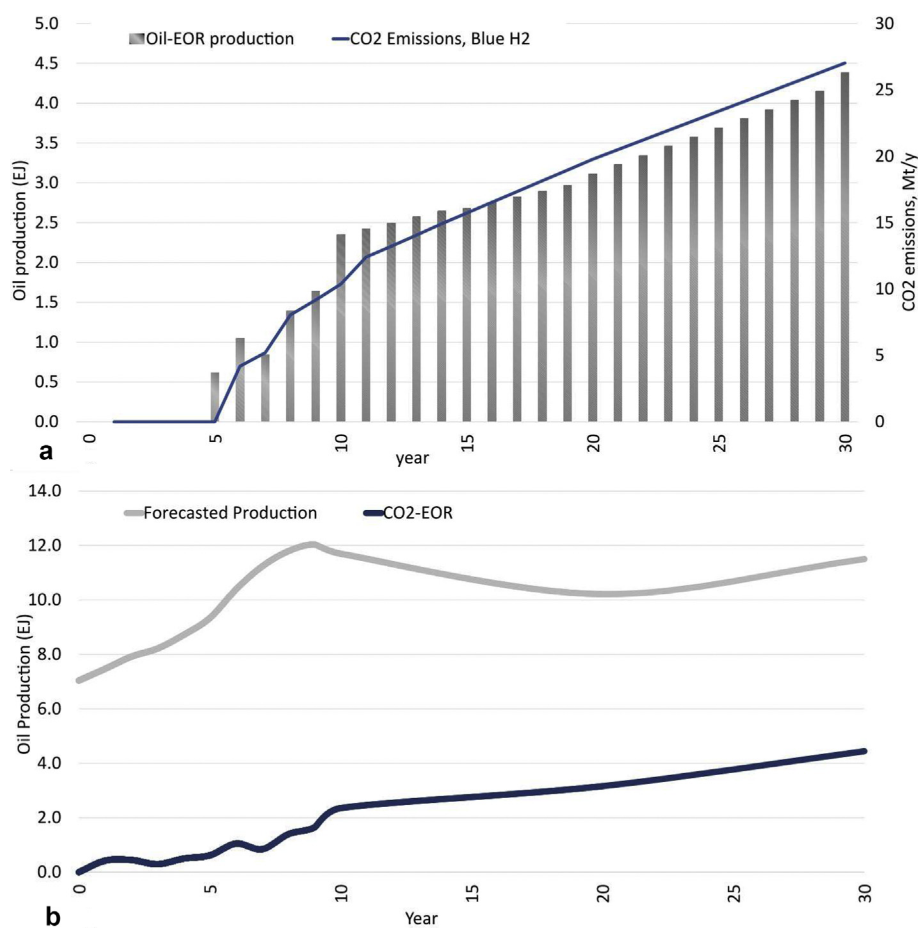

Fig. 6 — EOR Results in the long-term: (a) additional oil production and injected CO_2; (b) total oil production (Y1–Y10), with EOR derived production highlighted in blue. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

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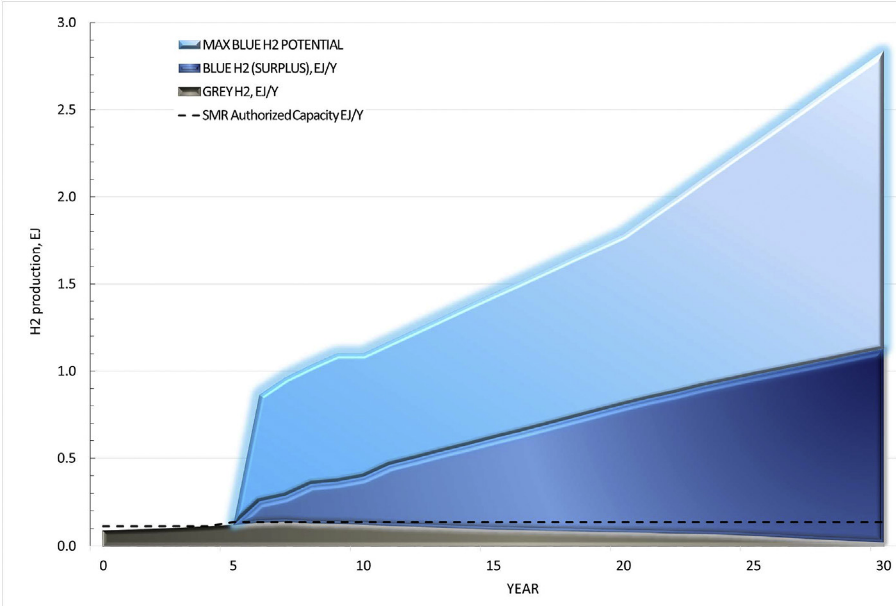

Fig. 7 – Blue and Grey H2 production in the first long-term. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

production of 0.08 EJ to reach 0.02 EJ, about 25% from this value in 2050. Comparatively, those values are lower than the expected values in the "accelerated decarbonization pathway" [41], which plans to demand 2.16 EJ blue H_2 in 2050 in Europe. According to this strategy, Blue H_2 production reaches in 2050 tenfold of the current total H_2 production capacity in Brazil. This is a meaningful change in the country's natural gas market.

After year 11, Blue H_2 associated emission rate decreases. It happens because in the initial years there is a need for a leap in Blue H_2 production. A single facility, such as a CO_2 pipeline meaningfully changes H_2 production profile, introducing Blue H_2. EOR demands for CO_2 storage are lower than the CO_2 produced according to the H_2 potential, thus curbing its growth. Considering CO_2 storage capacity from EOR production and emissions reduction, the current strategy reaches, 21.1 Mt CO_2 in (Y20) and 28.8 Mt CO_2 in (Y30), as may be observed in Fig. 6a.

EOR Oil production presents a steady growth from the beginning of the second decade on. This occurred due to the assumed premise regarding EOR that established values between 7 and 23% from production should come from EOR due to increasing technology learning favoring EOR participation in total oil production. However, it meets part from total forecasted oil production in Brazil [74,75,78], reaching 22% total production (Fig. 6b).

EOR availability imposes restrictions to Blue H_2 production. However, if those restrictions are relaxed by considering new storage modes, potential H_2 production reaches 1.12 EJ in 2050. Fig. 7 shows H2 production behavior in this situation. Developing other storage options than EOR might be also a potential option, as mentioned before Costa et al. [80] evaluated a meaningful storage potential in salt caverns offshore in Brazil and such an option should also be considered.

From Fig. 7 it may be concluded that storage capacity may curb Blue H_2 production. Therefore, it is relevant to develop alternative storage options other than EOR. Such a strategy is relevant not only to increase storage capacity but also to foster Blue H_2 independence from Oil industry. In this case, investors should strongly consider NGPU and SMR capacity increase. Even in a modest growth scenario, business as usual, this simulation indicates 1 NGPU in the first decade, 1 more in year 20 and 4 more until Y30. Considering this strategy and the New Gas Market, 2 NGPU would be required in year 6, 1 more in year 7 and 2 more until year 15. In year 30 such an increase in gas production would total 11 NGPU. From year 10 onwards these new facilities installed for monetizing NG resources increase, not necessarily linked to refining needs. However, since H_2 networks replace NG networks, eventual new refineries could benefit from this infrastructure. Once H_2 becomes an independent business, new refineries could dismiss such facilities, becoming just a H_2 buyer. From year 12 to year 30 at least one SMR unit would be required each two years to comply with H_2 projected production. Only in year 22 no new SMR would be required. Global SMR unit requirements are 11 through 30 years.

Regarding the oil production compared to CO_2-EOR it seems that the estimated values may be reachable, thus making it possible to store CO_2 generated from H_2 production.

Table 2 – Pipeline sizing.

CO2 flow, Mt/y	Nom Diam., in	Length km	Pres.Loss, KPa/km
27.0	44	250	20.1
27.0	42	250	25.3
15.7	36	250	18.8
11.3	32	250	17.8

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Table 3 – Pipeline costs.

Nominal Diameter, in	Unitary Cost, 2019	Estimated Cost, MUS$ 2019	Cost Source
44	2.23 US$/t$CO_2$,	$1803.72	IPCC [67]
42	2.43 US$/t$CO_2$,	$1702.47	
36	3.08 US$/t$CO_2$,	$1449.14	
32	3.74 US$/t$CO_2$,	$1268.98	
44	6.26 US$/t$CO_2$,	$5071.68	(Kjärstad et al., 2016)
42	6.82 US$/t$CO_2$,	$4786.79	
36	8.65 US$/t$CO_2$,	$4074.03	
32	10.52 US$/t$CO_2$,	$3567.18	
44	211.62 US$/m.in	$3066.30	Historic data
42		$2926.92	
36		$2508.79	
32		$2230.03	

In fact, for this level of EOR production, CO_2 produced in both in new and existing SMR units may be stored. On the one hand, such condition indicated that Blue H_2 production would be limited in this study only by NG availability and SMR facilities. On the other hand, a decrease in EOR production might also curb Blue H_2 production.

Pipeline sizing and cost evaluation

As depicted in Table 2, CO_2 captured from SMR facilities reached 27.0 Mt in year 30. Then, two options were addressed. In the first, a single 44 inches pipeline was designed with a head loss of 20.1 kPa/km (a 42 pipeline was not selected due to pressure loss found 25.3 kPa/km). In the second option, a 36 inches pipeline was required to comply with full load of 15.7 Mt CO_2 in year 15 and a 32 inches pipeline to an additional load of 11.3 Mt CO_2 in year 30. The head losses found were, respectively, 18.8 and 17.8 kPa/km.

Average cost from offshore pipelines built in Brazil in the last decade was US$ 211.62/m.in (US$ per meter and per inch nominal diameter). On the Other hand, IPCC [67] offered a curve that indicated ratios US$/t$CO_2$ (for a 250 km pipeline). More recently [68], indicated similar ratio unitary value in €/tCO_2, for pipelines analyzed in Norway. Those values may vary according to CO_2 volumes and were updated to 2019 (Y-1). Results may be compared global in Table 3:

Despite a large variation obtained from those sources, sizing reveals gains of scale. CO_2 flows around 15.7 Mt CO_2 were observed in year 15 of this simulation, while in year 30 total value of 27.0 MtCO_2 is reached. Comparison of global costs indicates that a larger pipeline would require less investments than two pipelines to convey the same quantity. However, a detailed feasibility study should be elaborated.

Table 4 – Calculated investment for Blue H_2 in the short term (Y1 to Y9).

	Gas Flow	Units	Investment, M US$
NGPU	79.74 M m^3/d	3	1631.82
SMR	14.59 M m^3/d	3	5096.87
CO2 Pipeline	27 Mt/Y	1	3066.30
Total Investment			9794.99

According to Kayfeci et al. [102] and Penner [103] apud Labanca [99], unitary costs for SMR unities should be between US$ 2080 to US$ 2655. Based on these data, costs for SMR units in the first 10 years would be between US$ 3369.60 and US$ 4301.10 million. In all other years of the analysis, CO_2 requirements for EOR would be higher than CO_2 generated within the H_2 production, which means that Blue H_2 production would not be capped by oil production.

In this preliminary approach, investment capital costs for producing Blue H_2 in the first decade would involve the facilities and costs presented in Table 4.

Incomes are based on a value of US$ 40/bbl, starting from year 5, when first CO_2-EOR facility produces. Findings show that by year 10 (9581.49 **MUS$**)-11 (14,256.19 **MUS$**) investments would equal oil revenues from additional production due to EOR. This result does not consider earnings from H_2 or NG sales.

The present strategy does not evaluate the detailed feasibility of each facility. Instead, it assesses monetizing NG resources in order to avoid stranded reserves, thus paving the way for a just energy transition, avoiding job losses and economic setbacks. Hence, the present strategy showed that it seems possible monetizing NG resources trough Blue H_2 strategy. Such a strategy involves simple calculation but executes a stepwise method to address monetizing fossil fuels in an increasingly curbing environmental framework. Providing low carbon methods are essential not only in the present but also in the future, when restriction to carbon emissions should become stronger.

Conclusion

This study modeled a strategy to monetize NG resources by means of increasing oil production by EOR technology. This strategy consisted in assessing NG production data and calculating H_2 production potential from NG. Brazil would reach a H_2 production of 1.12 EJ in 2050, relying only on endogenous natural resources. Comparatively to Europe business as usual scenario (0.54 EJ), it is a bold increase, standing for a tenfold rise compared to current H_2 production for Brazil. Compared to Europe, Brazil would reach about half of the projected Blue H_2 demand 2.16 EJ in the accelerated decarbonization pathway.

Furthermore, total H_2 production potential would reach 0.7 EJ in 2050, considering fossil resources. Monetizing such reserves seem to be feasible, once relatively low oil prices (US$ 40/bbl) would quickly pay investments done (9 years).

Storage capacity may curb Blue H_2 production, therefore, it is relevant to develop alternative storage techniques other than EOR. Such a strategy is relevant not only to increase storage capacity but also to foster Blue H_2 independence from oil industry.

The present strategy showed that it is possible to monetize NG resources trough Blue H_2 strategy. Monetizing Natural Gas resources may be a tricky business in a near future, regarding environmental restrictions. The current study offers an original strategy for fossil fuel producers to monetize those resources in such a restraining scenario.

However, a future detailed study should be developed, including an economic feasibility analysis. In addition, earnings from NG sales and regulatory issues should be further discussed, so as to account for local taxes and subsidies. Finally, a detailed study to assess and properly size the transportation network, including aspects such as fluid dynamics and network constraints is also an important future development. Those issues that were not addressed current study are relevant suggestions for future work.

Declaration of competing interest

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

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2021.05.112.

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Supplementary Material

Blue Sky Mining: strategy for a feasible transition in emerging countries from Natural Gas to Hydrogen

This supplementary material presents a brief description of the step-by-step procedure developed and applied to assess the strategy of monetization for blue hydrogen.

It begins with a brief but broad approach of the hydrogen production methods and concentrates on the focus of the article, which is the steam methane reforming (SMR). The strategy is then unveiled by a stepwise and concise description of the idle hydrogen production capacity, which addresses the following aspects:

- Evaluating the logistic options for hydrogen and natural gas blending and establishing rules for hydrogen-natural gas blending in gas pipelines;
- Establishing new natural gas pipelines facilities expansion to cope with the increase on hydrogen production volumes;
- Estimating the future natural gas resources availability and prioritizing hydrogen production instead of accumulating stranded reserves;
- Designing the approach to be undertaken for carbon capture storage and utilization, prioritizing the use of CO_2 from blue hydrogen production on enhanced oil recovery in the short term; establishing metrics for enhanced oil recovery (EOR) and forecasting the amounts of oil production from enhanced oil recovery;
- Calculating the required volume of CO_2 potentially sequestered and sizing the correspondent CO_2 pipeline needs.

There is a diversity of technologies for hydrogen production, which is thoroughly treated in the literature. **Figure S-1**, adapted from Nazir et al. [1], presents an overview of the methods to produce hydrogen from fossil fuels and from renewables.

Concerning the hydrogen production from fossil fuels, which is the motivation of the present study, it has been analyzed under a monetization perspective of taking into account the externalities associated with the "real" cost of hydrogen production [2] [3]. These studies were convergent with others [1] [4] to conclude that the SMR is the most mature technology used worldwide for hydrogen production, that it should maintain that position for the near future, and that it presents the lowest unabated total cost of hydrogen when it is equipped with carbon capture and storage, as of today. These findings create the basis to explore how the main and abundant current sources of methane, natural gas reserves, and the associated industrial infrastructure may strategically contribute to the energy transition and to a new hydrogen energy era.

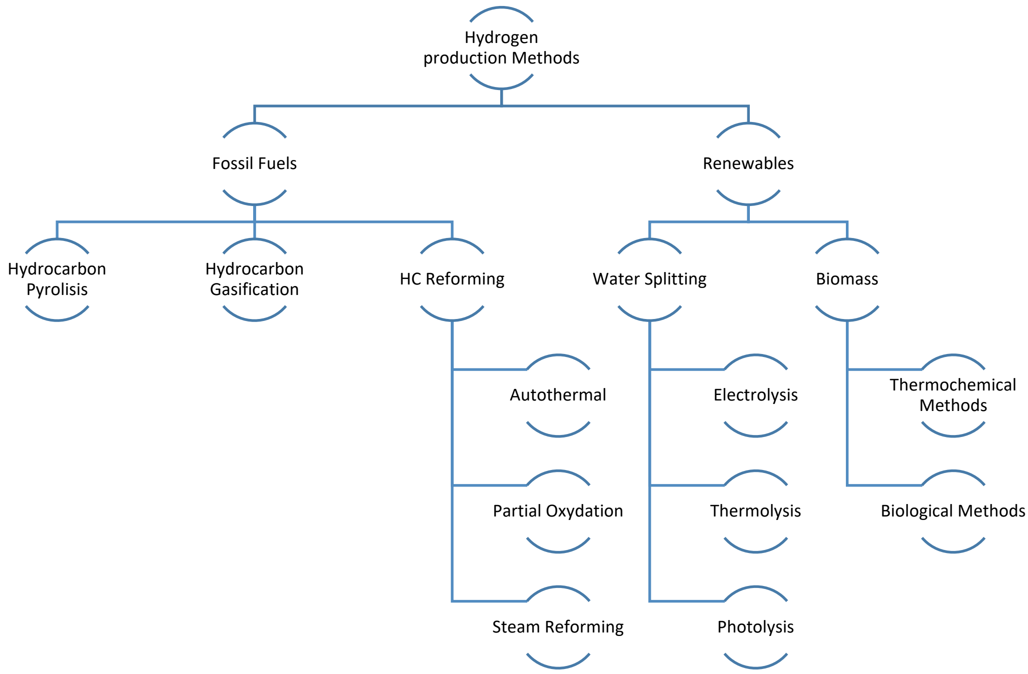

Figure S-1: Hydrogen production methods. Adapted from [1]**.**

The strategy proposed in this paper relies on the use of the SMR idle capacity in hydrogen-producing facilities and consists, essentially, of the following steps:

1) Estimating resources: In a country with prospective reserves, natural gas may be used for producing hydrogen. It was assumed that agents would prefer to produce hydrogen than accumulate stranded reserves. Hence, all extra natural gas production would be used for hydrogen production

2) Assessing the idle hydrogen production capacity: for the case study of this paper, refining capacity and utilization factors are provided by Brazilian official data sources. However, the production capacity can be assessed from other sources, such as Sun et al [5]. In this paper, the following data was obtained [6] - see Table S-1:

Table S-1: Hydrogen production capacity in Brazilian Petroleum Refineries [6].

REFINERY*	Full capacity, $Nm^3/d \times 10^3$	Authorization	Yearly Utilization Factor, %			Avg Idle Capacity, %	Available H_2 $Nm^3/d \times 10^3$
			2018	2019	2020		
RNEST	3,000.00	575/2017	64.0%	97.2%	102.0%	12.3%	368.00
RNEST (2025)**	6,200.00	565/2011	64.0%	97.2%	102.0%	12.3%	760.53
REPLAN SP	4,070.44	669/2016	48.3%	84.6%	52.4%	38.2%	1,556.26
RPBC	2,870.00	813/2019	93.6%	83.3%	82.8%	13.4%	385.54
REGAP/ REGAP II	2,120.00	156/2014	86.8%	71.4%	53.7%	29.4%	622.57
REPAR	1,870.00	554/2020	74.2%	66.3%	82.7%	25.6%	478.72
REFAP	1,800.00	80/2015	68.1%	61.0%	69.1%	33.9%	610.80
REVAP	1,630.00	521/2020	90.6%	52.5%	87.3%	23.2%	378.16
RLAM	3,985.30	811/2013	55.8%	66.9%	68.3%	36.3%	1,447.99
REDUC	822.83	322/2016	83.2%	88.0%	77.6%	17.1%	140.43
RECAP	550.00	976/2015	75.7%	79.8%	64.9%	26.5%	145.93
LUBNOR	35.00	401/2016	70.4%	78.5%	68.2%	27.6%	9.67
Average			**72.9%**	**77.2%**	**75.9%**	24,7 %	
Total - 2020	**22,753.56**						3946.92
Total - 2025	**34,713.56**						

*** Acronyms used to name refineries in Brazil:** RNEST - Refinaria do Nordeste; REPLAN - Refinaria de Paulínia; RPBC - Refinaria Presidente Bernardes de Cubatão; REGAP - Refinaria Gabriel Passos; REPAR - Refinaria do Paraná; REFAP - Refinaria Alberto Pasqualini; REVAP - Refinaria do Vale do Paraíba Henrique Lage; RLAM - Refinaria Landulpho Alves; REDUC - Refinaria de Duque de Caxias; RECAP - Refinaria de Capuava; LUBNOR – LUBNOR.
**** Estimate**

3) Evaluating logistic options for Hydrogen and Natural Gas blending: as SMR facilities require natural gas supply, natural gas pipelines are already connected upstream to those facilities. Thus, connecting hydrogen facilities upstream to the natural gas infrastructure for blending should require small adaptations in the refinery area.

For the case study of this paper, in Brazil, all refineries are connected to the natural gas network and a list of all pipelines diameters and capacities is available [7] [8]. Figure S-2 illustrates the Brazilian refineries connected to the network of natural gas pipelines.

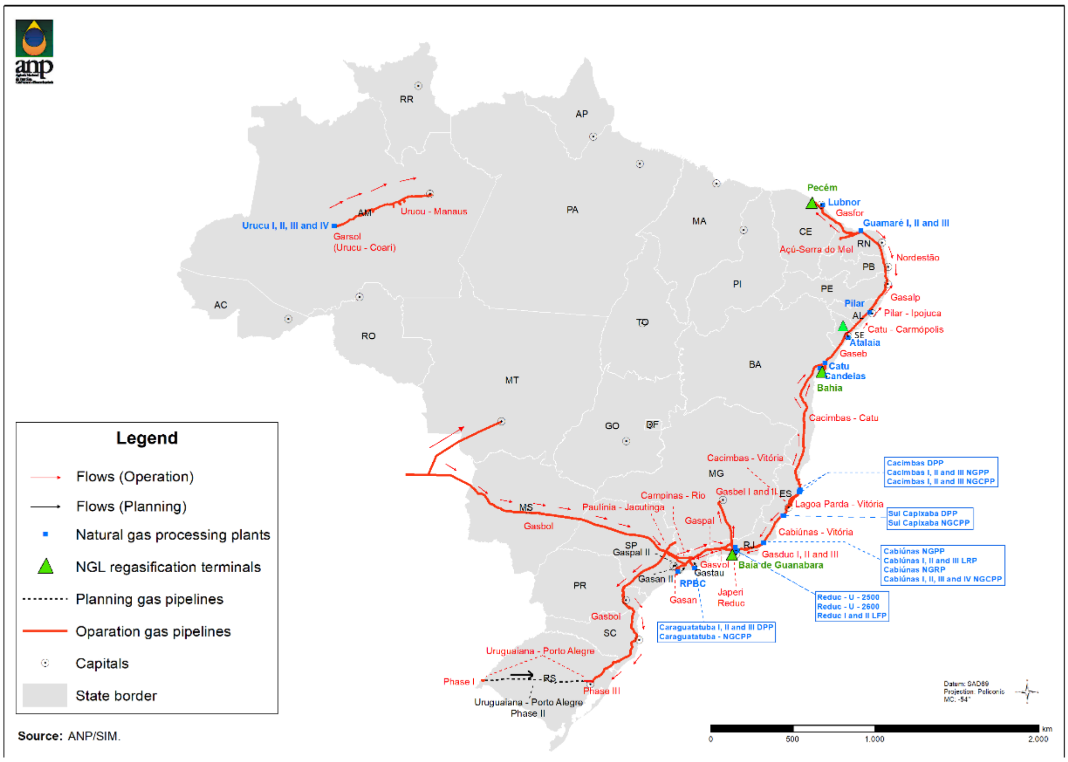

Figure S-2: Brazilian Natural gas Infrastructure [7]

Pipelines' main characteristics, such as nominal diameter, length, and localization are listed in Table S-2.

Table S-2: Natural gas transmission Pipelines in Brazil. Based on [8].

Name	Origin*	Destiny	Operation Year	Nominal Diameter (in)	Length, km
Atalaia-Santiago-Catu	Atalaia (SE)	Catu (BA)	1974	14	230.0
Santiago/Catu-Camaçari I	Santiago (BA)	Camaçari (BA)	1975	14	32.0
Atalaia-FAFEN	Atalaia (SE)	Laranjeiras (SE)	1980	14	29.0
Candeias-Camaçari	S. Francisco do Conde (BA)	Camaçari (BA)	1981	12	37.0
Ramal Campos Elíseos II - Ramal de 16"	Duque de Caxias (RJ)	Duque de Caxias (RJ)	1982	16	2.7
Lagoa Parda-Aracruz	Linhares (ES)	Aracruz (ES)	1983	8	38.0
Aracruz-Serra	Aracruz (ES)	Serra (ES)	1984	8	41.0
Reduc-Esvol	Duque de Caxias (RJ)	Volta Redonda (RJ)	1986	18	95.2
Guamaré-Cabo	Guamaré (RN)	Cabo (PE)	1986; 2010	12	455.8
Esvol-Tevol	Volta Redonda (RJ)	Volta Redonda (RJ)	1986	14	5.5
Esvol-São Paulo (Gaspal I)	Piraí (RJ)	Mauá (SP)	1988	22	325.7
Santiago/Catu-Camaçari II	Santiago (BA)	Camaçari (BA)	1992	18	32.0
RBPC-Capuava (GASAN I)	Cubatão (SP)	São Bernardo do Campo (SP)	1993	12	37.0

RBPC-Comgás	Cubatão (SP)	Cubatão (SP)	1993	12	1.5
Reduc-Regap	Duque de Caxias (RJ)	Betim (MG)	1996	16	357.0
Guamaré-Pecém	Guamaré (RN)	Pecém (CE)	1998	10 to 12	382.0
Bolívia-Brasil (Gasbol), Brazilian part	Bolivian Border	Brasil	1999-2000	16 to 32	2593.0
Uruguaiana-Porto Alegre	Uruguaiana (RS)	Uruguaiana (RS)	2000	24	25.0
Uruguaiana-Porto Alegre	Canoas (RS)	Triunfo (RS)	2000	24	25.0
Pilar-Cabo	Pilar (AL)	Cabo (BA)	2001	12	203.6
Lateral Cuiabá	Cáceres (MT)	Cuiabá (MT)	2001	18	267.0
Candeias-Aratu	São Francisco do Conde (BA)	Aratu (BA)	2003	14	15.4
Santa Rita-São Miguel de Taipu	Santa Rita (PB)	São Miguel (PB)	2005	8	25.0
Dow-Aratu-Camaçari	Aratu (BA)	Camaçari (BA)	2006	14	27.0
Atalaia-Itaporanga	Atalaia (SE)	Itaporanga D'Ajuda (SE)	2007	14	29.0
Cacimbas-Vitória	Linhares (ES)	Vitória (ES)	2007	26 to 26	129.4
Carmópolis-Pilar	Carmópolis (SE)	Pilar (AL)	2007	16	176.7
Catu-Carópolis	Itaporanga D'Ajuda (SE)	Carmópolis (SE)	2007	26	67.8
Catu-Carópolis	Catu (BA)	Itaporanga D'Ajuda (SE)	2008	26	197.2
Açu-Serra do Mel	Serra do mel (RN)	Alto do Rodrigues (RN)	2008	14	31.4
Cabiúnas-Vitória (Gascav)	Macaé (RJ)	Serra (ES)	2008	28	300.0
Campinas-Rio (Gascar)	Paulínia (SP)	Japeri (RJ)	2008	28	450.0
Fafen-Sergás	Divina Pastora (SE)	Laranjeiras (SE)	2009	8	22.7
Cabiúnas-Reduc III (Gasduc III)	Macaé (RJ)	Duque de Caxias (RJ)	2009	38	180.0
Japerí-Reduc (Gasjap)	Japeri (RJ)	Duque de Caxias (RJ)	2009	28	45.3
Campos Elíseos-Gas Ring	Duque de Caxias (RJ)	Duque de Caxias (RJ)	2009	20	2.3
Urucu-Coari (Garsol)	Urucu (AM)	Coari (AM)	2009	18	279.0
Coari-Manaus	Coari (AM)	Manaus (AM)	2009	20	383.0
Coari-Manaus (Branches)	Coari (AM)	Manaus (AM)	2009	3 to 14	140.1
Cacimbas-Catu	Linhares (ES)	Pojuca (BA)	2010	28	946.0
Paulínia-Jacutinga	Paulínia (SP)	Jacutinga (SP)	2010	14	93.0
Gascav Connection	Anchieta (ES)	Anchieta (ES)	2010	10	9.7
Rio de Janeiro-Belo Horizonte (Gasbel II)	Volta Redonda (RJ)	Queluzito (MG)	2010	18	267.0
Pilar-Ipojuca	Pilar (AL)	Ipojuca (PE)	2010	24	187.0
Caraguatatuba-Taubaté	Caraguatatuba (SP)	Taubaté (SP)	2011	28	98.0
Guararema-São Paulo	Guararema (SP)	São Paulo (SP)	2011	22	54.0
São Paulo -São Bernardo do Campo (Gasan II)	São Paulo (SP)	São Bernardo do Campo (SP)	2011	22	38.0
Total					**9409.0**

* Symbols in brackets refer to the following Brazilian States: AL – Alagoas; AM – Amazonas; BA – Bahia; CE – Ceará; ES - Espírito Santo; MG - Minas Gerais; MS - Mato Grosso do Sul; MT - Mato Grosso; PB – Paraíba; PE – Pernambuco; RJ - Rio de Janeiro; RN - Rio Grande do Norte; RS - Rio Grande do Sul; SE – Sergipe; SP - São Paulo.

4) Establishing in the year 3-5 a stepwise H_2 injection increase based on: (a) hydrogen availability due to idle capacity in SMR facilities; (b) the average Wobbe index in the pipeline that sets an initial maximum blending value.
5) Building CO_2 pipelines: after 5 years, CO_2 pipelines can be built to start compensating GHG emissions from SMR facilities. In the particular case of Brazil, these pipelines should ramp up in 5 five years [9].
6) Estimating oil recovery factors: studies show that EOR techniques might increase hydrocarbons exploitation by 7 to 23% (with an average of 13%) of total oil in place (OIP) [11]. Other authors [12] corroborate that range for miscible mixtures between CO_2 and oil in EOR. Hill [13] estimated an increase of 6% to 10% of total oil in place (OIP) production, although they highlighted that this result is not based on supercritical CO_2 injection, which stimulates miscibility and increases productivity. More recent studies reported incremental oil recovery ranging from 6.09 to 22.83% of OIP for techniques of CO_2-EOR [14].
7) Projecting oil production from EOR: In Brazil, the forecasts for crude oil production from the Ministry of Mines and Energy [15] [16] were used, see **Table S-3**.

Table S-3: Oil production forecasts in Brazil. Based on [15] [16].

Year	Forecasted Production (Millions of Barrels)
2020	3.24
2021	3.44
2022	3.65
2023	3.78
2024	4.01
2025	4.30
2026	4.78
2027	5.17
2028	5.43
2029	5.54
2030	5.39
2040	4.70
2050	5.30

8) Calculating CO_2 volume flow: the required CO_2 flows to be injected in the oil reservoir were estimated from the oil production forecasts. If the required volume for EOR is higher than the CO_2 produced in SMR facilities, than blue H_2

production is limited by SMR production. If the opposite happens, then blue Hydrogen production is limited by EOR production.

9) Sizing CO_2 pipelines: the diameters of pipelines are calculated according to the maximum CO_2 yearly flows obtained in the previous step. This estimate keeps the CO_2 flow in the pipelines as a supercritical fluid (above 31.1 ºC and 7.5 MPa). Above such conditions, CO_2 flow is in dense phase and presents minimum pressure losses [16]. Design temperature ranges from 10 to 35ºC. In this study, the design pressure was set at 25.00 MPa [17] [18] and the maximum pressure loss was established as 25kPa/km. The minimum operating pressure of 18.75 MPa is well-above supercritical conditions. The Darcy's equation was applied, considering the Churchill correlation for friction factor – see equations S-1 to S-5.

$$\Delta P = \frac{\left(kgf / cm^2\right)}{100m} = \frac{\upsilon^2 \times \rho \times f}{2 \times d}$$

Equation S-1

$$f = 8 \times \left[\left(\frac{8}{\mathrm{Re}}\right)^{12} + \frac{1}{(A+B)^{1,5}}\right]^{\left(\frac{1}{12}\right)}$$

Equation S-2

$$A = \left\{2,457 \times \ln\left[\frac{1}{\left(\left(\frac{7}{\mathrm{Re}}\right)^{0,9} + 0,27\frac{\varepsilon}{D}\right)}\right]\right\}^{16}$$

Equation S-3

$$\mathrm{Re} = 998,5 \times \frac{d \times \upsilon \times \rho}{\mu}$$

Equation S-4

$$B = \left(\frac{37530}{\mathrm{Re}}\right)^{16}$$

Equation S-5

Where:
ΔP = pressure loss
ν = velocity
ρ = Density
f = friction factor
d/D = pipe diameter
Re = Reynolds number
μ = viscosity

ε = roughness

This is a practical approach, which can be found in both industry manuals (e.g. [17]) and scientific papers [18] [19]. Pipeline wall thicknesses were obtained according to API 5L X65 pipelines apud Silva Telles [19] and Brazilian standard NBR 12712 [21], as shown in **Table S-***4* and Equation S-6.

Table S-4: External Diameters and calculated wall thicknesses for API 5L X65 pipelines.

Nominal Diameter, in	External Diameter, mm	Wall Thickness, mm
10	273.1	23.8
12	323.9	28.2
14	355.6	31.0
16	406.4	35.4
18	457.0	39.8
20	508.0	44.3
22	559.0	48.7
24	610.0	53.2
26	680.0	59.3
28	711.0	62.0
32	813.0	70.9
36	914.0	79.7
38	965.0	84.1
40	1016.0	88.6
42	1067.0	93.0
44	1118.0	97.5
48	1219.0	106.3
52	1321.0	115.2

$$e = \frac{P.D}{2.F.E.T.S_y}$$ **Equation S-6**

Where:

e = wall thickness;
P = design pressure (Kpa)
D = external diameter
S_y = minimum flow stress to the material according to NBR 12712
F = design factor according to locational placement
E = joint design factor
T = design temperature

The definition of the pipeline material also set the roughness applied in the previous equations.

Density was defined according to Crane [16], while for viscosity, the Sutherland's correlation was used – see equations S-7 and S-8.

$\rho = (349p'.Sg)/T$, **Equation S-7**

where $p' = 1.013 + p$
$T = 273.15 + t$,
Sg – specific gravity
T = temperature, Kelvin,
t = temperature ºC,
p'= absolute pressure,
p = gauge pressure,
R= Universal gas constant
ρ = density, kg/m^3

$$\mu = \mu_0 \left(\frac{T_0+C}{T+C}\right)\left(\frac{T}{T_0}\right)^{\frac{3}{2}}$$ **Equation S-8**

Where:

μ = viscosity at temperature T;
μ_0 = viscosity at temperature T_0;
T = Absolute temperature for calculated viscosity
T_0 = Absolute temperature for known viscosity
C = Sutherland's Constant
For most gases, viscosity variation with pressure is small [16]

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