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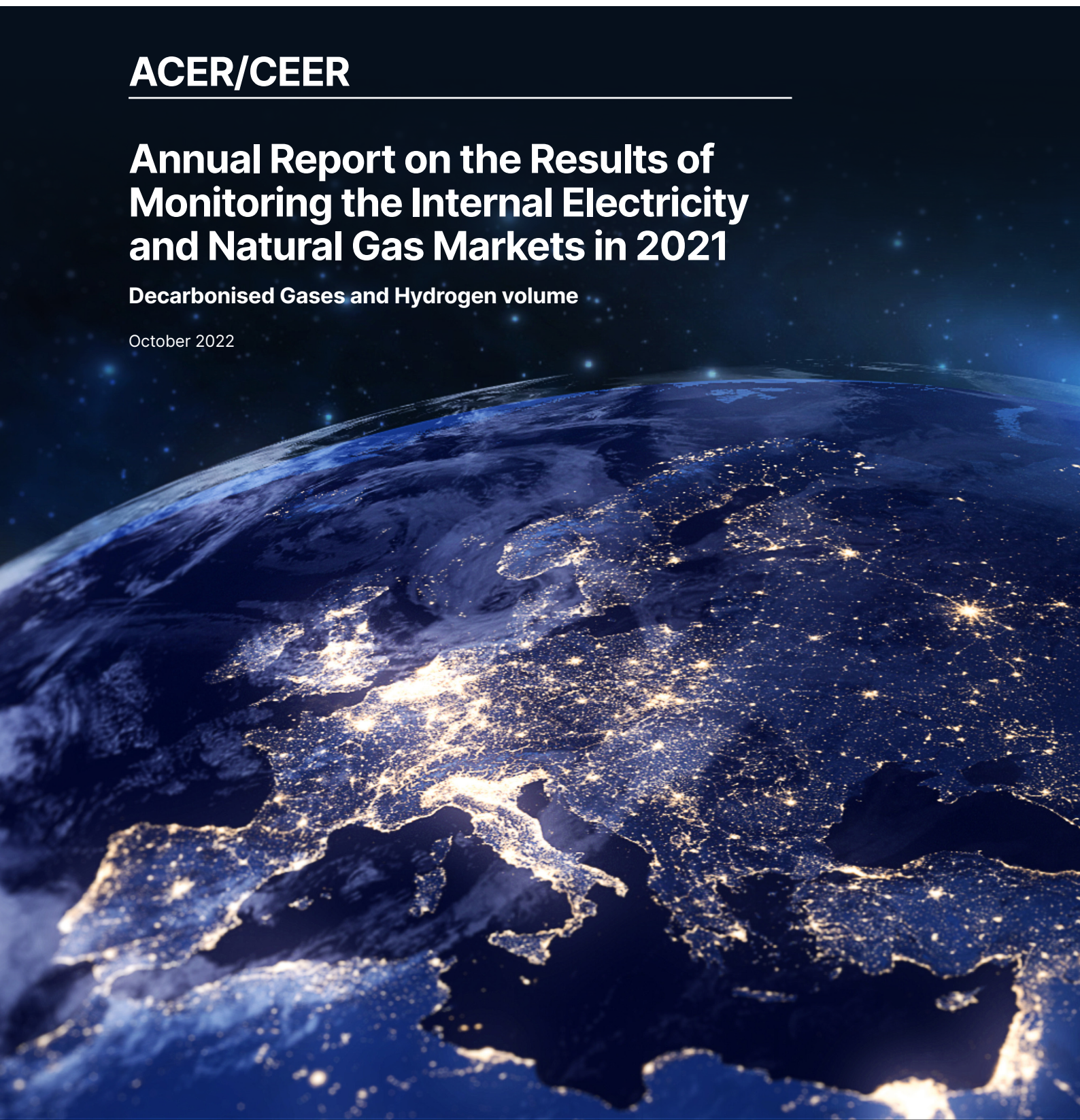


ACER/CEER

Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021

Decarbonised Gases and Hydrogen volume

October 2022



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Executive Summary

- 1 The Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) are publishing the eleventh edition of the annual Market Monitoring Report (MMR), produced in cooperation with the Energy Community (EnC) Secretariat. The MMR consists of several Volumes that cover different EU energy market segments.
- 2 The first Volume, published in July 2022, provided an overview of the status of the European gas wholesale markets in 2021 and the first half of 2022. This Volume describes the current state of EU decarbonised gases and hydrogen as well as examining the regulatory provisions and market context that may drive their evolution in the mid-term. ACER and CEER have published a third Retail and Consumer Protection MMR Volume in autumn 2022, which reviews the impacts on consumers of record-high energy prices.

The current energy crisis calls for accelerating the decarbonisation of the internal gas market¹

- 3 Wholesale natural gas prices have reached the highest levels ever observed in Europe since the end of 2021 and throughout 2022². Gas prices are likely to remain high in the next couple of years and until substantial new supplies become available (by way of illustration, in early October 2022 gas prices for delivery in the first quarter of 2024 exceeded 130 euros/MWh). In parallel, the usual gas supply security margins have been limited in a context in which Russian pipeline flows have fallen by more than a third this year to date. All this results from the Russian invasion of Ukraine³.
- 4 The Russian attack signifies a turning point for EU energy supply security. The European Commission and Member States (MSs) have set a political aim to diversify energy supply to European consumers and minimise the dependence on Russia as fast as possible. Decarbonised gases and hydrogen should play an important role on those supply diversification efforts.
- 5 Recent legal initiatives such as the Hydrogen and Decarbonised Gas Market Legislative Package⁴, issued by the European Commission in December 2021, together with Member States' National Energy and Climate Plans aim at mobilising legal and financial resources to speed up the penetration of decarbonised gases and hydrogen. The main regulatory provisions of the new Package as well as the decarbonised gases' production targets are analysed throughout Volume.
- 6 To enhance the speed of energy diversification, the European Commission issued the REPowerEU Plan in May 2022⁵. The Plan establishes a roadmap of measures to reduce the energy supply dependency on imported Russian gas. The measures include reducing energy demand⁶, promoting more diversified gas supplies and increasing renewable energy production. In particular, the Plan sets the target of producing 10 million tonnes of renewable hydrogen in the EU by 2030 and aims for an additional 10 million tonnes of renewable hydrogen imports⁷ (in total, those volumes would be equivalent to 65 bcm of natural gas). Moreover, it also aims at producing 17 extra bcm of biomethane by 2030, to reach a total biogas/biomethane production of 35 bcm within the EU by then.

1 A number of technological options allow to decarbonise fossil gas. The amended Renewable Energy Directive II and delegated acts will set a clearer taxonomy to classify the distinct types of decarbonised gases. In that exercise, assessing the lifecycle emissions and the carbon dioxide abatement potential of the different options will be key. Across this MMR 2021 volume, most analyses are separately presented for biogas and biomethane gases on the one hand and for (the distinct types of) hydrogen on the other hand. These gases can be labelled differently, like as renewable or low-carbon gases depending on the processes and carbon emissions abated. The [Gas Market Monitoring 2019](#) included an initial classification of decarbonised gases and hydrogen as presented by the EC in the 32 Madrid Forum (see its Figure 4).

2 See ACER-CEER's [Gas Wholesale market Volume of the MMR 2021](#), which analyses gas price levels and drivers until July 2022 and ACER MMR dashboard, which brings up to date recent price developments.

3 After the Russian attack on Ukraine in February 2022, EU sanctions and Russian countermeasures have been reducing the supply of contracted gas volumes to the EU creating concerns regarding supply adequacy. While rising EU LNG imports have partly offset the decreasing Russian pipeline flows, EU gas prices remain high in view of the tight global competition for LNG resources and the constrained alternative supplies. Additional factors have also contributed. Among others the low hydro and nuclear availability issues have requested extra gas-fired power generation what has pressed natural gas prices up.

4 The Hydrogen and Decarbonised Gas Market [Package](#) reviews the Gas Directive 2009/73/EC and the Gas Regulation (EC) No 715/2009. It puts forward policy measures to support the creation of an efficient decarbonised gases market. The Package is yet to be sanctioned by the European Parliament and the Council.

5 See [REPowerEU plan](#), which proposes measures and scenarios to reduce the dependence on Russian fossil fuels and fast forward the energy sector decarbonisation.

6 The plan aims a target of 30% reduction in the final EU gas demand by 2030. In July 2022, the [EC and MSs committed](#) to reduce demand by 15% in spring 2023, to safeguard supply security next winter.

7 Four million tonnes are expected to come in the form of hydrogen derivatives like ammonia and methanol.

- 7 Next to enhancing supply adequacy, decarbonised gases and hydrogen developments would contribute to achieving the EU decarbonisation targets. The EU aims at reducing the net greenhouse gas emissions by at least 55% in 2030, whereas carbon neutrality is aimed by 2050. These are the commitments adopted by the European Green Deal and settled in the EU Climate Law⁸.

Large financial resources are needed to promote renewable hydrogen production, which remains high-priced

- 8 Biogas and biomethane accounted for approximately 18 bcm in 2021. This figure represents 4.5% of EU gas consumption in 2021, even if less than 15% of this combined total production was upgraded and injected into the network (i.e. biomethane). EU hydrogen consumption was estimated in 320 TWh in 2020, which is equivalent to less than 10% of EU's natural gas demand⁹.
- 9 Yet, the prospects of renewable and low-carbon gases production are significant. Biogas and biomethane production could account for 10% of conventional gas demand by 2030 and for more than 20% by 2050. In turn, renewable electricity and renewable hydrogen are at the core of building an EU climate-neutral energy-integrated system. The EC and MSs Energy Plans aim for hundreds of GW of installed electrolyzers by 2050. According to some scenarios¹⁰, renewable hydrogen could meet a comparable supply share to carbon abated natural gas by then.
- 10 Massive and accelerated financial efforts are needed to develop the new production and transport infrastructures that would make those volumes available. Such investment will not be limited to production facilities, but will also go into network adaptation and importantly into additional electricity generation from renewable sources¹¹. According to REPower EU estimates, public and private investment needs by 2030 are in the range of 50 to 75 bn euros for newly installed electrolyzers, on top from 28 to 38 bn euros for adapting EU-internal pipelines and 6 to 11 bn euros for adapted storages.
- 11 To achieve the production targets, improving the price competitiveness of the decarbonised gases and hydrogen technologies is crucial. On the one hand, the high natural gas prices observed since the end of 2021 have reduced the price gap between conventional-unabated gas and decarbonised gases. In fact, domestic biogas production has become cheaper than spot procured gas in recent months: while TTF month-ahead prices have traded on average at more than 100 euros/MWh in 2022 YTD, most competitive biogas plants report production costs in the range of 40 to 50 euros/MWh. On the other hand, as Figure 1 shows, renewable hydrogen production has been affected by the skyrocketing electricity prices and remains high-priced (if taking the average spot electricity prices of 2022, renewable hydrogen production would range above 250 euros/MWh). Hydrogen production costs are project specific though, particularly influenced by power input costs and supply contracts.

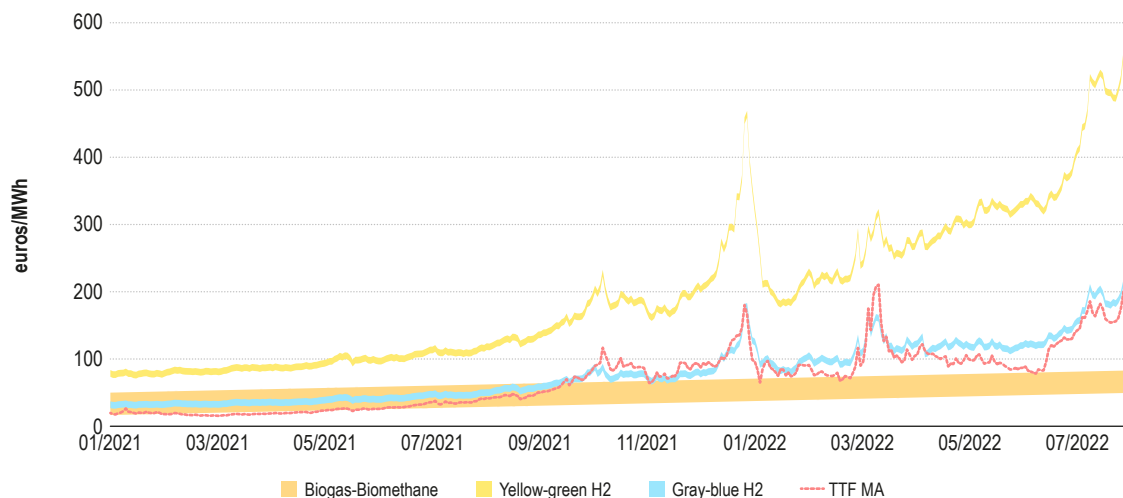
8 The [EU Green Deal](#) agreement set a commitment to reduce net carbon emissions by at least 55% by 2030 in comparison to 1990-levels and to make the EU a climate neutral continent in 2050. The related [EU Climate Law](#) develops legislation in various climate, energy, land use of taxation areas and sets binding commitments to achieve EU climate neutrality.

9 So far both gases have overall served different specific purposes and hence their replacement is not one to one. Hydrogen consumption is concentrated in specific uses such as refineries or fertilisers production so far.

10 E.g. ENTSOG Ten Year Network Development Plan Scenario. See Section 1.2.1.

11 As an illustration, the operation of the electrolyzers targeted for 2030 with renewable power supply would require an estimated extra 7% of EU electricity output by that year. [The EC Hydrogen strategy](#) infers that in 2050 up to a quarter of all the EU renewable power generation could be devoted to produce green hydrogen.

Figure 1: Overview of decarbonised gases and hydrogen production costs ranges and TTF MA price evolution – 2021 – 2022 – euros/MWh



Source: ACER based on ICIS Heren¹² and European Biogas Association.

Note: The various colours of hydrogen refer to different production technologies and pathways: yellow hydrogen is produced via the electrolysis of water using power supplied by the grid. Green hydrogen is produced with electrolyzers sourced with renewable electricity. Grey hydrogen is produced via steam reforming or auto thermal reforming of natural gas. When carbon emissions are subsequently captured and/or stored it refers to blue hydrogen.

- 12 Technological developments, economy of scale and a favourable evolution of renewable electricity generation costs could considerably enhance the future price competitiveness of renewable hydrogen (the International Energy Agency has recently offered some estimates on the subject, which are discussed in Section 2.1. IEA's estimates point to halved production costs of renewable hydrogen in 2030 in comparison to 'normal' 2021 cost levels). In addition, it seems reasonable that green hydrogen project promoters will hedge their electricity supply prices and/or will sign power purchase agreements, to guarantee a certain stability in production costs.
- 13 Financial support has been crucial to incentivise the production of decarbonised gases so far. Support measures take different forms across MSs and have been chiefly used to promote the production of biogas and biomethane. The support framework is clearly expanding to also incentivise the production of hydrogen. However, the rising needs for public subsidies in order to expand hydrogen production concur in recent months and will continue to do so with a troubled economic climate. Governments are facing budgetary tensions to back vulnerable household energy consumers, energy intensive industries and even selected utilities. Hence, mobilising public funds for renewable hydrogen production and network development is likely to become more difficult in this pressing environment.

Decisions need to be taken about efficient network development and system operation aspects

- 14 The current gas network, as well as most end-use appliances, can accommodate biomethane without significant upgrades. However, the readiness of the current gas network to integrate hydrogen admixtures is under discussion, as blending hydrogen could significantly affect the operation of the gas system and certain consumers.
- 15 This setting has raised a discussion about what the most appropriate strategy is to foster the hydrogen market: either developing dedicated infrastructure for pure hydrogen or admixing hydrogen with natural gas into the current gas network, up to a certain threshold.
- 16 The market is leaning to overall back the use of pure hydrogen infrastructure. In fact, to kick off hydrogen penetration, MSs are intending to develop the so called hydrogen valleys. Those valleys concentrate hydrogen production and demand in selected locations, to chiefly serve hydrogen consumption at industrial clusters. Today more than 70 infrastructure projects associated to those valleys are under development across Europe. Still, hydrogen blending is and will be enabled up to certain thresholds, as far as the gas system can operate without technical issues.

¹² The referential production costs of hydrogen are estimated by ICIS based on a methodology that takes into account among others electricity input costs, the size of production plants and financial amortization. Costs represent the average of various MSs.

- 17 Policy action will have a decisive influence over efficient system operation and for efficient infrastructure development. It is urgent to set the gas quality and interoperability aspects for the different gases, in order to secure a well-integrated market operation. In parallel, regulators and sector stakeholders need to decide on the most appropriate and efficient investments and their revenue recovery models.
- 18 With regards to hydrogen network development, in general, making use of repurposed gas infrastructure to transport hydrogen should be prioritised where relevant in terms of capacity and route. This solution may be cheaper than developing newly built hydrogen infrastructure and could enable a more cost effective transition. The Volume offers initial considerations about network evolution plans and lists some examples of projects under development. It also discusses considerations about the revenue recovery models to pay for hydrogen infrastructure and the proposed options to reallocate costs following the repurposing of gas assets for hydrogen.

Recommendations to support gas sector decarbonisation

- 19 This section offers recommendations to support the decarbonisation of the gas sector as part of the wider goal of energy sector decarbonisation. The proposals are presented in three blocks, relating to regulatory, financial and technical considerations. The first block contains more detailed proposals about regulatory aspects more closely related to ACER and CEER expertise, while the recommendations for the other two blocks have a more general character.

Regulatory considerations

- 20 The policy and regulatory aspects that govern the decarbonisation of the gas sector can be generally grouped into six areas, as shown in Figure 2:

Figure 2: Main regulatory areas governing gas sector decarbonisation

Technical rules	Market rules	Access conditions	Participation	New investments	Support
					
Setting the technical rules that will define gas quality, blending and interoperability aspects	Setting up market rules that promote and facilitate the access to liquid markets	Determining the network access conditions for new gases; connection tariffs will be key elements for that	Determining the activities and the conditions at which the market participants will be allowed to invest	Defining a framework to identify new network investments and to value the existing regulated asset base in case of transfer of assets	Identifying and mobilizing ad-hoc support to the new technologies, at least in early phases

Source: ACER.

- 21 The European Commission's Hydrogen and Decarbonised Gas Markets Legislative Package aims to address key regulatory provisions across all these areas. The proposed measures aim at facilitating the access of these gases to the market and to the networks to foster the production and consumption of decarbonised gases and hydrogen. They will clearly influence the sector's business models. Section 3 offers a more detailed summary of the proposed provisions.
- 22 ACER and CEER published a joint position paper in December 2021, which discussed key regulatory requirements to achieve the decarbonisation of the EU gas sector¹³. ACER and CEER published another position paper¹⁴ in June 2022, which reacted to the actual proposals in the Package.
- 23 The regulators' assessment recognises that the decarbonisation of the gas system introduces new regulatory challenges. This is because the legislation will be applied to a transforming sector that has components of both nascent and mature industrial technologies. In addition, the transformation has to deal with changes stemming from a more uncertain energy demand and price evolution. Examples of such uncertainties are the record high energy prices and the demand reduction targets caused by the recent supply crisis, and also the evolving cost-competitiveness of low-carbon technologies. Hence, regulators call for a certain level of flexibility and subsidiarity of the new regulations governing the gas sector decarbonisation.
- 24 ACER-CEER's general position is that the regulation governing the gas sector decarbonisation should make the most of those elements of the current regulatory model that have proved successful in promoting integrated gas markets. The current regulation has also importantly supported broad market-based investments that prevent national fragmentation, an aspect that needs to be maintained. However, it is also acknowledged that there are lessons to learn from the current crisis, which may lead to reconsidering specific elements of the gas regulations implemented so far. These elements include further enhancing the diversification of supply sources, additional enabling reverse flows and promoting a more efficient use of energy. This MMR summarises the specific recommendations that regulators have made:

13 See [ACER-CEER position paper](#) on Key Regulatory Requirements to Achieve Decarbonisation Objectives.

14 See [ACER-CEER Reaction](#) to the European Commission's Hydrogen and Decarbonised Gas Market Package

- a) The main principles that govern the internal gas market and that work well must be maintained for decarbonised gases and hydrogen: this entails non-discriminatory third-party access, (preferably) absence of cross-subsidies between users and networks, guaranteeing the unbundling of market-based and regulated activities, and reinforced monitoring and oversight. However, ACER and CEER acknowledge that to promote early market development, some flexibility might be needed in these provisions in the early phase.
 - b) In line with the EC proposals, regulators support that Member States might implement a system of negotiated third party access for hydrogen networks. This shall be done in accordance with objective, transparent and non-discriminatory criteria, to be maintained for a certain period of time and with a view to allow the sector to mature.
 - c) Regulators recognize that recovering the cost of new dedicated hydrogen infrastructure from hydrogen users only might be problematic in early phases. That approach could lead to very high tariffs and hinder the development of the sector. To address that, the EC has proposed that Member States may allow financial transfers to take place between separate regulated services (gas, hydrogen, and/or electricity) of the same TSO or network operator, under specific conditions, where NRAs and ACER have a primary role. Despite that the financial transfer would constitute a form of cross-subsidisation, regulators acknowledge that this can be a practical approach to speed up the uptake of the hydrogen sector, if done with clear time limitations.
 - d) Regulators support the separation of hydrogen and methane Regulated Asset Bases. Asset transfers should be allowed and valued, as a reference, based on their specific value in the RAB at the time of transfer. In addition, as a rule, gas and hydrogen network tariffs shall be assessed separately via a published methodology and should be independently charged. In particular, NRAs must audit the values of the assets transferred between gas and hydrogen regulated asset bases, to avoid that selected players take advantage of information asymmetry. It remains relevant to determine the fair transfer value of network assets including among others the residual value of the asset, the costs to assess the technical feasibility of a repurposing or the expected value of the asset for the hydrogen network operator.
 - e) While reiterating that financial transfers between separate regulated services should only occur with clear time limitations, ACER and NRAs call for granting national regulatory authorities a primary role in the governance of the Inter-TSO compensation mechanism (for gas network) and the financial compensation mechanism (for hydrogen networks) needed to address the system design choice of setting zero tariffs at cross-border Interconnection Points.
 - f) Unbundling of activities shall be the main principle of the future regulatory model for mature hydrogen systems. Unbundling, as a rule, entails that there is a clear separation between regulated network activities and market-based production and supply activities. This means that hydrogen production via electrolysis facilities shall be a competitive activity. However, again, regulators acknowledge that there could be some flexibility to the general rule, in particular during the early phase of the hydrogen sector's development. On the proposed phase out of the Independent Transmission Operator (ITO) model for hydrogen networks, regulators suggest a more flexible approach by allowing temporary and conditioned exemptions.
- 25 ACER and CEER agree that a well-functioning system of Guarantees of Origin needs to be in place, as they will be instrumental to promote trade. Also that the trading of decarbonised gases and hydrogen at organised markets needs to be promoted, looking for synergies with the current conventional gas trading platforms. Decarbonised gases and hydrogen injected at distribution level should be able to be equally traded at the national virtual trading points.
- 26 Finally, ACER and CEER agree that repurposing gas infrastructure is overall more cost-efficient than building new hydrogen assets. Hence, that option would generally take priority, although the assessment needs to be done on a case-by-case basis following a cost benefit analysis. Moreover, a more integrated approach to energy infrastructure development, needs to be adopted, consistent with the revised TEN-E Regulation. In addition, the principles for infrastructure development and revenue-setting methodologies should be consistent and further developed, while regulatory oversight is crucial to ensure a prudent and no-regret approach avoiding the risk of over-investment.

Financial considerations

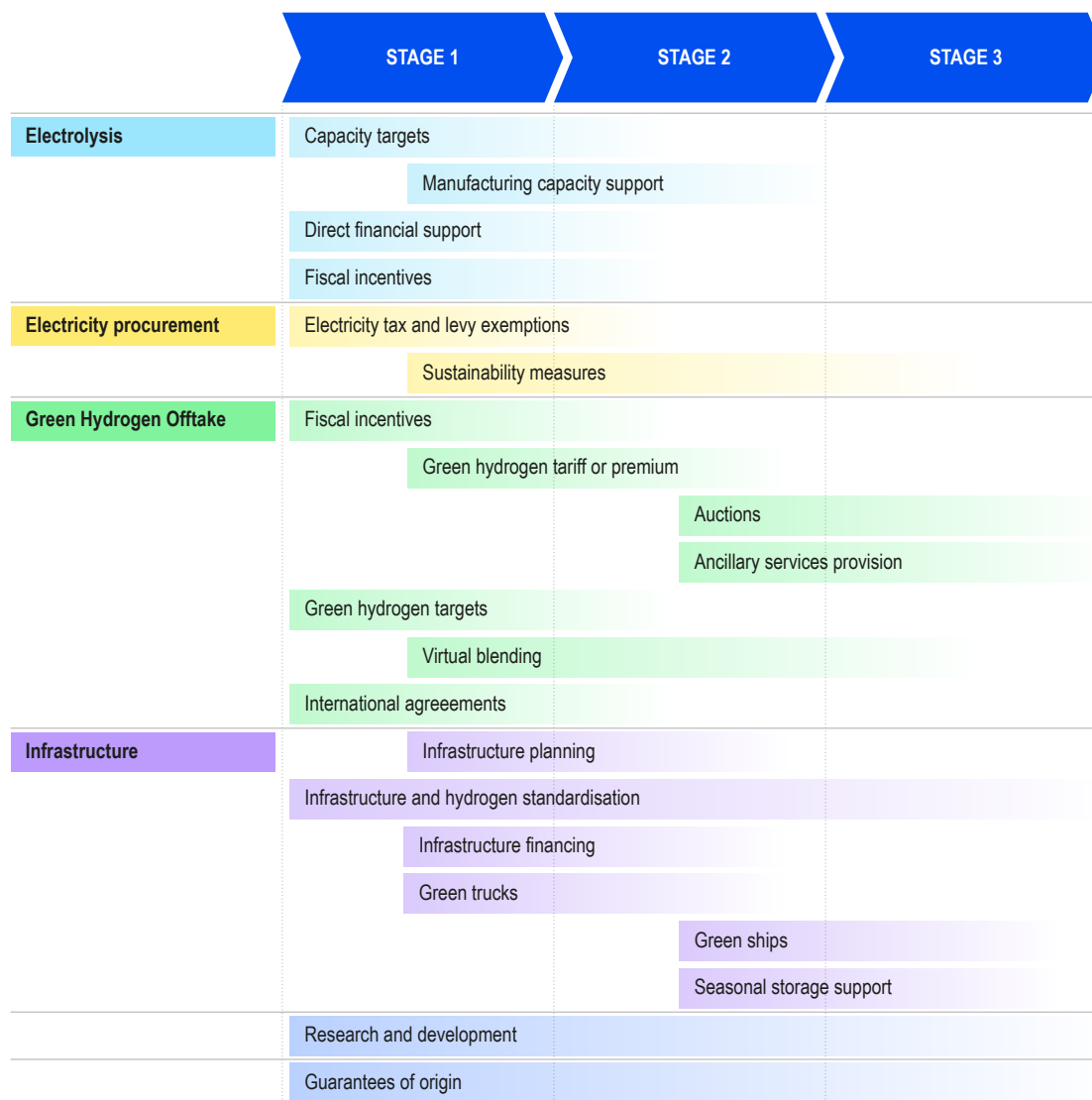
- 27 The accelerated decarbonisation of the EU gas sector is likely to require significant public financial support as well as substantial private investment. Most public contributions are earmarked today to promote renewable and low carbon hydrogen production. These contributions will be channelled to expand renewable power generation and electrolysis capacity investments, but also for network development and adaptation. Complementing that, certain end-use industrial sectors will need to invest and may need public funds to adapt their technologies.
- 28 In view of these significant financial needs, views diverge with respect to the transition. Such positions are influenced by technical and cost assumptions as well as by the economic interests of stakeholders. A number of interested parties in the gas industry and several energy-intensive consumers perceive the gas decarbonisation transition, and in particular the hydrogen economy, as a strategic business opportunity to maintain their relevance and diversify their revenue streams. As such, they are keen to back the transition.
- 29 For many policy makers, the hydrogen transition supports a sustainable sector that will help to assist the European economic recovery by investing in high-value technologies. Furthermore, it will promote the EU's domestic energy production, hence reducing import reliance. In addition, they underline that the use of hydrogen offers solutions in energy storage and in decarbonising hard-to-abate industrial and transport sectors, which cannot be fully supplied with electricity.
- 30 Other stakeholders see a more limited hydrogen penetration, in view of a broader energy system electrification. They believe that this approach is more cost-effective and technically more sound, while equally respecting the environment and emission reduction goals. In fact, there may well be various pathways which are different but equally in line with the climate goals.
- 31 As such, the political commitment and the amount of financial support available will constitute important factors for the development of the European hydrogen system. While large private investments, generally backed by public support, have been announced, it remains to be seen how much will actually be implemented.
- 32 In ACER and CEER's view this scenario calls for a practical progression, in which acceptable risks are shared between public and private actors. This means that production developments must take place preferably closely aligned to consumption commitments, granting that both can be stimulated with reasonable policy objectives and financial assistance and notwithstanding selected investments which can occur in anticipation of demand that will be there at a later phase.
- 33 ACER and CEER suggest MSs to initially target end-use support schemes to those demand segments that are harder to electrify, in order to make them more efficient. It also might make more economic sense to support electrolysis' manufacturing capacity development and research activities than final production. An idea to consider would be to link the extent of public financial support to the price of unabated natural gas. This could assist the competitiveness of decarbonised gases and hydrogen, whilst enabling to adjust public contributions when decarbonised gases might be sufficiently competitive on their own (e.g., exploring contracts for difference or variable feed-in tariffs). Support schemes might need to take into consideration users and systems' specific circumstances. For example, an approach to consider to foster biomethane production is allocating public financial support to connect the production plants to the network across an extended time period. This is in order to prevent that upfront payments to cover the costs of network expansion might constitute a barrier to production developments
- 34 Another point of critical attention relates to network expansion. ACER and CEER back the ongoing initiatives to reinforce the integrated planning of EU energy network development, including the coordinated development of electricity and gas network plans under common scenarios¹⁵. This is in order to make decisions based on sound technical and cost aspects, which shall aid to identify the most efficient infrastructure investments to serve the future energy system.

¹⁵ ACER will adopt, by 24 January 2023, Framework Guidelines for the TYNDPs joint scenarios that are to be developed by ENTSO-E and ENTSOG, aiming to ensure robust, non-discriminatory and transparent scenarios that are in line with the Union's latest energy and climate policy objectives.

Technical considerations and related policies

- 35 A range of technical considerations need to be resolved to develop an industrial setting that favours a rapid and coordinated expansion of the EU hydrogen market. Those technical considerations relate among other factors to gas quality and interoperability aspects, blending limits, end-use equipment features and infrastructure standardisation. Additional aspects relate, for example, to defining the procedures to assign project promoters (e.g. to assign the companies that will develop electrolyzers' capacity the use of tender procedures is favoured). Other technical aspects refers to setting rules for trading hydrogen in organised market places (e.g. products standardisation, financial requirements).
- 36 In parallel, a number of policies need to be issued to define and help implement those technical considerations. The new legal provisions should provide clarity to kick-start and expand the sector. For example, the International Renewable Energy Agency (IRENA) itemises the range of policies that are needed to promote renewable hydrogen. IRENA distinguishes their deployment across three different temporal stages, each relating to the degree and maturity of market evolution.

Figure 3: Range of policies to promote electrolysis across three stages of deployment



Source: IRENA¹⁶.

16 See green hydrogen [supply guide](#) to policy making report. Technology readiness at Stage 1, green hydrogen is not yet economically competitive with grey hydrogen. At stage 2 electrolyzers are at the gigawatt scale and renewable hydrogen is close in price to grey hydrogen; at stage, green hydrogen is fully competitive.

- 37 These technical considerations and related policies can be quite specific and tend to fall beyond the scope of this Report. They are gradually being addressed by the relevant policy makers and sector stakeholders in related discussion platforms. For example, a subset relates to the classification of hydrogen types and in particular, to the production methods that shall guarantee hydrogen' low carbon origin, and aspect being addressed Renewable Energy Directive RED II¹⁷.

Final considerations

- 38 Regulators see the need to clarify the regulatory, financial and technical aspects in time to ensure gas sector decarbonisation and clean hydrogen sector development. The Commission's proposal provides a firm basis for doing so. Regulators stand ready to provide technical advice to support a fact-based discussion.

17 RED establishes common principles and rules to remove barriers, stimulate investments and drive cost reductions in renewable energy technologies.

1. Decarbonised gases and hydrogen production and prospects

39 The EU gas sector – which accounts for around one quarter of total EU carbon emissions¹⁸ – must be fully decarbonised in the course of the next three decades. Although a specific roadmap setting binding decarbonisation objectives for the gas sector only hasn't been enshrined in the EU Climate Law¹⁹, the EC and the Member States are setting up ambitious plans to meet that aim. Those plans underwrite the ambition of reducing EU carbon emission levels by 55% in 2030 and to achieve a 45% of Renewable Energy penetration by then²⁰.

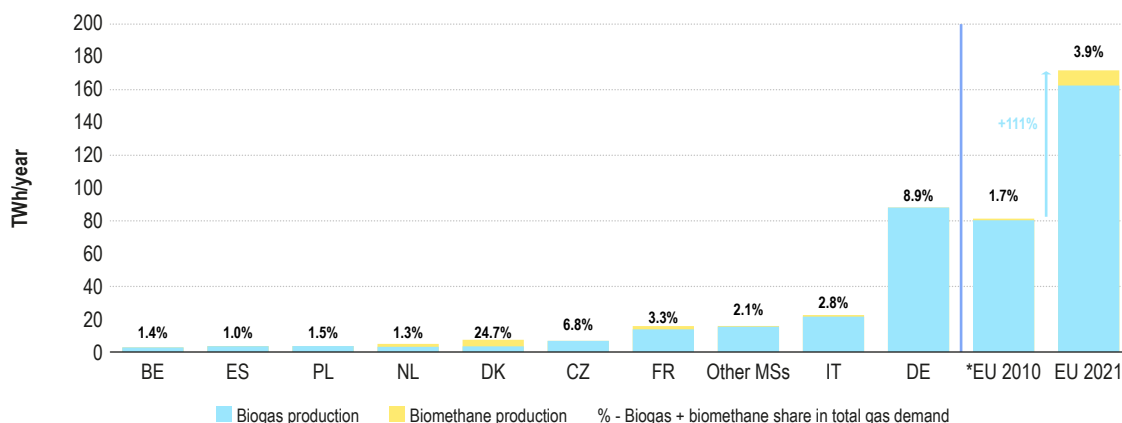
40 Gas sector decarbonisation also entails the overarching aim of reducing gas consumption by 30% in 2030, as set in the REPowerEU Plan. This target is in line with the commitments adopted by the EC and MSs to reduce natural gas demand by 15% in spring 2023, to safeguard supply security across next winter(s)²¹.

41 This chapter starts by offering information about the presence of decarbonised gases and hydrogen in the EU energy systems. That data is subsequently contrasted against the production prospects and the drivers for expansion in the coming years.

1.1 Current presence

42 EU production of biogas and biomethane has doubled in the last 10 years, making the EU the world's leading market. Figure 4 shows both gases' combined production volumes in 2021, as a share of the total natural gas demand per MS. At EU level, biogas and biomethane accounted for approximately 15% of total EU gas domestic production and for circa 4.5% of gas consumption.

Figure 4: Biogas and biomethane in selected producer MSs in 2021 and for the whole EU plus UK - 2010–2021 – TWh/year and % of total gas demand relative to production



Source: ACER calculation based on Eurostat and EBA.

18 This includes Agency estimates about the use of gas in power generation, industry and households in base of combustion reactions, and estimates of methane leakages across the gas supply chain. Sound differences appear among MSs though. See an extended analysis on the subject on MMR 2020 Section 3.1.

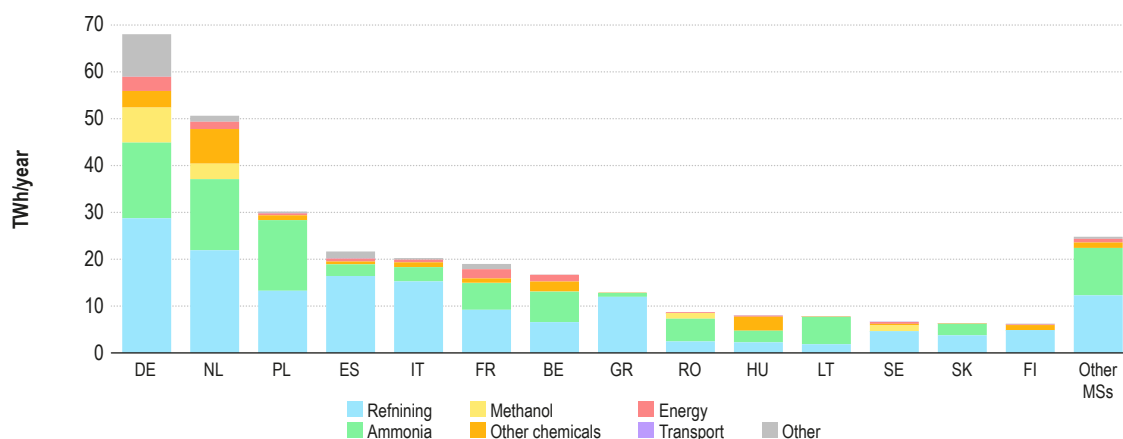
19 The EU Climate Law writes into law the goal set out in the European Green Deal for Europe's economy and society to become climate-neutral by 2050. The Law develops relevant legislation in various climate, energy, land use of taxation areas, as well as it sets binding commitments, such as reducing net carbon emissions by at least 55% by 2030 in comparison to 1990-levels.

20 The Renewable Energy Directive (RED) establishes provisions to promote investments in renewable energy technologies. The initial Directive set a common target of 32% for the amount of renewable energy in the EU by 2030, including different sub-target per specific energy sector. In July 2021, the EC proposed a first revision of RED, to align it with increasing decarbonisation targets. A further revision, to make it in line with the REPowerEU plan presented in May 2022, suggests further evolution of the target up to 45%. The Parliament approved the 45% target in July 2022, while the EU Council has yet to adopt a common stance on the matter (currently the Council backs a 40% target).

21 Member States shall use their best efforts to reduce their national gas consumption between 1 August 2022 and 31 March 2023 at least by 15% compared to their average consumption between 1 August and 31 March during the five years preceding years. The target will be possibly maintained for next winter. See also footnote 5.

- 43 Most biogas continues to be consumed close to the production site, either for electricity generation or heating, or for combined heat and power (CHP) cogeneration, with smaller percentages used in industry and agriculture. Germany, Italy and France are the EU production frontrunners in absolute terms. The combined share of biogas and biomethane in final gas demand varies between MSs. It reached more than 20% in Sweden and Denmark and circa 10% in Germany in 2021. Next section offers further insight into the predominant biogas feedstock across MSs.
- 44 Upgraded biomethane volumes injected into the network account for around 13% of biogas production on average across the EU. Biomethane injection has risen by 25% since 2019. Injections chiefly occur at the distribution level. The barriers to larger injections are related to higher production costs to meet more stringent gas quality and other technical constraints. The notable exceptions are Denmark and the Netherlands, where biomethane injections exceed 50% and 30% of total biogas production, respectively. France and Italy are leading MSs in terms of setting up new biomethane facilities, whereas Germany is the second largest (global) producer after the US and EU leader with more than 10 TWh in 2020.
- 45 Hydrogen volumes are rather moderate relative to future expectations, with an estimated EU consumption of 320 TWh/year in 2020²². This is equivalent to 2% of total EU primary energy demand and 7% of total EU natural gas inland consumption. Germany, followed by the Netherlands and Poland accounts for the highest hydrogen demand. Today hydrogen is chiefly consumed in refineries and used for ammonia and fertiliser production, as Figure 5 illustrates.

Figure 5: Hydrogen consumption per sector in selected leading MSs - 2020 - TWh/year



Source: ACER based on Fuel Cells and Hydrogen Observatory

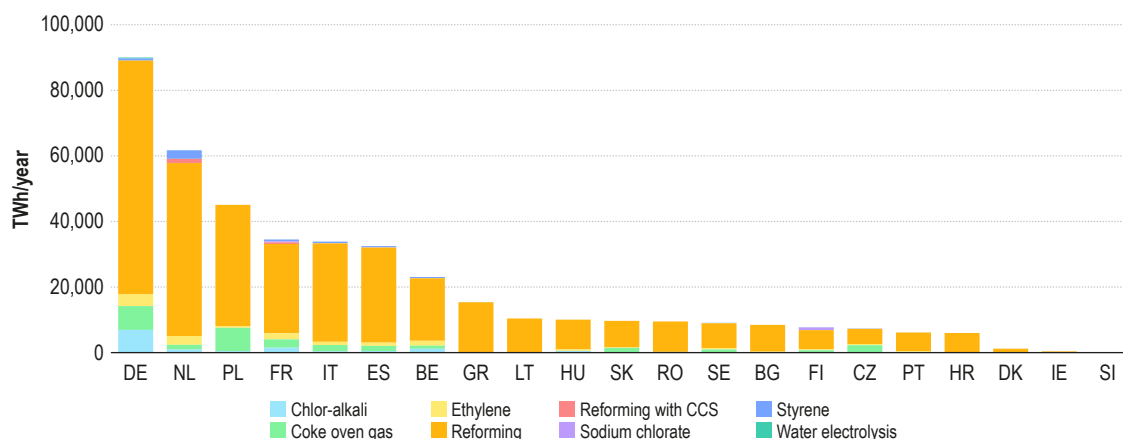
- 46 Most hydrogen production takes place close to demand sites, typically in large industrial settings²³, and mostly originates from steam methane reforming without Carbon Capture and Storage (CCS). That means that significant carbon emissions are associated with hydrogen production²⁴. According to Fuel Cells and Hydrogen Observatory (FCHO) figures, less than 2% of the hydrogen produced from steam reforming is subject to carbon emissions capture today (so called blue hydrogen) as Figure 6 illustrates.

22 According to latest [Fuel Cells and Hydrogen Observatory](#) data. FCHO is an EC and industry Joint Undertaking initiative to provide provides data and analysis about the hydrogen sector. 2020 is the latest year available.

23 In accordance to FCHO data, circa 90% of hydrogen is produced on captive plants sited in oil refineries or ammonia production facilities. In addition, there are circa 125 merchant hydrogen plants across the EU. From those, the larger ones are dedicated to supply single large-scale consumer and the small - medium ones mostly supply retail customers.

24 Hydrogen production associated carbon emissions is estimated to total up to 70 to Mt CO₂ annually in the EU. The production of one grey hydrogen tonne is assessed to release 10 tonnes of carbon dioxide.

Figure 6: Hydrogen production per technology in selected leading MSs - 2020 - TWh/year



47 FCHO data show that water electrolyzers produced less than 2% of EU's commercial hydrogen volumes in 2020, sourced chiefly from the grid. Germany and France today host most of the electrolyzers in operation, which totalled less than 1 GW in 2021 across the EU. However, electrolyzers' installed capacity has more than doubled in the course of the last four years. The largest facilities in operation today are in the range of tens of MW. However, electrolysing plants of several hundreds of MWs of nominal capacity are under construction. The market anticipates that electrolyzers' installed capacity will reach tens of GW in the coming years, as the next subsection discusses.

1.2 Mid-term prospects

48 Notwithstanding the relatively modest production to date, high volumes of decarbonised gases and hydrogen are targeted for the next decades. Production goals have been accelerated as a result of the supply diversification efforts resulting from the Russian invasion of Ukraine.

49 Production prospects can substantially differ among stakeholders, research entities and/or policy makers, depending on the assumptions made²⁵. This section offers some ranges and discusses the drivers and considerations taken by them.

50 In the field of biogas and biomethane, the REPowerEU Plan calls to produce a combined total of 35 bcm by 2030. This entails approximately doubling present day production. Sector associations assess that this objective is feasible and add that biogas and biomethane production could be quadrupled by 2050, to cover 25% of gaseous demand²⁶. The latest ENTSG's scenarios²⁷ estimate the biomethane share between 10% and 30% by mid-century, depending on the considered assumptions. All these prospects foresee import potential from neighbouring countries such as Ukraine and some modest role of synthetic gas obtained from coal and biomass thermal gasification technologies²⁸.

51 Some challenges have been identified to meet those biogas and biomethane production targets. They include enhancing the coordination of support measures for biogas and biomethane production across MSs (an overview of current subsidies per MS is provided in Section 2.1) improving infrastructure inter-connections at the distribution level and expanding the financing of new investments. For example, the EC REPowerEU Plan estimates 37 bn euros in new investments to achieve that.

25 The controversy tends to appear chiefly in terms of the evolution of costs and with regard to the scale of investments in power generation to produce renewable hydrogen and network development.

26 See [European Biogas Association](#) statistical report.

27 See latest ENTSG and ENTSG joint [10 Year Network Development Plan Scenario Report 2022](#).

28 Other associations publishing scenarios include the [Joint Research Centre](#) (JRC) and [IEA](#) with estimations within that range.

- 52 In the case of hydrogen, the REPowerEU Plan aims at 20 million tonnes of renewable hydrogen consumption in the EU by 2030. This would be equivalent to more than 60 bcm of natural gas, which is 15% of today's EU gas consumption. Sector associations agree that hydrogen, in its diverse forms, could rapidly escalate to meet that share and propose actions to make that feasible²⁹. These associations also underline that renewable hydrogen can be leveraged to provide energy storing and grid balancing services in systems built on very high shares of renewable electricity. The most favourable among the ENTSOs' scenarios³⁰ estimates that hydrogen could become an important energy carrier as methane by 2050.
- 53 A number of industrial sectors are called to absorb the big bulk of the new hydrogen production in this decade. They will chiefly do so by means of substituting their current grey hydrogen and/or conventional natural gas use. Some extra demand would come also from the transport sector³¹ - 2.3 million tonnes of hydrogen use are estimated by REPowerEU to meet more than 5% of transport energy consumption in 2030. Oil refineries and ammonia production will keep accounting for most of the new hydrogen consumption, where other industrial sectors hard to electrify, such as steel³², iron and cement would gradually gain prominence³³. Power generation and space heating, but also light road transport, could gradually expand their contribution in later phases.
- 54 The above referred renewable hydrogen prospects imply that hydrogen would scale up much faster than renewable electricity has done in the last decades. However, other mid- and long-term scenarios have been projected, making use of different assumptions and leading to quite different results³⁴. Some of these scenarios point to modest contribution of hydrogen (e.g. less than 5% of total EU gas demand by 2050) in view of the high hydrogen production costs and the overall more efficient electrification of the EU energy system.

Overview of National Energy and Climate Plans

- 55 The EC and a majority of MSs have endorsed renewable hydrogen as the most appropriate solution for the gas sector long-term decarbonisation. The support for blue hydrogen - obtained by methane reforming using heat, steam and pressure, plus carbon capture - is less marked in REPowerEU and the EC Legislative Package³⁵, although some MS's National Energy and Climate Plans (NECPS) also include it.

Blue hydrogen and Carbon Capture

- 56 The Netherlands has outlined the most ambitious plans connected to blue hydrogen. Other MSs, such as Germany, consider it will play a more limited transitional role. The reasons for more modest blue hydrogen investments are anchored to whether it is sufficiently sustainable, in view of the generated carbon emissions and because it's actual carbon footprint attracts controversy.

29 See for example [Hydrogen Europe Report](#) on how to deliver the EU hydrogen acceleration.

30 See footnote 26

31 Via its direct use in fuel cell electric vehicles (mostly for long-haul road transport) or potentially combined with nitrogen to produce ammonia, methanol and other synthetic fuels for shipping and aviation.

32 The steel industry is envisaged to shift from using coking coal to hydrogen in its processes.

33 See hydrogen consumption estimates per sector by 2030 in the [REPower EU Plan Implementing Acts](#).

34 Various other scenarios are proposed. The JRC offers a comparison of hydrogen penetration scenarios of the EC and other research institutions, as part of its energy consumption scenarios' per MS dashboard.

35 Both grant blue hydrogen a more transitional short-to-mid-run role to scale up hydrogen production and avoid current grey hydrogen's associated emissions.

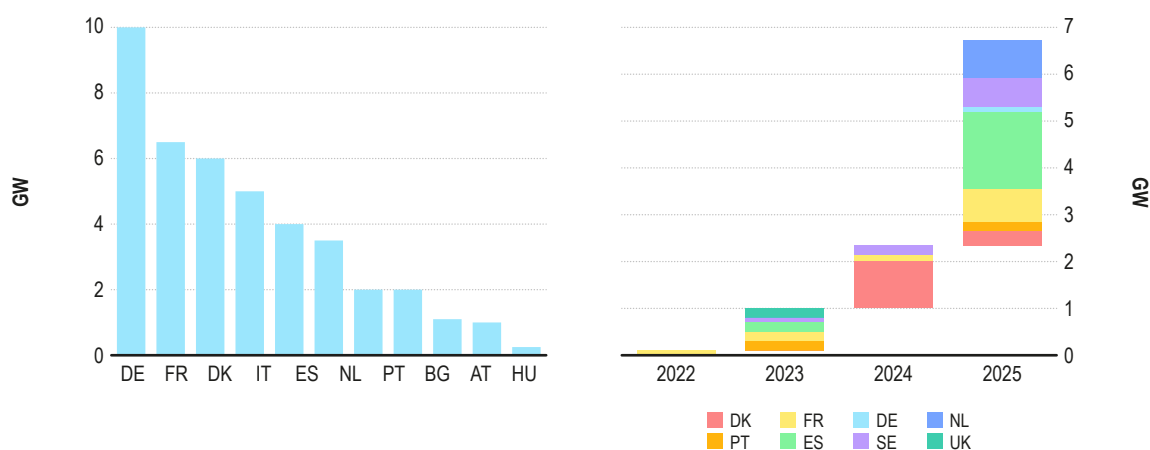
57 This is the case even if carbon dioxide is used in a number of industrial processes, such as in the fertilisers, food and chemical industry and for enhanced oil recovery, as well as it is increasingly employed for the production of synthetic fuels or for construction materials. In fact, the EU climate-neutrality objectives require to promote CCS technologies in order to capture massive volumes of carbon dioxide from current emitting carbon sources and processes³⁶. In accordance to a number of research organisations³⁷ CCS is indispensable to reduce emission from industrial plants and has advantages other types of carbon removal technologies. However, carbon capture technology is costly (see section directly below) while carbon storage attracts public dispute. Onshore carbon storage sites have in particular a lower approval rate than offshore ones³⁸. Global oil and gas producers are more vocally backing blue hydrogen technologies, which would better enable linking their ample fossil resources to a massive carbon-neutral output. They also argue that hydrogen transformation into easier-to-transport ammonia would facilitate their long-distance exports. Demonstration projects and further research shall help to increase the efficiency and reduce the costs of these technologies.

Renewable and low carbon hydrogen and electrolyzers expansion

58 The plans for expanding electrolyser capacity to produce massive volumes of renewable and low carbon hydrogen are in contrast highly ambitious. The case study below discusses how REPower EU, a number of NECPS and Hydrogen associations earmark tens of GWs being installed along this decade, accompanied by massive renewable power generation investments.

59 The industry reports that today's EU electrolyzers manufacturing capacity is already around 2 GW, while there is a commitment to scale that manufacturing capacity to 17.5 GW by 2025³⁹. The left part of Figure 7 offers an overview of the electrolyser capacity targets scheduled in front-running MSs by 2030 in accordance with their latest NECPs. The right part of Figure 7 compares these nominal targets against the electrolyzers' plants under development and planned to enter in operation by 2025.

Figure 7: Mid-term planned electrolyzers' capacity by MS at NECPs* and electrolyzers' plants on development up to 2025 – GW – 2030 and 2025



Source: ACER calculation based on NECPs, NRAs and Cedigaz database⁴⁰

Note: For the electrolyzers plants only those labelled as under construction or development are considered. Circa extra 8 GWs are reported in design phase from 2025 to 2030.

36 See EC carbon [capture, storage and utilisation](#) strategy and the communication on [sustainable carbon cycles](#).

37 See for example this [study](#) or this [study](#) related to CCS potential in the EU industry.

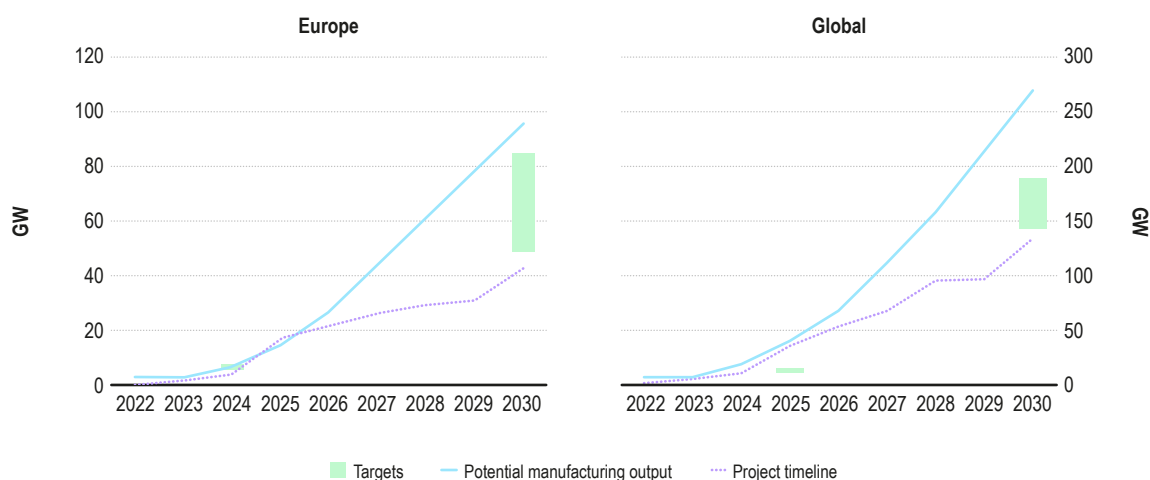
38 In accordance to IEA data, there are 35 commercial facilities across the world applying CCUS, with a total annual capture capacity of almost 45 Mt CO₂ and 200 more have been announced. The theoretical potential for carbon storage across the EU and the UK accounts for 120 Gt CO₂, equivalent to more than thirty years of the total EU power system carbon output. Sweden and Norway have particularly large offshore carbon suitable offshore storage capabilities. Carbon transport and storage costs are assessed between 10 to 30 euros/tonne, offshore sites being the costliest.

39 See EC and European Clean Hydrogen Alliance [joint declaration](#).

40 ENTSG also maintains a [registry](#) of the ongoing and announced production projects, but also of the hydrogen network expansion and retrofitting projects.

60 The International Energy Agency tracks in its latest Global Hydrogen Review 2022 Report the European and global electrolyzers' development targets arising from governments' National Energy Plans. The IEA contrast them both against the electrolyzers' projects already under development and the potential manufacturing output across the decade. The analysis reveals the ambitious objectives being set. Electrolyser manufacturing capacity could exceed 60 GW per year by 2030, with Europe and China leading the way. As the next case study discusses, 60 to 90 GW of electrolysing capacity would be needed to meet the renewable hydrogen production targets set by REPower EU at the EU by 2030.

Figure 8: Electrolyser project pipeline, manufacturing output and targets in Europe and globally



Source: IEA.

Note: Only projects with a disclosed start year for operation are included. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included. The potential manufacturing output is the cumulative production of factories considering 90% utilisation rate of planned projects with a disclosed start year of operation. For Europe, the targets includes the European Union and the United Kingdom electrolyser deployment targets; for the European Union, the lower range for the electrolyzers deployment corresponds to the Fit for 55 package and the upper range to the REPower EU plan. The global target is based on national hydrogen strategies.

How much renewable electricity is needed to produce renewable hydrogen?

The European Commission and a majority of MSs support the expansion of renewable hydrogen to decarbonise the EU gas sector. Renewable hydrogen investments would equally help to move away from Russian gas imports. Member States have endorsed plans for implementation and are mobilising financial resources for producing several millions of tonnes of renewable hydrogen across the decade. As referred in the Executive Summary, the REPowerEU Plan, the EC aims to produce 10 million tonnes of renewable hydrogen within the EU in 2030, as well as to import an additional 10 million tonnes from non-EU states.

To meet those targets, massive investments in new electrolyzers' capacity are needed in conjunction with a radical acceleration in renewable power generation. This case offers broad estimates about EU electrolyzers and renewable electricity capacity needs in view of the anticipated renewable hydrogen objectives. The discussion about costs will be further elaborated in the next Section.

Two aspects are key in determining renewable hydrogen production levels:

- The efficiency of the electrolysing systems, shaped among other factors by their technology and size, and also affected by their operation profile.
- The efficiency of the renewable electricity plants, similarly shaped by their technology and size as well as their load factors⁴¹. The latter are impacted by the plants' location and weather conditions.

Modern electrolyzers⁴² made use of 50 to 70 kWh of electricity input to produce one kg of hydrogen. The estimate takes into account the two most extended technologies at typical sizes: the Alkaline and the

41 The load factor is the measure of the actual electricity generation rate in relation to the nominal generation capacity of the plant.

42 See for example a benchmark of technologies at [IRENA report Green Hydrogen cost reductions](#) Report, table 6.

Polymer Electrolyte Membrane (PEM) electrolyzers. This entails a referential 65 to 70% energy efficiency factor in the conversion from electricity into hydrogen⁴³. The assumption in the industry is that both technologies will achieve an efficiency of 75% or more across this decade.

In turn, the load factors of renewable power plants vary according to generation technology and plant location. Load factors of 35 to 50% tend to be registered in wind offshore farms. Load factors tend to fall to 15 to 25% in photovoltaic plants⁴⁴. If assuming a load factor of 50%, a wind power plant with 1 GW of nominal capacity could produce 4.4 TWh of electricity per year. This is the electricity input needed to produce cca. 90,000 tonnes of hydrogen.

Ten million tonnes of renewable hydrogen would require 500 TWh of electricity input. That production would match up the electricity generation of 115 GWs of wind offshore capacity, at the referred 50% load factor. To compare, the total wind generation capacity installed in the EU (both onshore and offshore) equals 180 GW⁴⁵ in 2021 which reveals the extent of the ambition.

Electrolysing facilities operate a limited amount of time annually. A conventional estimate is 60% to 70% of the time (i.e. from 5,000 to 6,000 hours a year⁴⁶). Total operation hours of electrolyzers are amplified when connected to the grid. Depending on the final operation hours and actual efficiencies, the production of 10 million tonnes of renewable hydrogen would require from 65 to 90 GWs of new electrolyzers' capacity measured in terms of hydrogen output from now until 2030⁴⁷.

It is clear that operating power-to-hydrogen facilities at a scale large enough to substantially replace conventional natural gas would require a significant expansion of today's EU installed power generation capacity over the next 30 years⁴⁸. That target would entail significantly expanding the electricity network capacities.

1.3 Feedstock availability

- 61 The availability of feedstock resources, as well as their cost relative to their energy potential, have been decisive in driving their utilisation and application in the production of decarbonised gases. In the years to come, their explicit emission savings potential is likely to increase significantly.
- 62 Biogas has different production pathways that involve varied feedstock inputs. On average across the EU, the prevalent biogas feedstock originates from the agricultural sector (63%), either in the form of energy crops or agricultural residues. Even so, agricultural waste and biowaste from households or industrial facilities have a large penetration in certain MSs. Figure 9 shows the biogas feedstock' distribution per MS, together with the total number of operational plants. They totalled 19,000 in 2020 – 880 for biomethane – with the largest plant's capacity in the range of 50 MW (the average being less than 1 MW⁴⁹).

43 One kg of hydrogen accounts for 33 kWh of low heating value and around 39 kWh of high heating value. Solid Oxide electrolyzers offer today higher efficiencies, up to 80%, although they are more expensive and less mature.

44 See for example an overview of load factors in the [IEA renewables data explorer](#).

45 Those wind power plants produced 390 TWh in 2021, a 14.5% of the total of 2,700 TWh of EU electricity consumed. (hence, the average wind farms' load factor was lower than the above considered 50%). REPower EU Plan refers to more circa 600 GWs of photovoltaic capacity and more than 500 GW of wind by 2030 to meet the electricity system decarbonisation as well as the EU energy system electrification objectives. More than 100 GWs of this renewable electricity generation are earmarked to feed hydrogen electrolyzers.

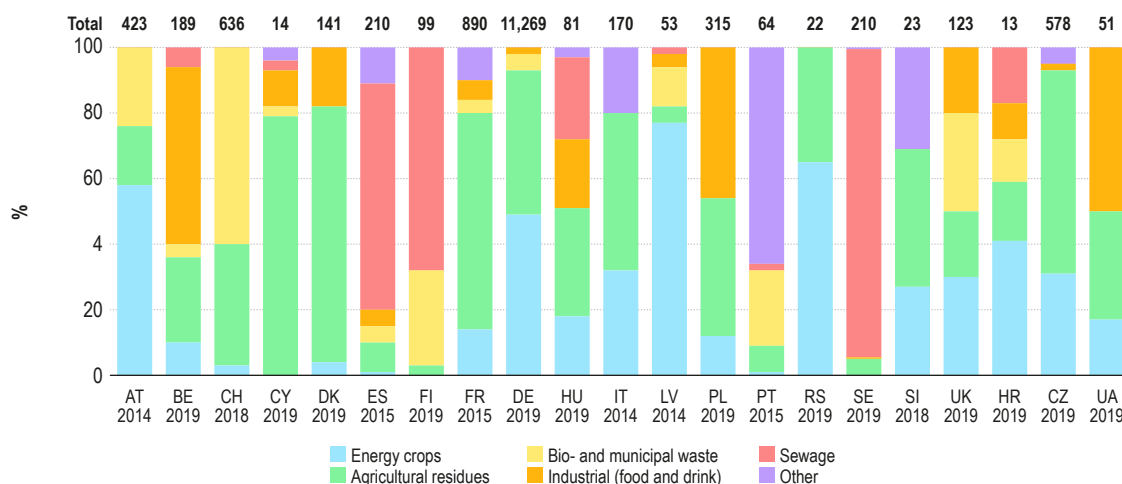
46 These total hours would be above renewable plants' load factors, but the assumption is that electrolyzers would be connected to the grid.

47 65 GW are the minimum capacities cited by REPower EU Plan, but lower running hours would request more GWs. The [Clean hydrogen Alliance reports](#) to 90 to 100 GWs. Running hours are determined among others by the electricity system, the system flexibility requirements and the location of electrolyzers and renewable electricity sources.

48 For example, the [EC Hydrogen strategy](#) referred and estimate of 500 GW of electrolyzers' capacity by 2050, mainly fed by new wind offshore electricity generation. At world level, [IRENA](#) has modelled that 30% of the global electricity use will be dedicated to the production of renewable hydrogen by 2050.

49 A map of the locations and size of [biomethane plants](#) is made available by EBA and GIE.

Figure 9: Breakdown of feedstock resources for biogas production across MSs and number of biogas plants – 2019 and EU aggregates



Source: ACER based on EBA Report 2021.

Note: Regardless of the feedstock, almost all EU biogas is obtained via anaerobic fermentation technologies, with syngas produced from thermochemical conversion having a much lower presence.

- 63 Even if still dominant, the use of agricultural resources as feedstock for biogas is being constrained following more stringent environmental regulations that prohibit competition with food production or land use changes. As such, the emerging trend is to move away from energy crops towards agrarian residues, biowaste and farms manure.
- 64 The capability of the various feedstocks to abate emissions is an increasingly relevant factor when deciding what biogas resources to uphold. The RED directive has set standardised methods to assess that contribution, with farm manure showing the most potential⁵⁰. As expanded in Section 3, the proposed Hydrogen and Decarbonised gas markets Directive has established that carbon emissions shall be reduced by at least 70% compared to conventional gas in order to be classified as decarbonised gas and this reduction shall be certified. The assessment will make use of the features of the raw materials in terms of the carbon that they capture and/or the fugitive methane emissions that they would have emitted if not processed into biogas. This is in addition to considering their production, processing, transport-distance and final use technicalities.
- 65 In its annual greenhouse gas inventory, the European Environmental Agency assesses that more than half of the methane emissions related to human activity originate from agriculture and farms, followed by household and industrial waste. Some of this lost methane could produce biogas. A widespread capturing and processing of all those biodegradable resources for its conversion into biogas would deliver critical decarbonisation benefits and a more circular economy.
- 66 To that end, the recent EC Methane Strategy heavily endorses biogas capturing to reduce the direct emissions that would otherwise escape into the atmosphere as well as to displace the consumption of conventional fuels⁵¹. Besides, the fermentation processes at biogas facilities produced residues could be further used as fertilizers for agricultural lands leading to the reduction of energy consumption to produce fertilisers.

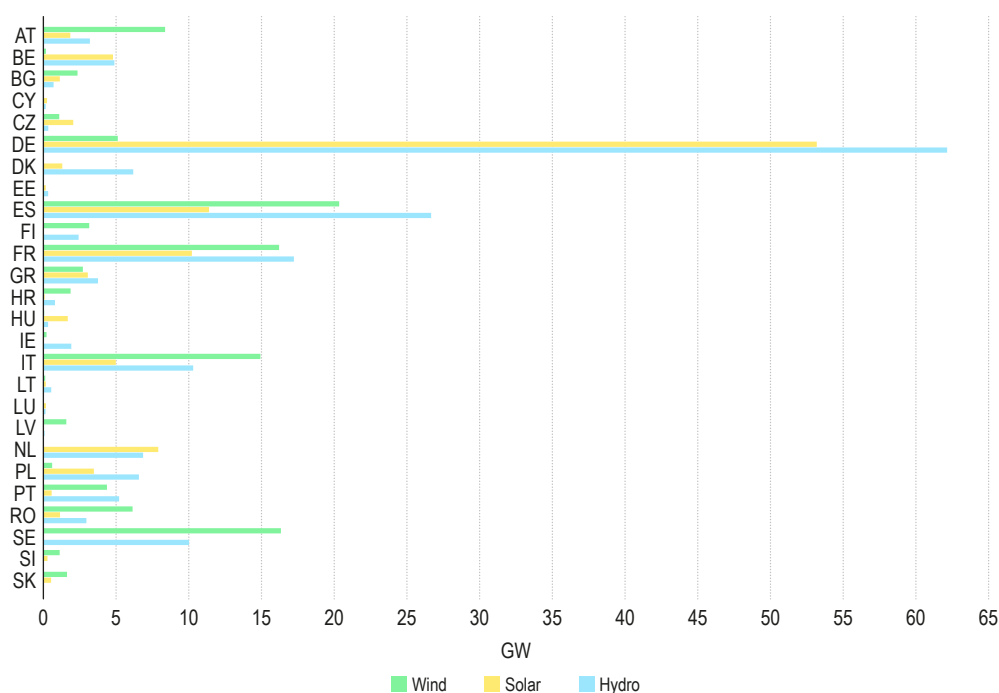
50 See [Renewables Directive](#), Part A Annex VI.

51 To promote the reduction of methane leakages in agriculture, the EC has developed an inventory of best practices, available technologies and innovative technologies as part of the Methane Strategy.

Renewable hydrogen

- 67 In the case of green hydrogen, the feedstock resource relates to the size and ease of access to renewable electricity generation, meaning there is benefit in placing the transformation plants at locations where water supplies, gas and electricity network, as well as if possible suitable underground gas storage and demand sites are concurrently easily accessible.
- 68 In particular regard to water supply, a variety of studies discuss the water requirements of renewable hydrogen production. INEA⁵² estimates that it can range from 20 to 30 litres per kg of hydrogen, which includes the average water consumption for the production of photovoltaic and wind energy. Whereas these volumes are significant, the expectation is that the volumes will fall below the water needs for electricity generation produced by gas or coal-fired plants. Moreover, at a broad scale, the water needs of hydrogen production would be relative minor in comparison to other sectors of the economy such as agriculture or industries.
- 69 Further coordination in planning gas and electricity networks should facilitate determining the most suitable locations. In this respect, there should be room for locational signals to promote the places where these plants contribute the most to the decarbonisation of the energy system. Critical for that will be the accessibility and generation capacity of renewable power technologies.

Figure 10: Renewable power generation installed capacity across EU MSs – 2021 – GW



Source: ACER based on ENTSOE.

52 See for example an overview at [this article](#).

- 70 Today's EU renewable installed capacity is less than 450 GWs. REPower EU plan earmarks approximately 600 GWs of photovoltaic capacity and more than 500 GW of wind by 2030 to meet the EU electricity system decarbonisation and energy dependence reduction objectives. More than 100 GWs of this renewable electricity generation are earmarked to feed hydrogen electrolyzers, whereas the rest of extra renewable electricity should assist the energy sector electrification, including the expanding electrification of vehicles and heating of households⁵³.
- 71 As a final point, the distinct availability of feedstock resources influences MSs' degree of support to different decarbonised gas technologies. For example, in Germany and Denmark, biogas production is intended to keep growing⁵⁴, while Spanish, Italian and Portuguese NECPs chiefly back hydrogen production from cost-competitive photovoltaic renewable electricity, along with wind sources. In the same context, France, for example, considers nuclear power as relevant input for future hydrogen production.

53 Accomplishing the mid-term targets set for EVs deployment and green hydrogen production would entail an extra 6-7% electricity supply for each by 2030 in accordance to IEA estimations. As such, there is likely to be competition between a direct use of RES-E or for using the RES-E input to source power to gas facilities.

54 Power-to-gas will play a very relevant role there, as the ample wind energy potential is aimed to feed hydrogen industrial consumption points. German NECP, for example, sets the target for a combined support of nine billion euros to develop up to 10 GWs of hydrogen by 2040.

2. Production costs of renewable and low carbon gases

72 This section explores the current production costs of decarbonised gases and hydrogen and contrasts those against their mid-term prospects. The analyses take stock of the key cost-drivers, including variable input costs and the capital costs of the different technologies. A case study below discusses in more detail the renewable hydrogen production technology.

Current status

73 The competitiveness of the various decarbonised gases production technologies has been and will be decisive to determine their future reach. Sound cost estimates are difficult to make though, as final production costs are affected by local specificities, the plants' technicalities and the prices of raw materials.

74 While decarbonised gases have traditionally been considerably more expensive than conventional gas⁵⁵, the price gap of biogas/biomethane with conventional natural gas has been closing in recent months. This has been a result of the rising costs of conventional gas, which has reached record highs due the gas crisis that emerged towards the end of 2021. Average production costs of biogas/biomethane range between 50 and 80 euros/MWh today, in contrast to natural gas prices trading at more than 200 euros/MWh across early autumn 2022.

75 Contrary to biogas, the production costs of hydrogen have significantly risen in view of the escalating natural gas and electricity prices. Figure 1 in the Executive Summary compares the evolution of hydrogen costs, produced from various technologies, against the price of conventional gas, using the Dutch TTF month-ahead prices as a benchmark. Blue and grey hydrogen production costs have risen by a factor of six or more, in comparing to similar increases in spot conventional gas prices (the price increase of each specific plant subject to the individual gas supply contractual terms).

76 On average, hydrogen produced via the electrolysis of water is today overall three times as expensive as hydrogen produced via steam methane reforming. In the first half of 2021, the relative price gap between renewable hydrogen and natural gas saw a slight reduction. However, the rising electricity prices have further amplified that gap on average since autumn 2021. Production costs remain project-specific though. For example, selected renewable hydrogen projects that might be benefitting from competitive electricity price sourcing (e.g., via favourable Power Purchase Agreements) could see a decrease in the price gap with natural gas.

77 In the absence of liquid hydrogen market offering transparent price signals – but also in view that most hydrogen consumers sign bilateral purchase agreements whose prices are not yet fully revealed – hydrogen price estimates are modelled based on educated guesses. At any rate, and as discussed in the next section, public support schemes are deemed crucial for starting off renewable hydrogen production, or until a competitive renewable hydrogen market gradually develops.

55 Until summer 2021, the production costs of the most competitive biogas facilities was at least twice higher than the price of natural gas traded at EU gas hubs.

Cost drivers

- 78 As discussed, the production costs of decarbonised gases are quite plant-specific and driven by a number of interrelated factors. The main cost drivers include the cost of inputs, namely the costs of raw materials and the energy inputs used, the capital costs of production units and ancillary equipment, the plant's capacities and process efficiency, waste management and financial aspects.
- 79 In the case of blue hydrogen, the main elements driving production costs include the price of raw materials (i.e., mainly natural gas but also coal supply in certain plants, steam and importantly the catalyst⁵⁶), the price of electricity supply, the capacity and efficiency of the process and the overall capital and financial expenditure costs⁵⁷. Additionally, pure oxygen supply is required in the case of Autothermal Reforming (ATR) of methane and gasification of coal production technologies. Finally, the price of carbon emissions has also relevant impact on the projects' price-competitiveness.
- 80 The addition of a carbon capture facility results in additional investment costs, which might amply oscillate per project⁵⁸. The capturing of carbon emissions employs chemical or physical solvents⁵⁹. The costs of direct underground storage of carbon emissions are deemed somewhat higher than its capturing. The cost of storage was estimated to lie in the range of 2 to 20 euros/tonne. Larger capacity storage sites will generally result in lower storage costs. Offshore storage is notoriously more expensive than onshore storage due to increased compression and transportation costs, resulting in the range of 12-30 euros/tonne.⁶⁰
- 81 In the case of biogas/biomethane production, the main cost drivers include the availability and cost of the feedstock, including collection and transportation, the capital and operation costs to convert the biomass into valuable product, the production technology adopted and the plant capacity. Additionally, the monetisation of the biogas bi-products plays an important role in final price formation. For instance, the digestate⁶¹ can be sold as natural fertiliser to partially offset the production cost of biogas, thereby increasing its overall economic competitiveness. Similarly, waste carbon dioxide can be sold to industries instead of being disposed of, although that requires of additional investments and favourable conditions and locations.
- 82 Depending on feedstock type and digester size, current production costs for biogas range between 50-80 euros/MWh and 90-100 euros/MWh for anaerobic digestion and thermal gasification technologies respectively⁶². Larger production facilities make possible lower production costs, as a result of economies of scale. Generally, capital fixed costs account between 20 to 40% of the total production cost of biogas and range between 2,100 to 9,500 euros/kW_{el}, depending on the complexity of the installation⁶³. Biomethane upgrading facility and interconnection costs add between 10 and 20 euros/MWh⁶⁴.
- 83 The case study below offers a general overview of the key drivers and costs associated to production of renewable hydrogen.

56 The catalyst facilitates the chemical reaction for converting methane into carbon monoxide and hydrogen by lowering the activation energy of the reaction and increasing the reaction rate. Typically, nickel-based and sulphur-resistant catalysts are employed in SMR processes. They need to be regenerated after a certain number of operating hours.

57 Based on studies by DNV and IRENA, capital costs for a 10 MW blue hydrogen SMR production facility range between 800 and 1700 euros/kW. Abated ATR production costs range between 1000 and 1500 euros/KW.

58 DNV, *Energy Transition Outlook 2021 – Technology Progress Report, 2021*

59 Amine-based solvents are most commonly employed in the industry.

60 Zero Emissions Platform, *The cost of subsurface storage of CO₂, 2019*

61 Digestate is the residue of fluids and fibrous materials left over from the production of biogas.

62 Gas for Climate, *Market state and trends in renewable and low-carbon gases in Europe, 2021*

63 Biosurf, D3.4 | *Technical-economic analysis for determining the feasibility threshold for tradable biomethane certificates, 2016*

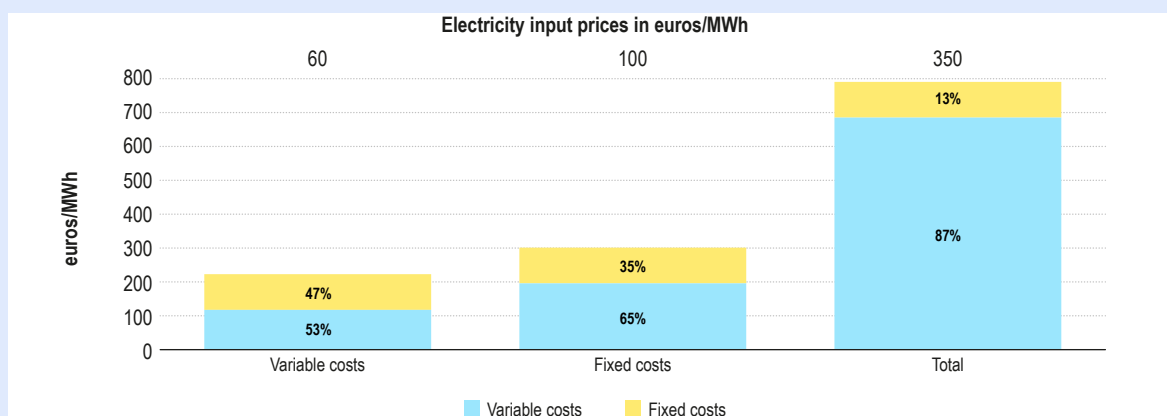
64 See above.

Renewable hydrogen production cost: Overview of relevant drivers

As previously discussed, renewable hydrogen is part of the EU energy system decarbonisation strategy. However, renewable hydrogen production costs are very expensive today, despite expectations they can be highly reduced by means of cheap electricity and higher efficiencies in electrolyser technology.

The split between fixed and variable costs is highly affected by the price of electricity and the plants' size. Fixed costs chiefly comprise of the electrolysing stack and the catalytic membranes in the electrode package. They also include all the other equipment and auxiliary systems that allow the stack to function (commonly referred as balance of plant). Electrolysers' fixed costs are assessed in the range of 650 to 1,500 euros/kW, depending on the technology and size⁶⁵. Before the strong increase in electricity prices occurred since autumn 2021, fixed costs accounted to between 25 and 50% of total production cost. That share, as mentioned, is highly influenced by the plant's size. However, as Figure 11 assesses, the share of fixed cost has visibly decreased since recently, in view of the record high electricity prices.

Figure 11: Illustrative overview of the renewable hydrogen fixed and variable production costs for different electricity prices – euros/MWh



Source: ACER based on values and methodologies cited by DNV, IRENA, IEA, FCHO and G4C.

Total variable costs are in turn strongly driven by electricity prices, but also the electrolyzers' efficiencies and the number of operation hours. Variable costs also comprise the costs of deionised water circulation and of hydrogen processing and cooling.

Final electricity consumption is highly determined by the efficiencies of the stack and the cells⁶⁶, but also the auxiliary systems. Electrolysers' efficiencies vary among the different technologies. As discussed in the case study in Section 1.1, efficiencies range between 65% to 70% for the most extended Alkaline and Polymer Electrolyte Membrane technologies.

Finally, the electricity supply profile determines the number of operation hours, which is a critical element in electrolyzers' competitiveness. Total operation hours need to be balanced with the evolution of electricity prices, aiming at minimising final production costs. The number of operation hours are case specific, depending on the power supply contracting schemes and importantly the possibility of connecting the plant to the grid. Studies have found that the equilibrium tends to be around 4000–6000 h/year⁶⁷. Below 2000 h/year, fixed costs tend to dominate final production costs and the cost-competitiveness of renewable hydrogen (further) falls.

⁶⁵ IRENA study based on of a 1 MW PEM/AE electrolyser. The renewable Agency weights that a capacity factor of ten can reduce fixed costs by 50%, while a factor of one hundred lessen them by 75%.

⁶⁶ The degradation rate of the stacks depends on the cumulative current passing through them, a higher number of operation hours reduces the efficiency and makes necessary their more frequent replacement.

⁶⁷ E.g. M. Ball, M. Weeda, in *Compendium of Hydrogen Energy*, 2016

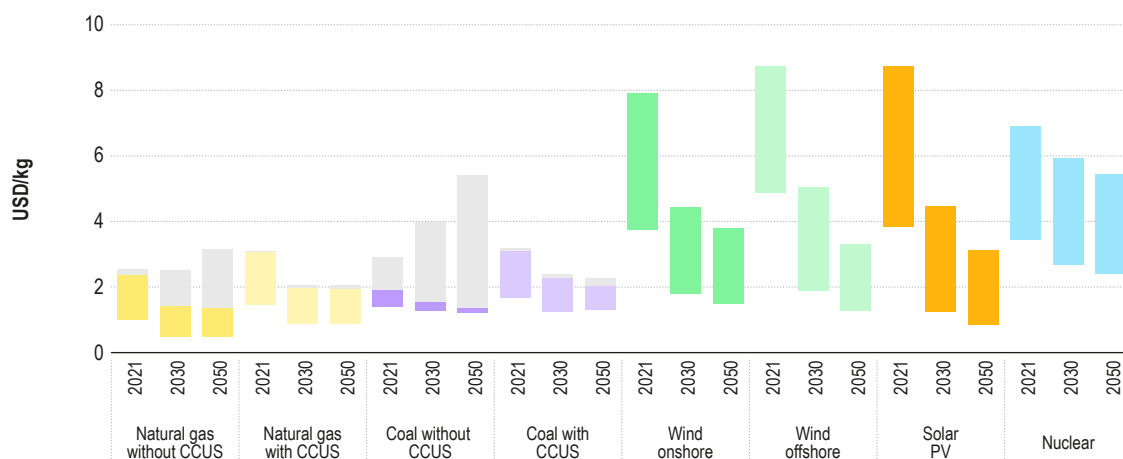
2.1 Mid-term prospects for renewable gases

- 84 The main factors that will drive the future price competitiveness of decarbonised gases and hydrogen are technological development, economy of scale and the evolution of renewable electricity prices.
- 85 In the field of biogas, production technologies are overall more mature than those of other renewable gas technologies. Therefore, its potential cost reduction trajectory is seen as more limited. However, the gradual upscaling of the equipment and incremental cost reductions of the technology, together with more efficient feedstock collection increases the competitiveness of biogas. Moreover, and critically, the probable rise in carbon emission certificate prices (EUAs) can build a good business case for biogas developments in the years to come.
- 86 For example, the IEA estimates that in 2040 overall production costs for biomethane will be 25% lower than today. The assumed average costs for biomethane production are 60 euros/MWh for anaerobic digestion and 40 euros/MWh for thermal gasification. In both cases, fixed costs would account for less than 40%.
- 87 In the case of renewable hydrogen two main elements will drive final production costs. The first is the electrolyzers' capital costs, which are expected to keep falling over the following years. Those reductions will be achieved by optimising and standardising the new systems and their designs by reaching economy of scale in production volumes and last but not least by developing new technologies⁶⁸. Stack lifetime can also be improved at the research and development stage, which would reduce the need for replacement and thus investment costs throughout the electrolyser's lifetime. According to some studies⁶⁹, a 25% drop in average costs by 2030 and 50% by 2050 can be expected.
- 88 The second element relates to electricity prices. While today's record high electricity prices are expected to remain for another two or three years (German electricity deliveries for 2025 were trading in European Energy exchange, EEX, at a price of 180 euros/MWh in early September, although subject to strong volatility) as the persistent deployment of renewable electricity generation is expected to bring prices down across the second half of the decade. According to some estimates, power prices of 20-30 euros/MWh in conjunction with carbon emission prices around 100 euros/tonne would make renewable hydrogen as competitive as average natural gas prices in previous years. Those power prices are not that far away from the prices of selected PPA agreements auctioned in selected MSs.
- 89 Finally, the investment costs for blue hydrogen are also expected to decrease as the technology matures as a result of standardisation, optimisation and upscaling. Moreover, the growing competition between CCS providers is likely to reduce the costs of capturing carbon dioxide. However, rising costs for gas are likely to make production of hydrogen via SMR more expensive compared to renewable hydrogen, contradicting earlier expectations. According to some studies, Autothermal Reforming technology could become more competitive in view of higher efficiency (74-80%) and lower carbon emissions (0.3-1.3 kgCO₂/kgH₂)⁷⁰.
- 90 As such, and as illustrated in the IEA estimates that both renewable and blue hydrogen production costs could fall by 50% by the end of the decade, depending on the technology.

68 The anion exchange membrane (AEM) electrolyzers are considered a promising technology. They share the flexibility for adjusting to load changes of a PEM electrolyser but does not require critical raw materials such as iridium, cobalt, platinum, and tantalum. These elements, in fact, might represent a bottleneck to a future large-scale deployment of both PEM and AE units. On the other hand, solid oxide electrolyzers (SOE) are expected to gradually gain competitiveness. Those electrolyzers can operate in reverse as a fuel cell, which is advantageous for grid balancing purposes. Furthermore, SOE units could make use of steam and carbon dioxide inputs.

69 DNV, *Hydrogen Forecast To 2050 - Energy Transition Outlook 2022*, 2022

70 DNV, *Hydrogen Forecast To 2050 - Energy Transition Outlook 2022*, 2022

Figure 12: Hydrogen production costs by technology - 2021 and 2030 and 2050 prospects – dollars/kg H₂⁷¹

Source: IEA.

- 91 Eventually, the availability and affordability of the resources used by the different production technologies, together with government policies and incentive schemes will determine the competitiveness of one production pathway for both hydrogen and biomethane over the others. The charges for accessing the electricity and gas networks and the taxation schemes will be also important elements impacting the economic feasibility of low-carbon gases.

2.2 Review of incentives granted to renewable and low carbon gases

- 92 Subsidies and ad-hoc financial support have been crucial to back the expansion of decarbonised gases. This is not surprising, as the production costs of decarbonised gases have traditionally been much higher than the price of conventional natural gas. Incentives have been chiefly assigned to biogas and biomethane production, but the frame is expanding to include renewable hydrogen too. Without such incentives the market for biomethane would have likely not developed to its present size.
- 93 The support measures can take different forms per jurisdiction, including favourable network access tariffs⁷², ad-hoc fiscal frameworks, the funding of new investments in production plants, direct subsidies to actual production and guarantees of origin, the latter effecting on their priority for production and carbon emission financing. Feed in tariffs are at present the most utilised support scheme available across the EU⁷³. For example, Germany, Luxembourg and France fund biogas and biomethane final production (e.g. 7 euros/MWh, from 60 to 90 euros/MWh and from 66 to 167 euros/MWh respectively⁷⁴). Greece and Hungary finance power generators sourcing from biogas, while other MSs such as Austria or Spain have set public financial programs that subsidise new investments in biogas production plants⁷⁵. The extent of the incentives tend to impact total decarbonised gases production⁷⁵.

71 As a general conversion reference, impacted by the exchange rate, 1 dollar per kg H₂ would relate to around 30 euros/MWh.

72 As discussed, the EC Directive proposal is to make these discounts the rule. Germany or Spain already implement those discounts.

73 The [REGATRACE study](#), done for the EC in 2020, for maps the type of biogas and biomethane production subsidies across Europe in 2019.

74 See for example [regulation](#) about biogas subsidies in Germany.

75 See for example ACER-CEER MMR 2020 Figure 17, correlating total production of biomethane in 2019 to the extent of financial support schemes.

France support scheme to biomethane production

The framework for the development of biomethane in France comprises three main instruments:

- a) A 'right to injection' principle, which eases the access of biomethane production plants to the gas network;
- b) A regulated feed-in tariffs system, which promotes the economic viability of the sector;

A system of guarantees of origin, that in combination with purchase obligations for gas suppliers, helps to allocate biomethane production

These combined instruments have facilitated the rapid expansion of biogas and biomethane in last years, with a significant acceleration since the entry into effect of the "right to injection" framework in 2020⁷⁶. France, has set a target for injecting biomethane volumes to cover up to 7-10% of final gas consumption by 2030.

In particular, a decree published in June 2019 has granted the right to connect biomethane facilities to the network (either distribution or transmission) following techno-economic criteria. The decree eases the financing of networks' adaptation and reinforcement investments. Detailed information on the scheme is available in a dedicated assessment published CRE in 2021.

Easing network interconnection has been crucial to boost biomethane injections in the last couple of years. In fact, biomethane producers have been benefitting since 2011 from a feed-in tariff. Production subsidies are guaranteed in France for 15 years, the final extent of the support depending on the size of the production facility and on the nature of the material treated. The subsidies upper limit is of 139 euros/MWh. New tariff decrees (November 2020) have limited the feed-in tariff to small installations and have introduced a decrease of the tariff for new projects.

Finally, biomethane producers benefit from an implemented purchase obligation system. Producers can sell their production to any gas supplier but also to a buyer of last resort. Buyers acquire biomethane at the regulated feed-in tariff and get compensated for the difference between the wholesale gas price and the regulated tariff. The volumes of biomethane acquired by suppliers are integrated to its balancing position.

94 The administering of guarantees of origin attracts specific interest. This is in view of their future standardisation in the Renewable Energy Directive revision. The RED review⁷⁷ will provide a more comprehensive methodology to certify low-carbon gases across MSs⁷⁸. That frame should assist the recording of decarbonised gases and hydrogen penetration per MS and importantly will be used to link those guarantees of origin to potential transportation tariff discounts. A European registry will be set to record the volumes of low-carbon gases that are entitled and have been subject to transmission tariff discounts (see Section 4.3). Moreover, those guarantees of origin could be traded in relevant markets, linking and promoting the transferring of certified emission savings (either at supply or consumption level) potentially within the EU ETS.

76 In accordance to [Open Data Gaz](#) biomethane production accounted to 4.3 TWh in 2021 with 365 sites in service. GRTgaz also publishes an [annual report](#) on biogas and biomethane market developments.

77 The Renewable Energy Directive (2009/28/EC) was revised in 2018, but the Commission proposed another revision in 2021 to better align it with the increased climate ambitions. The proposed revision of the RED is now being considered by the Council and the European Parliament. The adoption is expected by the end of 2022

78 A dedicated methodology is to be established, via a Delegated Act by 31 December 2024. The methodology will make use of a life cycle approach.

- 95 While favourable financial assistance helps to increase investment in renewable energy (including also renewable electricity generation) there are certain conditions to offer support schemes. The EC has aimed at providing certain guidance on the matter⁷⁹, to avoid that dissimilar and undue subsidies might distort the functioning of the energy market. In essence the guidance requests that financial support should be limited to make renewables competitive in the market and adjust to production costs⁸⁰. Retroactive changes to support schemes should be avoided not to undermine investor confidence and prevent future investments. The EC calls EU countries to take advantage of the renewable energy potential in other countries via cooperation mechanisms. This would keep costs low for consumers and boost investor confidence.
- 96 Subsidies for hydrogen production are gaining traction. National Programmes mobilising hundreds of millions of euros are being announced to enable these achievements. In accordance to Platt's analysis, ten Member States have allocated specific funding for hydrogen in their Recovery and Resilience Plans, worth 12 billion euros, which are to be summed up to the diversity of EU financing lines. The EC Public Funding Compass summarises the available EU and national budget lines.

79 See EC renewable support schemes [guidance](#) for EU Member States.

80 For example, the guidance suggests that feed in tariffs should be replaced by feed in premiums and other support instruments that incentivise producers to respond to market developments. As technologies mature, schemes should be gradually removed.

3. Regulatory framework for decarbonised gases and hydrogen

97 As discussed in the Recommendations Section, the Hydrogen and Decarbonised Gas markets Legislative Package has aimed at legislating a number of interrelated aspects that will notably drive the gas sector transition. This Section summarises the key aspects of the planned legislation – which can be generally grouped in six areas – offering relevant details of the proposals. (The texts in the blue boxes reflect the legal provisions enshrined either in the draft Directive or the draft Regulation.⁸¹)

1. Determining the activities and the conditions at which the market participants will be allowed to invest.

The Package establishes that the operation of hydrogen networks should be separated from the activities of energy production and supply⁸². This is in order to avoid conflicts of interest. However, Member States can rely on an alternative unbundling model called ‘integrated hydrogen network operator’ until 2030. That option will provide a transitional period for existing vertically integrated hydrogen networks while ensuring the non-discriminatory operation of such networks after 2030.

2. Determining the network access conditions for new gases (investment cost allocation and tariffs will be key elements for that).

The Package establishes that hydrogen networks should be subject to third-party access in order to ensure competition. Regulated third-party access, on the basis of regulated access tariffs, should be the default rule in the long-term. However, in order to ensure flexibility for operators during the ramp-up phase of the hydrogen market, Member States should have the option to allow the use of negotiated third-party access until 2030.

The transport and distribution tariffs for conventional and decarbonised gases should be assessed via a transparent methodology and shall as a rule avoid discrimination between network users. However, a specific frame is contemplated in the early phases. The recast Regulation proposes tariff discounts for the injection of renewable and low carbon gases production facilities, as well as for the tariffs at entry points from and exit points to storage facilities and for cross-border tariffs and entry points from LNG facilities (see expanded considerations in the case study at page 38). These discounts should not affect the general tariff setting methodology, but should be provided ex-post on the relevant tariff. The Regulation established that in order to benefit from the discount, network users should present the required information towards the transmission system operator using a certificate which would be linked to the union database.

Further considerations on investment cost allocation and revenue recovery are offered in Section 4.3.

81 EC proposal on a [Regulation for the internal markets for renewable and natural gases](#) and for hydrogen.

82 Moreover, operators providing regulated services for gas and/or hydrogen (as well as for electricity) shall comply with the requirement of unbundling their accounts and hence establish a separated regulated asset base for gas and hydrogen assets (or electricity). That shall ensure that revenues obtained from the different services can only be used to recover the expenditures related to those services.

3. Setting the technical rules that will define gas quality, blending, certification and interoperability aspects.

The Package establishes that gas TSOs, DSOs and hydrogen network operators should be responsible for gas quality. The applicable gas quality standards are to be developed by the European standardisation organisations⁸³ in collaboration with the industry. They shall ensure that decarbonised gases can technically and safely be injected into and transported through the natural gas system⁸⁴. The Regulation in particular foresees the amendment of the interoperability network code⁸⁵ to address aspects related to the volume of hydrogen blended in the natural gas system. Those aspects will include cost-benefit analyses for removing cross-border flow restrictions, Wobbe Index classification and the acceptance levels for gas quality parameters relevant for ensuring the unhindered cross-border flows.

Moreover, the Directive establishes that regardless of whether they are produced within the EU or imported, renewable gases shall be duly certified⁸⁶. As a rule, the carbon emissions savings from the use of decarbonised gases and hydrogen should be at least 70% compared to the emissions from conventional natural gas⁸⁷.

4. Defining a framework to identify new network investments, be it brand-new or repurposed network, and to value the existing regulated asset base in case of transfer of assets.

The Package establishes that a newly set European Network of Network Operators for Hydrogen (ENNOH) should identify and promote sufficient cross-border capacity to accommodate all economically reasonable and technically feasible demand. A biannual EU 10-year network development should be released. It will build on the national hydrogen network development reporting. The Plan shall be drawn up based on a joint scenario developed on a cross-sectoral basis⁸⁸. TSOs shall fully take into account the potential for alternatives to system expansion, for instance the use of demand response.

Moreover, LNG and storage system operators shall, at least every two years, assess market demand for new investment allowing the use of renewable and low carbon gases in the facilities.

5. Identifying and mobilizing ad-hoc support to the new technologies, at least in early phases.

The EC proposed Directive and the REPowerEU Plan have included some financing estimates and indicated the financing programs⁸⁹ that would promote hydrogen production and infrastructure development. The REPowerEU Plan⁹⁰ particularly offers an estimates of total public-private investment needs per separate categories by 2030; 50 to 75 bn euros for electrolyzers, 28 to 38 bn euros for EU-internal pipelines and 6 to 11 bn euros for storage.

83 The European Committee for Standardisation (CEN) received a mandate to set the acceptable ranges of gas parameters at EU gas systems, which will include carbon neutral gases.

84 While the system shall ensure a harmonised approach on gas quality for cross-border IPs, the Regulation grants Member States flexibility in the application of gas quality standards in their domestic natural gas systems.

85 The [interoperability network code](#) addresses aspects such as interconnection agreements, rules on flow control and measurement principles for gas quantity and quality, odourisation practises, allocation and matching rules, common sets of units, and data exchange.

86 In accordance with Article 29 and 30 of RED [Directive \(EU\) 2018/2001](#).

87 In accordance to article 8 of the Directive. A dedicated methodology is to be established to validate that threshold, via a Delegated Act by 31 December 2024. The methodology will make use of a life cycle approach.

88 While still keeping separate sectorial plans, infrastructure operators should work towards a higher level of integration taking into account system needs beyond specific energy carriers

89 From the EU side a number of financing sources are cited, including the Recovery and Resilience Funds, the Connecting Europe Facility, the Invest EU Programme, the Innovation Fund, the Life Programme and programmes under shared management such as European Regional Development Funds. Those are to be complemented with private investments. The [EC Public Funding Compass](#) summarises available EU and national budget lines.

90 See REPower EU [Implementing Acts](#).

6. Setting up market rules that promote and facilitate the access to liquid markets for producers and consumers.

A variety of rules and considerations are proposed to that aim. For example, the Package recognises that producers of renewable and low-carbon gases are often connected to the distribution grid. To facilitate the volume uptake, that production shall also gain access to virtual trading points. That setting entails enabling virtual and physical reverse flows from the distribution to the transmission network.

Besides, the Package considers that long-term supply contracts should not constitute a barrier to the entry of renewable and low carbon gases. Hence it proposes that the duration of contracts for the supply of conventional gas will not be able to run beyond 2049. Overall, the Package underlines that market integration shall be fostered to enhance the deployment of renewable and low-carbon gases. In that respect the EC is empowered to develop new implementing acts to set revised rules for trading related to technical and operational provision of network access services and system balancing.

- 98 Moreover, the Package also contains provisions to promoting the engagement of retail consumers, as discussed in the Retail and Consumer Protection MMR Volume.
- 99 ACER and CEER have actively participated in the discussion, offering recommendations and views on all these areas. They have been shared via related white papers and more recently via the Report regulatory requirements to achieve the energy sector decarbonisation objectives⁹¹. ACER and CEER most relevant considerations have been summarised in the Recommendations Section.

91 See [ACER and CEER white paper](#), When and How to Regulate Hydrogen Networks. See also ACER and CEER Report on the regulatory requirements to achieve the energy sector decarbonisation objectives in footnote 11 and ACER-CEER Reaction to the European Commission's Hydrogen and Decarbonised Gas Market Package in footnote 12.

4. Infrastructure development and revenue recovery models for gas and hydrogen networks

100 This section discusses aspects related to the infrastructure expansion and repurposing required to promote the use of decarbonised gases and hydrogen. It first talks over the anticipated investments and the feasibility to repurpose the existing gas network to flow hydrogen. Then it discusses tariff aspects and revenue recovery models to pay the existing gas and the new hydrogen infrastructure.

4.1 Network suitability and foreseen expansion

101 While the current gas network and most end-use appliances can accommodate biomethane without major technical adjustments, their readiness to integrate hydrogen admixtures is open to discussion. This is due to the distinct physical properties of hydrogen and natural gas⁹². These different properties imply that the existing gas networks and end-use equipment can in general only accept hydrogen up to a certain limit. Moreover, over a certain threshold of hydrogen admixture, the cost and technical challenges of network adaptation can result in substantial network costs⁹³.

102 This setting has raised debate about what is the most appropriate strategy to accommodate hydrogen: either developing pure hydrogen dedicated infrastructure - via both new investments and (chiefly) on the basis of repurposing existing natural gas assets -, or admixing natural gas and hydrogen at the current gas network up to a certain threshold.

103 Most stakeholders, including the EC in its recent Regulation recast proposal on the internal markets, say that blending hydrogen into the natural gas network is less efficient compared to the use of pure hydrogen⁹⁴. Hence they call for careful consideration of blending solutions, which might diminish gas quality and affect the interoperability of cross-border systems. As such, and although the recent EC proposals recognise the MS right to apply blending solutions in their national natural gas systems⁹⁵, they aim at setting an EU-wide harmonised hydrogen blending caps at cross-border IPs to limit the risk of market segmentation⁹⁶. The Regulation recast proposal entails that TSOs shall accept natural gas with hydrogen admixture levels below the 5% cap. Nonetheless, adjacent TSOs could agree on higher hydrogen blending levels for cross-border interconnection points⁹⁷.

92 The calorific value of hydrogen is about three times higher than of natural gas, while the density is nine times lower. However, at the operational pressures of gas network, the volumetric flow of hydrogen is around three times larger than the natural gas flow rate. These combined features entail that a quite similar energy quantity could be transported. With respect to combustion at final consumption points, the Wobbe Indexes of both gas and hydrogen are as such rather closely assimilated after factoring their specific gravities. This entails that both fuels (and their mixes) could be in the range of being substitutable. However, hydrogen has a higher flammability range and a faster burning velocity, so most end-use appliances would need some adaptation.

93 A reference of 10% admixture is commonly used; however, the exact quantity can vary among and within MSs in accordance to the technical features of their networks and final end-user industries and appliances. Main challenges can include measurement, energy conversion and importantly pipelines deterioration and higher compression needs.

94 Many of those stakeholders tend to also consider that hydrogen is in most applications a less efficient alternative to direct electrification.

95 In fact, at the REPowerEU Plan it is modelled that blending renewable hydrogen up to a 3% of volume into the current natural gas network can absorb about 1,3 million tonnes of hydrogen and replace 4,7 bcm natural gas. The EC estimates the costs for end-users and infrastructure operators to adapt to a 5% blending level to around 3,6 billion euros per year.

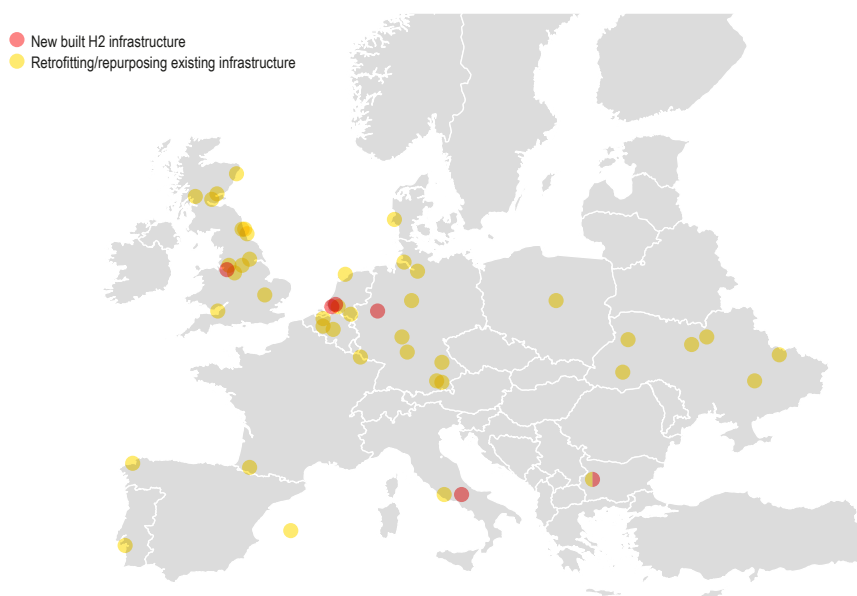
96 ACER published in 2020 a report summarising the current possibilities for admixing hydrogen at gas transmission networks, based on information proved by NRAs. In most MSs (65%), TSOs do not accept the injection of hydrogen into the transport grid, while Austria, France, Germany, Latvia, the Slovak Republic, Spain and Sweden accept it under certain conditions and thresholds.

97 This requires however considering all consequences and costs, including adaptation costs for household and industrial consumers. For example, the costs for end-users and infrastructure operators to adapt to a 5% blending level (by volume) it is estimated in around 3,6 billion per year for the whole EU.

Current hydrogen network status and foreseen development

- 104 Whilst the market appears to back the use of a pure and gradually enlarging pan-European hydrogen infrastructure, detecting the most appropriate investments is the next challenge. Making use of repurposed gas infrastructure to transport hydrogen is significantly cheaper than developing newly built hydrogen networks and hence repurposing solution should be prioritised to enable a more cost effective transition⁹⁸.
- 105 The aim is to start hydrogen network expansion by means of developing infrastructure that serves hydrogen valleys. The valleys will concentrate hydrogen supply and demand in early phases in connection with industrial clusters. MS's National Infrastructure Development Plans will be instrumental in detecting those demand clusters and their related necessary infrastructure. Furthermore, in those MSs that aim at developing more extended hydrogen networks, the construction of the system shall be based on realistic demand projections, including potential needs from the perspective of the electricity system.
- 106 The Clean Hydrogen Partnership⁹⁹ reports that a few dozens of relevant hydrogen valleys are in operation in Europe already. The valleys, but also other dedicated industrial clusters, are already served by a few hundred kilometres of dedicated hydrogen pipelines (e.g., more than 600 km in Belgium). These dedicated pipelines are by now outside of the regulated asset bases. In turn, ENTSOG reports in its Hydrogen Transparency Platform¹⁰⁰ that more than 70 new infrastructure projects, either for repurposing gas pipelines or for building new pure hydrogen infrastructure, are under development. These new projects have different objectives and sizes, such as serving industrial clusters, cross-border transportation of hydrogen, making available infrastructure to flow hydrogen from LNG terminals (including their adaptation to accept ammonia) or distributing hydrogen up to city gates and within cities.
- 107 The majority of the hydrogen pipelines in operation are in North West Europe. As for gas networks' retrofitting, and beyond NWE, relevant investments are announced in Spain, Italy and Poland and interestingly in Ukraine. This country is earmarked to export significant renewable hydrogen resources to the EU in coming years. Figure 13 shows the hydrogen infrastructure future developments reported at the ENTSOG's platform. Specific information for each project is available at the platform and the individual TSOs or project promoters' sites.

Figure 13: Overview of newly built hydrogen infrastructure and repurposed gas infrastructure projects under development by September 2022



Source: ENTSOG Hydrogen Transparency Platform

98 According to [ENTSOG, Hydrogen Europe and GIE studies](#) gas network repurposing costs can be between 0.2 and 0.6 million euros per km. That accounts to 10 to 35 % of the costs that would be required for a newly built hydrogen pipeline. If hydrogen needs to be shipped across the sea, it is more cost effective and/or only feasible to liquefy it or get it transported as ammonia.

99 The [Platform](#) provides an overview on the many different project locations of Hydrogen Valleys in Europe.

100 See ENTSOG Hydrogen [Projects Visualisation Platform](#).

- 108 In order to ensure transparency regarding the development of the hydrogen network across the whole of EU, the EC Gas Regulation proposes to establish a European Network of Network Operators for Hydrogen (ENNOH). The new Hydrogen TSO association should publish and regularly update a non-binding EU ten-year network development plan for hydrogen, which shall determine the coordinated needs for developing hydrogen markets.
- 109 Importantly, hydrogen investment plans need to be coordinated with the rest of energy infrastructure development plans. This is key, as the increase in renewable hydrogen production and its integration with renewable electricity requires an efficient and adapted electricity network. The plans shall, in particular, provide transparent information about the infrastructure that can be decommissioned within the current gas network, either to dismantle it or to use it for hydrogen transport.
- 110 While exact new infrastructure developments will be gradually determined in view of market progression, some initial estimates are being put for consideration. For example, the European Hydrogen Backbone Initiative¹⁰¹ arguably ambitiously predicts from 40,000 to 50,000 km of hydrogen transport infrastructure and associated compression stations to be in place by the year 2040. In accordance to their estimates, the initiative would require investment costs from 80 to 140 billion euros. The backbone would be achieved using 60 to 70% of repurposed natural gas pipelines and developing 30 to 40% new hydrogen pipeline.
- 111 Some of those projects are expected to receive EU grants and/or receive the Project of Common Interest (PCI) status, if they meet the criteria set by new TEN-E Regulation¹⁰². The new TEN-E Regulation has set new eligibility rules for funding cross-border energy infrastructure. The funds will prioritise and finance low-carbon gas infrastructure as well as, principally, electrical interconnectors and the deployment of offshore renewables. The proposal excludes conventional gas projects.

Methane leakages

- 112 To accomplish the ambition of decarbonising the EU gas sector, the reduction of methane leakages is crucial. Methane is a more potent contributor to the greenhouse effect than carbon dioxide in the short term¹⁰³. Therefore, undue flows can offset the benefits of natural gas relative to other fossil fuels in terms of the lower emissions generated by direct gas combustion.
- 113 The exact methane leakages across the supply chain that serves the EU are hard to delimit, as gas outflows can amply vary per producer and supply route. Methane leakages can originate at all the activities of the supply chain, from production and processing, to transmission, distribution, storage and end-use of gas¹⁰⁴. The IEA aims to tracking these volumes¹⁰⁵. The average leakage for the EU supply would be in the range of 2-3% led by fugitive leaks in the transportation and distribution chain (including LNG), followed by production.
- 114 All MSs monitor and report their methane emissions following the guidance of the United Nations Intergovernmental Panel on Climate Change. In accordance to the European Environmental Agency data¹⁰⁶, almost all EU's anthropogenic methane emissions originate from three sectors: the agriculture sector (in the lead), followed by waste and energy sectors¹⁰⁷. Gas supply chain leakages would account to 5 to 10% of that total. The exercise is quite challenging and further collaboration is becoming increasingly important to increase the accuracy of assessments¹⁰⁸.

101 The [European Hydrogen Backbone](#) initiative consists of a group of 31 energy infrastructure operators that aim to define hydrogen infrastructure to enable the development of EU renewable and low-carbon hydrogen market.

102 The [Trans-European Networks for Energy](#) (TEN-E) is an EU policy focused on linking the energy infrastructure of EU countries. It sets priority energy infrastructure corridors and priority thematic areas to develop better connected energy networks and provides funding for new investments. On June 2022, the revised TEN-E Regulation was published. The first PCI list adopted under the new rules is expected in autumn 2023.

103 The global warming potential of methane is assessed 25 times higher than for carbon dioxide across a 100-year period. Methane has a shorter atmospheric residence time than carbon dioxide, of around 10 years, but measured over a 20-year period, methane is up to 85 times more potent as a greenhouse gas.

104 Some leakages are unintentional, e.g. permeable connectors, leaking valves, while others are intentional, due to the design of the equipment or processes, e.g. venting for security reasons. See [Marcogaz report](#) for the Madrid Forum on ways the EU gas industry can contribute to the reduction of methane leakages for a categorization of methane emissions by activity.

105 See [IEA global methane tracker](#). The EC is also backing the activities of the [UN International Methane Emissions Observatory](#) (IMEO), which will collect methane emissions data streams to establish a global public record.

106 The EEA takes a responsible role in centralising the information at the EU level for the United Nations. See its analysis of GHG emission trends [here](#).

107 Approximately 60% of global methane emissions are anthropogenic. The largest estimated sources are agriculture (around 50%), waste (around 25%) and fossil fuel production and use (20 to 30%).

108 As emissions are not straightforward to assess they can be either measured or modelled.

- 115 Aiming at reducing total methane emissions, including those from the energy sector, the EC adopted an EU methane strategy in October 2020¹⁰⁹. Piecing together with that strategy, the EC proposed a detailed Regulation¹¹⁰ in December 2021, to clarify the rules improving measurement, reporting and verification of methane emissions in the gas supply chain. The Regulation aims an immediate reduction of methane emissions through mandatory leak detection and repair and a ban on venting and flaring at production points.
- 116 Monitoring and remediation is hence at the core of the Regulation. Up until now, the corrections had been, in essence, of a more voluntary character. This is because apart from environmental reasons, if the cost of the repair technologies to abate the leakages is competitive, there is an incentive to generate a profit¹¹¹. In fact, the EU gas industry is reported to have undertaken significant activities to better reporting and mitigate the different types of methane leakages in last years¹¹². These include using best practices and voluntary reduction targets.
- 117 The Regulation now proposes to legally require gas companies to annually measure and verify methane emissions by source, which will be reported to MSs. And then, to implement measures for methane leak detection and repair (LDAR). A harmonised approach will be set-up, including minimum requirements for LDAR measures, while allowing innovation and the development of new technologies and methods.
- 118 The Regulation has particularly appointed ACER to establish and make publicly available a set of indicators and reference values for the comparison of unit investment costs linked to measurement, reporting and abatement of methane emissions for comparable projects.
- 119 By now, the technicalities of methane leakage assessments fall out of the scope of the MMR. However, it will be important to look at market impact that a more stringent regulation on the subject may be required, aimed at external gas exporters in the years to come.
- 120 For example, according to IEA data, the emission intensity of the EU's gas producers is significantly lower than in countries that export gas to the EU, with the exception of Norway, which is deemed a low-emission producer¹¹³. Although the evaluation of the producers are very challenging and tracing leakage depends on several technical and transparency aspects, some estimates signal that relative leakages of selected external producers are at least three times higher. In this respect, an anticipated outcome of the EC Regulation is to set methane supply index standards for imported gas, which could become progressively stricter over time.

4.2 Transmission tariffs and TSO allowed revenue in the context of decarbonisation

- 121 This section reviews rules applicable to tariffs and to TSO costs and infrastructure in view of the decarbonisation pathways. The section draws on the proposals made in the Decarbonised Gases and Hydrogen Legislative Package Regulation recast and on the consultancy study on the Future Regulation of Natural Gas Networks that DNV Energy consultancy has conducted for ACER¹¹⁴.
- 122 Regarding tariffs, the Regulation recast has proposed a number of relevant changes, including setting tariff discounts for the access of decarbonised gases and hydrogen to transmission networks. These measures will have a clear impact on TSO revenue recovery and will require new mechanisms to be further designed.

109 See [EC methane strategy](#) as an integral part of the EU long-term climate strategy.

110 Proposal of [Regulation on methane emissions reduction](#) in the energy sector amending Regulation 2019/242.

111 In accordance to IEA estimates, it is technically viable to avoid around three quarters of the present-day global methane emissions, while 40-50% of them would be at a cost-efficient commercial value in past years' prices (and even more cost-effective now in view of the record-high prices).

112 In accordance to the previously referred study from Marcogaz, leakages have been reduced by 59% since 1990, including minus 10% in the last 5 years. This has been achieved not only due to better detection and technical repair but also due to declining EU domestic production.

113 See [IEA's methane tracker](#) figure 3 comparing the emission intensity of different gas an oil producers by tCH4/ktoe.

114 Future regulatory decisions on natural gas networks: repurposing, decommissioning and reinvestments done by DNV Energy Systems Germany published in October 2022.

Tariff provisions and discounts proposed in the Decarbonised Gases and Hydrogen Regulation recast

While the Decarbonised Gases and Hydrogen Directive establishes that transmission tariffs shall avoid cross-subsidies between network users, it also acknowledges that tariffs shall facilitate efficient gas trade and competition and provide incentives for investment and market development. To reconcile those aims, the recast Regulation establishes different tariff provisions for renewable and low carbon gasses and for hydrogen.

Regarding renewable and low carbon gasses (i.e., biomethane), the recast regulation proposes various discounts applicable to network users (Article 16):

- a) At least a 75% discount applicable to entry points from renewable and low carbon production facilities;
- b) A discount of 100% applicable to cross-border interconnection points including entry points from and exit points to third countries, as well as entry points from LNG terminals. These last discounts shall account to 100% of the regulated tariff from and shall be applied only for the shortest route, after providing the respective transmission system operator with a sustainability certificates.
- c) At entry points from and exit points to storage facilities¹¹⁵. Again, the discount takes the 75% of the values of capacity-based transmission tariffs.

In the case of hydrogen networks, the recast Regulation proposes, under Article 6, that no tariffs shall be charged for the access to hydrogen networks at interconnection points between Member States. The Regulation points at the need for an inter-TSO compensation agreement to redistribute the missing revenue resulting from the removal of these tariffs.

In addition, the recast Regulation proposes, under Article 4, a mechanism for users of natural gas networks to partly subsidise the costs of hydrogen networks. This mechanism is based on financial transfers to be recovered from domestic points of natural gas networks. These transfers should not be larger than the allowed revenue of hydrogen operators and should be approved for a limited period in time that can never be longer than one third of the depreciation period of the hydrogen infrastructure concerned.

The Agency shall issue recommendations to transmission or network operators and regulatory authorities on the methodologies for the criteria to allocate contributions to the dedicated charge among final consumers connected natural gas network.

123 Finally, the Regulation also establishes that the EC is empowered to establish a potential network code regarding harmonised tariff structures for hydrogen network, including rules for determining the value of transferred assets. Irrespectively of the granted tariff discounts or financial transfers, the future gaseous system development will be organised as a rule across two separated sub-systems, with a regulated asset base each:

1. A combined conventional-unabated and biomethane system, mainly built on existing gas infrastructure assets, which will be complemented by forthcoming infrastructure investments.
2. A hydrogen system, whose asset base will be gradually expanded consisting on newly built hydrogen infrastructure and repurposed existing gas infrastructure assets.

124 In addition, the recast Regulation proposes two new tasks to be performed on transmission tariffs and on the underlying allowed revenue of the TSOs.

¹¹⁵ Unless a storage facility is connected to more than one transmission or distribution network and used to compete with an interconnection point.

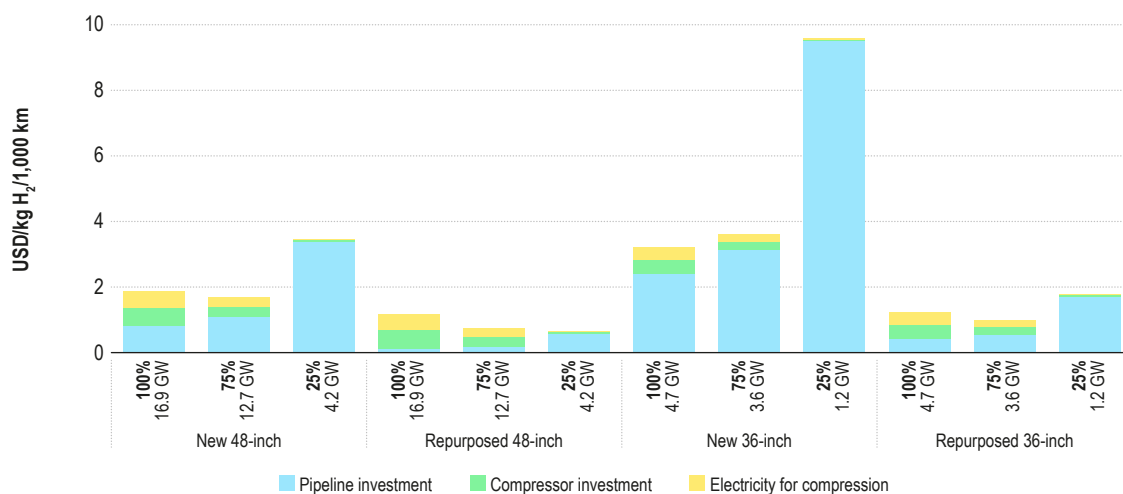
- 125 First, in relation to transmission tariffs, the relevant regulatory authorities shall assess the long-term evolution of transmission tariffs based on the expected changes in their allowed or target revenues and in gas demand until 2050. To perform this assessment the regulatory authority shall include the information of the strategy described in the national energy and climate plans of the respective Member State and the scenarios underpinning the integrated network development plan. TSOs' CAPEX are predominantly fixed costs. Their business model and the current national regulatory frameworks rely on the assumption of a long-term utilisation of their networks entailing long depreciation periods (30 to 60 years). In the context of the energy transition, regulatory authorities should be able to anticipate gas demand decrease to modify the regulatory arrangements in due time and prevent a situation where the cost recovery of transmission system operators through tariffs threatens the affordability for consumers due to an increasing ratio of fixed costs to gas demand. In doing that, they might place an obligation on the regulated entities - or at least place an incentive on them - to try and best avoid these situations. Where necessary, the depreciation profile or remuneration of transmission assets could, for example, be modified.
- 126 Second, the allowed revenue of the TSOs shall be subject to an efficiency comparison between TSOs to be appropriately defined by ACER. This is required by Article 17, which further establishes that ACER shall complete this assessment in four years. The results of such comparison shall be taken into account by the relevant regulatory authorities, when periodically setting the allowed or target revenues of TSOs.

Asset management in natural gas networks in the context of decarbonisation

- 127 The infrastructure that is currently used to transport natural gas will transform and face lower transport volumes in the future. It may transport biomethane or potentially be repurposed to transport hydrogen. In addition to this, a number of assets will reach the end of their regulatory accounting lives and might be decommissioned. This will require, the relevant authorities, to assess the choice of replacing existing natural gas assets or extending the asset lives.
- 128 In this context, the Agency has commissioned a study to be completed by DNV that will be published end October 2022. The report explores the key decision that NRAs will face in relation to the management of TSO transmission assets: repurposing, decommissioning and reinvestments.
- 129 First the DNV report looks at the repurposing of natural gas assets for hydrogen transportation. Repurposing will require transferring natural gas assets for its use as part of dedicated hydrogen networks. This will require clarity on the principles used to set the asset transfer value and to allocate the revenue received from the purchase to natural gas TSOs and to users of the natural gas networks.
- 130 Repurposing is a significantly cheaper option than building new hydrogen lines (e.g. gas network repurposing costs can be between 0.2 and 0.6 million euros per km, which is 10 to 35 % of the costs that would be required for a newly built hydrogen pipeline¹¹⁶). As such, repurposing is foreseen to become a dominant strategy, which shall also contribute to partly offset the foreseen decommissioning of segments of the current gas network in view of the anticipated natural gas consumption decrease in next years. In view of that, the EHB initiative estimates that levelised hydrogen transport cost could account from 2.3 to 4.4 euros for the transport of 1 MWh over 1,000 km. The transport costs are heavily impacted by the pipelines' capacity though. The IEA has also published some estimates on the subject, which are summarised in Figure 14.

116 See footnote 93.

Figure 14: Cost of hydrogen transmission based on pipeline diameter and throughput capacity



Source: IEA, *Global Hydrogen Review 2022*

Note: A 100% throughput capacity means that the pipeline is designed to operate at 100% of the theoretical maximum throughput capacity, e.g. a 48-inch pipeline would have a theoretical maximum capacity of 16.9 GW of hydrogen. Compressors electricity price is assumed to be 50 euros/MWh.

- 131 In accordance to the DNV consultancy study, most MSs don't have specific regulatory procedures in place for the detection and cost assessment of natural gas assets' repurposing yet. The identification of gas network assets to be repurposed is now days mostly a technical competence carried out by the TSO and approved by the relevant authority (in most cases the energy ministries). DNV's study offers an overview of the challenges involved in the repurposing of these natural gas assets. The study includes proposed procedures to identify assets, assess the benefits of repurposing, set the asset transfer value and provide incentives for the natural gas TSOs to transfer these assets. For the specific case of the asset transfer value, DNV recommends keeping the residual asset value as part of the current RAB as a reference for the transfer value. This value can further change based on specific circumstances that are assessed by DNV. According to the EC Regulation recast proposal, the value established should be such that cross-subsidies do not occur. The case study below offers some consideration on the related subject, focusing on the latest proposals to determine the transfer value of the repurposed assets for hydrogen network in The Netherlands.

Case study: Value of gas assets transferred to the future Dutch hydrogen network

In order to achieve a hydrogen market expansion as targeted by the Dutch government¹¹⁷, the development of a hydrogen network will be required. In June 2021, the Dutch Minister of Energy and Climate presented a three-phase rollout plan for the development of the Dutch hydrogen network by 2030¹¹⁸. The network will connect large industrial clusters, landing points for off-shore wind power generation, underground hydrogen storage facilities and interconnections with neighbouring countries. The network total length will be approximately 1200 km by 2030.

HyNetwork Services (HNS), a sister company of the Dutch gas TSO Gasunie Transport Services (GTS), will be tasked with the development and operation of this hydrogen network. At present, HNS is a non-regulated entity, which operates a 12 km hydrogen pipeline between two industrial companies in the Netherlands. It is anticipated that HNS will become a fully tariff-regulated hydrogen system operator by 2031.

Approximately 1,000 km of natural gas pipelines could be repurposed to be utilised by the future Dutch hydrogen consumers. This would entail large-scale transfers of assets between TSO and HNS over the coming years. However, at present, there is no clear framework defining the conditions for assets' transferring. In 2021, GTS and the Authority for Consumers and Markets (ACM), the Dutch NRA, initiated talks to define those conditions with discussions focusing on the value of the repurposed natural gas pipelines. However, the role of ACM in determining the value of assets' transfers was not clearly defined as HNS is not yet regulated by ACM. The regulatory framework applied to the TSO provides some indication about how asset transfers should be determined. As a rule, transfer value should avoid cross-subsidisation between network operators whilst the TSO should not be allowed to sell assets to its subsidiary company for a lower price than 'within the ordinary course of business'. Given the lack of clarity regarding this practice, ACM decided to initiate a public consultation. Following input from stakeholders, ACM formulated an opinion about reasonable assets' transfer prices.

Responses to the consultation were not aligned on the issue. Some respondents were of the view that no cost should be applied to transfers as (in their view) the transferred assets were not needed for the TSO anymore. However, other respondents were of the view that the full price of newly built pipelines should be provided (arguing that this would be the price of the alternative investments). ACM's view is that such asset transfers should be priced at the present value of the regulated asset base (RAB) of the gas TSO. This resulted in two options being put forward for consideration: first, determining the present value of the assets by means of calculating an average price per kilometre, based on the total RAB and total length of the gas network. Alternatively, a second option of using the specific RAB value of the pipeline segment subject to the transfer. On top of these two options, a distinction was possible; either using the asset value of the year of the transfer or using the asset value in an arbitrary fixed year (i.e., effectively stopping the depreciation of the assets that will be transferred in the future).

While ACM does not have the formal authority to make a binding decision about the transfer prices ACM published a position about transfer values¹¹⁹ favouring the specific RAB value of the pipeline segment option. This would be subject to the transfer in the year when the transfer occurs. This method would have been applied in case that HNS would be a regulated entity by now, something likely to be the case in the near future. ACM realizes that this method could mean that old gas assets are transferred for a relatively low price. However, this is an acceptable approach, given the objective of decarbonising the gas sector in the coming years. Moreover, the transfer of certain assets could be beneficial for the gas network users. This is because these transfers would be treated as divestments in the gas RAB, leading to reduced tariffs for the transport of gas as well as to reduced maintenance costs. If the TSO had to face investment to separate pipelines from its gas network, HNS network users should pay those additional costs.

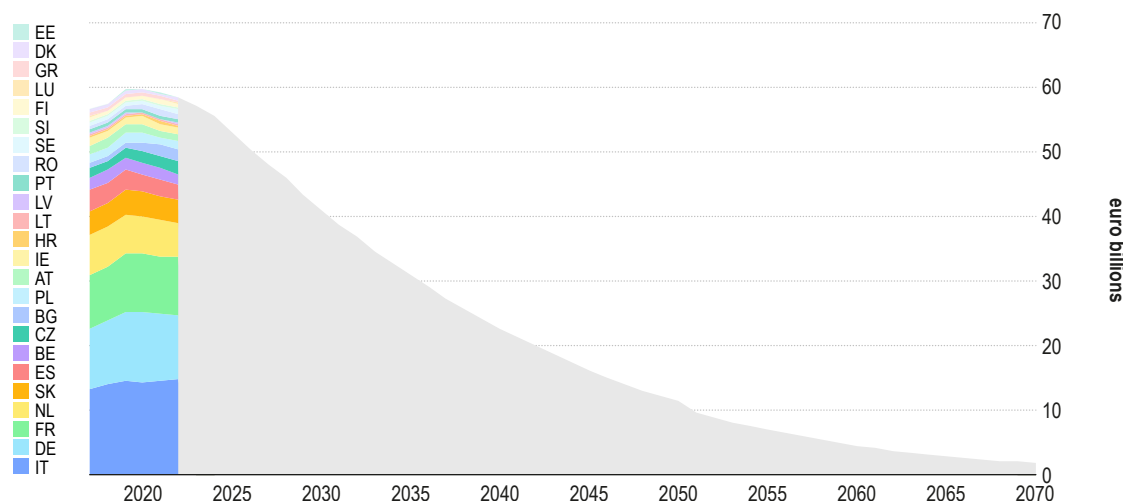
117 Gasunie published in June 2021 a referential [study](#) about the potential hydrogen transmission network in The Netherlands.

118 See the Minister [Letter](#) to the Dutch Parliament, 29 June 2022

119 See ACM relevant [conclusion](#) (in Dutch).

132 Second, the DNV report looks at the decommissioning of assets potentially becoming stranded. The decline of natural gas could potentially use to the underutilisation of specific network assets. The Report explores i) regulatory tools currently used for the decommissioning of natural gas assets, including the types of costs that are subject to decommissioning and ii) different options to allocate the costs of assets that could potentially become stranded. These costs could potentially be borne by users of the natural gas network, taxpayers or TSOs. For this analysis, the report includes the regulatory asset base cost projections of all EU TSOs. These trajectories, as shown in Figure 15 below, are a good instrument to assess the potential risk of stranding in the future in view of the decarbonisation objective.

Figure 15: Evolution of the existing conventional gas regulated asset base per MS – 2010 – 2070 – billion of euros

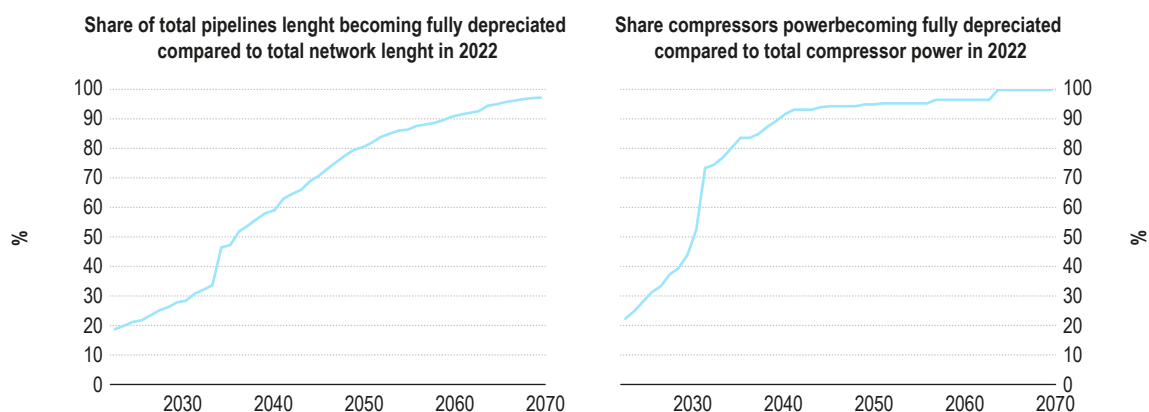


Source: ACER study of revenue recovery models executed by DNV. Information collected from NRAs.

Note: In the EC's proposal for a decarbonised gases and hydrogen Regulation, ACER would be tasked with carrying out every four years a TSO efficiency cost comparison. The RAB analysis only takes into account the gas assets currently in service. Additional investments could be concluded in the referred period, for example to shift away from Russian supply and expand LNG capacities.

133 Third, the report looks at reinvestments. As assets reach the end of their regulatory asset lives, NRAs will have to take decision on replacing these assets or on extending their useful life whenever this is technically possible. DNV argues that pipelines that are well maintained can remain in service for 80 years depending on the technical characteristics. The regulatory depreciation times of these assets are often lower, between 30 to 50 years. The depreciation times of the TSO infrastructure show a significant amount of assets becoming fully depreciated before 2050. Figure 16 shows the share of pipelines and compressors reaching the end of their regulatory lives in the 2022-70 period. NRAs will have to take decisions about extending the operation of this infrastructure or of replacing it with new assets. The latter could significantly increase the risk of stranding assets.

Figure 16: Share of total pipelines length and compressors becoming fully depreciated compared to total network length in 2022 (%)



Source: ACER study of revenue recovery models executed by DNV. Information collected from NRAs