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THE FUTURE OF HYDROGEN IN ROMANIA: DISPELLING MYTH FROM REALITY

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The future of hydrogen in Romania: Dispelling myth from reality

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About EPG:

Energy Policy Group (EPG) is a non-profit, independent think-tank specializing in energy and climate policy. EPG does evidence-based policy analysis on the decarbonization of the energy, industry, buildings and transport sectors. Its geographical focus is mostly the European Union and Southeast Europe, yet its analyses are informed by the global market, technology, and geopolitical trends. EPG is based in Bucharest, Romania, where it was founded in 2014.

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Hydrogen renewable energy production - hydrogen gas for clean electricity solar and wind turbine facility. Photo by *Audio und werbung* on Shutterstock.

Contents

List of Abbreviations 3
Executive Summary 5
Context 13
Support for hydrogen investments at EU and national level 14
The clean hydrogen landscape in Romania 19
1. Myths about hydrogen production 21
Myth: Renewable hydrogen production will be expensive 21
Myth: Hydrogen produced from fossil fuels is more cost-competitive 24
Myth: Blue hydrogen will be a cost-effective alternative to renewable hydrogen 25
Recommendations for hydrogen production 26
2. Myths about hydrogen consumption 27
Myth: Hydrogen will replace natural gas in the heating of individual households 27
Myth: Hydrogen is a competitive solution for decarbonising passenger transport 29
Myth: Hydrogen will replace current fossil fuel consumption in gas-fired power plants 31
Recommendations for hydrogen consumption 33
3. Myths about hydrogen transport 34
Myth: Natural gas pipelines can be easily repurposed for hydrogen 34
Myth: Hydrogen can be immediately blended with natural gas in existing pipelines 36
Myth: Hydrogen can easily be transported over long distances 38
Myth: Replacing gas with hydrogen eliminates mid-stream emissions 40
Recommendations for hydrogen transport 40
Policy recommendations 41
Bibliography 43

Table of figures

Figure 1. Subsidies for electrolyser capacity (bn €/GW) 15
Figure 2. Hydrogen production by technologies in tonnes, 2017-2021 19
Figure 3. Hydrogen valleys in Romania 20
Figure 4. Projected price of green vs grey hydrogen 22
Figure 5. Share of gas consumed during transportation through pipelines 32
Figure 6. The hydrogen ladder 33
Figure 7. Reduction in CO2 (compared to burning CH4) when burning a mixture of H2 and CH4 (units of volume) 37

List of Abbreviations

BEV	Battery Electric Vehicle
BNEF	BloombergNEF
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CH4	Methane
CHP	Combined Heat and Power
CO2	Carbon dioxide
CZK	Czech Koruna
DC	Direct Current
EC	European Commission
EPG	Energy Policy Group
ETS	Emissions Trading System
EU	European Union
EUR	Euro
FCEV	Fuel Cell Electric Vehicle
FLH	Full Load Hours
GDIP	Green Deal Industrial Plan
GHG	Greenhouse Gas Emissions
GO	Guarantee of Origin
GW	Gigawatt
GWP	Global Warming Potential
H2	Hydrogen
HHV	Higher Heating Value
IPCC	Intergovernmental Panel on Climate Change
IPCEI	Important Project of Common European Interest
IRENA	International Renewable Energy Agency

LCOE	Levelised Cost of Electrcity
LCOH	Levelised Cost of Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LTS	Long-Term Strategy
MPa	Megapascals
MS	Member States
Mt	Million tonnes
NECP	National Energy and Climate Plan
NOx	Oxides of Nitrogen
NREL	National Renewable Energy Laboratory
NZIA	Net-Zero Industry Act
OPEX	Operating Expenses
PEM	Proton Exchange Membrane
PLN	Polish Zloty
PPA	Power Purchase Agreement
PSA	Pressure Swing Adsorption
PV	Photovoltaics
R&D	Research and Development
REACT-EU	Recovery Assistance for Cohesion and the Territories of Europe
RED	Renewable Energy Directive
RES	Renewable Energy Sources
RFNBO	Renewable Fuels of Non-Biological Origin
TEN-T	Trans-European Transport Network
UK	United Kingdom
HBI	Hot Briquetted Iron
OEM	Original Equipment Manufacturer
SME	Small-Medium Enterprise

Executive Summary

Clean hydrogen plays an important role in the European Union's (EU) efforts of reducing greenhouse gas (GHG) and becoming climate neutral by 2050. According to the REPowerEU plan, the EU aims to produce a highly ambitious 10 Mt/year of hydrogen domestically and to import another 10 Mt/year by 2030. To stimulate investments in hydrogen, clear targets for RFNBOs in industry and transport sectors were set through the Renewable Energy Directive (RED) III. Also, the European Hydrogen 'Bank' was introduced as an EU-wide facility for supporting projects. EU member states have committed consistent amounts of public funding for renewable hydrogen production, ranging from 0.39 billion €/GW in Spain to 1.43 billion €/GW in the Netherlands.

In response to the EU Hydrogen Strategy, Romania drafted its own strategic document. The draft National Hydrogen Strategy, currently in final adoption stages, estimates a need for investments worth €4.8 billion to produce 152,900 tonnes per year of renewable hydrogen by 2030. 47.3% of this hydrogen is envisioned to be used in transport, 37.2% in existing industrial activity, and 15.5% in new industrial applications, namely steelmaking. The draft strategic document suffered various changes during the consultation process, currently proposing an approach that is better aligned with the objectives of decarbonising Romania's economy, by steering clear of proposing support for the use of hydrogen for heating in the residential sector and in combined-cycle gas turbines (CCGTs). Nonetheless, the public discourse is still flooded with faulty narratives on the future of hydrogen, especially on the doubtful expectation that hydrogen can either replace the use of natural gas in most current uses and it can therefore provide a lifeline for the continued use of fossil fuels throughout the following decades. To counter such narratives, this paper dispels a set of ten myths that are still pervasive in national discussions on hydrogen.

1. Myths about hydrogen production

Proponents of the continued fossil fuel-based production of hydrogen or those trying to dismiss the need to wean off fossil fuels, especially natural gas, invoke the potentially high cost of renewable hydrogen as the main challenge, seeing steam methane reforming as a cost-efficient alternative.

Myth: Renewable hydrogen production will be expensive. Although renewable hydrogen comes at a premium cost compared to fossil-based alternatives, there are more promising premises for cost reduction overtime based on expected strong reduction of investment costs in electrolysers (around 5 times until 2030 compared to 2023) and lower fuel costs, as the cost of renewable energy has been constantly decreasing over the past decade, especially for PVs.

Myth: Hydrogen produced from fossil fuels is more cost-competitive. The recent energy crisis demonstrated the volatility in the natural gas prices that can be induced by sudden, unforeseen geopolitical actions. Romania's currently unexploited natural gas reserves (in the Black Sea) have generated expectations of decreasing natural gas prices in the future, but there is limited evidence that this new natural gas production would bring significant reductions in wholesale gas prices. Moreover, the utilisation of fossil fuels will become increasingly costly given the expected

increases in CO2 price as a result of the EU-ETS revision. Current fossil-based production will need to be gradually phased out.

Myth: Blue hydrogen will be a cost-effective alternative to renewable hydrogen. Another common narrative is that blue hydrogen combines the potential advantages of relatively lower production costs (grey hydrogen – myth dispelled above) with a reduced carbon footprint, by capturing the CO2 emissions. Nonetheless, CO2 emissions cannot be fully avoided, with expected capture rates not going higher than 85-95%, while fugitive methane emissions would remain. The carbon price would therefore also affect this production method, while CCUS technologies are costly and increase operational costs. Access to CO2 storage infrastructure remains an additional barrier for this production route.

2. Myths about hydrogen consumption

Hydrogen has also been touted as an alternative to directly replace natural gas in multiple applications, including home heating, combined cycle gas turbines (CCGTs) and combined heat and power (CHP) plants. This narrative is used to create expectations on the continued use of the existing fossil infrastructure and to counter criticisms against new investments in gas-based infrastructure and capacities based on their inability to recover investment costs.

Myth: Hydrogen will replace natural gas in the heating of individual households. According to IRENA, a mix of 80% natural gas and 20% hydrogen could result in an increase by more than a third in the blended natural gas price and implicit in consumers' bills. Such a replacement would also be inefficient, almost half of energy within this process would be lost, as for every 1 MWh of renewable energy, between 0.5 and 0.55 MWh of energy would be produced as heat. Alternatively, the direct use of renewable energy for heating through heat pumps is 6 to 9 times more efficient than using hydrogen for heating, as 1 MWh of electricity produced from renewable sources would generate 3-4 MWh of heat.

Myth: Hydrogen is a competitive solution for decarbonising passenger transport. Based on a comparison between fuel cell electric vehicles (FCEVs) and battery electric vehicles (BEVs) in terms of cost, overall efficiency, range, time of refuelling/recharge, infrastructure development and environmental footprint, it is difficult to make a definitive statement of the advantages on one over another. Still, the market favours BEVs for cost considerations resulting from constant improvements in battery technology, economies of scale created, and more developed charging infrastructure (build through public support). The higher overall efficiency of BEVs is also important – around 83% conversion efficiency compared to 30% in FCEVs. Therefore, the cost of energy per km is around 2.8 times lower for a BEV compared to a FCEV. Nonetheless, hydrogen will still play an important role in decarbonising long-haul transport, either through fuel cells, or as part of synthetic fuels used in aviation and maritime transport.

Myth: Hydrogen will replace current fossil fuel consumption in gas-fired power plants. The overall process would be highly inefficient, estimated at 37%. The combined effect of this lower overall efficiency and higher cost of hydrogen compared to natural gas would make such power plants highly uneconomical. These cost considerations raise the risk of continuing to operate on natural gas in the long run with additional pressure on consumers' bills and detrimental effects on emissions.

3. Myths about hydrogen transport

The potential repurposing of gas grids for hydrogen transport and distribution and the blending process has also gained some traction domestically following the narratives on hydrogen use in household heating.

Myth: Natural gas pipelines can be easily repurposed for hydrogen. The main challenges and uncertainties of transporting hydrogen pure or blended with natural gas in the existing infrastructure are based on the negative effects on pipeline materials (as hydrogen increases the fatigue cracks rates in steel pipelines over time) and the consequences on operational indicators caused by the lower volumetric energy density of hydrogen compared to natural gas. For long distances, pumping hydrogen through pipelines becomes uneconomical with 50% of energy content being lost when pumped over 6,000 – 6,500 km. In the case of existing gas turbines, small amounts of hydrogen blended with natural gas can be used as fuel, without significant impact, but as the share of hydrogen increases problems are likely to appear.

Myth: Hydrogen can be immediately blended with natural gas in existing pipelines. Although there is real-world evidence on the feasibility of such approach (e.g. Winlaton, UK using a blend of 80% natural gas and 20% hydrogen or the national 20HyGrid test performed by Delgaz in Darlos), the climate impact of such blending would be minimal. Above this threshold (20%), significant changes would be needed for various components - the maximum concentration of hydrogen in natural gas pipelines is significantly affected by pressure fluctuations, structure and existing defects. A major challenge at EU level would also be the wide variety of permissible hydrogen blending rates, which could constitute a barrier to trade.

Myth: Hydrogen can easily be transported over long distances. There are significant challenges associated with all potential hydrogen transport options. For distances lower than 1,500 km, the transmission of hydrogen as a gas by pipeline is generally the cheapest option, but this requires either the repurposing of existing infrastructure or new investments to connect sources of production to points of demand. For longer distances, transmission as ammonia or liquid organic hydrogen carriers (LOHC) might be a comparatively cost-effective option. but conversions come with significant efficiency losses. Shipping hydrogen could be done similarly with liquefied natural gas (LNG), requiring the liquefaction of hydrogen by cooling it to -253°C, but this is an energy-intensive process equivalent to between 25% and 35% of the energy content of the hydrogen transported. Transportation of electricity may, in some circumstances, be preferable to pipelines or shipping. Long distance ultra and high voltage DC cables, transporting energy in the form of electrons and generating hydrogen locally by water electrolysis represents a promising alternative. However, there are also challenges associated with expanding the existing power grid.

Myth: Replacing gas with hydrogen eliminates mid-stream emissions. Fugitive hydrogen emissions and their potentially detrimental effect on the climate should also be considered when assessing the usage of this energy carrier. Hydrogen's indirect warming potency per unit mass is round 200 times higher than that of CO2 according to the Atmospheric Chemistry and Physics.

Hydrogen will be an energy carrier most likely used in a limited set of high-value applications where few technological alternatives exist. Romania could benefit from the opportunities of the clean hydrogen economy by adopting a pragmatic approach on the optimal use of hydrogen. This could be done by:

1. Grounding the national strategic vision and specific legislation in objective, science-based analysis about the associated opportunities and risks;
2. Aligning strategic national documents and legislation in terms of decarbonisation targets and hydrogen perspectives;
3. Developing and mapping targeted funding opportunities for renewable hydrogen at national level;
4. Training the necessary human resources;
5. Adopting a strategic approach on imports and exports of hydrogen;
6. Understanding the important role of hydrogen storage;
7. Attracting investors in the manufacturing of hydrogen-related equipment.

Rezumat executiv

Hidrogenul regenerabil va avea un rol important în reducerea emisiilor de gaze cu efect de seră (GES) și obținerea neutralității climatice la nivelul Uniunii Europene până în anul 2050. Conform planului REPowerEU, UE își propune să producă pe teritoriul european o cantitate ambițioasă de 10 Mt/an de hidrogen și respectiv să importe alte 10 Mt/an până în anul 2030. Pentru a stimula investițiile în dezvoltarea proiectelor privind producția de hidrogen au fost stabilite obiective clare pentru consumul de combustibilii regenerabili de origine nebiologică (RFNBOs) în sectorul industriei și al transporturilor, prin intermediul Directivei privind sursele regenerabile de energie (RED) III. De asemenea, a fost propusă "Banca Europeană pentru Hidrogen" ca un mecanism de sprijin financiar în acest demers. Statele membre ale UE au alocat sume consistente de finanțare din fonduri publice pentru producția de hidrogen din surse regenerabile, care variază de la 0,39 miliarde €/GW în Spania la 1,43 miliarde €/GW în Olanda.

România și-a elaborat propriul document strategic, ca răspuns la Strategia UE privind hidrogenul. Proiectul Strategiei Naționale pentru Hidrogen, aflat în prezent în faza finală de adoptare, estimează un necesar de investiții în valoare de 4,8 miliarde € pentru a produce 152.900 de tone pe an de hidrogen din surse regenerabile până în anul 2030, din care 47,3% va fi utilizat în transporturi, 37,2% în activitatea industrială existentă și 15,5% în noi aplicații industriale, respectiv în siderurgie. Proiectul Strategiei Naționale a suferit diverse modificări pe parcursul procesului de consultare și propune, în prezent, o abordare aliniată obiectivelor de decarbonizare a economiei României, prin eliminarea utilizării hidrogenului pentru încălzire în sectorul rezidențial și în turbinele cu gaz natural cu ciclu combinat (CCGT). Cu toate acestea, discursul public este, în continuare, marcat de relatări eronate privind viitorul hidrogenului, în special în ceea ce privește așteptările îndoielnice privind înlocuirea gazelor naturale din majoritatea aplicațiilor actuale, pentru a menține astfel utilizarea combustibililor fosili în următoarele decenii. Raportul EPG are obiectivul de a răspunde, cu date și surse fundamentate, acestor zece “mituri” prezente la nivel național.

1. Mituri privind producția de hidrogen

Susținătorii producției de hidrogen pe bază de combustibili fosili, respectiv cei care resping necesitatea de a renunța la combustibilii fosili, în special la gazele naturale, consideră costul ridicat al hidrogenului regenerabil drept principala provocare în dezvoltarea acestuia și pledează pentru utilizarea reformării cu abur a metanului, ca reprezentând o alternativă mult mai eficientă.

Mit: Producția de hidrogen din surse regenerabile va fi costisitoare. Deși hidrogenul din surse regenerabile are un cost mai ridicat decât alternativa pe bază de combustibili fosili, există premise promițătoare pentru reducerea costurilor per total, în anii următori, pe baza prognozelor privind reducerea semnificativă a costurilor de investiții în electrolizoare (de aproximativ 5 ori până în 2030, comparativ cu 2023) și a costului energiei din surse regenerabile, care a scăzut constant în ultimul deceniu, în special al energiei solare.

Mit: Hidrogenul produs din combustibili fosili (gri) este mai competitiv din punct de vedere al costurilor. Recenta criză energetică a demonstrat volatilitatea prețurilor gazelor naturale, care poate fi indusă de acțiuni geopolitice neprevăzute. Deși rezervele de gaze naturale neexploatate în prezent în România (Marea Neagră) creează așteptări privind scăderea prețului gazelor naturale în anii următori, nu există o prognoză clară/certă despre impactul asupra prețurilor de pe piața angro a gazelor naturale. În plus, utilizarea combustibililor fosili va deveni din ce în ce mai costisitoare, având în vedere creșterile preconizate ale prețului dioxidului de carbon (CO_2), ca urmare a revizuirii EU-ETS. Astfel, producția actuală a hidrogenului pe bază de combustibili fosili va trebui eliminată treptat.

Mit: Hidrogenul albastru va fi o alternativă rentabilă la hidrogenul regenerabil. Un alt argument invocat în spațiul public este acela că hidrogenul albastru reprezintă un mix între avantajele potențiale ale unor costuri de producție relativ mai reduse (hidrogenul gri – mit contestat anterior) și reducerea amprentei de carbon, prin captarea, utilizarea și stocarea (CCUS) emisiilor de CO_2. Cu toate acestea, emisiile de CO_2 nu pot fi evitate în totalitate, întrucât ratele de captare estimate nu pot fi mai mari de 85-95%, în timp ce emisiile fugitive de metan se mențin. Prin urmare, prețul dioxidului de carbon ar afecta și această metodă de producție, în timp ce tehnologiile CCUS sunt costisitoare și cresc costurile operaționale. Mai mult, accesul la infrastructura de stocare a CO_2 rămâne o barieră suplimentară pentru această cale de producție.

2. Mituri despre consumul de hidrogen

De asemenea, hidrogenul a fost prezentat ca o alternativă la înlocuirea directă a gazului natural în mai multe aplicații, inclusiv în încălzirea locuințelor, în turbinele pe gaz cu ciclu combinat (CCGT) și în centralele de cogenerare (CHP). Această narativă este utilizată în spațiul public pentru a crea așteptări privind utilizarea infrastructurii existente a gazului natural și pentru a contracara criticile la adresa investițiilor în capacități noi de gaz natural și infrastructura asociată.

Mit: Hidrogenul va înlocui gazele naturale în încălzirea gospodăriilor individuale. Potrivit IRENA, o combinație de 80% gaz natural și 20% hidrogen ar putea duce la o creștere de peste o treime a prețului gazului natural rezultat și implicit a facturilor consumatorilor. Totodată, o astfel de abordare ar fi ineficientă, întrucât aproape jumătate din energia asociată acestui proces ar fi pierdută, respectiv pentru fiecare 1 MWh de energie regenerabilă, între 0,5 și 0,55 MWh din energie ar fi produsă, în final, sub formă de căldură. Alternativ, utilizarea directă a energiei regenerabile pentru încălzire prin intermediul pompelor de căldură este de 6 până la 9 ori mai eficientă decât utilizarea hidrogenului, întrucât pentru 1 MWh de electricitate produsă din surse regenerabile s-ar putea genera 3-4 MWh de căldură.

Mit: Hidrogenul este o soluție competitivă pentru decarbonizarea transportului de pasageri. Pe baza unei comparații între vehiculele electrice cu pile de combustie (FCEV) și vehiculele electrice cu baterii (BEV) din perspectiva costurilor, eficienței, autonomiei, timpului de realimentare/reîncărcare, dezvoltarea infrastructurii și amprenta asupra mediului, este dificil de asumat o afirmație cu privire la soluția optimă pentru decarbonizarea transportului de pasageri. Cu toate acestea, piața favorizează BEV-urile din considerente legate de cost, pe fondul îmbunătățirii constante a tehnologiei bateriilor, a dezvoltării economiilor de scară și de existența infrastructuri de încărcare (create prin sprijin din fonduri publice). Eficiența generală, mai mare în cazul BEV este, de asemenea, importantă - aproximativ 83% fiind eficiența de conversie, față de 30% în cazul FCEV. Prin urmare, costul energiei pe kilometru este de aproximativ 2,8 ori mai mic pentru BEV în comparație cu FCEV. Cu toate acestea, hidrogenul va juca în continuare un rol important în decarbonizarea transportului pe distanțe lungi, fie prin intermediul pilelor de combustie, fie *prin intermediul* combustibililor sintetici utilizați în aviație și în transportul maritim.

Mit: Hidrogenul va înlocui consumul actual de combustibili fosili în centralele electrice pe bază de gaz. Acest proces ar fi extrem de ineficient, estimat la 37%. Efectul acestei eficiențe scăzute și al costului mai ridicat al hidrogenului în comparație cu gazul natural conduce la concluzia că aceste centrale ar fi necompetitive economic. Considerentele legate de costuri pot conduce la situația în care aceste centrale vor funcționa pe termen lung pe bază de gaze naturale, ceea ce va determina o presiune asupra facturilor consumatorilor și va avea riscul de a nu reduce emisiile de gaze cu efect de seră.

3. Mituri despre transportul pe bază de hidrogen

Potențiala utilizare a rețelelor existente de gaze naturale pentru transportul și distribuția hidrogenului și pentru procesul de amestec (blending) a căpătat, de asemenea, amploare pe plan intern, ca urmare a narativului privind utilizarea hidrogenului pentru încălzirea locuințelor.

Mit: Conductele de gaze naturale pot fi ușor recondiționate pentru utilizarea hidrogenului. Principalele provocări și incertitudini legate de transportul hidrogenului pur sau în amestec cu gazul natural în infrastructura existentă se bazează pe efectele negative asupra materialelor conductelor (deoarece hidrogenul crește în timp rata fisurilor în conductele de oțel) și pe consecințele asupra indicatorilor operaționali cauzate de densitatea energetică volumetrică mai redusă a hidrogenului în comparație cu cea a gazului natural. Pentru distanțe lungi, injectarea hidrogenului prin conducte devine nerentabilă, 50% din conținutul energetic fiind pierdut atunci când este transportat pe distanțe de 6.000 – 6.500 km. În cazul infrastructurii existente de gaz natural pot fi utilizate cantități reduse de hidrogen amestecat cu gaze naturale, fără ca acest proces să aibă un impact semnificativ, dar pe măsură ce ponderea hidrogenului crește, este posibil să apară probleme.

Mit: Hidrogenul poate fi amestecat cu gazele naturale în conductele existente. Deși există dovezi concrete privind fezabilitatea unei astfel de abordări (de exemplu, Winlaton, Marea Britanie, care utilizează un amestec de 80% gaz natural și 20% hidrogen sau testul proiectului pilot la nivel național 20HyGrid realizat de Delgaz în Dârlos), impactul privind reducerea emisiilor de CO2 ar fi minimal. Peste acest prag (20%), ar fi necesare modificări semnificative pentru diverse componente, întrucât concentrația maximă de hidrogen în conductele de gaze natural este afectată în mod semnificativ de fluctuațiile de presiune, de structura și de defectele existente. O provocare majoră la nivelul UE ar fi, de asemenea, varietatea ratelor de amestec de hidrogen permise, care ar putea constitui o barieră din perspectiva comercializării acestuia.

Mit: Hidrogenul poate fi transportat cu ușurință pe distanțe mari. Potențialele opțiuni de transport al hidrogenului prezintă provocări majore. Pentru distanțe mai mici de 1,500 km, transportul hidrogenului prin conducte de gaz natural este, în general, opțiunea cea mai puțin costisitoare, dar aceasta necesită fie reutilizarea infrastructurii existente, fie investiții noi pentru conectarea surselor de producție la punctele de cerere. Pentru distanțe mai mari, transportul sub formă de amoniac sau de purtători de hidrogen lichid - organic (LOHC) ar putea fi o opțiune relativ rentabilă, dar conversiile vin cu pierderi semnificative de eficiență. Transportul de hidrogen ar putea fi realizat în mod similar cu cel al gazului natural lichefiat (GNL), necesitând lichefierea hidrogenului prin răcirea acestuia la -253°C, proces energointensiv, echivalent cu 25%-35% din conținutul energetic al hidrogenului transportat. Transportul de energie electrică poate fi, în anumite circumstanțe, preferabil conductelor sau transportului maritim. Cablurile de curent continuu de înaltă tensiune și de ultratensiune pe distanțe lungi, care transportă energia sub formă de electroni și generează hidrogen la nivel local prin electroliza apei, reprezintă o alternativă promițătoare. Cu toate acestea, există, de asemenea, provocări asociate cu extinderea rețelei electrice existente.

Mit: Înlocuirea gazului cu hidrogen elimină emisiile fugitive (mid-stream/pe parcursul procesului). Emisiile fugitive ale hidrogenului și efectul lor asupra mediului trebuie luate în considerare atunci când este evaluată utilizarea acestuia. Potrivit Atmospheric Chemistry and Physics, hidrogenul are un potențial de încălzire indirectă pe unitate de masă de aproximativ 200 de ori mai mare decât cel al CO2.

Hidrogenul va fi utilizat, cel mai probabil, într-un număr limitat de aplicații cu valoare adăugată ridicată, respectiv în sectoare unde alternativele tehnologice de decarbonizare sunt reduse. România ar putea beneficia de oportunitățile oferite de economia hidrogenului regenerabil prin adoptarea unei abordări pragmatice privind utilizarea optimă a acestuia, respectiv prin:

1. Fundamentarea viziunii strategice naționale și a legislației specifice pe baza unei analize obiective cu date științifice, referitoare la oportunitățile și riscurile asociate;
2. Alinierea documentelor strategice naționale și a legislației în ceea ce privește obiectivele de decarbonizare și perspectivele privind hidrogenul;
3. Dezvoltarea și cartografierea oportunităților de finanțare specifice pentru hidrogenul regenerabil la nivel național;
4. Formarea resursei umane necesară;
5. Adoptarea unei abordări strategice privind importurile și exporturile de hidrogen;
6. Înțelegerea rolului important al stocării hidrogenului;
7. Atragerea de investitori în producția de echipamente pentru dezvoltarea economiei hidrogenului.

Context

Hydrogen developments at EU level

The European Union's objective to reduce greenhouse gas emissions (GHG) by at least 55% until 2030 compared to 1990 (European Commission, 2021) levels and to become climate neutral by 2050 will be achieved through a plethora of measures, ranging from electrification, energy efficiency, uptake of clean energy sources, and circular economy. For those economic activities that will not be able to electrify, either because of cost-efficiency considerations or technical limitations, hydrogen has been touted as a potential emissions-free energy carrier that can contribute to deep decarbonisation, especially in high-temperature heat and feedstock for industry, as well as in aviation and long-haul shipping. At the EU level, the narratives on hydrogen have oscillated between extremes: from high optimism for a hydrogen-fuelled revolution to stubborn pessimism about its overall inefficiency and inability to scale up in due time.

In 2020, at a time of 'hydrogen optimism', the European Commission (EC) published its Hydrogen Strategy (European Commission) with the aim of developing a hydrogen market that will contribute to both decarbonisation and economic growth in Europe. The strategy focused on 5 main policy actions: (i) investment support, (ii) support for production and demand, (iii) creation of a hydrogen market and infrastructure; (iv) stimulation of research and cooperation, and (v) development of international cooperation. The stated goal was the installation of 6 GW of electrolysers by 2024 with a production of up to 1 million tonnes (Mt) of renewable hydrogen per year and 40 GW by 2030, with a respective production of up to 10 Mt per year. The strategy foresaw EU public support primarily for clean hydrogen production, with the support for the decarbonisation of current hydrogen production through carbon capture and storage retrofits left mainly within national remit.

Similarly, the European Clean Hydrogen Alliance, developed to support the large-scale deployment of clean hydrogen technologies by bringing together actors from across the value chain, prioritised renewable hydrogen production, while acknowledging a smaller role for other forms of low-carbon hydrogen.

In response to the Russian invasion of Ukraine and the disruption to energy markets, the REPowerEU plan consolidated the objective for 10 Mt/year of hydrogen to be produced domestically and another 10 Mt/year to be imported in the EU by 2030 as part of the package of measures for weaning off Russian gas.

To clarify what is considered renewable hydrogen that can also contribute to existing renewable targets, in the summer of 2023 the EC (European Commission, n.d.) published two hydrogen Delegated Acts, which define under which conditions hydrogen, hydrogen-based fuels or other energy carriers qualify as renewable fuel of non-biological origin (RFNBO). According to the acts, fuels can only be considered renewable if they meet the criteria of additionality, temporal and geographic corelation. A monthly correlation of green power supply with hydrogen production until the end of 2029 and hourly thereafter. In this way it was ensured that green hydrogen production via electrolysis does not use renewable energy that would otherwise have been used to decarbonise the current electricity mix.

Importantly, the Fit-for-55 package has also brought significant changes, including to the EU-ETS, which should favour hydrogen production through electrolysis over fossil-based alternatives in the long run, and the revised Renewable Energy Directive (RED III), which sets clear targets for RFNBOs in industry and transport sectors:

- ◊ Industry targets: 42% in 2030 and 60% in 2035;
- ◊ Road transport targets: 1% in 2025 and 5.5% biofuels + RFNBO in 2030, with a minimum 1% RFNBO;
- ◊ Shipping targets: 1.2% in 2030.

Support for hydrogen investments at EU and national level

The European Union

To shoulder in some of the financial effort needed for creating a clean hydrogen economy, the European Hydrogen 'Bank' was introduced as an EU-wide facility. The European Hydrogen Bank supports the objectives of the Green Deal Industrial Plan (GDIP) and the Net-Zero Industry Act (NZIA) by scaling up the electrolyser manufacturing for renewable hydrogen production, that should in turn contribute to the competitiveness and resilience of European industry, as well as enable European companies to play a leading role in the emerging global hydrogen market. It functions through a subsidy designed to cover and lower the green premium of renewable hydrogen, based on four main pillars:

1. *Domestic market creation* through auctions organised under the Innovation Fund that will award a fixed premium per kg of clean hydrogen produced for a maximum of 10 years of operation. For the first auction the allocated budget was €800 million, and the auctions started in November 2023. Further rounds will follow, while the European Commission has stated that it will make the auctioning platform available for any member state that wants to use this mechanism for domestic purposes, funded through national means. Due to the huge interest shown for this scheme, the European Commission announced a second auction in the spring of 2024 with an indicative budget of €2.2 billion.

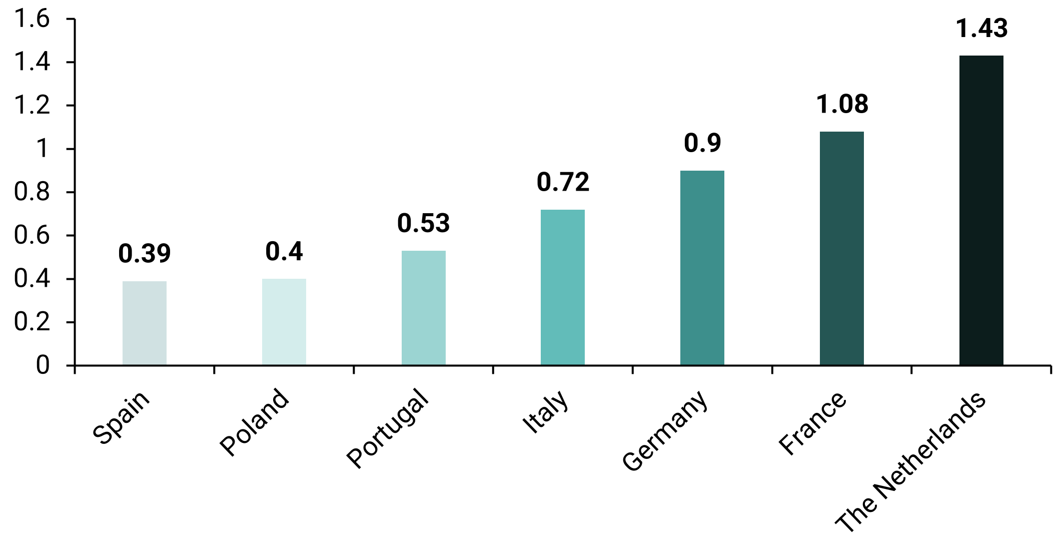
2. *Support for international hydrogen production* through a similar competitive bidding mechanism, but the budget is yet to be identified.

3. *Coordination & Transparency* of hydrogen flows, transactions, and prices to strengthen confidence in the developing hydrogen market and facilitate agreements between producers and off-takers, as well as develop price benchmarks.

4. *Coordination on existing European and international financing instruments* such as InvestEU, Innovation Fund, structural funds, as well as loans, blending and guarantees are efficiently used to support investments.

Moreover, multiple EU member states have committed consistent amounts of public funds. A material prepared by Rabobank, based in the Netherlands, (Zeeuw, 2022) shows the top European players in terms of public funds allocated per GW of electrolyser – see Figure 1. The Netherlands is the leader, with 1.43 billion €/GW, followed by France, Germany, Italy, Portugal, Poland and Spain.

Figure 2. Subsidies for electrolyser capacity (bn €/GW)



Source: Zeeuw 2022

Table 1. Support schemes for hydrogen within EU countries

#	Country	Support
1	**Germany**	Germany is the first member state which decided to join in the EU's Auctions as a Service (European Commission, 2023) scheme under European Hydrogen Bank. Germany announced it would make €350 million available from its national budget for hydrogen production at national level. This action came to complement the scheme already launched by Germany in December 2022 through the H2Global funding instrument where almost €900 million were made available for hydrogen derivatives to be imported in Europe in 2025 (Hydrogen Europe, 2022). Germany's government has also agreed on plans to subsidise gas power plants that can switch to hydrogen, with a price tag of €16 billion in subsidies (Alkousaa, 2024). Moreover, the German state and several banks have agreed to support Siemens' financially struggling subsidiary Siemens Energy with guarantees of about €12 billion. The company is an important provider of energy transition equipment but has struggled to make key components of its business profitable, notably the German-Spanish wind power turbine joint venture Siemens Gamesa (Wehrmann, 2023).
2	**France**	France proposed a €4 billion fund for the development of 1 GW of electrolysis capacity over the next three years (Dokso, 2023). According to the French Multiannual Energy Program for 2019-2023 and 2024-2028, France is betting on carbon-free hydrogen production and planning €7 billion in public support until 2030 (FleishmanHillard, 2022a).
3	**Belgium**	To consolidate its hydrogen value chain and support innovation, Belgium will continue to fund companies and research institutes, using its existing Energy Transition Fund (20-30 million €/year) as well as a new budget of €60 million (€50 million coming from the Recovery and Resilience Fund). The aim is reaching 150 MW of electrolysis capacity by 2026 (FleishmanHillard, 2022b). Belgium also envisions the development of a minimum of 100 to 160 km of pipelines by 2026 for the transport of hydrogen. €95 million are allocated for this from the Recovery and Resilience Fund (FPS Economy, 2022). The country already has around 570km of H2 pipelines, more than a third of the total 1,600km in Europe, most of which connect industrial clusters within its borders with some outreach into France and the Netherlands. It now plans to construct additional H2 networks between industrial clusters in Ghent, Antwerp, Mons, Charleroi and Liège, as well as connections with Germany, using "new and/or repurposed [gas] pipelines". A further €300 million is foreseen for the interconnection of the Belgian hydrogen transport network with the German one (Martin, 2023).
4	**Denmark**	Denmark has started several programs to support the development of hydrogen production. €170 will be allocated for the production of hydrogen and other power-to-x products (European Commission, 2023). Another €46 million from the EU's post-Covid cohesion fund (REACT-EU) and the Just Transition Fund are allocated to encourage the

		expansion of green technologies, and € 114 million will contribute to the development of a so-called Important Project of Common European Interest or IPCEI at EU-level.
5	**The Netherlands**	In December 2021, a new climate transition fund was announced amounting to € 35 billion for the next decade, aimed at developing sustainable energy infrastructure. €15 billion is reserved for renewable energy carriers, among including renewable hydrogen. The goal of the Netherlands is to install 500 MW in electrolysers by the end of 2025. The Commission has already given approval for €246 million in support for the construction of at least 60 MW electrolyser capacity (European Commission, 2023).
6	**Poland**	Poland foreseen total investments in hydrogen of PLN 11 billion (€2.53 billion) until 2030. In April 2023, the EC approved €158 million for the of support renewable hydrogen production used in refinery processes (European Commission, 2023). The grant will support the installation of an electrolyser with a capacity of 100 MW, as well as the construction of 50 MW of photovoltaic power plant and 20 MWh in battery storage.
7	**Portugal**	Estimated investments of €7 billion will be dedicated to hydrogen development projects according to the national hydrogen strategy until 2030. Moreover, Portugal is among the states for which the EC has green-lit funding for the third project of common European interest to support hydrogen infrastructure (Hy2Infra). 790 MW of electrolysers are expected to be installed in Portugal in the coming years.
8	**Spain**	Estimated investments of €8.9 billion will be made in hydrogen projects until 2030. At the end of 2023, the Spanish Government awarded 12 projects with €150 million worth of grants to build 309 MW electrolysers for use in hard-to-abate sectors (hydrogeninsight.com, 2023). This was part of the second round of the Ministry for the Ecological Transition and Demographic Challenge's H2 Pioneers programme which was designed to promote initiatives demonstrating the viability on a renewable hydrogen business model. The first round in April 2023 consisted of €150 million awarded for 19 projects.
9	**Italy**	Up to €10 billion worth of hydrogen investments are expected by 2030. Italy has allocated nearly €60 billion (over 30% of the total value of its National Recovery and Resilience Plan) to the energy transition, including for boosting the country's share of renewable energy, such as hydrogen (European Commission, 2023). In April 2023 the European Commission approved a €450 million Italian scheme to support the production of renewable hydrogen. Another state aid of €100 million for renewable hydrogen production was approved by European Commission in the autumn of 2023 (European Commission, 2023)
10	**Estonia**	Estonia participates in 3 important Projects of Common Interest (IPCEIs), with a share of €111 million in hydrogen investment (Estonian NECP, 2023), €50 million coming from the National Recovery and Resilience Plan.
11	**Lithuania**	The country will invest €300 million in the development of the hydrogen sector by 2030. A first call for projects to develop renewable hydrogen production capacities was launched in the summer of 2023. It aimed to support the

		installation of electrolysers with a capacity of at least 65 MW for use in fertiliser industry and transport sector, with an allocated budget of €50 million.
12	**The Czech Republic**	The Czech Republic currently has committed CZK 6 billion (€240 million) for investments in alternative fuel infrastructure, with expectations for additional funding by the end of the decade (Expats.cz, 2023). The EC has approved a €2.5 billion scheme to support decarbonisation, which will partly contribute to hydrogen projects (Oprea, 2023).
13	**Hungary**	The EC has approved a €2.36 billion scheme for accelerated investments in strategic sectors to foster the transition towards a net-zero economy. Under this measure, the aid will take the form of (i) direct grants and/or (ii) tax advantages (European Commission, 2023).
	Slovakia	The EC approved a €1 billion state aid scheme to support investments in equipment necessary to foster the transition to a net-zero economy. Under this measure, the aid capped at €350 million per company, will take the form of direct grants, income tax reliefs and transfers or leases of immovable property for a price below market value (European Commission, 2023).
14	**Croatia**	In spring 2024 Croatia has taken a decisive step towards greener transportation by allocating €30 million in grants for the construction of hydrogen fuel stations, aiming to catalyse the use of hydrogen-powered vehicles. (connectingregion.com, 2024).

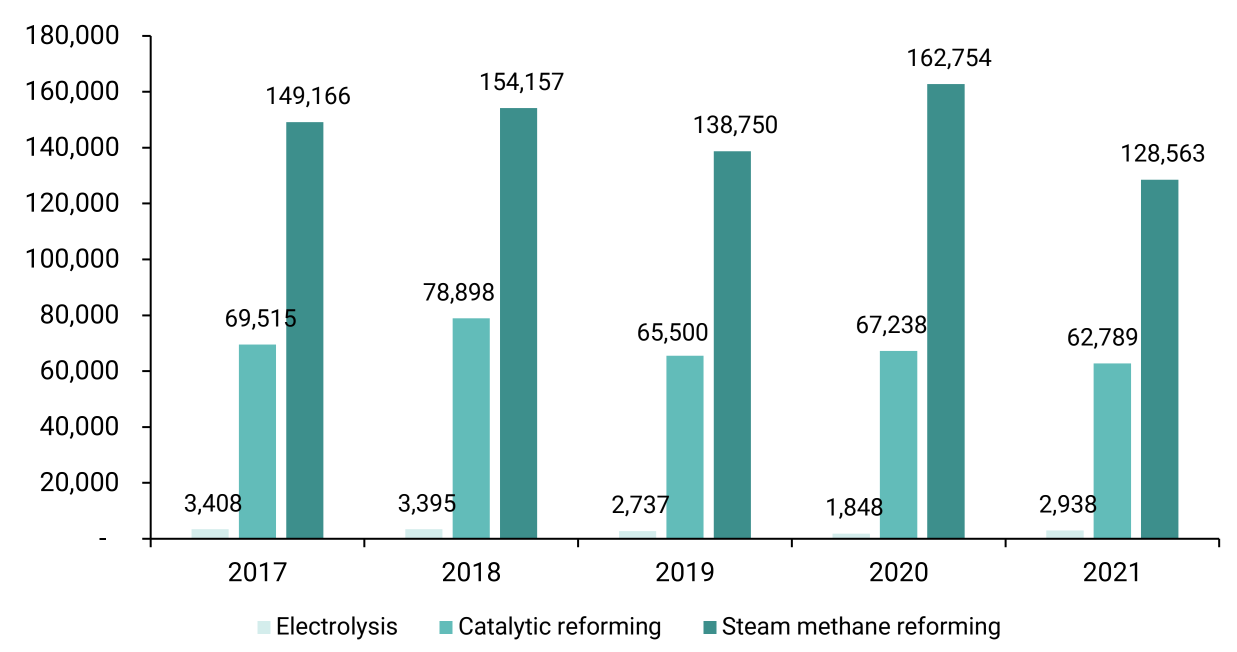
Source: FleishmanHillard, 2022, European Commission, 2024

The clean hydrogen landscape in Romania

In response to the EU developments, Romania drafted its own Hydrogen Strategy, which is now in the final adoption stages. The current version[1] proposes an approach that is in line with the objectives of decarbonizing Romania's economy by supporting the production of hydrogen from renewable sources and gradually decarbonising current hydrogen production that relies mainly on fossil fuels. Figure 2 gives a brief overview of Romania's current hydrogen production technologies. The vast majority of hydrogen is currently produced either by catalytic methane reforming or by steam methane reforming.

The Strategy proposes a scenario with an estimated implementation cost of €4.8 billion and an annual total hydrogen consumption of 152,900 tonnes per year of renewable hydrogen production by 2030. Out of the total consumption, 47.3% will be used in the transport sector, 37.2% in existing industrial activity, and 15.5% will be used for new industrial applications, namely steelmaking. The initial version of the draft s targeted the use of hydrogen in the energy sector, mainly in Combined Cycle Gas Turbines (CCGTs), however, following the public consultation process, this use case was removed in the final version of the document (Energy Policy Group, 2023), similar to plans for using hydrogen in household heating.

Figure 2. Hydrogen production by technologies in tonnes, 2017-2021



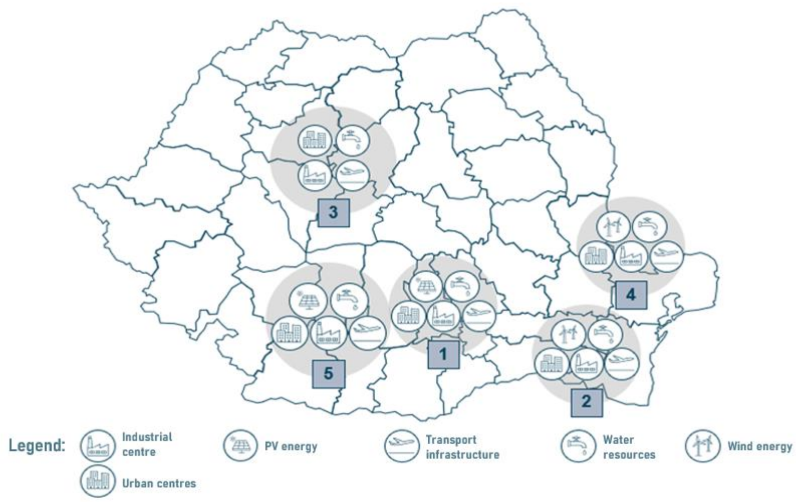
Source: Draft Romanian Hydrogen Strategy (Ministry of Energy, 2023)

[1] The first version of the draft Romanian Hydrogen Strategy was published for consultation in May 2023. The document has had several versions following the feedback received within public consultation process.

The draft Strategy selected 5 potential hydrogen ecosystems (H2 valleys) based on criteria such as (i) the presence of relevant industries and companies, (ii) the renewable energy potential, (iii) the existence of energy infrastructure, (iv) transport infrastructure, etc. (see Figure 3):

1. Bucharest – Ploiești – Târgoviște – Pitești;
2. Constanța – Medgidia – Călărași – Slobozia;
3. Cluj – Târgu Mureș – Sighișoara – Sibiu – Sebeș;
4. Galați – Brăila – Tulcea;
5. Craiova – Slatina – Târgu Jiu – Vâlcea.

Figure 3. Hydrogen valleys in Romania



Source: Draft Romanian Hydrogen Strategy (Ministry of Energy, 2023)

Through its natural gas transmission system operator, Transgaz, Romania joined the European Hydrogen Backbone (newsenergy.ro, 2024) and proposed 11 corridors that could be included in the future European hydrogen transmission system. The draft H2 strategy mentions that hydrogen could be transported by road with trucks on distances shorter than 200 km, as compressed hydrogen. Another option considered is rail transport for distances between 100-800 km, as Liquid Organic Hydrogen Carrier (LOHC) or ammonia. As for the distribution part, the strategy specifies that 66.25% of the national natural gas distribution grid is made of polyethylene pipelines, which resists at hydrogen permeability. However, coupling elements, compressor stations and other grid elements would have to be adapted to allow hydrogen distribution. When it comes to storage, the options considered are salt caverns or depleted oil and gas fields, depending on their feasibility and proximity to the consumption site.

Albeit its flaws (Energy Policy Group, 2023), this strategy creates the foundations of a new economic branch with significant growth potential. Through an adequate development of the hydrogen ecosystems, Romania has the opportunity to reduce the social and economic inequalities between the various regions of the country, through the development of innovation hubs and high skilled workforce. The final version of the strategy marks a significant improvement on previous drafts and generally sets a good framework for the next 6 years.

Simultaneous with the development of the strategy, the Romanian Parliament has also adopted the first law on clean hydrogen consumption in the region, Law no. 237/2023. This legislative document establishes that fuel suppliers need to ensure a content of 5% RFNBO in the supplied fuel by 2030 for the transport sector, with intermediate targets between 2025-2029. Also, for industrial consumers, the minimum target was set for 2030 at 50% renewable hydrogen or low carbon hydrogen, out of which 42% must be RFNBOs, which increases to 75% renewable hydrogen or low carbon hydrogen in 2035, with at least 65% being RFNBO. The law introduces the measures to ensure these quotas are met.

To support the development of renewable hydrogen production within the Recovery and Resilience Plan Romania launched during 2023 a first call of projects for the installation of 100 MW in electrolysers. In this regard 4 projects follows to receive financial support of €149 million.

Despite these significant steps forward for the development of a clean hydrogen economy in Romania, the national discourse is still bogged down in faulty narratives regarding the future of hydrogen, some visible even in the draft revised NECP (Ministerul Energiei, 2023). Some of those pervasive ideas are related to the doubtful expectation that hydrogen can either replace the use of natural gas in most current uses or that it can provide a lifeline for the continued use of fossil fuels throughout the following decades. Contrary to these expectations, it is becoming increasingly clear that hydrogen will be an energy carrier that will likely be used in a limited set of high-value applications where few technological alternatives exist and, even more importantly, it does not detract in any way from the need to gradually phase out fossil fuel consumption as part of the decarbonisation efforts. Therefore, this paper sets out to dispel some of the current myths still present in the public discourse and to offer recommendations on how and where should public support be targeted for turning hydrogen into an enabler of climate change mitigation efforts.

1. Myths about hydrogen production

Myth: Renewable hydrogen production will be expensive

The potentially high cost of green hydrogen production is often invoked as a major barrier in expanding consumption, thus showing the need to support alternative fossil fuel-based production processes, or even justifying the continued direct usage of fossil fuels, especially natural gas, carefully labelled as transition fuels. The National Hydrogen Strategy, while it only promotes public support for renewable hydrogen, fails to provide compelling arguments against this line of thinking.

While hydrogen produced from electrolysis comes indeed at a premium cost compared to fossil-based alternatives, there are more promising premises for cost reduction overtime. This will be the result of technological learning curves for electrolyser manufacturing, the increase in efficiency of electrolyser design, and reductions in the cost of renewable energy.

The National Hydrogen Strategy offers estimations for the Levelised Cost of Hydrogen (LCOH) for different production pathways in 2030. In spite of its own price projections offered,[2] the strategy recommends channelling public support solely towards renewable hydrogen.

Table 2 Levelized cost of hydrogen (LCOH, EUR/kg)

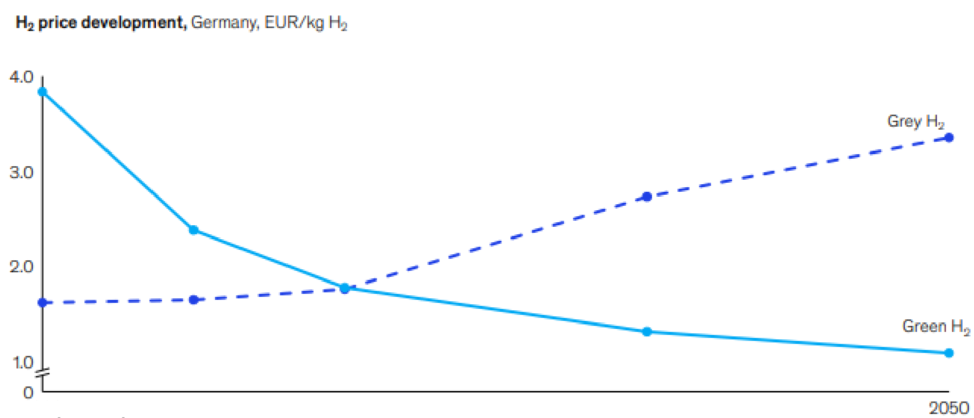
Type	2022	2026	2030
Grey hydrogen	2.90	2.55	2.58
Hydrogen from alkaline electrolysis	4.56	4.04	3.58
Hydrogen from PEM electrolysis	5.40	4.47	3.58

Source: Draft Romanian Hydrogen Strategy (Ministry of Energy, 2023)

In contrast to the estimations presented in the draft Strategy, an EPG study (Energy Policy Group, 2021) presented different projections for the cost of clean hydrogen production in Romania. Based on an electricity price of €50/MWh, reasonable for Romania in 2030 given the renewable energy potential, and using expected reductions in the cost of electrolysis equipment according to the relevant literature, the resulting LCOH for alkaline electrolysis would be between €2.21/kgH2 and €2.3/kgH2, while for PEM electrolysis it ranges from €2.34 to €2.73/kgH2, depending on load factor. The LCOH reach values as low as €1.38/kgH2 for alkaline electrolysis and €1.59/kgH2 for PEM electrolysis in 2030 for an electricity price (LCOE) of €25/MWh if a higher load factor for the electrolysers is considered (5,500 full load hours).

The trend of relative cost reductions of renewable hydrogen compared to fossil alternatives is confirmed by multiple reports. Various analyses[3], including one by McKinsey (McKinsey & Company, 2020), with a focus on Germany shows that in 2030 renewable hydrogen production is expected to become more cost-competitive.

Figure 4. Projected price of green vs grey hydrogen



Source: EPG based on McKinsey, 2020

[2] It is important to mention some of the limitations of the assumptions used for these estimations, which fail to take into account certain factors: the evolution of gas prices, the prices of CO2 certificates prices, and the zero CAPEX requirement for grey hydrogen production.
[3] Examples include CEPS, 2021 (link) Goldman Sachs, 2022 (link), Renze and Bauman, 2023 (link), Snam Sustainability Report (link).

As noted in the National Hydrogen Strategy, the decrease in the LCOH of renewable hydrogen will be mainly driven by a decrease in the investment costs for electrolysers, as well as reductions in the cost of electricity used by these systems. By 2030, it is estimated that electrolyser stack cost will reach between 52-79€/kW (AE) and 63-234€/kW (PEM) Krishnan, et al., 2023). To put this in perspective, in 2023 the electrolyser stack cost ranged from 242€/kW to 388€/kW (AE) and 384€/kW to €1,060/kW (PEM). Importantly, cost reduction expectations are not the same for all electrolysis technologies. Alkaline and PEM electrolysers are the most technologically mature and commercially available. Alkaline electrolysers have the lowest installation costs, while PEM electrolysers have an advantage in flexibility, physical footprint, and output pressure, which may eliminate the need for a compressor or significantly reduce the additional energy input required for the compression stage, given that hydrogen storage or transport generally require high pressure.

Also, the International Renewable Energy Agency (IRENA, 2021) estimates that the current cost differences between the two electrolyser technologies in terms of cost and performance are likely to narrow in time as innovation and widespread deployment of various types of technologies will boost convergence towards similar cost structures – which is also confirmed by BNEF (Bhashyam, 2023a). However, it is worth mentioning that the cheaper alkaline electrolysers expected to be available by 2030 will likely be supplied by Chinese manufacturers, while the European hydrogen value chain will likely focus more on PEM electrolysers.

When it comes to fuel costs, the cost of renewable energy has been constantly decreasing over the past decade, with solar PV reaching a record low in 2020, although the sector is experiencing some increases in cost in the last years caused by supply chain issues. In the most favourable locations at global level, involving solid policy support and adequate financing, solar power can be generated at or even under €20/MWh. Regions with high levels of solar irradiation are expected to enjoy the strongest solar cost reductions, effectively reducing the production cost of hydrogen on account of cheaper electricity. In Romania, price forecasts for renewable energy are still relatively high. Auctions for under the new CfDs scheme have put ceilings on strike prices at€91/MWh for solar and €93/MWh for onshore wind. Nonetheless, further cost reductions should be expected (European Commission, 2024).

As more large-scale hydrogen projects are planned, electrolyser utilisation will increase over time. This can be attributed to a more efficient mix of renewables and integrated design optimisation. Generally, the higher the load factor for the electrolyser, the lower the hydrogen production costs. Solitary renewable installations in Romania cannot meet a high enough number of full load hours (FLH) to power electrolysers at a sufficient load factor that would make LCOH less CAPEX-intensive. Solar PV would offer around 1,500 FLH, onshore wind between 2,500 and 3,000 FLH, while offshore wind might reach up to 4,000 FLH (EPG, 2020), but at a higher electricity cost. The way of ensuring a stable and predictable source of low-cost power for electrolysers is to close long-term Power Purchase Agreements (PPAs) with multiple renewable capacities, or through wholesale purchasing of electricity that comes with Guarantees of Origin (GOs). The additionality and the geographical and temporal correlation principles for RFNBOs will also have to be ensured.

Myth: Hydrogen produced from fossil fuels is more cost-competitive

By relying on already existing hydrogen production capacities and directly connecting the natural gas industry with the hydrogen economy, grey hydrogen production is seen by some as a cost-efficient alternative in the short and medium term. As indicated in the draft National Hydrogen Strategy, the price of grey hydrogen – produced through steam methane reforming or catalytic reforming – is expected to decrease in the next years, from 2.90 €/kg in 2022 to 2.58 €/kg in 2030 – see Table 2. Nonetheless, the assumptions behind these projects are potentially problematic.

The main contributor to the price of grey hydrogen is the price of the fossil feedstock – in essence, the price of natural gas. The LCOH of grey hydrogen is shown to increase almost linearly with the price of natural gas, reaching almost 4 €/kg for natural gas prices of 50 €/MWh and approximately 6 €/kg for natural gas prices of 90 €/MWh (ING, 2021). Although not explicitly stated, the strategy seems to suggest that the price of natural gas is expected to fall in the upcoming period. A reverse calculation of the cost of grey hydrogen based on the methodology made available by Argonne National Laboratory (Sun & Elgowainy, 2019), reveals that the variation in the price of natural gas considered in the strategy is 42.7€/MWh, 34.0€/MWh and 33.3 €/MWh for 2022, 2026 and 2030, respectively.

One might infer that the main reason for considering such low prices is the currently unexploited gas reserves (in the Black Sea) that would increase the amount of gas Romania produces in the near future. It is clearly stated that today, Romania is the second-largest natural gas producer in the EU (Eurostat, 2023). The timeline for Black Sea gas exploitation is not only dependent on the regional security context, but there is also limited evidence to suggest that it would bring significant reductions in wholesale gas prices. On the contrary, due to the much larger initial investment, the cost of offshore gas is generally higher than onshore production. Moreover, the recent energy crisis demonstrated the volatility in the gas prices that can be induced by sudden, unforeseen geopolitical actions. Literally overnight, the price of natural gas can substantially increase, solely driven by the international (geo)political situation. Based on these arguments, the price projections for natural gas in the National Hydrogen Strategy are uncertain.

The strategy also fails to properly account for the carbon price incurred by the revised ETS for fossil-based hydrogen production. Under the new European rules, free allocation of emissions allowances currently awarded to industry, including for hydrogen production, will be phased out by 2034, while no additional allowances will be introduced on the primary market by 2039, which will put sustained upward pressure on the carbon price. Again, a reverse calculation of the cost of grey hydrogen from the strategy reveals that the assumed costs of CO2 are 70.3€/tCO2eq, 75.6€/tCO2eq and 82.2€/tCO2eq for 2022, 2026 and 2030, respectively. Meanwhile, the World Energy Outlook 2023 IEA, 2023, p. 297) projects a cost of 120 €/tCO2 in 2030, with continuous growth thereafter.[4] Based just on these alternative CO2 price projections, the LCOH in the strategy would rise to 2.65 €/kg and 2.93 €/kg, respectively, for 2026 and 2030.

[4] The calculations made in this paragraph do not take into account other harmful GHG emissions associated with fossil-based hydrogen production, including methane emissions.

The third major contributor to the price of grey hydrogen is the capital investment costs. One of the hypotheses in the strategy is that there is zero investment required (zero CAPEX) for the development of the grey hydrogen production facilities, as these facilities already exist. It is unclear, however, how the existing facilities can cope with a significant increase in the demand for hydrogen. Most likely, assuming the grey hydrogen production needs to increase, new steam methane reforming capacities would need to be developed, thus contradicting the zero CAPEX hypothesis.

One option for reducing the cost associated with the price of carbon emissions would be the installation of carbon capture and storage (CCS). Such an investment can only be compensated by an increase in the overall price of produced hydrogen. Nevertheless, the draft Hydrogen Strategy specifically mentions that blue hydrogen is not considered in the evaluation.

In conclusion, a gradual increase in the price of grey hydrogen production is most likely, contrary to what the national hydrogen strategy assumes. The trend is already visible today - in some geographies, grey hydrogen is already more expensive than renewable hydrogen and by 2030, new renewable hydrogen projects are expected to become cheaper compared to fossil alternatives (Bhashyam, 2023).

Importantly, aside from cost considerations, according to the revised Renewable Energy Directive, hydrogen off-takers have to comply with minimum quotas for RFNBOs – either in the form of green hydrogen or products derived from green hydrogen. These quotas amount to 42% in 2030 and 60% in 2035 for industry, and 5.5% for the transport sector in 2030[5]. These obligations will have the likely effect of channelling investment towards RFNBO production and divestment from fossil-based hydrogen production.

Myth: Blue hydrogen will be a cost-effective alternative to renewable hydrogen

At a superficial level, by capturing CO2 emissions associated with fossil-based production, blue hydrogen seems to combine the advantages of relatively lower production costs (see section above) with the potential for a reduced carbon footprint. At the very minimum, it appears to offer a lifeline for existing hydrogen production assets, which can be retrofitted with carbon capture and storage technologies (CCS). However, upon a closer analysis, the limitations of this argument become visible.

Blue hydrogen (sometimes assimilated under the concept of 'low-carbon hydrogen') is based on the same production method as grey hydrogen (mainly steam methane reforming) and partial oxidation, in a facility equipped with CCS, which reduces the amounts of CO2 emitted in the atmosphere by permanently storing it underground. This production method, however, only partially eliminates GHG emissions (fugitive methane emissions would remain, while the

[5] The transport target combines the use of advanced biofuels and RFNBOs, setting a minimum sub-target of 1% for RFNBOs.

uncaptured CO2 emissions would lead to carbon costs). Additionally, CCS comes with an energy penalty, reducing the overall efficiency of the process.

While the latest draft version of the Romanian Hydrogen Strategy does not recommend support measures for blue hydrogen, Romania's natural gas resources and the industrial, economic and political ecosystem created around them, create an implicit (and at times explicit) expectation among many national stakeholders that blue hydrogen production will be more competitive compared to renewable hydrogen. Romania is the second largest natural gas producer in the EU, with an annual production of about 351,683 terajoules in 2022 (Eurostat, 2023), and poised to become the largest once deepwater gas production in the Black Sea would start.

While deemed as a less carbon intensive solution compared to grey hydrogen and a way of building up the hydrogen market, blue hydrogen still involves significant GHG emissions throughout its lifetime, ranging between 1.27 – 6.45 kgCO2eq/kgH2 (Pembina Institute, 2021). Carbon dioxide emissions cannot be fully avoided, with expected capture rates not going higher than 85-95%. Moreover, fugitive methane emissions are an important factor in determining the carbon footprint of this production method. Methane emissions have a significant impact, respectively, 86 gCO2eq/gCH4 over 20 years (University of California Riverside, 2023) and must be accounted for when assessing the climate implications and the economic opportunity to develop blue hydrogen.

Blue hydrogen has a similar cost structure to grey hydrogen, though somewhat more expensive, when factoring in the price of CCUS technology. The transitional narrative of using blue hydrogen as an intermediary product for expanding the hydrogen markets is problematic given the lack availability of off-the-shelf CCS technologies, with no such large-scale facility operating. The costs of CCS retrofits also remain high, as investments are both CAPEX and OPEX-intensive. Price projections based on assumptions of stable has prices generally result in lower LCOH estimations for blue hydrogen in the short term compared to renewable alternatives. However, BNEF (BNEF, 2023) estimates that renewable hydrogen will undercut blue hydrogen and become cheaper by 2028 in all global markets, including Romania, where the higher CO2 costs and the elimination of free allocation are expected to reduce the cost competitiveness of fossil-based hydrogen production routes.

Recommendations for hydrogen production

Romania should prioritise renewable hydrogen production, based on less favourable cost evolution projections for fossil-based alternatives. Public support for renewable hydrogen should be reflected across the entire value chain: source of renewable energy, electrolyser technologies, transport, storage and lead-market creation.

Romania should implement a favourable legal and regulatory framework for incentivising investments in renewable energy sources, addressing the current challenges and barriers related to grid and land access, permitting, supply chain and workforce. This is paramount for tapping into Romania's potential to produce cost-competitive renewable hydrogen, which will require access to renewable electricity. In addition, Romania's offshore wind potential should be thoroughly assessed, followed by the creation of a fair investment framework. The destination of financial support should reflect the high probability that by 2030, hydrogen production will be increasingly an OPEX-intensive process, with the cost of electricity becoming the highest cost component.

Access to renewable energy and support for electrolyser investment costs should be done in an integrated manner. New renewable capacities should be incentivised to sell their electricity to renewable hydrogen production facilities, either through long-term PPA contracts or through financing of integrated (renewables plus electrolyser) projects. Other than avoiding curtailment, there are currently limited incentives for renewable producers to sell electricity to hydrogen producers.

Romania should also take full advantage of the facilities and instruments that are currently in place at the European level for the development of the hydrogen market, such as the European Hydrogen Bank, as well as leverage the significant financing instruments available at EU and national level.

Finally, a critical aspect is the need for training the human resource required for the development of the hydrogen economy. Dedicated undergraduate and master-level educational programmes/ curriculum are needed to produce new generations of hydrogen specialists in the next 4-8 years. Incentivising research activities in the field of renewable hydrogen technologies can increase the number of PhD students in the field. Dedicated graduate level scholarships could be made available for 6 months to 1-year specialisations in renowned hydrogen-focused research institutes and universities all over the EU.

2. Myths about hydrogen consumption

Myth: Hydrogen will replace natural gas in the heating of individual households

An ever-present narrative in Romania is that of hydrogen partially or fully replacing natural gas use in the heating of households. By repurposing current distribution grids and through some adjustments to home appliances, hydrogen is said to represent a handy and minimally invasive alternative, which would also allow for the continued use and repurposing of existing gas infrastructure. Projects meant to test and demonstrate the feasibility of hydrogen injection in the gas network are already in the works – an example of such project is the one implemented in Romania by Delgaz (Delgaz, 2024).

However, the fact that many of the promoters of the replacement of gas with hydrogen are incumbents of the distribution networks indicates that this argument may be to a certain extent self-serving. The vast majority of the projects implemented to date are merely meant to test the technical and not economic feasibility of hydrogen injection and switching. Applying this at a broader level would not only be inefficient, but it may also have an inflationary impact on household heating bills.

Using renewable hydrogen for household heating would rely on a tremendously inefficient process. Renewable electricity would be converted to hydrogen through electrolysis, with an average conversion efficiency of about 60% at the electrolysis system level, based on the Lower Heating Value of hydrogen. Further losses would be incurred in the compression, storage and transport of hydrogen via pipes. Burning fuel in condensing boilers is also about 90% efficient. So, for every 1 MWh of renewable energy, between 0.5 and 0.55 MWh of energy would be produced as heat. Almost half of the energy would be lost.

Alternatively, the direct use of renewable energy for heating through heat pumps (with 300-400% efficiency) means that 1 MWh of electricity produced from renewable sources would generate 3-4 MWh of heat, i.e. 6-9 times more efficient than using hydrogen for heating. Such an approach would be fully in line with the increased energy efficiency direction promoted by the EU. The switch to heat pumps is confirmed even in governmental plans, as the Romanian Long-Term Strategy foresees that in 2050 a quarter of the heating sectors will be supplied through heat pumps (SGG, 2023). A higher process efficiency directly translates into a reduction of the operational cost – i.e. a 6-9 smaller number of energy units are required per household for heating if renewable electric energy is used directly rather than producing hydrogen and mixing it into the gas network.

Therefore, the relative inefficiency would translate into comparably higher energy prices for households in a scenario of a complete replacement of natural gas with hydrogen. When it comes to potentially using a hydrogen natural gas blend, according to IRENA (IRENA, 2021) a mix of 80% gas and 20% hydrogen would result in 37% increase in the natural gas price and implicit impact in consumer bills.

There is also a potential feedback loop, which can put additional negative pressure on the costs associated with using hydrogen as an alternative to natural gas in home heating. The more households electrify their heating, the fewer users of the natural gas grids will have to support through their bills the infrastructure operation costs. This effect can be further amplified if certain economic sectors will disconnect from the natural gas network. As an ever-smaller pool of consumers will have to bear the cost of maintaining the current gas network, their distribution component in the bill will have to be increasingly larger, putting upwards pressures on prices.

The arguments presented in this section have focused mainly on efficiency and operational costs, but there are also concerns regarding the readiness of current appliances, such as boilers and cookers, to be repurposed for hydrogen use. The combustion characteristics of hydrogen are largely different compared to the characteristics of natural gas: the flame velocity is much higher, and the temperature of combustion is also higher, in particular for the diffusion-type combustion. A maximum threshold of 20% hydrogen in the mixture, by volume, is generally considered to be acceptable with no to minimum impact on most appliances using this mixture. It is advisable to check with the manufacturer if the equipment can be switched to using a blend of hydrogen and natural gas, even if the proportion of hydrogen is as low as 20% by volume.

Moreover, as the mixture of gases is supplied at constant pressure, the transported heat is lower per unit of volume, compared to the case when the gas is 100% natural gas. Therefore, the time of operation of these appliances generally increases. For example, in case of a gas-burning stove, the time for preparing food increases when the gas contains 20% hydrogen, by volume. A similar delay can be noticed when using the gas mixture in a gas boiler for heating.

Myth: Hydrogen is a competitive solution for decarbonising passenger transport

Hydrogen has also been touted as a solution for eliminating tail-pipe emissions in road transport, either by acting as an energy carrier for electric vehicles equipped with fuel cells (FCEV) converting it to electricity, or as feedstock in the production of synthetic fuels, combining clean hydrogen with captured CO2, which would eliminate the need for fossil fuels.

A comparison between a fuel cell electric vehicle (FCEV) and a battery electric vehicle (BEV) can be made on performance indicators such as cost, overall efficiency, range, time of refuelling/recharge, infrastructure development, environmental footprint, etc.

Cost-wise, BEVs have a clear advantage over FCEVs. The constant improvement of battery technology, the economies of scale already achieved and the financial incentives made available by various EU member states significantly decreased the average price of BEVs. The relatively large cost of FCEVs, driven mainly by the cost of the on-board fuel cell stack drawbacks of this technology. Despite this, there are some vehicle manufacturers, i.e. Toyota (Toyota Europe Newsroom, 2023), that invest significant amounts of capital in FCEV development, despite clear indications that the market favours BEVs.

The overall energetic efficiency is the most widely used critic to the FCEV technology. A simple energetic analysis of the FCEV reveals the following chain of energetic efficiencies: the efficiency of the electrolysis system is about 60%, based on the LHV of hydrogen. Compressing hydrogen from atmospheric pressure to 90 MPa (for storing it at 70 MPa), consumes between 4.31 and 6.46 kWh/kg of hydrogen (Knop, 2022). If an average energy consumption of 5.5 kWh/kg is considered, this represents 16.5% of the total energy content of hydrogen. Therefore, the compression efficiency is about 83.5%. The efficiency of the on-board fuel cells has constantly increased over time and now peaks at about 60%, again, based on the LHV of hydrogen. Finally, an efficiency of about 97% can be considered for the electro-mechanic drivetrain of the vehicle. Putting together all these efficiencies results in total efficiency of about 30%. It follows that for each MWh of renewable electric energy input into the process, only 0.3 MWh are actually used for propulsion, in the case of a FCEV.

For a BEV, the renewable energy is fed directly to the battery. The transmission losses between the point of production and the point of consumption can vary, on average, between 8-15%, depending on the type of transmission line and its length (CHINT, n.d.). Should a 10% loss be considered, this amounts to a transmission efficiency of 90%. The typical efficiency of a Li-ion battery for BEVs is around 95%. As for the FCEVs, the efficiency of the drivetrain is about 97%. It follows that the overall efficiency of a BEV is about 83%. Therefore, for one MWh of renewable energy, about 0.83 MWh are used for propulsion. Therefore, the cost of energy per km is around 2.8 times lower for a BEV compared to a FCEV.

On the other hand, range is one of the net advantages of a FCEV compared to a BEV. While a typical range for a BEV lies between 200 – 400 km, for FCEVs this can extend to 800 – 900 km, or even more, without refuelling. When it comes to the time of refuelling, the FCEV presents, once again, a net advantage. Depending on its size, the hydrogen tank can be refilled within 5-7 minutes. This is slightly longer than the time required for filling a petrol or Diesel tank. However, for the BEV, the recharge time can vary between 15 min (quick recharge, for a SoC of less than 80%) and 1.5 hours. Therefore, the charging time is not only advantageous at vehicle level for the FCEV, but also at the station level, allowing the refuelling of up to 12 vehicles per hour. Nonetheless, the average distance travelled yearly by a personal vehicle is 18,000 km for Western Europe, in 2020 (Marrero, et al., 2019). This amounts to about 50 km per day. Therefore, one full battery charge is enough to cover roughly one week of operation, making the use of BEVs generally convenient according to a typical usage pattern in the EU.

Given the widespread of BEVs, the electric charging station is much more developed than the corresponding hydrogen refuelling stations. Despite the changes made through the Alternative Fuels Infrastructure Regulation (Official Journal of the European Union, 2023) the number of charging stations will likely remain lower compared to the electric charging network (the Regulation requires the construction of a hydrogen re-fuelling station every 200 km on the TEN-T core network by the end of 2030, as well as a station in each urban node). Besides, the complexity, cost, and footprint an electric charging station are much lower compared to the hydrogen refuelling station.

The environmental footprint of both types of vehicles can be assessed from the point of view of the types of materials used in the manufacturing (their availability and the emissions per kg in the extraction/production process), the manufacturing process itself, the recyclability of the subsystems and the emission index of the energy used for powering the vehicle. Assuming both types of vehicles are fuelled with 100% renewable energy, the embedded CO2 is higher for newly built BEVs compared to FCEVs.

A definitive statement on advantages of BEVs compared to FCEVs is therefore difficult to make. The assessment is highly dependent on the usage profile and the existing infrastructure. The market seems to favour BEVs for the time being for costs and efficiency considerations.

When it comes to using hydrogen in synthetic fuels, one could also identify a variety of limitations, the most severe one being represented by the cost. The fact that the fuel itself is rather expensive is amplified by the low efficiency of the internal combustion engines making use of such fuels. Therefore, the fuel/km metric is high, resulting in a high cost/km.

Despite this assessment, it should be mentioned that RED III, which sets targets for the use of renewable fuels of nonbiological origin (RFNBO) in transport, leaves the door open for limited use of hydrogen, as MS will need to reach in 2030 a share of RFNBO in the total energy consumption in transports between 1% and 5.5%.

While the above discussion refers to personal vehicles, the usage of hydrogen in cargo vehicles, in particular long-haul, heavy-duty transport appears to present more advantages. The low energy density of lithium-ion batteries makes them difficult to scale without a significant weight penalty, which is a disadvantage for freight transport. Therefore, as for this type of application, the attainable range and recharge/refuelling time are more important than energetic efficiency, FCEVs offer an attractive alternative.

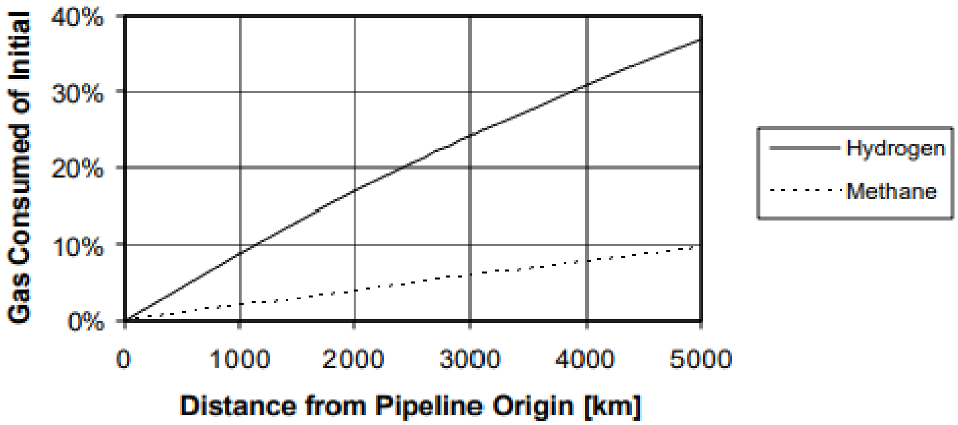
Myth: Hydrogen will replace current fossil fuel consumption in gas-fired power plants

While emitting less than coal, gas-fired power plants produce significant amounts of CO2. Romanian authorities plan to significantly increase the installed capacities in combined cycle gas turbines (CCGTs) and to retrofit existing cogeneration combined heat and power (CHP) plants over the coming years. However, given the imperative to decarbonise the power sector by 2040 (European Commission, 2024) and the increasing pressure from the carbon price of the ETS, such investments with long lead times and operating lifetime may not be able to make a return on investment in due time.

A much-touted solution at national level, including in the Long-term Strategy and the National Hydrogen Strategy is to gradually replace natural gas with hydrogen as a means of ensuring the long-term viability of these new power plants. At first glance, replacing natural gas (or other fossil fuels) with hydrogen might appear an elegant solution for eliminating the associated CO2 emissions, while being able to keep all the advantages of the gas-turbine based power generation system. Nevertheless, a more careful analysis reveals major drawbacks for this solution.

Hydrogen is not a natural resource, readily available underground or in a different natural environment. Hydrogen needs to be produced, preferably from renewable energy sources. Energy needs to be consumed for producing it, irrespective of the production method, as also shown earlier in this paper. But the main role (and sometimes, the only one) of a gas turbine powerplant is to produce electricity. Replacing natural gas with hydrogen would require using renewable electricity in the electrolysis process, to be converted back to electricity at a later stage. The conversion of renewable energy to hydrogen has an efficiency of about 60%. The transport of hydrogen from the production to the consumption points entails extra energy consumption in the form of pressure increase required for driving the gas through the pipe. Because of the low volumetric energy density of hydrogen, about 4.6 times more energy is needed to move hydrogen through the pipeline compared to natural gas (Bossel & Eliasson, n.d.). Figure 5 shows the fraction of gas energy content (expressed as Higher Heating Value - HHV) consumed for driving the gas through the pipe, as a function of pipe length. Assuming the distance between the production and consumption points is 500 km, the consumed energy is roughly 5% of HHV, namely 1.97 kWh/kg of hydrogen. Connecting this to the LHV, results in a transport efficiency of 94%. The conversion of hydrogen energy into electrical power within the gas turbine based powerplant has an efficiency of up to 65%, assuming the powerplant has a combined cycle architecture. It follows that the overall process efficiency is 37%, namely for each MWh of renewable energy, the process generates only 0.37 MWh of electricity.

Figure 5. Share of gas consumed during transportation through pipelines



Source: Bossel, U. & Eliasson, B., n.d. Energy and the Hydrogen Economy.

The modelling of Romania's Long-Term Strategy shows that the planned new CCGT capacities would operate at a capacity factor of 34% in 2025, 39% in 2030 and 28% in 2035, even before an eventual switch to hydrogen in 2036. A part-load operation of a gas turbine based powerplant is associated with a significant loss of powerplant efficiency, which implies that the output of the process is much lower than 0.37 MWh for each MWh of renewable energy input.

Although this brief analysis points to a waste of resources when burning hydrogen in gas power plants designed to produce baseload electricity, it is not to say that hydrogen should not be used in this process under any circumstances. There are cases in which hydrogen combustion is a desirable solution, for example during the time shift between the moment when hydrogen is generated, through electrolysis and the one it is burnt in the powerplant. Such scenario can ensure the storage of energy in the form of hydrogen when there is a higher production from RES (excess of production), to be later released by burning the hydrogen in the powerplant at times of high demand. The process can therefore contribute to grid balancing. However, large-scale hydrogen storage represents a pre-requisite for this solution. This is an extra step in the process, involving high technical complexity and further energy losses, as hydrogen needs to be either liquefied or converted into a storable liquid like ammonia and then reconverted to gaseous hydrogen right before being injected in the gas turbine. Given the high inefficiency of the entire process, hydrogen storage is preferable for long-durations– weeks, months or even seasons. The shorter the time interval, the more competitive a battery-based storage system becomes, as opposed to using hydrogen as an intermediate medium of energy storage.

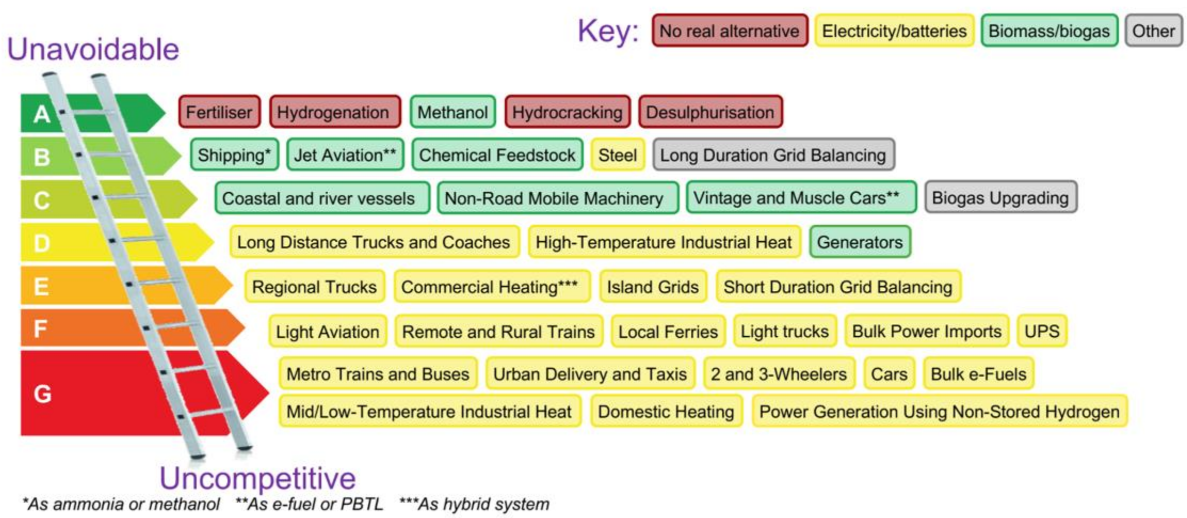
The current investments in gas-fired power plants seem to focus more on technologies designed to generate baseload electricity and less to contribute to grid balancing. A direct replacement of natural gas with hydrogen in such facilities is not only highly inefficient, but it would also render those capacities uncompetitive. This in turn raises the risk that, out of competitiveness concerns, those power plants would continue to operate on natural gas, with the associated impact on renewables. Hydrogen can play a role in a decarbonised power sector, but this would require not only significant investments in hydrogen storage, but also power plants designed to function as peakers at times of high energy demand.

Recommendations for hydrogen consumption

Conversations on a future 'hydrogen economy' generate significant hype not just among investors, but even among companies seeking to prolong the utilisation of their assets designed to consume fossil fuels, for which a switch to hydrogen could provide a much-desired lifeline. However, given the inefficiency and cost of such a switch, not to mention the amounts of additional renewable energy that would have to be installed to produce renewable hydrogen (which has a higher potential to lead to deep emission reductions compared to fossil alternatives), hydrogen should not be treated as a potential replacement of natural gas and other fossil fuels. Hydrogen will likely be used mainly in high-value applications where no technological alternatives exist, or they are not cost-competitive. Identifying those high-value applications is crucial for determining where public support should be targeted and where it would be wasteful.

To provide an answer to this conundrum, Michael Liebrich (Liebreich, 2023) has proposed his infamous sector-ranking for the optimal use of hydrogen, the so-called 'hydrogen ladder' (see Figure 6). The ladder ranks the various sectors of economy in which hydrogen can be used on 7 levels, from A to G, where A represent the sectors in which hydrogen usage is extremely competitive and G the sectors where more financially and technically viable alternatives exist to hydrogen.

Figure 6. The hydrogen ladder



Source: Liebrich, 2023

The assessment underpinning Liebrich's hydrogen ladder seems to confirm the analysis in this section for the three myths debunked regarding the use of hydrogen for domestic heating, for generating power in a continuous manner (without using hydrogen storage) and in FCEVs for personal use.

Comparatively, higher-value applications of hydrogen, which should also be reflected in strategic planning in Romania, include:

- **Heavy industry** – where fossil fuels as well as (grey) hydrogen is widely used today as feedstock or a source of energy. Examples include fertilisers, the steel industry (thus facilitating the technological conversion from coal-based blast furnace to direct reduction of iron) and industries in which hydrogen can be used as a source of high temperature heat (for example in the glass, food and ceramic sectors, where hydrogen can be valorised mainly by combustion);
- **Heavy duty transport** – aviation (either in the form of liquid hydrogen or as e-fuels), long range shipping (in the form of liquid and/or ammonia and/or methanol), in coastal and river vessels, non-road machines (like the mining trucks), long distance trucks and coaches and, to a lesser extent, regional trucks;
- **Energy applications** – long duration grid balancing (in the form of liquid/gaseous hydrogen burned in gas turbine-based powerplants) and electric energy generation using hydrogen fuel cells (hydrogen used as compressed gas or methanol).

3. Myths about hydrogen transport

Myth: Natural gas pipelines can be easily repurposed for hydrogen

Linked to the narratives on hydrogen use in household heating, the potential repurposing of gas grids for hydrogen transport and distribution has also gained some traction domestically. Even more, as local authorities are investing in the expansion of the current natural gas transport and distribution networks, pipelines are built to be 'hydrogen ready' in the expectation of the eventual switch to the new energy carrier. Nonetheless, repurposing is not as straight forward as generally presented.

Even though replacing or blending hydrogen with natural gas in existing infrastructure is theoretically possible from a technical perspective, the hydrogen molecule is significantly different from the natural gas one. It is the smallest molecule in the periodic table, meaning that it is particularly difficult to be contained, thus posing a high risk for permeation or leaks. Additionally, from a safety perspective, the air/hydrogen mixture range at which ignition occurs is much wider than the equivalent mixture ranges for air/natural gas. Hydrogen can also potentially have a damaging effect on the materials that are currently used for natural gas transport and distribution infrastructure.

A recent study explores the main uncertainties and challenges related to transporting hydrogen, pure or blended with natural gas in the existing infrastructure (Topolski, et al., 2022):

a. Effects on pipeline materials and equipment performance

Existing natural gas transport and distribution infrastructure mainly uses steel pipelines. The presence of hydrogen increases the fatigue crack growth rate in such pipelines and also has effects on seam welds and hard spots. Also known as embrittlement, the phenomenon occurs due to the diffusion and dissolution of hydrogen in the microstructure of metal, and in combination with mechanical stress, the hydrogen creates hairline cracks that grow progressively larger over time. The damage is done over time, but when the quality of the steel is damaged, the structure needs repairing quickly to avoid more severe risks, incurring additional costs. Using polyethylene pipelines is regarded as an efficient solution, particularly for distribution networks where the pressure is relatively low.

In addition to the pipes themselves, the hydrogen transport and distribution infrastructure includes compressors, valves, and storage facilities, requiring additional efforts for standardisation and new regulations adapted for the accommodation of hydrogen.

b. Effects on operational indicators

Because of the physical and chemical properties of the hydrogen molecule, operating a distribution or transmission system accommodating a share of hydrogen also poses challenges. Because hydrogen has a lower volumetric energy density than natural gas, there is a significant reduction in the energy transmission capacity, assuming the pressure levels are maintained the same. Increasing the pressure in order to preserve energy transmission capacity requires a significant increase in the energy used for compression, because of the lower molecular weight of hydrogen. As seen in Figure 7, the energy required for pumping the same amount of energy through a pipeline is many times higher for hydrogen than for methane, as a function of the pumping distance. Therefore, for long distances, pumping hydrogen through pipes becomes highly uneconomical (almost 50% of hydrogen's energy content is lost when pumped over distances over 6,000-6,500 km). According to the National Renewable Energy Laboratory (NREL), assessing hydrogen blending opportunities should be done based on the trade-offs between operational considerations (pressure de-rating of existing pipelines, increased compression energy, and increased inspection frequency), capital-intensive upgrades (new pipelines, compression stations, and end-use application retrofits), and the opportunity costs associated with reduced energy transmission capacity.

The extent to which it is technically feasible for current natural gas consumers to switch to hydrogen is also unclear. Home appliances have already been discussed in a previous section, but this may be equally problematic for other types of consumers, for example industrial users, or burning hydrogen in gas turbines for power generation.

For the particular case of gas turbines, relatively small amounts of hydrogen blended with natural gas can be used as fuel, without significant impact on the gas turbine performance. As the share of hydrogen in the mixture increases, problems are likely to be identified, especially in the transient phases in which the uprating and derating time constants are significantly different (much larger). Furthermore, for stabilised operation, burning hydrogen significantly increases the flame temperature, if a diffusion-type burner is used, as the stoichiometric flame temperature of hydrogen is much higher than for natural gas. This not only impacts the mechanical integrity of the turbine (the combustors and the turbine blades can be affected by the increased temperature), but also increases the production of NOx.[6] A solution to this problem might be using premixed burners, in which hydrogen (or the natural gas + hydrogen mixture) is first mixed with air (at a less than stoichiometric equivalence ratio) and then burned, in a downstream section of the combustor. This approach is also susceptible to incidents as the flame velocity of hydrogen is much higher than for methane. As a consequence, the pre-mixed combustor requires a careful design for avoiding the flame being propagated upstream and leading to potential accidents. In a nutshell, gas turbines can be adapted (or designed, from the onset) to run on hydrogen or a mixture of hydrogen and natural gas, but this adaptation poses some technical challenges. Simply replacing natural gas with hydrogen in a gas turbine is far from being a straightforward process.

Myth: Hydrogen can be immediately blended with natural gas in existing pipelines

As a transitional solution to full hydrogen switching, blending hydrogen with gas in the current pipeline network is another often mentioned solution. However, not only does this pose significant technical challenges, but the minor improvements in emissions may be insufficient to justify the additional costs. As shown in a previous section, all routes of hydrogen production led to higher costs than the price of natural gas.

There is already real-world evidence regarding the feasibility of such an approach. In Winlaton, UK, for 11-months a pilot project was implemented through which 668 households used a blend of 80% natural gas and 20% hydrogen. For this test no changes were made to the existing distribution grid or home appliances. Throughout the operation, the equipment has operated safely, ensuring that the blend limit was not exceeded. There have been no issues on the network with satisfactory technology, well controlled network composition and no unusual issues on the network. The appliances have all performed as expected, with no CO alarm issues, nor adverse customer feedback (HyDeploy, 2018).

Although 90% of the components of natural gas boilers are similar to hydrogen boilers, there is a consensus among manufacturers of such equipment that the threshold of 20% hydrogen is the maximum that can be achieved for current gas boilers (Eunomia, 2023) Above this threshold, significant changes are needed for various components. Nevertheless, the maximum possible concentration of hydrogen in natural gas pipelines is heavily affected by pressure fluctuations, structure, and existing defects, which lower the possible level of blending. General assumptions point to a blending percentage of 2-10%, if certain adaptations are made (THyGA).

This is crucial, as hydrogen's energy density is about a third of natural gas' per unit of volume, which means that, when blended, the energy content of gas and hydrogen mixture would incur a significant reduction. As such, a 3% hydrogen blend (by volume) in natural gas pipelines could potentially reduce the energy delivery of the pipeline by about 2%. This loss in energy content

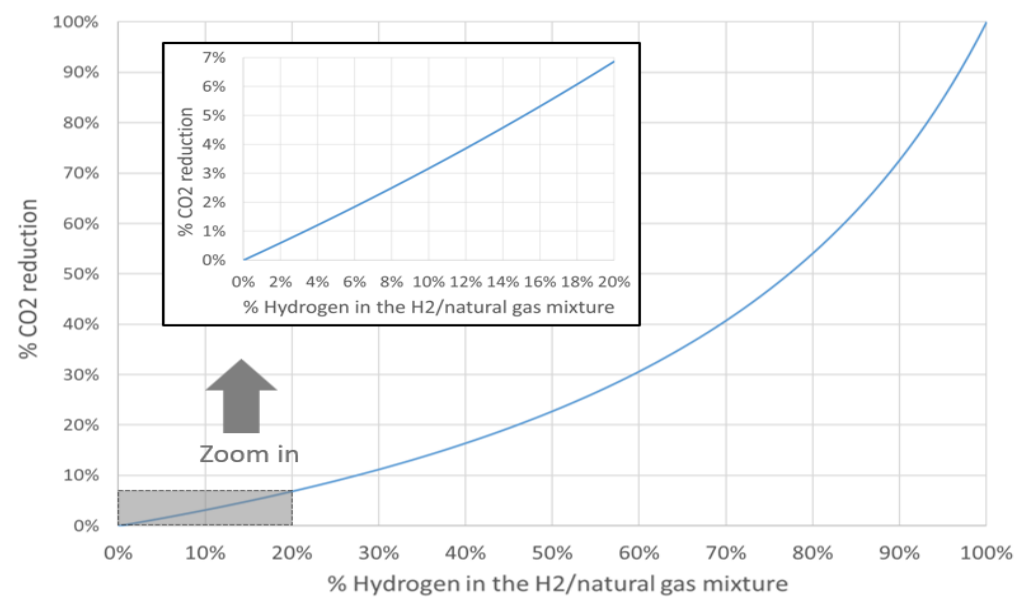
[6] This chemical is directly related to the flame temperature- the higher the temperature, the higher the NOx production.

would likely not be offset by the relative reduction in emissions. As seen in Figure 7, a 3% hydrogen blend translates into less than 1% reduction in CO2 emissions. If the percent of hydrogen increases to 20%, the reduction in CO2 is just below 7%.

The volume of hydrogen that would be blended in the natural gas grid would be variable, following the nature of its production, meaning that the hydrogen concentration would vary in time, with adverse impacts on the grid. Natural gas pipelines and equipment are generally designed to only allow a limited range of gas mixtures.[7] Moreover, end-users may not be able to accommodate much or any hydrogen content and using a higher value molecule such as hydrogen would only make it lose value and raise costs for end consumers, with limited climate benefits.

Issues of standardisation and impact on cross-border gas flows also need to be considered. Natural gas is transported through the EU's gas networks in a variety of gas qualities, with different physical and chemical characteristics. The injection of hydrogen into existing natural gas networks would change the parameters of the gas transported and consumed in certain geographies. This can have a negative impact on the possibility of cross-border gas flows and may cause problems and additional costs, especially for system operators and end-users.

Figure 7. Reduction in CO2 (compared to burning CH4) when burning a mixture of H2 and CH4 (units of volume)



Source: EPG estimations

Currently, permissible hydrogen blending rates vary significantly across the member states. The highest allowed hydrogen admixture rates are in Germany (10%), France (6%), Greece (6%) and Spain (5%) (THyGA, n.d.). Other states allow mixture rates below 1%, 15 member states have no regulations, while three states (Belgium, Czechia and Denmark) do not allow any hydrogen blending with gas. As for Romania, it is among the 15 member states that have not yet regulated

[7] In line with standard EN 437, 2021.

a specific hydrogen blending rate. Without closer cooperation between member states for uniformising regulations, the EU risks creating a fragmented gas market, with associated trade restrictions, that in turn may further result in higher prices for consumers.

As some consumers may not be technically able to take in hydrogen blends over a certain percentage, the idea of re-separating the natural gas and the hydrogen close to the consumption point has also been discussed. Nonetheless, there are a series of technical challenges to this approach. The separation of hydrogen is a mature technology but likely cost-prohibitive for low hydrogen concentration blends. Various separation technologies have been developed over time: Pressure Swing Adsorption (PSA), membrane separation, cryogenic separation, and electrochemical separation. In a study by National Grid (UK) (Topolski, et al., 2022), blend ratios of 5%, 10%, 20%, and 40% were investigated. The minimum specific cost of hydrogen recovery was identified for a mixture of 20% by volume, in the range of 1.17 € – 1.87 €/kg for the membrane-PSA system and 1.05 € – 1.64 €/kg for the cryogenic process, when minimum compression costs are accrued because the downstream natural gas systems operate at low pressure. Moreover, one other major drawback of the separation technology is the purity of the resulting hydrogen. If hydrogen is to be used in combustion applications, relatively low purity is required (about 99%). However, if it used for fuel cell applications, much higher purities must be obtained (about 99.999%). Most separation systems can obtain high hydrogen purity at the expense of a reduced mass flow and higher energy consumption.

Myth: Hydrogen can easily be transported over long distances

A key argument for supporting the development of a hydrogen economy is the ability to carry emissions-free energy over long distances. Theoretically, hydrogen could allow for the creation of global flows of clean energy, from areas with high potential for renewables to regions with high energy demand. Not only can hydrogen be transported over long distances, but it is generally expected to be cheaper to transport than electricity. This is partly why the EU's hydrogen ambitions for 2030 foresee equal amounts being produced domestically and imported. Nonetheless, there are limitations, especially on the short and medium term that make such an endeavour difficult.

The previous sections have presented some of the trade-offs associated with repurposing existing infrastructure. This section dives into some of the intricacies of newly built infrastructure for hydrogen transportation. Transporting hydrogen, especially over long distances, is not an easy process due to its low energy density per unit of volume. There are several options to transport hydrogen, which fall into three main categories: (i) pipelines, (ii) tanks or (iii) cables.

Pipelines tend to have low operational costs and lifetimes of between 40 and 80 years (IEA, 2019). Building new pipelines however comes with high capital costs and faces several permitting and regulatory barriers. Through pipelines hydrogen could be transported as gas, as ammonia or LOHC. For distances lower than 1,500 km, the transmission of hydrogen as a gas by pipeline is generally the cheapest option.

For longer distances, transmission as ammonia or LOHC might a comparatively cost-effective option. Nonetheless, converting hydrogen to ammonia requires an energy equivalent of between 7% and 18% of the energy contained in the transported hydrogen, with a similar level of loss when converting it back to pure hydrogen (IEA, 2019). Ammonia is also toxic chemical, which can cause air pollution and acidification. LOHCs have similar properties to crude oil and oil products, so they could use existing oil pipelines or similar ones. But there are costs associated with the conversion and reconversion processes involved, which are equivalent to between 35% and 40% of the cost of the hydrogen itself. Besides, the carrier molecules from the LOHC are often not used when it is converted back to hydrogen, so they need to be transported back or safely disposed, further increasing the cost and complexity of the transport process.

Hydrogen can also be transported in tanks, via trucks, rail, or ships. Shipping hydrogen could be done similarly with liquefied natural gas (LNG), requiring the liquefaction of hydrogen by cooling it to -253°C. This is an energy-intensive process equivalent to between 25% and 35% of the energy content of the hydrogen transported. This is significantly higher than in the case of LNG, which requires around 10% of the energy content of the natural gas transported. The fuel consumption of the actual shipping process accounts for an equivalent of another 0,2% (IEA, 2019b) per day of the transported hydrogen, similar to LNG. The costs of developing the necessary infrastructure such as liquefaction and regasification plants, conversion and reconversion plants, etc. are also not negligeable. Shipping ammonia is a more technologically mature alternative, but similar to the case of pipelines, this comes with associated losses in efficiency and additional costs stemming from conversion and reconversion. Nonetheless, despite the high energy input for the conversion of hydrogen into ammonia and then reconverting ammonia back to hydrogen, the relatively high boiling point of ammonia (-33°C) compared to liquid hydrogen (-253°C) greatly reduces the complexity of the transport process and the energy input for keeping the fluid below its boiling point. Still, if the end-use molecule is hydrogen, shipping over long distances can be more expensive than the hydrogen produced locally, even in areas with lower potential for renewable energy.

Transportation of electricity may in some circumstances be preferable to pipelines or shipping. Long distance ultra and high voltage DC cables, transporting energy in the form of electrons and generating hydrogen locally by water electrolysis represents a promising alternative. The continuous nature of the DC current greatly diminishes the transmission losses, but it presents increased levels of uncontrolled and spurious discharge, thus representing a safety issue. The location of the electrolyser can also in turn affect the economics of the production and consumption of renewable hydrogen (CEPS, 2021). Feeding the electrolyser electricity from the grid can contribute to improving load factors, by channelling electricity flows from areas with higher renewable potential. There is also some evidence that transport costs can be 25% lower by using the grid, especially in geographies that would need new hydrogen transport and storage infrastructure (Aurora Energy Research, 2020). In practice, this is expected to location-specific with significant intra-EU variation.

Today, hydrogen is mainly produced close to the point of consumption – only about 15% of total hydrogen production in the EU is delivered to a different point of demand (European Commission, 2020). Developing the necessary transport infrastructure will take time. The complexity and associated costs of hydrogen transportation over long distances reinforces the idea that the hydrogen market will be local at first, before it gradually reaches regional proportions. While continental and global hydrogen flows will likely be developed, these are expected to be relatively limited, especially compared to current commodity markets for fossil fuels. Importing hydrogen in regions with structurally higher energy prices, like Europe, can contribute to the continent's decarbonisation efforts, but is currently unlikely to become a large-scale and reliable solution for the coming decade.

Myth: Replacing gas with hydrogen eliminates mid-stream emissions

Hydrogen is expected to play a crucial role in reducing greenhouse gas emissions. However, when released into the atmosphere, it alters atmospheric composition and exacerbates indirect warming. Hydrogen is not a strong absorber of infrared radiation so does not act as a direct greenhouse gas. Nonetheless, it reacts with, and depletes naturally occurring hydroxyl radicals in the earth's atmosphere which are a key mechanism for methane removal. Methane is a potent greenhouse gas and leakage of hydrogen will increase its atmospheric lifetime and its impact on the climate.

A research article published in Atmospheric Chemistry and Physics (Ocko & Hamburg, 2022) estimates that hydrogen's indirect warming potency per unit mass is around 200 times higher than that of CO2. Since according to the Intergovernmental Panel on Climate Change (IPCC) the global warming potential (GWP) of methane is 86 times that of CO2 on a 20-year scale, this estimate means that hydrogen is nearly 2.5 times more potent than methane in the short term.[8] As mentioned in the section on repurposing gas infrastructure, hydrogen is a particularly difficult molecule to contain and is particularly prone to leakage. Therefore, fugitive hydrogen emissions and their potentially detrimental effect on the climate should also be considered when assessing the usage of this energy carrier.

Recommendations for hydrogen transport

Romania should carefully assess the hydrogen transport options based on an optimal use of this energy carrier in a limited set of high-value applications. Existing natural gas pipelines cannot be easily repurposed for hydrogen considering the impact of hydrogen on pipeline materials, through fatigue crack growth rate, effects on seam welds and hard spots, on equipment performance, on operational indicators, not to mention the additional energy required to transport it and on consumers' bill.

The blending of hydrogen in existing natural gas pipelines should assess the following challenges:

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[8] While the IPCC standard is to look at GWP over a 100-year timespan, some scientists argue for a focus on 20-year GWP, since some greenhouse gases, such as methane, have a strong near-term impact, which directly affects our climate goals.

- ◊ Lack of standardisation among EU MS blend limits. Having a variability in the volume of hydrogen blended into the natural gas grid will have an impact on the functionality of the equipment designed to accommodate only a certain range of blend.
- ◊ Potential cost increases of transmission and distribution, on top of the costs of hydrogen production.
- ◊ Limited assessment/certifications among industrial applications that use natural gas for hydrogen blending.

Considering the three main options to transport hydrogen, respectively pipelines, thanks or cables, Romania should propose a clear path for hydrogen transport, currently missing from the draft National Hydrogen Strategy. The approach should take into account that for distances lower than 1,500 km, the transport of hydrogen as a gas by pipeline is generally the most competitive option, however challenges of using existent natural gas pipelines were presented above, while investments in new pipelines are costly. Over long distances, the transportation of electricity seems a preferable solution to pipelines or shipping, given Romania's high renewable energy potential for generating hydrogen locally through water electrolysis and transport the electricity through ultra and high voltage DC cables.

Policy recommendations

1. **Grounding the national strategic vision and specific legislation in objective, science-based analysis about the associated opportunities and risks.** The opportunities of the hydrogen economy are broad, yet public support should be carefully targeted at high-value applications, rather than wasted on costly and inefficient solutions unlikely to bring significant climate benefits. The myths presented in this paper describe only a handful of examples of areas that need more in-depth assessment for dispelling pervasive faulty narratives.

2. **Aligning strategic national documents and legislation in terms of decarbonisation targets and hydrogen perspectives.** The draft Romanian Hydrogen Strategy and relevant legislation should be aligned with the draft updated NECP, Romanian LTS, and draft Romanian industrial strategy, especially in terms of estimated demand, shares among sectors, need for new RES capacities, infrastructure development and import/export approach. This should be done based on realistic expectations regarding production and transport potential, with targeted support only for high-value applications.

3. **Developing and mapping targeted funding opportunities for renewable hydrogen at national level.** The draft Romanian Hydrogen Strategy fails to include a mapping of current or potential funding opportunities. To move away from CAPEX to OPEX-support instruments, Romania should take full advantage of the EU Hydrogen Bank platform for allocating nationally available funds to a larger pool of beneficiaries. Romania should also develop financial support instruments such as grants for R&D activities, grants for hydrogen-related equipment & services, grants for training of specialists, and tax

exemptions for producers. The government should also strive to create aggregation tools to facilitate information exchange on hydrogen demand and supply.

4. **Training the necessary human resources.** Romania currently lacks sufficient trained workforce to implement its hydrogen ambitions. Dedicated educational curricula are needed at undergraduate and postgraduate level in domestic universities. Scholarships should be created for specialisation in academic tracks in international universities (e.g. France, UK, Germany). Funding programmes can also be deployed to facilitate exchange programmes between Romanian and international companies. Reskilling efforts should be targeted at professionals in economic sectors that will be gradually phased-out (e.g. coal miners, oil/gas extraction technicians), for technical reconversion in operating, among others, electrolysis stations, pipelines, hydrogen compressors, valves and other types of equipment, hydrogen dispensing stations, hydrogen transportation by trucks, ships, and rail.

5. **Adopting a strategic approach on imports and exports of hydrogen.** The draft Romanian Hydrogen Strategy lacks clarity on the expected regional role of Romania and potential commercial flows of hydrogen. Based on the strategy's production cost estimates, Romania risks not being competitive on regional and international markets. If the LCOH projections in the national strategic document materialise, it might be uneconomical for some economic sectors to rely on domestically produced hydrogen. Romania should therefore explore opportunities to import hydrogen, especially when it is already "incorporated" into products that are easier to transport, such as ammonia, methanol, or hot briquetted iron (HBI). Such assessments on competitiveness should always be coupled with considerations of national strategic autonomy (i.e. maintaining certain levels of domestic production of products such as ammonia and primary steel).

6. **Understanding the important role of hydrogen storage.** The capacity of storing large quantities of hydrogen (thousands of metric tonnes) over long periods of time (months and even seasons) can contribute to national energy security. Stored hydrogen can ensure that power demand is satisfied irrespective of RES availability and geopolitical context. Geological formations such salt caverns or depleted oil and gas fields should be analysed for their potential to store hydrogen.

7. **Attracting investors in the manufacturing of hydrogen-related equipment.** This can generate positive economic and social outcomes at national level through new (high skilled) jobs, human capital development, increased R&D activities, capital flow, fiscal revenues to the state budget, and new trade opportunities. Current hydrogen projects are mainly implemented with technology purchased from original equipment manufacturers (OEMs) with experience in the field in producing water electrolysis systems along with additional subsystems, compressor liquefaction units, storage tanks, vehicles for the transport of hydrogen, hydrogen fuel cells, etc. Romania should seek to attract parts of this value chain domestically.

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