From natural gas to green hydrogen: Developing and repurposing transnational energy infrastructure connecting North Africa to Europe

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Abstract

This paper studies the economic and regulatory conditions for the implementation of large-scale projects of production and transport of green hydrogen from North Africa to Europe. The EU has shown a remarkable interest in importing hydrogen from North Africa, to reach climate commitments while compensating for the reduction of gas imports from the Russian Federation. The idea to import green hydrogen from North Africa stems from the potentially low costs of production thanks to abundance of solar energy and land in desertic areas, and to existing export infrastructure. The paper analyses the cases of Egypt and Algeria and finds that Algeria has a potential cost advantage in transporting green hydrogen to Europe thanks to overcapacity in its existing gas infrastructure, which could be upgraded. By contrast, Egypt is more competitive in the generation of renewable power, a key input of green hydrogen, thanks to regulation that attracts investments. Overall, both countries are cost competitive in a similar way, although production of renewable energy is still too low to make export infrastructure to Europe viable. Based on their regulatory and political economy differences, the paper suggests ways for the EU to adopt a differentiated approach of cooperation with Egypt and Algeria, which suits their strategic and commercial interests and contributes to boosting their production and transport potential.

Keywords: Natural gas; Green hydrogen; Renewable energy; Infrastructure; Egypt; Algeria.

1. Introduction

North Africa has been historically a major producer and exporter of energy to Europe (Cardinale, 2019). Today, it has a unique opportunity to retain and even relaunch this strategic role by taking advantage of the energy transition. The development of a green hydrogen supply chain can serve this purpose, considering the increasing interest expressed by governments, investors, and the energy industry in the EU and worldwide, and the great potential that North African countries have in this sector. This potential derives from the abundance of natural resources and inputs needed to produce green hydrogen, but also from the favorable geographic location for export, the availability of infrastructure, and a position of leadership in the energy sector.

North Africa is a region with one of the world's largest solar energy potential, thanks to the high solar radiation and the abundance of land across the desertic area (The World Bank, 2020). This combination of solar power and availability of land creates unique conditions to realize a scale of production that cuts costs and allows green hydrogen to be competitive with traditional energy sources. In addition, North Africa is in proximity to the EU, which is one of the world's largest energy importers (Zhao et al., 2018). This is another essential factor for the development and commercialization of green hydrogen.

Furthermore, the two continents are already well connected with energy infrastructure, which could be upgraded at a relatively low cost in view of progressively replacing the current flows of natural gas with new flows of green hydrogen. Currently, there are four undersea gas pipelines with a combined transport capacity of 60 bcm, and four Liquefied Natural Gas (LNG) terminals that provide an additional capacity of around 43 bcm (see Figure 4 in the appendix) (Mott MacDonald, 2010). Plans to develop *ad-hoc* hydrogen infrastructure are under consideration. The upgrade of existing facilities or the creation of new ones, in addition to the development of production facilities, would greatly benefit from the expertise of local governments and companies, which stems from their decade-long leadership in the energy industry, in addition to historical partnerships with EU companies.

However, beside a common potential, each North African country faces different challenges and opportunities, due to specificities concerning industrial capabilities, availability of infrastructure, government policies and regulation. The latter is crucial to attract investments and generate a scale of production that reduces costs, enhances competition between renewables and fossil fuels, and creates the social and political acceptability for exports to the EU. North Africa shows a variety of experiences in this regard, as some countries have implemented substantial reforms to open domestic markets to private and foreign investors, while others have retained a more cautious approach to reforms. This gap can be explained by different factors, mainly related to the perception by local elites on the priority of such reforms vis-à-vis of other objectives in the national agenda, but also on the implications that reforms have for political stability.

This article analyses the cases of Egypt and Algeria to provide insights on the diverse range of opportunities and challenges that important North African energy players face. The comparison considers (i) the countries' existing gas export infrastructure capacity, which is key to realising cost savings by repurposing it to transport green hydrogen; and (ii) their approaches to energy regulation, which is essential to attract investment and realise a scale of production that reduces the cost of renewable energy generation, which accounts for more than two-thirds of hydrogen production costs.

Egypt's existing gas export capacity is limited to about 26.8 bcm per year if the Arab Gas Pipeline (AGP) connecting Egypt to the Levant is also considered. Currently, its existing LNG infrastructure is being used at full capacity to meet the high level of demand in the international market, suggesting that new green hydrogen export infrastructure might be needed. However, Egypt's market-oriented regulation has succeeded in attracting investment in the generation of renewable power, leading Egypt to rank first in North Africa and second in Africa with an installed capacity of 6,226 GW (IRENA, 2022).

By contrast, Algeria has an advantage in gas export pipeline capacity, which amounts to about 53 bcm per year. This capacity increases to 80 bcm if LNG facilities are also considered. This advantage is relevant as repurposing an existing pipeline to transport green hydrogen results in remarkable cost savings relative to the construction of a new one (IEA 2022). Nevertheless, Algeria's attempt to attract private investment in the renewable power sector was more challenging than expected. This may be explained by Algeria's policy of securing extensive government control of projects while pursuing the objective of local industrial development. For example, tenders envisaged that projects should be majority-owned by national companies and should use local equipment and financing up to specified quantities.

In view of these differences, the paper suggests that the EU approach to energy and climate diplomacy with North African countries should be diversified and consider their specificities. To date, the literature on green hydrogen has mainly focused on production and transport costs, and the technical aspects associated to them (Dodds, 2015; Shoots et al., 2008; Bartels et al., 2010; Pham Minh et al., 2018; El Mrabet et al., 2021; Glachant and Dos Reis, 2021). To some extent it has also addressed economic and regulatory aspects, with some contributions focusing on the EU domestic market (Pototschnig, 2021; Kakoulaki et al., 2021; Kneebone, 2021; Wolf and Zander, 2021; Sens et al., 2022; Tanese and Herrera Anchustegui, 2022). Recent contributions have also focused on the potential development of green hydrogen production in North Africa (Drenkard & Atom, 2021; Habib, 2021; Mukelabai et al., 2022), with some focusing also on the potential for trade with Europe (Timmerberg and Kaltschmitt, 2019; van der Zwaan et al., 2021). However, these studies focus mainly on technical aspects and cost estimates. Therefore, to date there are no contributions that combine analysis of both regulation and cost structure in selected North African countries, and how their specificities should inform the emerging EU strategy for hydrogen import.

This paper aims to also contribute to the current debate among EU policymakers on the potential approaches to cooperation with North African countries. The goal is to understand their respective interests and challenges, and how to reconcile these with the EU vision on decarbonization. The importance of this issue is growing beyond the theme of decarbonization to involve energy security, as the EU is planning to phase out imports from the Russian Federation at the soonest.

The draft on "Hydrogen and Decarbonized Gas Market Package" issued in December 2021 by the European Commission launches a debate on the extent to which competition rules should be applied to the emerging hydrogen market, and on the timescale. The draft is mainly focused on the regulation of EU markets. This paper aims to extend this debate to the external dimension of the EU market, namely on the markets for the import of hydrogen from non-EU countries such as the North African ones[1]. The issue is important as the REPowerEU[2] plan envisages the EU to import 10 million tons of green hydrogen by 2030, of which 6 million tons from North Africa.

[1] Previous studies (Cardinale, 2019) have addressed the issue of North Africa – EU energy infrastructure and trade, but with referenve to natural gas. This study builds on this strand to understand the aspects of continuity and change in the switch to green hydrogen.

[2] See « REPowerEU Plan » by the European Commission, Brussels May 2022, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483

The paper is structured as follows. Section 2 provides a literature review. Section 3 explains the choice of methodology. Section 4 analyses trends in investments and regulation in Egypt's energy sector and provides recent updates on plans to develop green hydrogen. Section 5 analyses trends in investments and regulation in Algeria, with reference to renewables and green hydrogen. Section 6 builds on the previous analyses on economic and regulatory differences in Egypt and Algeria to discuss potential hydrogen strategies through which the EU could successfully engage with them. Section 7 concludes the paper by reporting the main findings. Section 8 provides policy suggestions.

2. Literature review

Green hydrogen is an emerging field of research, particularly within economic and policy studies. Despite technologies for hydrogen production date back several decades, only recently and thanks to increased societal sensitivity on environmental sustainability it has attracted interest among policymakers and industries.

The study of costs of existing production and transport technologies is very relevant in the literature on green hydrogen, considering that affordability has been traditionally the main constraint to commercialization on a large scale. Schoots et al. (2008) find that regardless of the technology – and specifically steam methane reforming, coal gasification and electrolysis – in the period 1940 – 2007 there was no substantial reduction in the production cost of hydrogen. By contrast, the analysis by Dodds (2015) provides a slightly optimistic conclusion. He argues that in the long term both mature and unproven green hydrogen technologies have chances to become viable. Bartels et al. (2010) reaches similar conclusions. While their analysis find that hydrogen produced from coal and natural gas is currently cheaper than green hydrogen, they note that the cost of fossil fuels is on the rise while the cost of low carbon energy and technology is declining. Pham Minh et al. (2018) examine the potential viability of alternative options to Steam Methane Reforming, currently the only commercialized technology to produce green hydrogen from biogas. El Mrabet et al. (2021) explore potential synergies between green hydrogen and renewable energies in the joint use of existing energy networks, and the implications for reduced transport costs. In a similar way, Glachant and Dos Reis (2021) study potential ways to realize cost savings by using existing infrastructure to transport green hydrogen, and find that transmission, storage and refueling infrastructure require little to no investment if green hydrogen replaces grey hydrogen; while considerable investments are needed if green hydrogen is transported in infrastructure conceived for other energy carriers.

An emerging literature addresses economic and regulatory aspects of green hydrogen, with most contributions focusing on the EU domestic market. For example, Sens et al. (2022) conduct a cost analysis green hydrogen production in Europe and find that the North Sea region is one of the most viable, while production potential in the Middle East is ten times higher than in Europe. Kakoulaki et al. (2021) examine the potential for European countries to replace production of grey hydrogen with green hydrogen based on generation potential of renewable energy and find this to be feasible in most countries. Wolf and Zander (2021) share these optimistic views although they emphasize the importance of national differences within the EU both in terms of production and regulation, and how this requires a substantial harmonizing effort. One of the measures to be harmonized at the EU level is 'additionality', which, as reported by Pototschnig (2021), envisages limitations to the production of green hydrogen if this reduces the availability of renewable power for final consumers. He argues that too strict temporal requirements might negatively affect electrolizers' optimal utilization rate. Kneebone (2021) discusses the "Hydrogen and Gas Market Decarbonisation Package" released in December 2021 by the European Commission, which envisages the extension of natural gas market regulation based on the principle of market competition also to the emerging green hydrogen market. Of the same EU hydrogen package, Tanese and Herrera Anchustegui (2022) examine green hydrogen infrastructure, highlighting that the introduction of long-term supply contracts might be needed as a guarantee to investors' returns.

Recent contributions have also focused on the potential development of green hydrogen production in North Africa. Mukelabai et al. (2022) conduct a systematic analysis of the production potential in Africa and find that transmission infrastructure between Nigeria and Algeria offers one of the most efficient and low-cost transport routes. Drenkard & Atom (2021) provide a comprehensive analysis of the expected costs of green hydrogen from different renewable energy sources and in different geographic locations in Algeria. Habib (2021) conduct a similar analysis in the context of Egypt and show different green hydrogen price ranges depending on the technology used and on the expected prices of renewable energy. Abou Saeda and Hatem (2022) provide an overview of the potential demand, supply, and environmental benefits of green hydrogen in Africa, while also offering insights on specific countries, including Morocco's involvement in the development of large-scale production projects.

Other studies focus on the potential for green hydrogen trade between North Africa and Europe. For example, Timmerberg and Kaltschmitt (2019) estimate the costs of transporting green hydrogen from North Africa to Europe, including the option of blending it with natural gas, suggesting their future viability. In a similar way, van der Zwaan et al. (2021) find that production and transport from North Africa to Europe would be viable, and that countries in North Africa will benefit from a trade surplus of 50 billion euro per year.

While the above-mentioned studies focus either on technical aspects, cost estimates, or regulation but only in the EU, this paper aims to fill the current research gap by analyzing the linkages between production and transport costs with regulation in selected North African countries, and how their specific features should be considered by the EU strategy for hydrogen import.

3. Methodology and data collection

Understanding the conditions for the development of green hydrogen production requires an overall approach to the analysis of energy systems and prevailing policies in a given country. Several variables matter and therefore should be investigated. For example, both renewable and non-renewable subsectors are relevant, as production of green hydrogen on a large scale depends on the generation capacity of renewable energy, while transport costs can be reduced substantially in presence of existing natural gas infrastructure to be repurposed. In addition, each subsector shows a diversified value chain across the phases of generation, transmission, distribution, and sale in end markets. Lastly, government regulation plays a relevant role in driving investment decisions across the whole value chain.

The case study methodology suits the research objectives of this paper, as it envisages the selection of a limited number of units of analysis characterized by variables with a high level of specificity and complexity (Collier, 1993; Flick, 2006; Yin, 2009). In this paper, units of analysis are the energy systems of Egypt and Algeria, while the specificity of energy subsectors, including their value chains, infrastructures, and regulation, are the variables investigated. The comparative approach makes it possible to highlight strengths and weaknesses of the two energy systems in several aspects, and to provide policy suggestions on how to overcome existing challenges.

The selection of the cases of Egypt and Algeria among other countries in North Africa has followed the criteria identified by the case study methodology (Dion, 2003), which suggests that cases should be selected based on similarities of variables that are not investigated and differences of variables under investigation. In our case, both countries have similar (i) production potential, including availability of land in desertic areas, high solar radiations and wind, (ii) capabilities in the energy industry, (iii) demand from domestic and international markets, due to a large domestic petrochemical industry and proximity with Europe, respectively (iv) ambitious government plans to develop a green hydrogen industry. By contrast, they have different (i) renewable energy generation capacity (ii) endowment of export infrastructure (iii) approaches to regulation, which are the variables under investigation. Their comparative analysis aims to highlight current aspects of strength and weakness in Egypt's and Algeria's energy systems, and how these aspects matter for the development of green hydrogen production and export. The comparison also leads to policy suggestions on how the two countries should face their respective challenges, and how the EU hydrogen strategy should consider these differences to establish successful mechanisms of cooperation for the import of green hydrogen.

The exclusion of Libya, Tunisia and Morocco from the case study can be explained by the differences they show in the control variables. Overall, the methodological choice of this research does not aim to generalize the findings on all the North African countries, but to provide insights on the specific cases of large countries with high production potential.

The paper relies on both primary and secondary sources. The primary sources consist of semi-structured interviews to experts, government legislation, annual reports from ministries and press releases from energy companies. The interviews were conducted with managers of large energy companies operating in Egypt and Algeria which are involved (or have shown interest) into investing in green hydrogen. Interviewees also include managers of companies that own and manage export infrastructure facilities that could be repurposed, energy consulting company directors and advisors to infrastructure companies; advisors to government agencies that promote international cooperation in the renewable energy sector headquartered in North Africa; executive and technical directors of International Organizations' agencies providing technical assistance on renewable energy projects to North African governments.

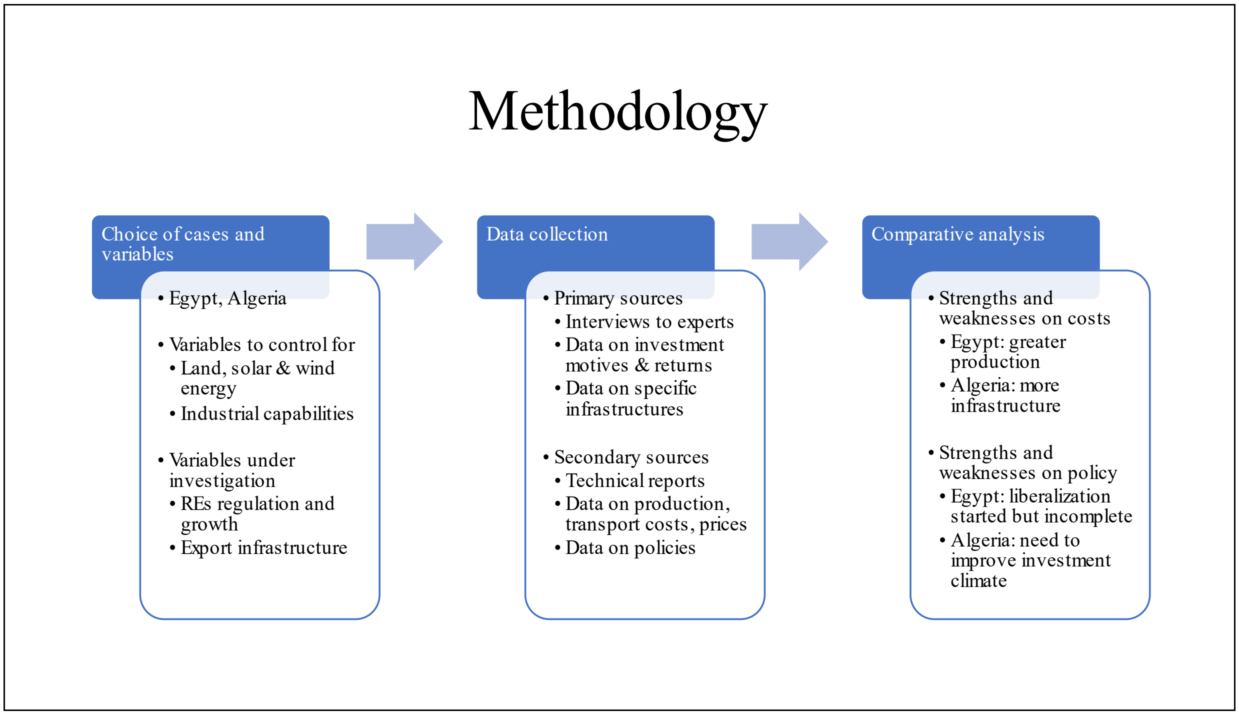
The interviewees were chosen for their roles in companies and public bodies with a direct involvement in decision-making concerning investments, or with direct technical experience in the sector. The goal of the interviews was to provide data to fill the current void of information on how the regulatory environment affects investment decisions, but also on the technical challenges of producing green hydrogen, repurposing existing infrastructure, and developing new ones.

Legislation and press releases of government institutions of Egypt and Algeria made it possible to explore the most up to date policy steps undertaken. Data on annual energy production were collected from Egypt's Ministry of Electricity and Renewable Energy, the Egyptian Electricity Holding Company (the grid operator), Algeria's Ministry of Energy, Sonelgaz (Algeria's grid operator) and the International Renewable Energy Agency (IRENA).

The secondary sources consist of media appearances by experts, academic literature, consultancies and trade journals that provide estimates on costs, investments, and planned energy projects. The estimates on production costs of green hydrogen in Egypt and Algeria are provided by Habib (2021) and Drenkard & Atom (2021), respectively (see Table 3 of for more details). The two reports were selected as the most up to date studies on the two countries and for the comparable methodologies used to calculate production costs. They both use the Levelized Cost of Hydrogen (LCoH), which is a methodology that takes into account similar capital and operating costs to allow for comparisons among different hydrogen projects. The studies by Habib (2021) and Drenkard & Atom (2021) calculate LCoH by assuming costs of renewable power based on average prices on power purchasing agreements ($25 MWh in Egypt, $35 MWh in Algeria); capacity factors of 30% and 60%, which indicate the intermittence in solar PV and wind energy supply; the same CAPEX of $650 KW, which indicates the capital cost of electrolizers; a similar OPEX of about 1% of CAPEX.

Figure 1 provides a visual representation of the choice of the case study, the typology of data collected, how these were analyzed.

Figure 1. The comparative case study: case selection, data collection and analysis.



4. Investments and regulation of renewable energy in Egypt: promising trends for green hydrogen production

Egypt is not a newcomer in the production of green hydrogen. This was launched as early as in the 1960s by the Egyptian Chemical Industries (KIMA) by using hydroelectric energy produced in the Aswan Dam to generate green ammonia (Choksi et al, 1980). However, in the last decades, green hydrogen has been replaced by grey hydrogen, due to the need to use the most abundant energy source available in the country, namely natural gas.

High domestic demand can be explained by Egypt's large industrial base, which contributes to around 30% of the GDP, the largest in the MENA region. The remarkable share of heavy and chemical industries on the overall industrial production explains the high levels of demand for hydrogen. Currently, demand of hydrogen by the ammonia industry producing fertilizers is the highest and it represents around 41% of the total demand. The other main consumers are the steel industry with 35%, refineries industry with 16%, and the petrochemical industry producing methanol with 7% (Habib, 2021). Overall, total hydrogen production and consumption in Egypt is estimated to reach 1,824,540 tons yearly.

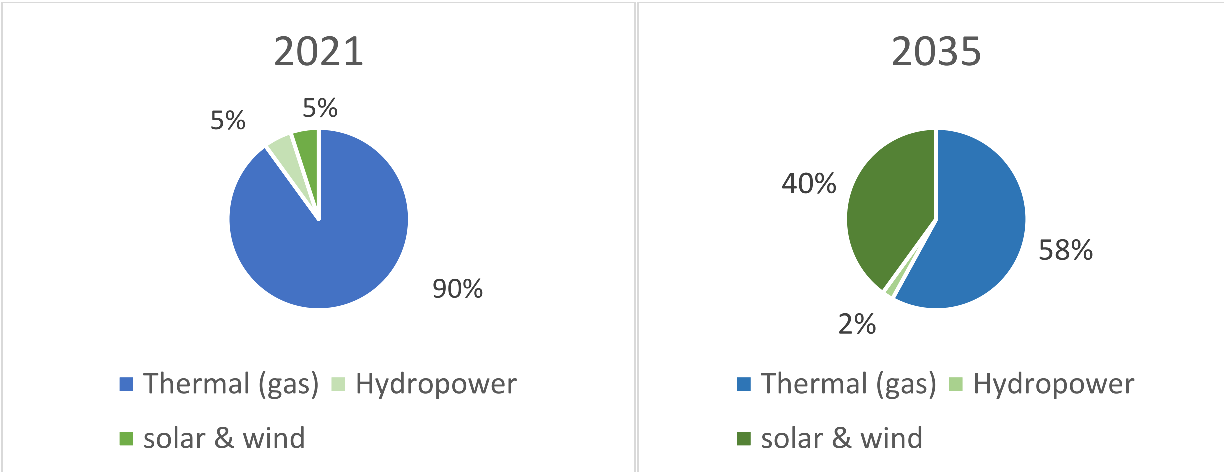
As mentioned earlier, Egypt is currently using natural gas to produce hydrogen. Replacing natural gas with renewables to shift from grey to green hydrogen is one of the goals of Egypt's "Integrated Sustainable Energy Strategy", which was drafted based on Egypt's commitment to the 2015 Paris Agreements and the submitted Nationally Determined Contribution (NDC) (UNFCCC, 2017). The full transition from grey to green hydrogen would have a considerable impact on achieving the emission reduction targets, considering that the main consumers of hydrogen are hard-to-abate industries. Estimates reveal that the switch would reduce CO_2 emissions by 16 tons, representing about 6% of Egypt's total CO_2 emissions (Abdallah, 2020).

However, the transition from grey to green hydrogen poses some challenges concerning the necessary increase in the production of renewable energy. More specifically, it would require an additional installed capacity of 36 GW. This is a remarkable amount considering that the current total installed power capacity is 59 GW, of which 10% is generated from renewables, 5% from solar and wind and an additional 5% from hydropower (Egyptian Electricity Holding Company, 2022). The current 10% capacity from renewables corresponds to about 22% of the additional power needed for the full switch to green hydrogen. However, according to managers involved in green hydrogen projects in Egypt, a full switch to green hydrogen for the medium term is not in the government plans, and part of it could be exported[3].

Egypt plans renewables to account for 42% of the country's total installed power capacity by 2035. This capacity (excluding hydro) is expected to grow from the current 3.5 GW to 54 GW in 2035. The renewable energy portfolio would include 21 GW of wind, 17 GW of solar photovoltaic (PV), 11 GW of concentrated solar power (CSP), and around 5 GW of biomass capacity (International Trade Administration, 2022).

[3] Interviewee 3 has stressed that the option of exporting green hydrogen becomes more realistic due to existing long-term supply contracts of grey hydrogen to domestic industries, which cannot be removed. In a similar way, Interviewee 4 argues that export is definitely an option, considering the current booming international energy prices. Interviewee 8 highlights that currently there is an excess of power production in Egypt, which is increasingly convincing domestic and international investors to develop green hydrogen projects for export.

Figure 2. Egypt's electricity generation by source (actual and future gov't targets)



Source: IRENA (2022); International Trade Administration (2022)

If this scale of production in renewables is achieved, production cost of green hydrogen would decrease, becoming become competitive with fossil fuels. Costs of green hydrogen are estimated to be at least double as compared to the cost of grey hydrogen in the most favorable scenario of cheap and competitive wind and solar energy, namely \$25 MWh. Costs of green hydrogen would range between \$2.57 – \$3.73 KgH_2 (\$3.15 KgH_2 on average, as shown in Table 3) as compared to the costs of grey and blue hydrogen in 2021 of \$1.25 and \$1.65 KgH_2, respectively (Habib, 2021)[4].

Scaling up the costs of renewables and of electrolyzers in Egypt would mean implementing a large-scale investment program to reach an installed capacity of 36 GW devoted to renewables only. In addition, to transform this amount of electricity into hydrogen, an electrolizer capacity of 21 GW is needed (Habib, 2021), proving challenging both from the financial and technical viewpoint[5]. Another issue in green hydrogen production is the use of water. Although the Nile could be a

[4] Interviewees 3 and 4 provide similar estimates as Habib on this point. However, Interviewees 4 and 5 note that if high energy prices that prevailed in 2022 will remain in a similar range also in the future, green hydrogen could easily be produced at similar costs of grey and blue hydrogen. According to Interviewee 7, the assumption of renewable power cost of \$25 MWh is realistic as it corresponds to the current average price of renewable energy in Egypt's Power-Purchasing Agreements.

[5] On this point, Interviewee 1 notes that electrolysis of large quantities of green power does not have to necessarily require large-scale electrolizers, but it could also be achieved through several small-scale electrolizers.

potential source, most of the water should be taken from the sea to avoid jeopardizing water security for industry and households[6].

Understanding whether these challenges can be successfully addressed requires considering the existing regulatory framework, and how the Egyptian government and institutions have in recent years attempted to reconcile energy security, price affordability for consumers and decarbonization. Although solar and wind still account for 5% of Egypt's installed generation capacity, it is worth noting that this has witnessed a more than fourfold growth in the last five years, from roughly 690 MW in 2014/2015 to 3.15 GW in 2019/2020. The newly introduced regulatory framework has played an important role in this positive trend.

In the years after the political turmoil, the Egyptian government has worked to remove the long-term structural conditions that exacerbated the socio-economic context, and that originated mainly from the energy sector. This was done by creating macroeconomic and regulatory conditions to attract domestic and foreign investments in the energy sector, increase the level of domestic production with the goal to decrease energy prices by means of market competition rather than artificially through public subsidies.

In the biennium 2014-2015, the government was very active in issuing new tenders for exploration and production in oil & gas, characterized by favorable conditions for the private sector in terms of taxation, cost recovery and profitability (El-Shahid and Badawy, 2021). The policy succeeded in attracting investments in the petroleum sector amounting to 16 trillion EGP (equivalent to about $63.5 billion USD) in the period 2015-2019 (Ahmed, 2020b). The turning point for the country was the discovery of Zohr in 2015 by the Italian energy company Eni in Egypt’s offshore. Zohr is a giant gas field, the largest in the Mediterranean Sea, with proven reserves of 850 bcm. Thanks to Zohr, Egypt has doubled its gas reserves and has returned to the previous condition of net exporter.

[6] Interviewee 2 notes that cost of water and desalinization is negligible, and it would be possible to take advantage of Egypt’s coastal areas both in the Mediterranean and Red Seas, in which large desertic areas exist and where solar and wind farms can be more easily located.

With Gas Market Activities Law 196/2017, the Egyptian government has shown the intention to capitalize on the current abundance of natural gas and liberalize the supply chain from upstream to downstream. The law requires the Transmission System Operator (TSO) GASCO, a subsidiary of the Egyptian Natural Gas Holding Company (EGAS), to implement the provisions on Third-Party Access (TPA) in a non-discriminatory way. The Gas Regulatory Authority overseas GASCO's activities and monitors market competition and consumers' price affordability. TPA applies also to export infrastructure, most notably LNG liquefaction plants and gas pipelines (El-Shahid and Talaat, 2020). As a result, in a few years EGAS' monopoly was turned into a slightly more competitive market, with 14 companies operating in the downstream, 9 of which private and 5 state-owned (Kafafy, 2020).

Similar measures were adopted in the power sector. With the New Electricity Law No. 87 of 2015, the government pursued the double goal of (i) liberalizing power generation and sales, and (ii) incentivizing private investments. A key measure was ownership unbundling of the TSO Egyptian Electricity Transmission Company (EETC) from the parent Egyptian Electricity Holding Company (EEHC), the former vertically integrated state-owned monopolist. Although EETC is still state-owned, it is independent from any other company involved in the power sector, and its new mandate includes an explicit clause on TPA with an obligation to grant access to the grid to licensed generation companies without preferential treatment on capacity allocation and tariff applied[7] (Fahmi and Hussein, 2020).

Although the system remains dominated by EEHC, its subsidiaries are increasingly competing especially in the generation phase among themselves as well as with emerging independent power producers. Currently, the system operates under two market schemes: regulated and competitive, with EETC acting as a TSO in both markets but with different responsibilities. The regulated market allows EETC to buy electricity from generators and sell it to customers who aren't eligible under the competitive market conditions, including low-income consumers. Industrial high voltage consumers, on the other hand, buy electricity directly from generators in a competitive market.

[7] However, Interviewee 3 notes that despite unbundling and TPA, in practice, it might take time before new entrants would be able to compete with the incumbent, considering the market power it still retain and lower costs it is still able to realize.

This scheme allows independent power producers to sign bilateral electricity purchase agreements with qualified customers and sell them produced electricity directly.

In 2014, a year before the above-mentioned liberalization policies, a Feed-In Tariff (FIT) system for solar and wind power was introduced. The goal was to encourage the private sector to enter the renewable power generation market and increase power supply. In fact, FIT allows private investors to own, build, and manage renewable energy power plants and sell generated electricity with Power Purchase Agreements (PPAs) to EETC or to licensed distribution firms. The PPA establishes the contract's duration as well as a fixed electricity price, providing a guarantee of the return on investments. Solar projects have a 20-year PPA, while wind projects have a 25-year PPA[8]. FIT, PPA and other provisions for market competition have succeeded to attract private investors, despite the average power price paid by the national grid as part of PPAs decreased extensively to $25 MWh[9].

Table 1. Egypt's increase in gas and power generation as a result of policy reforms (2014-2021)

	2014	2021
Total installed capacity (GW)	32	59
Natural gas production (bcm)	44	73
Renewables total capacity (GW)	3.5	6.2
Hydro (GW)	2.8	2.8

[8] Interviewee 5 confirm that PPA have had a positive impact on reducing investment uncertainty for the private sector. Interviewee 8 agrees with the positive role of PPA but warns on the importance of the macroeconomic outlook as well, especially on the effects of currency devaluation in Egypt.

[9] According to the CEO of Siemens Energy (Egypt Today, 2019), recent regulatory reforms in Egypt have played a key role in Siemens Energy's decision to invest massively in Egypt's energy sector and in the achievement of successful results. In 2016, Siemens has signed contracts with EEHC worth 8 billion euro for the realization of three Combined Cycle Gas Turbines (CCGTs) power plants with a total generation capacity of 14.4 GW, and 12 wind farms for additional 2 GW, representing a 18% increase in total wind energy capacity. The CCGTs became fully functional by 2018, accounting for a 22% increase in the total electricity generation of the country, while the wind farm became operational by 2022.

Wind (GW)	0.5	1.6
Solar (GW)	0.3	1.7

Source: IRENA (2022); Egypt Ministry of Electricity (2022)

As a result of a surplus in the generation of power, Egypt is currently pursuing a number of initiatives and projects aimed at developing low-carbon hydrogen production. Three international alliances have applied for projects in Ain Sokhna and East-Port Said, all located near the Suez Canal[10].

Siemens and the Egyptian Electricity Holding Company (EEHC) signed a memorandum of understanding (MoU) in August 2021 to jointly develop a hydrogen-based industry in Egypt with exporting capabilities. They will work on a pilot project with a capacity of 100 to 200 MW, which will help accelerate early technology deployment. Another initial agreement was signed with the Italian energy company Eni to cooperate on green and blue hydrogen production. The parties will conduct research to manufacture green hydrogen using renewable electricity and blue hydrogen using carbon dioxide (CO_2) storage in depleted natural gas fields. Finally, Fertiglobe, an Egyptian Emirati firm, and Scatec, a Norwegian renewable energy company, signed a deal in October 2021 for the combined development of green hydrogen and green ammonia.

As mentioned in the previous section, the Egyptian market would be able to absorb large quantities of green hydrogen produced locally, due to the presence of energy-intensive industries. However, companies such as Siemens and Eni are also evaluating the option of exports to Europe[11].

[10] According to Interviewee 3 and 4, the capacity and reliability of national gas and electricity grids are playing an important role in encouraging the government and the industry in accelerating a green hydrogen strategy. Despite that, projects located in the Suez Industrial Zone might be preferred as production and export facilities would be very close, which makes it possible to avoid expensive upgrades on the national grid.

[11] However, according to the Director of Public Affairs of Eni (Ispi, 2021), the production and export of hydrogen in Egypt now has several drawbacks in terms of costs and efficiency. In particular, he points out the loss of energy along the process of transformation of renewable power into gaseous hydrogen and then back to electricity. This suggests that green hydrogen is likely to be viable for domestic consumption and export directed to large industrial consumers that use it in the form of ammonia, rather than a full replacement of electricity consumption by households and industry.

Currently, Egypt's main export infrastructure are Damietta and Idku LNG plants. The Damietta plant has a liquefaction capacity of 6.6 bcm and it is owned by Eni and Egyptian State companies EGAS and EGPC through an equal joint venture. The Idku plant has a larger liquefaction capacity of 9.9 bcm and it is owned by an international consortium comprising Shell, Petronas, Engie, EGAS and EGPC. Another important infrastructure for export is the EMG (reverse flow) gas pipeline, which has a transport capacity of 10.3 bcm and connects Egypt to the Levant region (Mott MacDonald, 2010).

Therefore, despite the favourable conditions that have been created in the renewable energy generation, and the interests shown by international investors in producing hydrogen in Egypt, export infrastructure capacity that could be repurposed to transport hydrogen is quite limited. This amounts to 26.8 bcm/y if the Arab Gas Pipeline (AGP) pipeline connecting Egypt to the Levant is considered. If we only consider infrastructure that can supply Europe (so far where potential demand exists), total capacity amounts to only 16.5 bcm/y (see Figure 3 in the appendix) (Mott MacDonald, 2010). This suggests that investment to develop new green hydrogen export infrastructure is needed.

The main reasons are at least two. First, existing LNG infrastructure is being used at full capacity to meet the high level of demand in the international market, in line with the Ministry of Petroleum's strategy to take advantage from the record-high gas prices. Second, estimates suggest that upgrading LNG to liquefy green hydrogen or green ammonia (a hydrogen carrier) would cost up to 20% more the cost of building a new LNG terminal[12] (IEA, 2022). In addition, for short transport distances such as Europe, liquefaction and transport by boats is likely to be unviable (Collis and Schomacker, 2022).

For this reason, in line with other industry's forecast (van Wijk and Wouters, 2019), we assume that a green hydrogen pipeline would be a viable option for Egypt. This would be a large (48 inches) offshore pipeline with approximate length of 2500 km connecting Egypt to Greece and Italy. According to European Hydrogen Backbone (2022), the cost of a large, offshore pipeline

[12] On this point, Interviewees 9 and 10 pointed out that repurposing LNG to liquefy green hydrogen pose both financial and technical challenges. More specifically, two essential parts of the LNG facilities should be replaced, namely the Main Cryogenic Heat Exchanger (MCHE) and the storage tanks. Interviewee 11 argues that in addition to these two essential parts, compressors and pumps might also need full replacement.

with such length amounts to €5.8million per km. Therefore, the total cost would be around €14.5 billion. Nevertheless, the large dimensions of the pipeline, which would allow to transport up to 9 million tons of green hydrogen, make it possible to realize economies of scale and reduce the cost of transport to \$1.4 kgH_2, (see Table 4 for further details). This figure is lower than the forecasted cost of \$5.5 kgH_2 for the transport of Liquefied Hydrogen (LH_2) and of \$2.6-\$3.9 kgH_2 for Liquid Organic Hydrogen Carrier (LOHC). In addition, both these solutions require distances above 7000 km to be viable, which is well above the distance between Egypt and Europe.

However, the crucial factor for the viability of Egypt's hydrogen export supply chain is the scale of hydrogen production. In other words, the pipeline investment would be profitable if enough hydrogen volumes are available to fill the pipeline at full capacity. Currently, the production of renewable energy that could be transformed into green hydrogen is too low to justify the development of a new hydrogen pipeline. Current installed capacity in Egypt is 6.226 GW, while the pipeline could transport hydrogen up to 31 GW (or 9 million tons). However, if the 54 GW government target of renewable installed capacity by 2035 is achieved, the pipeline could be used at full capacity, therefore generating economies of scale that make the project viable. Moreover, an additional capacity of 23 GW would be left to supply the local economy, which is desirable to diversify the energy mix (see table 4 for more details).

5. Algeria's challenges in the renewable energy sector: implications for green hydrogen production and export

Algeria is another candidate for the regional leadership in the production and export of green hydrogen. This is due to the availability of large desertic areas and of existing infrastructure for export to Europe. However, some industrial and regulatory factors suggest that the path towards it has challenges that must be overcome.

Algeria's experience with production and consumption of hydrogen is not new, and this represents a positive factor in the transition to green hydrogen, although current production of hydrogen derives almost exclusively from natural gas. The petrochemical industry is by far the largest consumer of grey hydrogen. The importance of this industry can be explained by Algeria's refining capacity, which ranks second in Africa after Egypt. Currently, the petrochemical industry consumes 12070 tons per day of hydrogen, one third produced internally, while the rest is bought on the market. Hydrogen is also used to produce ammonia to be sold to the fertilizer industry. There are three plants producing ammonia, which overall produce around 10000 tons per day. While iron and steel industries are currently minor producers and consumers of hydrogen, as energy-intensive industries they are good candidates to increase its use. The same applies to cement and transport, which are among the sectors targeted by the Algerian hydrogen strategy[13] (Drenkard and Mirakyan, 2021).

The development of a green hydrogen supply chain is one of the Algerian government strategic plans[14] (Algeria's Ministry of Energy and Mines, 2022a). The plan envisages the installment of 22 GW of renewable energy by 2030, and to achieve 27% of electricity produced from renewable energy by 2035. As a result, by 2030 Sonelgaz plans to expand the electricity network by an additional 20,000 km (Sonelgaz, 2020). The objectives are multiple, namely, to alleviate the pressure on a declining natural gas production, but also to create a new industry that contributes to employment and economic growth, as well as to reduce 193 million tons of CO_2 emissions.

However, the switch from grey to green hydrogen may prove challenging. This is evident, for example, in the results achieved so far. Currently, Algeria's installed power capacity amounts to 21.4 GW, 96% of which is produced with natural gas while only 2% with renewables, namely hydro, solar PV and wind. For example, solar PV has an installed capacity of just 423 MW.

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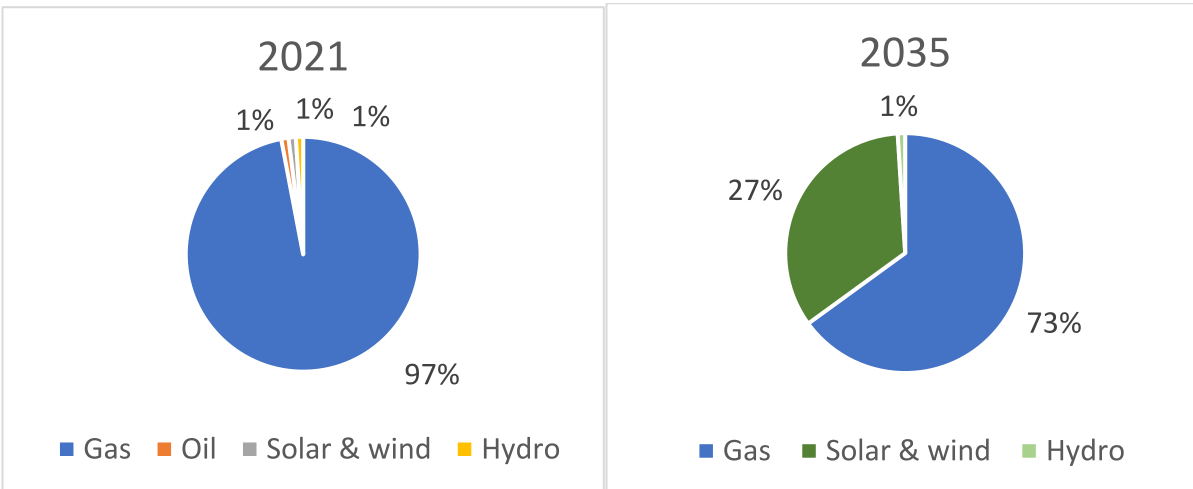
[13] As suggested by Interviewee 3 for the case of Egypt, Algeria has also an industrial structure that favor the production of hydrogen, and thus the potential transition from grey to green hydrogen. The presence of energy-intensive heavy and chemical industries suggests that the scale of consumption of hydrogen would be adequate to the nature of the high upfront investments needed to produce it.

[14] Based on frequent engagement with governments in North Africa, Interviewee 6 has confirmed the relevance of hydrogen among Algeria's national strategies.

Figure 3. Algeria's electricity generation by source (actual and future gov't targets)



Source: IRENA (2022); Algeria's Ministry of Energy and Mines, 2022b)

Drenkard and Mirakyan (2021) estimates that Algeria has a potential to produce between 6 and 6.50 million tons of green hydrogen per year through solar by 2030, while an additional 1 million ton per year could be generated from onshore and offshore wind. The regions with the highest potential for the generation of solar energy are in the southeast part of the country, which together would contribute for about three quarters of the national production.

By 2030, the cost of production and transport of hydrogen obtained by solar PV and wind is estimated to be on average \$4.12 kgH_2[15] (Drenkard and Mirakyan, 2021), with southeastern regions producing at the lowest cost thanks to the economies of scale that can be realized. By contrast, the northern regions would produce at higher costs but would benefit from proximity to export infrastructure located on the Mediterranean coast. Hydrogen derived from wind has a lower cost of production of \$4 kgH_2 on average, while solar PV would cost around \$4.14 kgH_2 (see Table 3 for a comparison with Egypt). Regarding water demand to produce green hydrogen, this is expected to equal 819k m^3 per year. This value corresponds to only 0.01% of the total capacity of desalinization in Algeria, which amounts to 766.5 million m^3 per year.

[15] For simplicity, this cost excludes the domestic fees charged by the Transmission System Operator, which nevertheless are not likely to impact the final price to a major extent, considering that Algeria's energy grids are well developed across the country.

Ultimately, studies suggest that in principle Algeria has all the resources needed to achieve a scale of production that ensures a competitive cost of hydrogen vis-à-vis other energy sources or vectors (Drenkard & Atom, 2021). However, these estimates assume that government targets for the installment of additional capacity of renewable energy are achieved. This shall not be taken for granted if one considers the results of recent years. Regulation and the ability to attract investments are key factors that enable or constrain Algeria's ability to become a regional leader in the production and export of green hydrogen.

In the last two decades, the attractiveness of Algerian market for investors has decreased, due to multiple reasons. This is evident from the decreasing levels of energy production, which gave worrying signals of a depletion risk, including in the oil & gas sectors.

The latter is due to a lower-than-expected performance of some tenders in the early 2000s, issued to International Oil Companies (IOCs) for the concession of exploration and production rights in the Algerian onshore and offshore. Conditions for IOC were not as favorable as in previous rounds, including high taxation and a high share of revenue appropriated by the national company. As a result, between the mid-2000s and the mid-2010s, production decreased by 10 bcm while exports decreased by 25 bcm (Aissaoui, 2016).

A similar dynamic occurred in the electricity sector, particularly in recent attempts to promote renewables. The first important step was taken in 2002, when the government revoked the monopolistic concession to Sonelgaz – the vertically-integrated state-owned company dominating the generation, transmission, distribution and sale – in view of incentivizing new entrants. Although *de facto* Sonelgaz continued to dominate the market for some years, the introduction of Law 99-09 of 2009 has proved determinant in attracting investments and accelerate the deployment of renewable generation capacity thanks to specific incentives.

The law envisaged the establishment of the National Fund for Renewable Energy (NFRE), which was funded with 0.5-1% of the royalties deriving from the oil & gas sector, and that aimed at providing financial support to investments in renewables. The Executive Decree 13-218 of 2013 envisaged specific ways to allocate these fundings. In particular, the fund would support investments from both the supply and demand side. On the supply side, the fund would provide aid for the construction and maintenance of production facilities and power plants, the purchase of technologies and equipment, training and R&D. On the demand side, and under the Feed-in-Tariff/Power Purchasing Agreement schemes, the fund commits itself to purchase all renewable electricity generated for 20 years at prices above production costs and superior to market prices (Bouznit et al., 2020).

However, with the Executive Decrees 17-98 and 17-204 of 2017, some new terms on tenders and auctions were introduced to secure government control of projects while pursuing the objective of local industrial development. One of the conditions was that the project awarded had to be majority-owned by Algerian companies (Bouznit et al., 2020). This has discouraged international investors that are used to structuring joint ventures with local partners through equal or majority stakes. Other important conditions concerned minimum local content for both the manufacturing of solar panels and the financing needed. Considering the limited local capacity as compared to international markets, from which international companies usually rely, it seems that rules on minimum local content have also played a role in discouraging foreign investors (Hochberg, 2019).

The need to rethink the aspects of the regulation emerged from the outcome of the first tender, launched in 2019 with total concessions of 150 MW of renewable energy capacity to be installed and the award of only 60% (or 90 MW). This led to a slowdown in the expected growth of renewables compared to previous periods, which had benefited from the adoption of feed-in-tariff schemes and from the establishment of the National Fund for Renewable Energy. Overall, of the government plan to install 5 GW of new power capacity from renewables in the period 2010-2020, only 9% of it was successfully executed. By 2020, only 440 MW were installed, 390 from solar and 50 from wind.

According to agencies and analysts, the energy sector regulation is not the only factor discouraging some foreign investments in Algeria. According to Heinemann et al. (2022), investment climate in Algeria is deteriorated by a low quality in the regulation of different economic sectors, as well as political instability. These and other factors contribute to a high cost of capital, which is a major obstacle to new investments. According to the US Department of Commerce (2023), the excessive market power of SOEs is a major challenge for US companies investing and operating in Algeria. The report mentions also that contradictory government policies and a weak regulatory framework contribute to creating a difficult business climate.

However, both reports mention that, despite these challenges, ample opportunities for investments and growth remain, in addition to a strong government willingness to attract foreign investments. In fact, from 2021, some of the unfavorable terms for private investors contained in the previous tender were lifted or removed. For example, majority-ownership of large renewable energy projects is not mandatory anymore[16]. In addition, some clauses of minimum local content became less stringent.

Table 2. Algeria's increase in gas and power generation as a result of policy reforms (2014-2021)

	2014	2021
Total power installed capacity (GW)	15	21.4
Natural gas production (bcm)	93	103
Renewables total capacity (GW)	0.2	0.7
Hydro (GW)	0.2	0.2
Wind (GW)	0.01	0.01
Solar (GW)	0.02	0.4

Source: IRENA (2022)

Green hydrogen is considered strategic by the Algerian government also because it can benefit from the remarkable network of national gas infrastructures, which is the most extended in Africa[17]. This was declared jointly by the ministers of the Energy Transition and Renewable

[16] This was announced by the Minister of the Knowledge Economy, Startups and Micro-enterprises, in occasion of the forum Mediterranean Dialogues 2022, Rome, 4 Dec.
[17] On this point, the Director of Public Affairs Eni pointed out that the objective of energy access has been, and it will be a priority for the Algerian leadership. This does not prevent from the possibility of using the national grid to transport green energy if the fundamental objectives of energy security and energy access are not jeopardized.

Energies and of the Higher Education and Scientific Research in occasion of the "Declaration of Alger", signed on the 19th of April by the two ministries to lay the foundation of a national hydrogen strategy.

While the declaration is a preliminary step of the national strategy, three main agreements with foreign partners are leading the way forward. The entities involved are the EU, Germany, and Italy. The cooperation with the EU is not yet formalized, but both counterparts have expressed a mutual interest in cooperating in this field. The EU plans to invest about 300 billion euro in the development of a green hydrogen supply chain, and that part of the investment should be destined to North Africa. EU and Algeria have pre-existing partnerships and ongoing negotiations for mutual investments and harmonization of their respective regulation, which is a starting point in view of consolidating a collaboration on hydrogen.

Another important development has occurred in the framework of the "Algerian-German energy partnership", which promotes strategic initiatives of political and economic nature related to the energy sector. So far, this platform has promoted meetings at the ministerial level, the dialogue between financial and industrial stakeholders of both countries, and the launch of a study on the development of hydrogen in Algeria. More specific initiatives were launched by the Italian energy company Eni and the Algerian Sonatrach, thanks to Eni's established presence in the North African country. For example, since March 2021, the two companies signed a series of agreements to cooperate on the reduction of CO_2 emissions in the jointly operated fields. In this framework, they agreed to launch a pilot project to produce green hydrogen from solar and wind, and to use water from existing wells for the electrolyzing process.

The role of Eni in the development and export of hydrogen from Algeria is likely to be relevant, also thanks to its majority stake in the Trans-Mediterranean Pipeline (or Transmed), which connects Algeria to Italy via Tunisia and has an annual transport capacity of natural gas of 33.5 bcm. Recently, the Italian TSO Snam has purchased a 49.9% stake of Transmed from Eni, in view of jointly investing in the upgrade of the pipeline for the transport of green hydrogen (exclusively or blended with natural gas). These plans have received diplomatic support in occasion of the visit of the Italian Prime Minister Mario Draghi to Algiers in April 2022.

Considering the presence of strong political and corporate support from both the Algerian and Italian sides, we assumed that Transmed is one of the main candidates for being repurposed to transport green hydrogen[18]. According to European Hydrogen Backbone (2022), the cost of repurposing a 48 inches large offshore pipeline would be €0.6 million per km. As Transmed is 1075 km long, the total cost of the upgrade would be €645 million (see Table 4).

As the IEA (2022) suggests, a repurposed pipeline can transport hydrogen up to 80% of its original gas transport capacity. As Transmed has two parallel lines with a total capacity of 33.5 bcm, we assume that only one line is repurposed, while the other still transports natural gas, for energy security reasons. Therefore, the transport capacity of the repurposed line would be 13.4 bcm, which equals 9 million tons of hydrogen per year.

Considering that the Algerian potential to produce green hydrogen by 2035 is 6.5 million tons per year, revenues from exports would be more than enough to justify the modest investment needed for repurposing Transmed. Therefore, the key obstacle that remains concerns reaching the 20 GW target of renewable energy installed capacity by 2035, equivalent to the targeted 6 - 6.5 million tons of green hydrogen. This requires a change of pace in investment rates, considering that in the last 8 years, renewable capacity increased only from 0.2 to 0.7 GW (see Table 2).

[18] However, according to Interviewees 9 and 10, repurposed pipelines might not be able to be employed for the sole purpose of transporting hydrogen, while a blending with natural gas might be needed.

Table 3. Estimates of hydrogen production and transport costs by 2030

	Egypt	Algeria	Europe
Production cost ($/kg$H_2$)	3.15[19]	4.12[20]	7.5 – 9.7[21]
Transport cost ($/kg$H_2$)	1.4[22]	0.5[23]	0.4 – 1.2[24]
Total cost ($/kg$H_2$)	4.55	4.62	7.9 – 10.9

Source: Author's own calculation based on different sources (see footnotes)

[19] Based on Habib's (2021) renewable electricity price estimation of $25 MWh (which reflects average prices of wind and solar PV power purchasing agreements), a CAPEX of $650 KW and an OPEX of 1%.

[20] Based on estimates by Drenkard and Mirakyan, (2021) of a renewable electricity price of $35 MWh (in line with the latest price of $36 MWh in Algerian power purchasing agreements), a CAPEX of $650 KW and an OPEX of 1%.

[21] Based on results of production cost analysis conducted by Collis and Schomacker (2022) and Christensen (2020).

[22] The cost refers to an estimate by Collis and Schomacker (2022) on the cost of transporting green hydrogen from Egypt to Germany via pipeline. The rather low transport cost of 1.4 is explained by the efficiency of H_2 pipeline transport in a gaseous form vis-à-vis other systems, for example liquefied hydrogen, or its transformation into ammonia, which determines high energy losses across conversion phases.

[23] Based on European hydrogen Backbone (2022) data, which assumes a cost of €0.5 kg /1000 km for large repurposed offshore pipelines such as Transmed.

[24] Collis and Schomacker (2022) estimate a cost of $0.4 kg$H_2$ for the transport of hydrogen by an onshore pipeline, and in a typical European distance of about 1000 km between production and consumption sites. In their case study, this cost is calculated for a distance of 1200 km from Parc Eolien de Port la Nouvelle (South France) to Cologne (North-West Germany). By contrast, the higher $1.2 is estimated for transport by truck, which is used for lower quantities and in absence of pipelines.

Table 4. Capex estimates for repurposing existing infrastructure and developing new ones

	Egypt	Algeria
Cost of repurposing existing infrastructure	Not viable/strategic	Transmed pipeline (1075 km) = €645 million[25]
Cost of developing new infrastructure	Egypt-Greece-Italy pipeline (2500 km) = €14.5 billion[26]	Not viable/strategic
Total capacity (million tons)	9 million tons (= 31 GW)	9 million tons (= 31 GW)[27]
Installed renewable capacity (2021)	6.226 GW	0.7 GW

Source: Author's calculation based on data from European Hydrogen Backbone (2022)

6. Discussion: The EU hydrogen strategy and the need for differentiated strategy of import from North Africa

Green hydrogen has been identified as a strategic source by the EU, decisive to achieve the "Fit for 55" objective of decreasing greenhouse gas emissions by 55% by 2030. With the deterioration of the political relations with the Russian Federation and the determination to cut imports of Russian gas, the development of hydrogen became a priority of energy security as well.

As for Egypt and Algeria, the EU green hydrogen sector is at its very early stages. However, differently from the North African countries, the EU has officially developed a comprehensive and detailed strategy, started with a Communication of the European Commission (EC) to the other

[25] For a 48 inches offshore pipeline such as Transmed, the cost estimate is € 0.6 million/km. As Transmed length is 1075 km, the cost of upgrade would be € 645 million.
[26] To develop a new, large (48 inch) offshore pipeline, the cost is estimated to be €5.8million per km. As this pipeline will be 2500 km long, the total cost would be €14.5 billion.
[27] Considering that only one of the two parallel lines of Transmed is repurposed, while the other still transports natural gas for energy security reasons. Therefore, the transport capacity of the repurposed line is half the current 33.5 bcm, that is 16.75 bcm. Given that repurposed pipelines can transport hydrogen for up to 80% of its original gas transport capacity, namely 13.4 bcm, this equals 9 million tons of hydrogen.

EU institutions in July 2020[28], subsequently upgraded into a draft of "Hydrogen and Decarbonized Gas Market Package" in December 2021[29]. The latter was recently revised in the "REPowerEU"[30], which provides indications on how to overcome the reduction of Russian gas.

REPowerEU has very ambitious objectives of installing 40 GW of electrolizers in the EU and to import an additional 40 GW from abroad by 2030, making available around 20 million tons of green hydrogen to EU consumers. This is more than double of the current quantity of gray hydrogen consumed by the EU industry, namely 8.4 million tons. The European Commission argues that these targets of production can be achieved considering the maturity of EU energy industry. However, it recognizes that investments in infrastructure might be challenging (Tanese and Herrera Anchustegui, 2022).

More specifically, provisions concerning market competition could discourage investments in newly developed hydrogen pipelines, as investors would be concerned that competition might hamper their returns on very high upfront costs. For this reason, the debate among EU institutions, energy industry and other stakeholders, concerns the extent to which market competition rules should be conceived for the early phases and the speed at which these rules should be enforced in the next years or decades.

The idea is to apply existing rules on natural gas infrastructure in a gradual way also for the emerging hydrogen infrastructure. The rules are those concerning ownership unbundling, Third Party Access (TPA), non-discriminatory tariffs, and long-term supply contracts (Kneebone, J., (2021). For example, ownership unbundling between infrastructure and production companies may not be mandatory in the early years, as legal unbundling is deemed to be sufficient. In a similar way, infrastructure companies may restrict access or apply differentiated tariffs to alternative hydrogen producers to avoid competitors acting as free riders (Tanese and Herrera Anchustegui, 2022). Although 2030 has been identified as the year in which such exemptions in principle should

[28] See "A Hydrogen strategy for climate-neutral Europe", Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, Brussels, July 8th, 2020, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
[29] See "Commission proposes new EU framework to decarbonize gas markets, promote hydrogen and reduce methane emissions", press release, Brussels, December 15th, 2021, https://ec.europa.eu/commission/presscorner/detail/en/ip_21_6682
[30] See "REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition" press release, Brussels, May 18th, 2022, https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3131

cease to exist, some stakeholders such as ACER deem important to adopt a flexible approach and guarantee a comprehensive adhesion to the EU hydrogen plan by investors (ACER, 2021).

However, there is a large consensus on the fact that inefficient incentives such as geographical cross-subsidization should be avoided. In this way, infrastructure will be built only in areas in which users will be willing or able to pay for their capital and operational expenditures. Although this has clear advantages in terms of efficiency, it has also disadvantages in terms of missed positive externalities from infrastructure that are economically unviable in the short term but beneficial for the economy and society in the long term. For this reason, it has been proposed to introduce a "temporal cross-subsidization", in which the high upfront costs will be paid in the future by the users of the same region.

While there is an ongoing debate within EU institutions on the timing of applying existing competition rules to the emerging hydrogen market in the EU, an issue that has not been explicitly addressed is whether sooner or later the same rules should be applied also to the import market. This is probably the direction that EU policymakers are willing to take, to avoid that high market power of few non-EU exporters and EU importers neutralizes the benefits of domestic market competition.

One of the options is to look at the revision of the 2009 Directive[31] by the Council in 2019, which extends competition rules of EU natural gas markets, for example Third-Party Access (TPA), also to import infrastructure that supply the EU from abroad. This revision caused a legal and political debate on its compatibility with European Treaties (Goldthau and Sitter, 2014; Hancher and Marhold 2019), which envisage Member States to retain exclusive competence in matters of energy supply from non-EU countries. However, another important implication to consider is whether non-EU exporting countries are also willing to respect this rule. For example, TPA was in contrast with the law of the Russian Federation, which confers Gazprom the monopoly on gas exports.

One way through which the EU has worked in recent years to make TPA on import infrastructure effective was to negotiate with non-EU producing countries on ways for them to implement

[31] See "Directive (EU) 2019/692 of the European Parliament and of the Council of 17 April 2019 amending Directive 2009/73/EC concerning common rules for the internal market in natural gas"

liberalization reforms. Besides the strategic gain of coopting these countries into the EU sphere of influence, this would allow EU firms easier access to neighboring markets and the possibility to make EU competition mechanisms effective and not weakened by non-EU exporters, which are often monopolies in their country of origin.

However, in non-EU producing countries, the option to reform the energy governance based on EU competition rules was not always seen as a priority or convenient. For example, Algeria has been reluctant to adopt of reforms inspired to the EU model. This emerged in different rounds of negotiation between the European Commission and the Algerian government in the last 20 years. The divergent visions between the two counterparts prevented exploring potential convergences on less ambitious, though as much relevant, issues of the energy cooperation, for example the terms of concessions for European companies in the Algerian upstream (Cardinale, 2019). This led to underinvestment by European companies in the Algerian energy sector, increasing the depletion risk.

In the newly emerging hydrogen sector, the approaches to energy policy by both counterparts seem to be rather unchanged. The Algerian government has introduced measures to protect the local economy, such as those on minimum local content and on majority-ownership of large projects by national companies. The EU will probably extend its competition rules to the hydrogen import markets, in a similar way it has done with natural gas. However, the persistence of polarized approaches to energy policy in Algeria and the EU in this occasion should not lead again to a missed opportunity for cooperation, as for natural gas in previous years.

The difficulty to harmonize regulation should lead both counterparts to target more specific objectives, in view of developing a green hydrogen supply chain. In particular, the main problem that should be tackled is the low investment rate in the Algerian renewable generation capacity. The EU could establish co-finance mechanisms that support the work of the Algerian National Fund for Renewable Energy in de-risking investments. In exchange, the Algerian government could lift some stringent conditions imposed on foreign investments, particularly from Europe. The EU could also co-finance the upgrade of Transmed to transport green hydrogen, although this is not a top priority considering the relatively limited investment needed.

In a more ambitious scenario of negotiation, Algeria could concede the application of TPA specifically on the repurposed export infrastructure. This could be a win-win solution for all the stakeholders involved. In fact, European energy companies would be encouraged to invest in Algeria knowing that they can access the repurposed infrastructure and export green hydrogen to profitable European markets. As a result, Algeria would overcome the challenge of low investments and the EU would be able to import green hydrogen within the framework of competition rules.

Different is the case of Egypt, which might explore the possibility to capitalize on the opportunities offered by liberalization reforms to become an energy hub. While pros and cons of this choice should be carefully evaluated, this option would certainly offer several opportunities for cooperation with the EU, who prioritizes commercial deals with partners that share similar approaches to energy policy and regulation.

Liberalization reforms that started in 2015 succeeded in attracting foreign and domestic private investors, turning an energy deficit into an energy surplus. Although this process started with important discoveries of natural gas, similarly positive results are being achieved in the sector of renewable energy, which has seen the growth of installed capacity by almost 1 GW yearly since 2016, positioning Egypt as the second largest producer of renewable energy in Africa.

Liberalization reforms in Egypt are mainly aimed at attracting private and foreign investments to increase generation of renewable power. The recent adoption of unbundling and TPA measures on existing transmission and export infrastructures might be an additional driver to investment. The access to existing infrastructure would allow investors to vertically integrate and operate along the entire value chain from generation of renewable power to green hydrogen conversion, transport and sale in domestic and international markets. By doing so, Egypt could reach a scale of production that justifies the high investments needed for the development of a new green hydrogen pipeline for exports to Europe, as discussed in section 3.3.

The EU could contribute to the acceleration of this process. For example, it could provide financing for the new pipeline and become a shareholder. It could also provide guarantees on the additional stakes that will be owned by other private shareholders to de-risk the financing process and encourage investors to join the consortium.

In exchange, the EU might ask to intensify the process of energy market liberalization in Egypt, which remains at its early stages. For example, Egypt has adopted a model of legal unbundling, with major generation facilities remaining at least partially owned by the grid company. Therefore, ownership unbundling would be a further step ahead in the process of liberalization and it would imply the full separation between grid companies and those operating in the generation and supply to end users. In addition, the existing free trade area between the EU and Egypt could be extended to the energy sector, to speed up investments in Egypt and create the conditions for scalability of green hydrogen.

7. Concluding remarks

The cases of Egypt and Algeria show similarities and differences across economic and regulatory aspects. Similarities emerge in the current cost structures, as their relative strengths and weaknesses in the generation of renewable energy and availability of natural gas infrastructure that could be repurposed, respectively, offset each other.

Algeria has overcapacity in its existing export infrastructure, which represents a remarkable cost advantage in the transport phase, thanks to subsea gas pipelines that can be repurposed with a relatively affordable investment of about €645 million. By contrast, Egypt's export capacity is limited and mainly concerned with LNG terminals, which are more expensive to repurpose as compared to pipelines and are characterised by higher technological uncertainty. This suggests that Egypt might need to develop a new export infrastructure that requires an investment of about € 14.5 billion.

Egypt's infrastructure deficit is positively offset by an installed generation capacity of about 6.2 GW. By contrast, Algeria has a more limited installed capacity of 0.7 GW. Overall, green hydrogen production and export costs from Egypt and Algeria will be from 3 to 5 $\$/kgH_2$ lower than the costs of domestic production in Europe, which in principle justifies North African exports to Europe. However, in both Egypt and Algeria current volumes of renewable energy generated are still too low to make export infrastructure investment viable. For example, Egypt would need an additional 25 GW to fill an export pipeline to Europe with a transport capacity of 31 GW or 9 million tons, while Algeria's difficulty to fill a repurposed pipeline will be even greater, due to its limited generation capacity.

While production and transport cost differences are currently offsetting each other, Egypt and Algeria show some divergences in the approaches to regulation, which might play a role in their future ability to emerge as regional leader in the production and export of green hydrogen. More specifically, regulation plays an important role in attracting an adequate volume of investments in the generation of renewable energy, which is needed to justify large-scale infrastructure investments.

In Egypt, the newly introduced regulation has succeeded in attracting investment. Around 1 GW of capacity was added every year since 2014, contributing to lowering the price of renewable power envisaged by Power-Purchasing Agreements to an average of $25 MW/h. Based on interviews to managers and experts, the paper suggests that this additional capacity was made possible thanks to the following regulatory measures: (i) opening of a market dominated by state-owned companies to private investments; (ii) introduction of Feed-in-Tariff (FIF) and Power Purchasing Agreements (PPA), which provide guarantees on capital recovery and stable profits.

By contrast, Algeria has encountered some challenges in attracting investment in the renewable power sector, leaving the country with a limited installed capacity. The latter has grown only from 253 MW to 686 MW in the period 2012 – 2018 and has almost stopped growing in the last four years. The paper suggests that the mandatory clause on majority-ownership of large projects by national companies and the rules on minimum local content have played a role in discouraging investments, in addition to other factors including disproportionate market power of State-Owned Enterprises (SOEs), weak regulation and political instability.

8. Policy suggestions

Despite Egypt and Algeria are both potentially viable, they retain economic and regulatory differences, suggesting that the EU should consider those when negotiating the governance of the newly emerging hydrogen supply chains connecting North Africa to Europe.

The paper suggests that the EU could help Algeria tackle the shortage of investments in two main ways. One is to establish a co-finance mechanism that supports existing national funds in attracting and de-risking investments in renewables and electrolizers. Conditional to this funding could be to lift some stringent measures on foreign investments (although some of them have been recently removed). A more ambitious level of cooperation would be reached if Algeria agree on implementing Third-Party Access on specific infrastructure. The possibility for European companies to access repurposed export infrastructure could represent a further incentive to invest in the production of hydrogen in Algeria, as it would provide a channel to stable returns from exports to Europe. However, the feasibility of this option is uncertain as Algeria has historically been reluctant to implement measures that decrease government control on strategic assets.

By contrast, Egypt shows interest in exploring ways to gradually open the energy market, with the aim to become an energy hub. This emerges from the recent reforms adopted on unbundling, TPA, non-discrimination in tariffs and capacity allocation. However, financial support might be needed for investments in new hydrogen infrastructure, which would amount to billions of euros. The EU could provide a helpful contribution by becoming a shareholder of the pipeline, and by providing guarantees on the remaining stakes to encourage private investors to join the consortium as shareholders. If Egypt will agree to open further its market to European capitals, for example by extending the existing free trade area between the EU and Egypt also to the energy sector, investments to Egypt might witness a remarkable acceleration, which in turn would create the conditions to scale up green hydrogen and make infrastructure investment viable.

Personal Interviews[32]

Interviewee 1: Technical Director at International Organization’s agency, Cairo, April 2022

Interviewee 2: Executive Director at International Organization’s agency, Cairo, April 2022

Interviewee 3: Senior Engineer at large international energy company, Cairo June 2022

Interviewee 4: Senior Manager at large international energy company, Cairo June 2022

Interviewee 5: Advisor to the CEO at large international energy company, Cairo July 2022

Interviewee 6: Expert at International Organization’s agency, Sharm El sheikh, November 2022

Interviewee 7: Director at energy consulting company, Cairo, December 2022.

Interviewee 8: Advisor to government agency for international cooperation, Cairo, April 2023

Interviewee 9: Manager at large national energy company, Cairo, April 2023

Interviewee 10: Engineer at large national energy company, Cairo, April 2023

Interviewee 11: Advisor to energy infrastructure companies, London, April 2023

[32] Names of the managers and experts are kept confidential, following the principles of research ethics.

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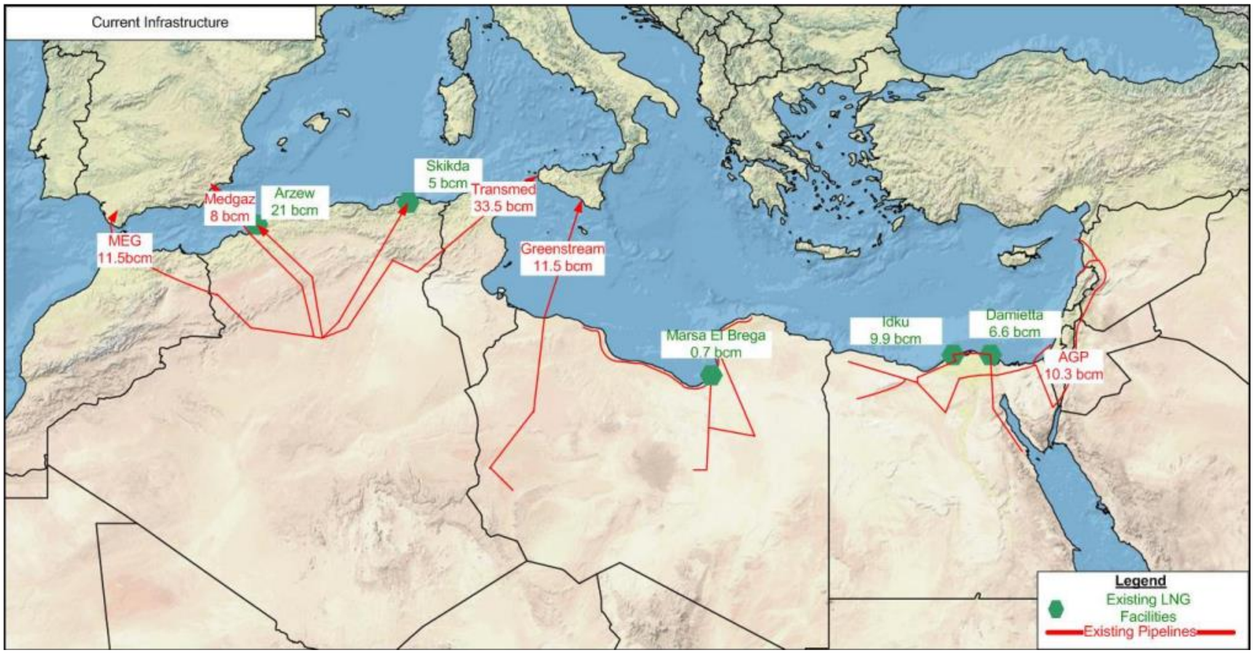
Appendix

Figure 4: Existing gas infrastructure connecting North Africa to Europe



Source: Mott MacDonald (2010)