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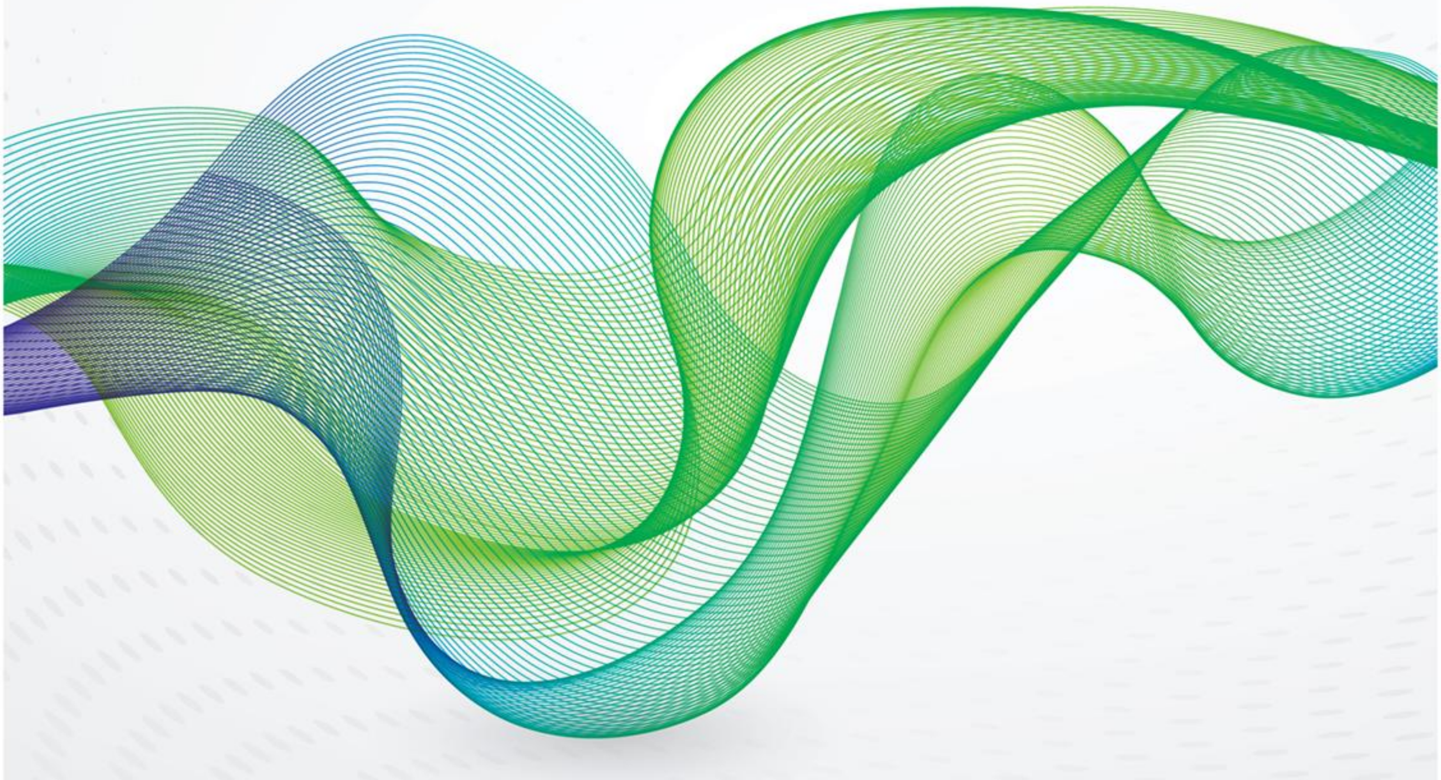
From natural gas to hydrogen:

what are the rules for European gas network decarbonisation and do they ensure flexibility and security of supply?



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Abbreviations

ACER – Agency for the Cooperation of Energy Regulators

CAM – Capacity Allocation Mechanisms

CEER – Council of European Energy Regulators

CMP – Congestion Management Procedures

CCUS – Carbon Capture Utilisation and Storage

DSO – Distribution System Operator

EC – European Commission

ENTSOG – European Network of Transmission System Operators for Gas

ENNOH – European Network of Network Operators for Hydrogen

ENTSOE – European Network of Transmission Operators for Electricity

EU – European Union

GHG – green-house gas

HNO – Hydrogen Network Operator

HTNO – Hydrogen Transmission Network Operator

HDNO – Hydrogen Distribution Network Operator

ITO – Independent Transmission Operator

IP – Interconnection Point

ISO – Independent System Operator

LNG – Liquified Natural Gas

LTC – Long Term Contract

NDP – National Network Development Plan

NECP – National Energy and Climate Plan

OU – Ownership Unbundling

PCI – Project of Common Interest

PMI – Project of Mutual Interest

RNGH Directive – Renewable and Natural Gases and Hydrogen Directive

RNGH Regulation – Renewable and Natural Gases and Hydrogen Regulation

TEN-E Regulation – Regulation on guidelines for trans-European energy infrastructure

TYNDP – EU Ten-Year Network Development Plan

TSO – Transmission System Operator

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Executive Summary

The paper's rationale

On 11 April 2024 the European Parliament adopted the Renewable and Natural Gases and Hydrogen (RNGH) Directive and the RNGH Regulation – otherwise known as the Decarbonised Gas and Hydrogen Package – and published both documents on 12 April 2024. Once approved by the Council and published in the EU Official Journal – expected by June 2024 – the Package, together with the TEN-E Regulation (adopted in 2022), will constitute the new regulatory framework, governing construction of, and access to, hydrogen networks, and the re-purposing and de-commissioning of, and access to, natural gas networks in the EU.[1] This paper seeks to understand the impact of this framework, which is aimed primarily at the development and operation of hydrogen networks, on the existing natural gas networks (200,000 km of transmission and over 2,000,000 km of distribution pipelines) and the emerging hydrogen networks (at present, total length of hydrogen pipelines is only ~2,000 km – mostly privately owned, small capacity unregulated lines). In particular, the paper seeks to determine whether the new framework provides flexibility, enabling a step-by-step development of hydrogen networks, whose topology, scale and size will depend on the supply and demand for hydrogen (which is at present highly uncertain) and on the decarbonisation pathways chosen by (mostly) industrial users (i.e. via renewable and/or low - carbon hydrogen). It also seeks to determine whether the framework provides flexibility, enabling the required evolution of natural gas networks (Chapters 2 and 3). The paper also seeks to establish whether the new framework provides assurance that network decarbonisation – constituted by phasing out natural gas networks and phasing in hydrogen networks – will take place in a co-ordinated manner across the EU without negatively affecting the security of natural gas supply (Chapter 4).

Regulatory flexibility (natural gas)

To analyse the flexibility of the new EU framework, the paper examines the provisions of the RNGH Directive and the RNGH Regulation governing the operation of natural gas system (Sections 2.1.1 and 2.2.1) and hydrogen system (Sections 2.1.2 and 2.2.2). Both documents preserved main principles governing the **natural gas market** (unbundling models, regulated access to networks and LNG terminals, negotiated access to storage, regulated tariffs), while adding new provisions aimed at decarbonisation and security of supply. As far as decarbonisation is concerned, the RNGH Directive prohibits the signing of new long-term contracts (LTCs) for unabated fossil gas with a duration beyond 2049, with no exemptions allowed – in sync with the EU's 'net zero' 2050 target. The RNGH Regulation facilitates access of renewable and low carbon gases to the natural gas system by mandating tariff discounts at the entry points from production facilities and at the intra-EU Interconnection Points (100% for renewable and 75% for low carbon); it also mandates discounts at the entry points from, and the exit points to, storage facilities (100% for both renewable and low carbon). However, national regulators are allowed not to apply such discounts or set lower rates. As far as measures aimed at security of supply are concerned, the RNGH Regulation incorporates some 'emergency' legislation, adopted during the 2021-23 energy crisis. This includes:

- mandating certification of storage system operators (SSOs),
- enabling regulators to apply a tariff discount (of up to 100 per cent) in respect of natural gas at entry points from, and exit points to, storage facilities and at entry points from LNG facilities until 31 December 2025 and potentially beyond,

[1] This paper is based on the analysis of the texts of the RNGH Directive and the RNGH Regulation adopted by the Parliament on 11 April and published on its website on 12 April 2024, see European Parliament (2024a) and (2024b).

- establishing the EU Energy Platform for demand aggregation and joint purchasing, and
- amending gas sharing (solidarity) rules.

Some measures that could interfere with market functioning were softened (e.g. demand aggregation and joint purchasing were not made mandatory) whereas others (e.g. mandatory gas storage filling targets/trajectories and demand reduction) were not included. Yet the Regulation's permission for regulators to abolish tariffs at the IPs could potentially enable market distortion. Guided by the RePowerEU Plan, some measures were specifically directed against Russian gas, such as enabling national regulators to introduce (pipeline and LNG) import capacity restrictions and excluding Russian gas supplies from the EU Platform. While existing capacity allocation mechanisms (CAM) and congestion management procedures (CMP) have been preserved, changes are expected as part of the CAM network code revision, aimed at more efficient utilisation of existing capacity in view of changed flow patterns in the aftermath of the crisis, whereas an incremental (new) capacity allocation procedure could be eliminated altogether. Should this happen, an exemption regime – requiring the approval of national regulators and ultimately the EC – would become the only way to build new natural gas infrastructure**. Thus, while the regulatory framework for the natural gas market has been largely preserved, the planned changes would introduce some uncertainty in respect of future capacity allocation.**

Regulatory flexibility (hydrogen)

The RNGH Directive and the RNGH Regulation have largely extended the rules governing the (mature) natural gas market onto the (nascent) **hydrogen market**. The Directive requires hydrogen transmission network operators (HTNOs) to be unbundled under the same models as natural gas TSOs (OU, ITO (integrated HTNO), or ISO (independent HTNO)). It also mandates horizontal legal unbundling (allowing natural gas network operators to operate a hydrogen network within a framework of a separate legal entity), with regulators empowered to provide derogations. It stipulates regulated access to (onshore and offshore) hydrogen networks, regulated access to hydrogen storages and negotiated access to hydrogen (ammonia) terminals. This regulatory straight–jacket was partly loosened by introducing <u>a transition period</u> for implementing regulated access to hydrogen networks and storages (making it mandatory from 1 January 2033) as well as by <u>allowing an ITO unbundling model to be used indefinitely</u>.

Some regulatory flexibility was provided by establishing an exemptions and derogations regime. The Directive allowed the regulators to grant some potentially indefinite **derogations** for:

- <u>existing hydrogen networks</u> belonging to a vertically integrated undertaking from the provisions of the Directive on network access, unbundling of HTNOs, unbundling of HDNOs, certification of HTNOs and from some of the provisions of the RNGH Regulation, for instance on access to networks and regional cooperation within ENNOH, for as long as the existing network is not connected to another network and not expanded by more than 5%;
- <u>existing and new hydrogen networks transporting hydrogen within a geographically confined, industrial or commercial area</u> from the provisions of the Directive on vertical unbundling of HTNOs, unbundling of HDNOs, and certification for HTNOs, for as long as the network does not include hydrogen interconnectors, does not have direct connections to hydrogen storage facilities or terminals, primarily supplies hydrogen to directly connected customers, and is not connected to any other hydrogen network.

The Regulation allows the regulators to grant **exemptions** for a defined period for:

- <u>major new (or significant increases in existing) hydrogen infrastructure</u> (interconnections, import terminals and underground storages) from the Directive's provisions on vertical unbundling of HTNOs, access to networks, terminals and storages, and from some of the Regulation's provisions (e.g. access to networks), subject to the EC's approval.

Coordination and financing of network decarbonisation (natural gas and hydrogen)

To analyse the EU regulatory framework's ability to guarantee coordinated network decarbonisation across the EU, without negatively affecting security of supply, this paper examines the RNGH Directive, the RNGH Regulation and the TEN-E provisions governing national (NDPs) and EU-wide (TYNDPs) network development plans (Sections 4.4 – 4.7). While network development coordination has previously been achieved through the biannual EU-wide natural gas TYNDPs, the RNGH Regulation mandates development of two separate TYNDPs – one for natural gas and another for hydrogen – splitting responsibility between ENTSOG and ENNOH (yet to be established in 2025). ENTSOG will remain responsible for developing both TYNDPs until ENNOH assumes responsibility for developing the hydrogen TYNDP 2028. From then ENTSOG will only be responsible for developing the natural gas TYNDPs. ENTSOG has not been obliged to develop natural gas CBA methodology since 2022, when the TEN-E Regulation made natural gas infrastructure, except that which is associated with repurposing, ineligible for a PCI status. It will no longer be obliged to develop any CBA methodology once the responsibility for developing hydrogen CBA methodology shifts to ENNOH. This applies to hydrogen projects, including natural gas projects associated with repurposing but not any other natural gas projects. This makes it unclear which methodology – if any – will be applied by ENTSOG for analysing the existing and prospective natural gas infrastructure in its future gas TYNDPs, including in respect of security of supply. **This problem could be overcome if both the EC and ACER were to recommend ENTSOG to develop such methodology. It is not legally required to do so, but is not prohibited from doing so either.**

Significant and growing inconsistency between the EU-wide TYNDPs and national NDPs presents another problem for coordinated network development across the EU. This is demonstrated by the TYNDP 2022, where only 17% of hydrogen infrastructure projects were included in the NDPs. The decision to include many projects identified through the RePowerEU Plan rather than through NDPs, which would have been the normal procedure, was the key reason for TYNDP 2022 – NDP inconsistency. Subsequently, many of these projects have been included in the first EU hydrogen PCI/PMI with only a light-touch assessment based on the EC's simplified CBA methodology. While some accepted projects reflect the reality as they are planned to be located in or connect existing industrial clusters, others appear to reflect EC desire to 'fill in' the RePowerEU Plan hydrogen import corridors rather than genuine readiness to invest (Section 4.7).

TSOs and HTNOs are obliged to include information on natural gas infrastructure that can or will be decommissioned, and on hydrogen infrastructure that can or will be repurposed, in their separate or integrated NDPs. NRAs are obliged to ensure coordinated development of networks at national level and through cross-border coordination with adjacent NRAs. It is paramount therefore that only those projects that have been included in the national NDPs are also included in the TYNDPs. Negative impacts of TYNDP-NDP inconsistency will probably be more pronounced in the future than in the past, as the EU gas system is undergoing a profound transformation caused by EU decarbonisation policies. **This inconsistency could potentially endanger security of natural gas supply by preventing hydrogen networks from being phased in and natural gas networks form being phased out in a coordinated manner across the EU.**

Finally, it is not clear yet how the transformation will be financed. As re-purposing of existing natural gas networks to transport hydrogen is expected to play a significant role in developing the European hydrogen network, the rules governing the transfer of natural gas assets for repurposing – including how their transfer value is determined – will be of key importance (Section 4.3). While the RNGH Regulation mandates separate RABs for natural gas, hydrogen and electricity assets, it ultimately allows cross-subsidization between different regulated services – e.g. natural gas and hydrogen transportation – in the form of a dedicated charge, which could only be applied to end-users within the same Member State, and subject to regulator's confirmation that the network financing through access tariffs paid by its users only was not viable. This would limit cross-subsidization to the national level, with regulators approving the size and duration of the transfer charge, the value of transferred assets and inter-temporal cost allocation in line with the rules to be stipulated in the EU Network Codes for hydrogen developed by the end of the 2020s. It would also allow hydrogen network operators to spread the cost recovery over time. The TEN-E Regulation has enabled financial support for different categories of cross-border infrastructure, relevant for the development of the European hydrogen network – such as new onshore and offshore hydrogen pipelines and repurposed natural gas pipelines, hydrogen storage facilities, hydrogen (ammonia) import terminals, CO2 pipelines and storages – by making them eligible for a PCI/PMI status and hence EU CEF funding (Section 4.2). Although the CEF energy infrastructure budget is constrained (5.84 bn euros during 2021-27), a project that has received funds under CEF may also receive funds from other EU funding programmes.

The EU natural gas and hydrogen regulation: "work in progress"

The paper concludes that regulatory flexibility, built into the EU regulatory framework by means of establishing a transition implementation period, allowing exemptions and derogations for existing and new hydrogen infrastructure, and enabling financial and regulatory support via a PCI/PMI status, **is far from certain to be sufficient for enabling the EU hydrogen market to develop at scale.** The transition period allowed – until 1 January 2033, when regulated access to networks and storages becomes mandatory – **is likely to prove to be too short, in which case an avalanche of applications for exemptions and derogations can be expected**. The framework also does not guarantee that phasing in hydrogen networks and phasing out natural gas networks – either through re-purposing or de-commissioning – will be carried out in a coordinated manner across the EU, without negatively affecting the security of natural gas supply. **Overall, the framework appears to be built on the premise that the EU hydrogen market will develop fast and at scale, while it lacks the "safety cushion" – including in respect of re-purposing the natural gas networks that could still be needed – should the hydrogen market roll-out be slower and more gradual.** However, as the speed and the scale of the hydrogen market development in the EU becomes more apparent, the regulatory framework could be adjusted. The framework is not complete yet, as more rules will be established in the upcoming EU Network Codes for hydrogen (and the amended Network Codes for natural gas) in the 2020s, as the hydrogen market rolls out (or fails to do so) in the EU. Thus, the framework will continue to evolve and remain 'work in progress' at least until 2030 and possibly beyond.

1. Introduction

The European natural gas networks are facing an existential challenge from the ongoing process of decarbonisation of the European energy system. Given the EU Climate Law legally binding green-house gas (GHG) emissions reduction targets (55% by 2030 and 'net zero' by 2050), there will be less and less natural gas for these networks to transport as time goes by, particularly post-2030. According to the EC, renewable and low carbon gases are expected to "represent some 2/3 of the gaseous fuels in the 2050 energy mix" whereas fossil gas with carbon capture, utilisation and storage (CCUS) is expected to represent the remainder.[2] Therefore, the natural gas networks must decarbonize by becoming capable of accepting and transporting renewable and low carbon (decarbonised) gases (e.g. hydrogen, biomethane, synthetic gas) in addition to, and increasingly instead of, unabated methane.

While the EC welcomes various renewable (including biomethane) and low carbon gases into the European energy mix, hydrogen has been its absolute favourite, viewed as "the energy molecule of choice" for achieving the EU Climate Law GHG emissions reduction targets. Indeed, hydrogen could play an important role in decarbonizing the EU industrial sector, particularly in 'hard-to-abate' applications such as fertilizers, refineries, steel making and cement – if the conditions (including the regulatory framework for hydrogen market) are right. Hydrogen's role in decarbonizing power, heat and transport sectors would likely be more modest due to significant competition from electrification.[3]

The EC hydrogen ambition is manifested in various policy and legislative initiatives, such as the EU Hydrogen Strategy, Fit for 55 Package[4] and RePowerEU Plan. The **EU Hydrogen Strategy**,[5] presented in July 2020, stipulated a target of 10 mn tons of renewable hydrogen by 2030. This target was later re-affirmed in **the Fit for 55 Package**, presented in July 2021.[6] These documents were followed by **the RePowerEU Plan**, adopted in May 2022, which further reinforced the EU hydrogen ambition, by doubling the renewable hydrogen target to 20 mn tons by 2030 (of which 10 mn tons was expected to be produced in the EU and another 10 mn tons – imported from non-EU countries).[7] The RePowerEU Plan was adopted in furtherance of the EU Versailles Declaration, whereby all EU Member States had pledged to phase out their dependence on Russian gas 'as soon as possible', and as such the Plan reflected the EU's hope (as opposed to knowledge) that hydrogen would play an important role in doing so.[8]

The EC hydrogen ambition and its vision of the future European gas system being a 'tale of two systems' – one for (progressively decarbonised) methane and another for hydrogen, both developing in parallel and co-existing[9] – is also reflected in its legislative initiatives, which provided a legal/regulatory framework for the development of a hydrogen market. These include the **TEN-E Regulation** (revised and adopted in summer 2022) and the **Renewable and Natural Gases and Hydrogen (RNGH) Directive and the RNGH Regulation** (advanced as part of the Fit for 55 Package in 2021 and adopted by the European Parliament in April 2024).

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[2] EC (2021a), explanatory memorandum, p. 1.
[3] Lambert and Schulte (2021).
[4] A set of proposals adopted to reach the GHG emissions reduction target of 55% by 2030, including inter alia the EC Proposals for a RNGH Directive (EC (2021a)) and Regulation (EC (2021b)).
[5] EC (2020), EU Hydrogen Strategy, p. 6. For analysis of the Hydrogen Strategy, see Lambert (2020), Barnes and Yafimava (2020).
[6] Council (2023e), 'Fit for 55: shifting from fossil gas to renewable and low carbon gases'
[7] For comparison, the EU Fit for 55 Plan had envisaged 10 mn tons of renewable hydrogen by 2030, which at the time was considered as too ambitious and hardly realistic.
[8] There has been growing realisation that the RePowerEU Plan targets for renewable hydrogen are unrealistic, particularly because of estimated significant shortage of renewable power that would need to be available for producing this amount of hydrogen.
[9] This paper primarily focuses on pipeline transportation dimension of natural gas and hydrogen systems.

The revised TEN-E Regulation aimed at enabling and facilitating access of renewable and low carbon gases to the EU energy system, bringing the original TEN-E Regulation (adopted in 2017) in line with the Green Deal and the EU Climate Law targets. It did so by establishing the rules, which allowed for faster permitting in respect of, and enabled the EU financing for, the Projects of Common Interest (PCIs) and Projects of Mutual Interest (PMIs).[10] These included *inter alia* cross-border pipelines for renewable and low carbon gases and CO2 pipelines as well as carbon storage facilities.[11] While the Regulation stipulated the rules for renewable and low-carbon gases at large, it mostly focused on hydrogen by providing a regulatory framework for:

- refurbishing the existing natural gas pipelines to enable them to transport hydrogen-methane blends (potentially as a transitional step towards carrying pure hydrogen), and
- repurposing the existing natural gas pipelines to enable them to carry pure hydrogen,

thus reflecting the EU vision for the future European gas system, consisting of natural gas and hydrogen systems.

The RNGH Directive and the RNGH Regulation – otherwise known as the Decarbonised Gas and Hydrogen Package[12] – seek to facilitate an introduction of renewable and low-carbon gases into the European energy system, enabling a shift from natural gas and allowing for "new gases to play their needed role towards the goal of EU climate neutrality in 2050."[13] They did so by establishing the rules governing development and operation of the (nascent) hydrogen market, largely modelling it on the rules governing the (mature) natural gas market. The EC has sought for the RNGH Directive and Regulation to replace the Third Gas Directive and Gas Regulation 715, which have governed the natural gas market operation for more than a decade but contained no rules for hydrogen. In particular, the EC Proposal for a RNGH Directive stated that the current legal/regulatory framework did "not address the deployment of hydrogen as an independent energy carrier via dedicated hydrogen networks", there were "no rules at EU level on tariff-based investments in networks, or on the ownership and operation of dedicated hydrogen networks," and there were "no harmonised rules on (pure) hydrogen quality".[14] By stipulating the rules for the hydrogen market development, the EC aimed to remove the existing barriers to "the development of a cost-effective, cross-border hydrogen infrastructure and competitive hydrogen market". In addition to providing the rules for developing and operating the hydrogen market, the RNGH Directive and the RNGH Regulation established and updated the network planning provisions in respect of natural gas and hydrogen networks respectively, aiming at coordinated development of gas infrastructure.

The EU vision for the future European gas system is reflected in the aforementioned policy (Hydrogen Strategy, RePowerEU) and legislative (the TEN-E Regulation, the RNGH Directive and the RNGH Regulation) initiatives. The vision is that eventually there will be two separate systems: one for natural gas, which will transport increasing volumes of biomethane and synthetic gases and decreasing volumes of unabated methane (possibly blended with hydrogen), and another – for pure hydrogen. While some natural gas networks will continue to remain in operation, others will have to be either re-purposed to transport pure hydrogen or CO2 or de-commissioned. Specific options will differ for different networks in different EU Member States.

It is important to acknowledge that, at present, the European hydrogen market does not exist yet. The total length of hydrogen pipelines in Europe is less than 2,000 km, compared to the total length of

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10 A PCI is a project necessary to implement the energy infrastructure priority corridors and areas in EU Member States whereas a PMI is a project promoted by the EU in cooperation with non-EU countries.

11 For detailed analysis of the TEN-E Regulation, see Yafimava (2022), 'The TEN-E Regulation: allowing a role for decarbonised gas'.

12 Sometimes also referred to as the Fourth Gas Package or recast Gas Directive and Regulation.

13 EC (2021a), p. 2.

14 EC (2021a), pp. 2-3.

natural gas transmission pipelines of over 200,000 km.[15] Therefore the large-scale deployment of hydrogen would necessitate the development of a European hydrogen pipeline network. Given the significant uncertainty about hydrogen supply and demand as well as competition from power cables capable of transporting electricity over long distances to produce renewable hydrogen close to demand centres,[16] the scale and the topology of this future hydrogen network are unclear.[17] But it is clear that more hydrogen pipelines will have to be built.[18] There will also be an impact on the existing natural gas network. Some pipelines would have to be retrofitted to enable transport of hydrogen blends, and some repurposed to make them capable of transporting pure hydrogen. Indeed, while some percentage of hydrogen – varying from one network to another – could be blended with methane (as well as biomethane and synthetic gas) transported by the existing natural gas networks, significant readjustments and often complete replacement of networks would normally be needed for enabling transportation of pure hydrogen. This suggests that while blending could be a short-term strategy to enable hydrogen's early phase-in, the long-term strategy for natural gas networks should be about transition to hydrogen as well as biomethane and synthetic gas (at TSO level) and biogas (at DSO level).

As the RNGH Directive and the Regulation, together with the TEN-E Regulation, provided a regulatory framework, governing construction of, and access to, hydrogen networks, as well as re-purposing and de-commissioning of, and access to, natural gas networks, these documents are the main subject of this paper. The paper seeks to understand the impact of the regulatory framework created by these documents – aimed primarily at the development and operation of hydrogen networks – on the existing natural gas networks, particularly in respect of re-purposing and de-commissioning. It will examine whether this framework is adequate for ensuring that the hydrogen networks are phased in and natural gas networks are phased out – either through re-purposing or de-commissioning - in a coordinated manner across the EU, without jeopardising natural gas (and hydrogen) security of supply. More specifically, it seeks to understand whether the framework provides sufficient assurance that a natural gas network would not be re-purposed to transport hydrogen when there was no hydrogen available to flow through it in that timeframe, or consumers previously served through this network would be left with no alternative energy supply. This question is especially pertinent given significant uncertainty in respect of the future supply and demand for hydrogen in Europe, and therefore the scale and the topology of the required European hydrogen pipeline network. In turn, this leads this paper to enquire whether the regulatory framework, provided by the RNGH Directive and the RNGH Regulation as well as the TEN-E Regulation, is sufficiently flexible initially to enable development of smaller scale hydrogen networks, confined to regional industrial clusters ('valleys'), before moving towards the development of an integrated pan-European hydrogen network (which may or may not happen). While the paper is focused on the natural gas networks, it also explains the main principles, stipulated in the RNGH Directive and the RNGH Regulation, governing both the (existing) natural gas and the (emerging) hydrogen networks – namely unbundling, access and tariff regimes – given an intrinsic connexion (not in the least because of the role the repurposing of the latter is expected to play in the development of the former) between the two.

While the TEN-E Regulation has been in force since 23 June 2022, the RNGH Directive and the RNGH Regulation will enter into force on the 20th day following their publication in the EU Official Journal – expected by June 2024. As this paper goes to print in April 2024, both documents are awaiting adoption by the Council and subsequent publication in the Journal, having been adopted by the European

[15] Lambert and Schulte (2021).
[16] The so called 'molecules vs electrons' debate.
[17] There is a European Hydrogen Backbone (EHB) initiative advanced by European TSOs which presents a vision for a pan - European hydrogen transportation network of 53,000 km by 2040. However, it is uncertain if such vision will be realised, see Section 3.1 for discussion.
[18] Patonia et al (2023), 'Hydrogen pipelines vs HVDC lines: should we transfer green molecules or electrons?'.

Parliament on 11 April and published on its website on 12 April 2024.[19] This paper is mostly focused on analysing the RNGH Directive and the RNGH Regulation (based on the texts published by the Parliament), while also comparing both documents with the EC, the Parliament and the Council Proposals to demonstrate how different views were reconciled and what impact it would have on gas network decarbonisation. It also summarises the relevant clauses of the TEN-E Regulation, analysed by this author in detail in an earlier OIES publication.[20]

The paper is structured as follows:

- this Introduction (Chapter 1) is followed by the presentation of the EU vision for the future of European gas networks – both natural gas and hydrogen – including the key provisions of the RNGH Directive and the RNGH Regulation on the proposed structure of the natural gas and hydrogen markets and their rules of operation (unbundling, access, and tariffs) (Chapter 2);
- discussion of the uncertainty around the scale and the topology of the future European hydrogen network and the need for regulatory flexibility enabling both lower- and higher-scale developments (Chapter 3);
- analysis of the main options available for the existing European natural gas networks to decarbonize (re-purposing for hydrogen transportation, de-commissioning, and continued operation while transporting increasingly decarbonized gases) (Chapter 4),
- analysis of the main provisions of the RNGH Directive and the RNGH Regulation governing the regulatory treatment of gas networks' repurposing, de-commissioning, and continued operation, while also reflecting the Council and the Parliament positions (Chapter 5),
- analysis of the RNGH Directive and the RNGH Regulation as well as the TEN-E Regulation' network planning provisions, including those on faster permitting and funding for renewable and low-carbon gas infrastructure PCI/PMI projects (Chapter 6).
- the paper concludes with the Conclusions (Chapter 7).

2. The EU vision for the future European gas system, consisting of natural gas and hydrogen systems, and legislative provisions governing its operation

As noted in the Introduction, the EC views the future European gas network as "a tale of two systems":

- **a natural gas system**,[21] which will include <u>a natural gas network</u> (as well as natural gas storages and LNG facilities), which will increasingly transport biomethane and synthetic gas and decreasingly – natural gas (possibly blended with hydrogen), and
- **a hydrogen system**, which will include <u>a hydrogen network</u> (as well as hydrogen storages and hydrogen import terminals), which will transport pure hydrogen, and will consist of newly built hydrogen pipelines and repurposed natural gas pipelines.

The EC acknowledged that the hydrogen network will 'progressively complement' the natural gas network thus suggesting that the two networks will develop in parallel and co-exist for a foreseeable

[19] These texts were adopted on the basis of a provisional political agreement that had been reached between the Council and the Parliament in respect of the Directive on 27 November 2023 and the Regulation – on 7 December 2023, and published by the Council on its website on 21 December 2023.
[20] See Yafimava (2022), 'The TEN-E Regulation'.
[21] This paper refers to the natural gas system as it is the term used in the EU regulation although a 'methane system' might have been a more appropriate term, as not all the gas that will be moving through this system would be a naturally occurring gas.

future, given that the deployment of renewable and low carbon gases is 'likely to develop at a different pace across the EU'.[22] As the role of hydrogen will be quite different to that of natural gas, the role of the hydrogen pipeline system will also be different to that of the natural gas pipeline system. It will play more of a balancing role rather than providing for large scale transmission over long distances.

The key principles of natural gas and hydrogen system operation are provided in the RNGH Directive and the RNGH Regulation, which are summarised and analysed in this Chapter.

2.1 Key definitions

2.1.1 Natural gas system

Notably, while the previous generations of Gas Directives did not provide any definition of natural gas – simply presuming it to be methane – the RNGH Directive defines **natural gas** as:

> 'gas that <u>primarily consist of methane</u>, including biomethane, <u>or other types of gas</u>, that can technically and safely be injected into, and transported through, the natural gas system'.

In so doing, the RNGH Directive re-confirmed a legal basis for entry of renewable and low carbon gases into the natural gas system, as the rules, established by the Third Gas Directive for natural gas, also applied to 'biogas and gas from biomass or other types of gas', as long as they could be technically and safely injected into and transported through the natural gas system.

The RNGH Directive defines **a natural gas system** as

> "a system of infrastructures, including <u>pipelines, LNG terminals and storage facilities</u>, which <u>transports gas, that primarily consist of methane and include biomethane, or other types of gas</u> that can technically and safely be injected into, and transported through, the natural gas system" (Art. 2.4).

While this definition does not state that the gas in the system needs to be of a reasonably consistent quality – a key requirement for the principle of the current gas trading system to continue to be workable – the question of cross-border coordination of gas quality is addressed by the RNGH Regulation in Art. 21, which obliges TSOs to cooperate to avoid restrictions to cross-border flows due to gas quality differences at interconnection points (IPs) between Member States, including in respect of hydrogen blends where the hydrogen content blended into the natural gas system does not exceed 2%.

Correspondingly, **transmission** – a network component of the natural gas system – is defined as "the transport of natural gas through a network, which mainly contains high-pressure pipelines […]" (Art. 2.16) while **a transmission system operator (TSO)** is defined as "a natural or legal person who carries out the function of transmission and is responsible for operating, ensuring the maintenance of, and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transport of natural gas' (Art. 2.17). The Proposal also defined **an interconnector** as "a transmission line which crosses or spans a border between Member States for the purpose of connecting the national transmission system of those Member States or a transmission line between a Member State and a third country up to the territory of the Member States or the territorial sea of that Member State' (Art. 2.33). **Distribution** – another network component of the natural gas system – is defined as "the transport of natural gas through local or regional pipeline networks with a view to its delivery to customers, excluding supply" (Art. 2.18). Separately, the Proposal defines **an upstream pipeline network** as 'any pipeline or network of pipelines operated and/or constructed as

[22] EC (2021a).

part of an oil or natural gas production project or used to convey natural gas from one or more such projects to a processing plant or terminal or final coastal landing terminal' (Art. 2.15).

Apart from pipelines, the natural gas system also includes LNG terminals and storage facilities, operated by LNG system operators and storage system operators respectively. **LNG facility** is defined as "'a terminal which is used for the liquefaction of natural gas or the importation, offloading, and regasification of LNG, including ancillary services and temporary storage necessary for the regasification process and subsequent delivery to the transmission system, but not including any part of LNG terminals used for storage" (Art. 2.27). **Storage facility** is defined 'a facility used for the stocking of natural gas and owned and/or operated by a natural gas undertaking, including the part of LNG facilities used for storage but excluding the portion used for production operations, and excluding facilities reserved exclusively for transmission system operators [TSOs] in carrying out their functions' (Art. 2.25).

2.1.2 Hydrogen system

The RNGH Directive also defines **a hydrogen system** as:

> "a system of infrastructure, including hydrogen networks, hydrogen storage, and hydrogen terminals, which contains hydrogen of a high grade of purity" (Art. 2.5),

while defining a **hydrogen network** as:

> 'a network of onshore and offshore pipelines used for the transport of hydrogen of a high grade of purity with a view to its delivery to customers, excluding supply' (Art. 2.20).

This definition means that the hydrogen system is legally allowed to accept only **hydrogen** of a high degree of purity – and not any other gas. At present, most of hydrogen produced and consumed in the EU is produced from natural gas through methane reforming process, whereas subsequent CO2 emissions are not captured.

The EU Hydrogen Strategy distinguished between renewable and low carbon hydrogen, defining each as follows:

- **renewable hydrogen** is produced through the electrolysis of water (in an electrolyser, powered by electricity), using electricity produced from renewable sources;
- **low carbon hydrogen** is produced through a variety of processes (reforming, pyrolysis) using fossil fuels (natural gas and coal) as feedstock, with subsequent carbon capture (low carbon fossil-based hydrogen), the electrolysis of water (in an electrolyser, powered by electricity), regardless of the electricity source, with significantly reduced full life-cycle GHG emissions compared to existing hydrogen production.

Based on these definitions, renewable hydrogen was a sub-set of low carbon hydrogen (as it could be produced via the electrolysis of water provided that it used electricity from renewable sources). However, the RNGH Directive departed from the Hydrogen Strategy definitions, making the renewable or non-renewable nature of the source from which (the energy content of) hydrogen is derived, a single defining criterion for each respective type of hydrogen.

Thus, the RNGH Directive defines **low-carbon hydrogen** as

> "hydrogen the energy content of which is derived from non-renewable sources, which meets the green-house gas [GHG] emission reduction threshold of 70% compared to the fossil fuel comparator for renewable fuels of non-biological origin [RFNBOs]' (Art. 1.10).

The GHG emission requirement applies irrespective of whether hydrogen has been produced in the EU or imported. The RNGH Directive stipulates that the EC is obliged to adopt Delegated Acts which will specify the methodology for assessing GHG emissions savings from low carbon hydrogen (as well as all other low carbon fuels). While the EC proposal for a RNGH Directive set the 31 December 2024 deadline for adoption of these Acts, the RNGH Directive stipulates that these Acts must be adopted within 12 months of its entry into force (Art. 8.5), which suggests late spring 2025. (The methodology must ensure that credit for avoided emissions is not given for CO2 the capture of which has already received an emission credit under other provisions of law.) As long as the methodology for assessing GHG emissions savings from low carbon hydrogen is not available, the low carbon hydrogen definition remains incomplete and provides no certainty for investors. The EC decision not to provide methodology simultaneously with the RNGH Directive has been criticised by many stakeholders. For example, ENTSOG – the association of European gas TSOs – called for a faster development of the methodology for calculating the 70% GHG emissions saving threshold and for the provision of the low carbon hydrogen definition to coincide with the adoption of the RNGH Directive.[23] While both the Council and the Parliament have also called for a speedier adoption of the low carbon hydrogen definition (i.e. including the methodology) – the Council calling for providing such definition within 12 months of the RNGH Directive's entry into force (which would have provided for an earlier deadline that that end of 2024 as envisaged by the EC, had finalization of the RNGH Directive not been delayed by the 2021-23 energy crisis) and the Parliament – within 6 months of the Directive's adoption – neither would allow significant reduction of the period within which the low carbon hydrogen definition (methodology) would be adopted.

While **renewable hydrogen** is not expressly defined in the RNGH Directive, some of it is indirectly defined as the renewable gaseous fuels part of **Renewable Fuels of Non-Biological Origin (RFNBOs),** defined in the REDiii Directive as 'liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass', thus including renewable hydrogen and renewable hydrogen-made synthetic fuels.[24] However, it would be wrong to narrow down renewable hydrogen only to RFNBOs, as hydrogen of biological origin – such as hydrogen produced through gasification of biomass or reforming of biogas/biomethane – would also be produced using renewable energy sources. In February 2023, the EC adopted two Delegated Acts, which stipulated the conditions that must be met for electricity used for the production of RFNBOs to be considered fully renewable (and for hydrogen produced using such electricity to count towards the legally binding RFNBO targets) (Box 1). Notably, while hydrogen of biological origin would not count towards the RFNBOs targets, it would count towards the overall EU RES targets. These Delegated Acts specified the methodology for assessing GHG emissions savings from RFNBOs, such that would cover the life-cycle GHG emissions.[25] The Delegated Act on Additionality and Temporal and Locational Correlation aimed to ensure that RFNBOs can only be produced from "additional" renewable electricity generated at the same time and in the same area as RFNBO production (Boxes 2 and 3). (This requirement applies to domestic EU production and imports of RFNBOs from non-EU countries). The Delegated Act on GHG emissions savings set the methodology for calculating GHG emissions savings, with RFNBOs would only to be counted towards EU's renewable energy target if they provided more than 70% GHG emissions savings compared to fossil fuels.

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[23] Contexte Énergie *(2022)*, 'Transmission network operators are only (very) moderately satisfied with the European gas package', ENTSOG (2022), 'High-Level Position on Hydrogen and Decarbonised Gas Market Package'.

[24] This is different compared to the RED-ii Directive, which defined RFNBOs as 'liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass'. RED-iii Directive defined RFNBOs as 'liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass'. In so doing it removed a reference to their usage in the transport sector thus suggesting that they could be used in any sector.

[25] Life-cycle emissions – otherwise known as 'well to wheel' – cover upstream emissions, production (electrolysis, SMR) emissions, (re-)conversion, transport (transmission and distribution), use, de-commissioning. Other emissions accounting systems also exists, such as 'well to production gate' (which only includes upstream emissions and production emissions) and 'well to delivery gate' (which additionally includes (re-)conversion and transport but excludes use and de-commissioning).

Box 1. REDiii targets for RFNBOs

The REDiii Directive introduced legally binding targets for RFNBOs in industrial and transport sectors, thus effectively aiming to create demand for renewable hydrogen. On 30 March 2023, the Council and the Parliament reached a political agreement on the RED-iii Directive thus concluding a trilogue process. It was agreed to increase the RES share to at least 42.5% by 2030 with an additional 2.5% indicative top up. Also, the Council and the Parliament agreed various sectoral targets for industry, transport, building, heating and cooling, some of which are legally binding.[26] In particular:

- Indicative target for an increase in RES in industry by 1.6% per annum, with binding target of 42% of hydrogen used in industry to come from RFNBOs by 2030 and 60% by 2035;
- the combined share of advanced biofuels and biogas and of RFNBOs in the energy supplied to the transport sector to reach at least 1% in 2025 and 5.5% in 2030, of which a share of at least 1% is from RFNBOs in 2030;
- indicative target of 49% RES in buildings by 2030, binding annual increase in RES at national level for heating and cooling (0.8% until 2026, 1.1% from 2026 to 2030);
- RES 'acceleration areas' with fast permit-granting procedures (overriding public interest status).

RED-iii Directive entered into force on 20 November 2023. Objections raised particularly by France in respect of the Directive's definition of RES, according to which hydrogen produced via electrolysis using nuclear power would not be considered 'renewable' and its deployment would not be counted towards RES/RFNBO targets, have been taken into account in the final text of the Directive.

Box 2. RFNBO Delegated Act on Additionality & Temporal/Locational Correlation: RFNBO production is connected to the grid ("On-Grid RFNBOs")

ELECTRICITY TAKEN BY A RFNBO PRODUCER FROM THE GRID IS COUNTED AS FULLY RENEWABLE if

- "HIGH RES GRID": RFNBO production is located in a bidding zone where RES >= 90%
- "LOW EMISSION GRID": RFNBO production is located in a bidding zone where the electricity emission intensity <= 18 gCO2eq/MJ ("LOW EMISSION GRID") subject to RES PPA and temporal and locational correlation
  - monthly (pre-2030) and hourly (post-2030) correlation between RES and RFNBO production, and
  - RES generation and RFNBO production are located in one zone, or RES generation is located in an interconnected zone and the day ahead price there is at least as high, or RES generation is located in an offshore interconnected zone
- "GRID IMBALANCE": electricity used to produce RFNBO is consumed during an imbalance settlement period, if RES generation was re-dispatched downwards and electricity used for RFNBO production has reduced the need for re-dispatch
- "REFERENCE GRID": additionality and temporal/locational correlation
  - RFNBO producers produce RES in their own installations or have concluded PPA with RES producers, provided that RES generation installation came into operation not earlier than 36 months before RFNBO production installation, and has not received operating or investment aid, and
  - monthly (pre-2030) and hourly (post-2030) correlation between RES and RFNBO production

[26] European Parliament, Revision of the Renewable Energy Directive – legislative train schedule.

Box 3. RFNBO Delegated Act on Additionality and Temporal and Locational Correlation: Direct connection between RFNBO production & RES generation ("Off-Grid RFNBOs")

ELECTRICITY, TAKEN BY AN RFNBO PRODUCER FROM DIRECT CONNECTION TO A RES GENERATION INSTALLATION, IS COUNTED AS FULLY RENEWABLE if

- RES generation and RFNBO production installations are connected via a direct line or are part of one installation, and
- RES generation installation came into operation not earlier than 36 months before RFNBO production installation; and
- RES production installation is not connected to the grid
  - or if it is connected the grid then a smart metering system shows that no electricity has been taken from the grid to produce RFNBO (Art. 3)

ELECTRICITY, IF ALSO TAKEN BY AN RFNBO PRODUCER FROM THE GRID, IS COUNTED AS FULLY RENEWABLE if

- RFNBO producer complies with the rules specific for each type of the grid (i.e. "REFERENCE GRID", "HIGH RES GRID", "LOW EMISSION GRID", or "IMBALANCE GRID") (see Box 2)

While these Delegated Acts were welcomed by the industry for finally providing legal certainty in respect of investment in renewable hydrogen, there were significant disagreements between Member States in respect of their specific provisions, particularly over the stringency of additionality and correlation requirements. Nonetheless, neither the Council nor the Parliament rejected either of these Delegated Acts and they entered into force on 11 July 2023.[27]

As the chemical composition of both renewable hydrogen and low carbon hydrogen is identical, the European hydrogen network would be indifferent between accepting and transporting either of these gases. However, as these gases are produced through different processes, their temporal flow pattern would differ. Production of hydrogen from renewable energy would result in the intermittent flow of hydrogen – mirroring the intermittent nature of renewable electricity. This would have an impact on the degree of pipeline network utilisation as well as the necessity for dedicated hydrogen storage. As some industrial processes require a steady flow of hydrogen, a more volatile intermittent flow of renewable hydrogen would necessitate the development of hydrogen storage from where hydrogen could be transported to demand centres when renewable electricity is not available, thus reducing renewable hydrogen flow volatility. Alternatively, the renewable hydrogen flow could be complemented by the flow of low carbon hydrogen as the latter's production from e.g. natural gas would result in a steady flow of hydrogen. Combined usage of both renewable and low carbon hydrogen would result in more stable large-scale flow of hydrogen thus leading to increased utilisation of hydrogen pipelines and could decrease the need for hydrogen storage.

The RNGH Directive makes a distinction between transmission and distribution for the hydrogen system – like for the natural gas system – and defines **hydrogen transport** as:

> 'the transmission or distribution of hydrogen through a hydrogen network with a view to its delivery to customers, but excluding supply', (Art. 2.21).

Consequently, the RNGH Directive defines **a hydrogen network operator** (HNO) as "a natural or legal person who carries out the function of hydrogen transport and is responsible for operating, ensuring the maintenance of, and, if necessary, developing the hydrogen network in a given area and, where applicable, its interconnections with other hydrogen networks, and for ensuring the long-term ability of the system to meet reasonable demands for the transport of hydrogen" (Art. 2.22).

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[27] EC (2023i), Renewable hydrogen production: new rules formally adopted.

While the RNGH Directive does not define hydrogen transmission or hydrogen distribution, it defines **hydrogen transmission network** as

> 'a network of pipelines for the transport of hydrogen of a high grade of purity, in particular, networks which include hydrogen interconnectors, or which are directly connected to hydrogen storage, hydrogen terminals or two or more hydrogen interconnectors or which primarily serve the purpose of transporting hydrogen to other hydrogen networks, hydrogen storages or hydrogen terminals. Such networks may serve the purpose of supplying directly connected customers' (Art. 21a),

and **hydrogen distribution network** as

> 'a network of pipelines for the local or regional transport of hydrogen of a high grade of purity, which primarily serve the purpose of supplying directly connected customers, and do not include hydrogen interconnectors, and are not directly connected to hydrogen storage or to hydrogen terminals, unless the network in question was a natural gas distribution system on [entry into force of this Directive] and has been partially or fully repurposed for the transport of hydrogen, or to two or more hydrogen interconnectors' (Art. 21b).

Notably, neither the EC Proposal for a RNGH Directive nor the Council's Proposal distinguished between transmission and distribution of hydrogen, merging them into one category of 'hydrogen transport'. However, the Parliament's Proposal for RNGH Directive made a distinction between the two. It defined **hydrogen transmission** as "[t]the transport of hydrogen through a network which mainly contains high-pressure pipelines, other than an upstream pipeline and other than the part of high-pressure pipelines primarily used in the context of local distribution of natural gas, with a view to the delivery of hydrogen to customers, excluding supply" (Art. 21a) and **hydrogen distribution** as "[t]he transport of hydrogen through local or regional pipeline networks with a view to its delivery to customers, excluding supply" (Art. 21b). Correspondingly, the Parliament's Proposal defined **hydrogen transport** as "[t]he transmission or distribution of hydrogen through a hydrogen network with a view to its delivery to customers, excluding supply, irrespective of transmission or distribution, the geographic coverage or the connected customer group of the network (Art. 21). Consequently, it defined both a hydrogen transmission network operator (HTNO) and a hydrogen distribution network operator (HDNO) (Art. 22a and 22b). It is understood that during the trilogue the Council had agreed with the Parliament's proposal to distinguish between hydrogen transmission and distribution, with the vertical unbundling requirement only apply to transmission.[28] Correspondingly, the final RNGH Directive also distinguishes between hydrogen transmission and hydrogen distribution.

The RNGH Directive defines **a hydrogen interconnector** as 'a hydrogen network which crosses or spans a border between Member States for the purpose of connecting the national hydrogen networks of those Member States, or a hydrogen network between a Member State and a third country up to the territory of the Member States or the territorial sea of that Member State (Art. 2.34).

It is worth noting that the TEN-E Regulation, in force since 23 June 2022, defined **a hydrogen interconnection** as follows:

> 'hydrogen infrastructure and the repurposing of gas infrastructure, enabling the emergence of an integrated hydrogen backbone, directly or indirectly (via interconnection with a third country), connecting the countries of the region and addressing their specific infrastructure needs for hydrogen supporting the emergence of a Union-wide network for hydrogen transport, and, in addition, as regards islands and

[28] Contexte *Énergie (2023a)*, 'Gas Directive: the distinction between hydrogen transport and distribution network operators is established', Contexte *Énergie,* 13 October 2023.

island systems, decreasing energy isolation, supporting innovative and other solutions involving at least two Member States with a significant positive impact' on the EU energy and climate targets, and contributing significantly to the sustainability of the island energy system and that of the EU,

thus confirming that the hydrogen interconnections could consist not only of hydrogen infrastructure per se but also of repurposed natural gas infrastructure.

Apart from hydrogen networks, the hydrogen system also includes hydrogen terminals and hydrogen storages. The RNGH Directive defines **a hydrogen terminal** as

"an installation used for the offloading and transformation of liquid hydrogen or liquid ammonia into gaseous hydrogen for injection into the hydrogen network or the natural gas system or the liquefaction of gaseous hydrogen and its onloading, including ancillary services and temporary storage necessary for the transformation process and subsequent injection into the hydrogen network, but not any part of the hydrogen terminal used for storage" (Art. 2.8).

This definition provides a legal basis for importing liquid hydrogen and liquid ammonia (which could be made into hydrogen by adding nitrogen on arrival) through a hydrogen terminal. It allowed for two types for terminals (a) converted from the existing LNG terminals and adapted to received ammonia, or (b) a newly built hydrogen terminals. It is significantly more efficient to transport liquid ammonia than liquid hydrogen by boat (as ammonia liquifies at -30C whereas hydrogen – at -253C). Furthermore, it allowed not only transformation but also offloading of liquid hydrogen and ammonia as well as allowed for injection of gaseous hydrogen not only into the hydrogen network but also into the natural gas system, thus enabling blending of hydrogen with methane. This definition is based on the definition provided in the Council Proposal and as such it is different from the definition provided in the EC Proposal and the Parliament Proposal, which only allowed the transformation of liquid hydrogen or ammonia into gaseous hydrogen but not offloading, and only allowed for its injection into the hydrogen network but not into the natural gas network.

The RNGH Directive also provides a definition for a **hydrogen terminal operator** as

'a natural or legal person who carries out the function of offloading and transformation of liquid hydrogen or liquid ammonia into gaseous hydrogen for injection into the hydrogen network or the natural gas system or the liquefaction and onloading of gaseous hydrogen and is responsible for operating a hydrogen terminal' (Art. 2.8a).

This definition is fully based on the Council's Proposal and as such differs from the Parliament Proposal, which did not allow for gaseous hydrogen injection into the natural gas network. On its part, the EC Proposal did not contain any definition of a hydrogen terminal operator.

The RNGH Directive defines **a hydrogen storage** facility as

"a facility used for the stocking of hydrogen of a high grade of purity:

(a) including the part of a hydrogen terminal used for storage but excluding the portion used for production operations and facilities reserved exclusively for hydrogen network operators in carrying out their functions;

(b) including large, in particular underground, hydrogen storage but excluding smaller, easily replicable smaller hydrogen storage installations" (Art. 2.6),

thus providing a legal basis for hydrogen to be stored both at a hydrogen terminal and at large underground storage sites, specifically built (or re-purposed) for that purpose.

The Parliament's proposal defined **a hydrogen storage** facility differently as:

"A facility used for the stocking of hydrogen of a high grade of purity or ammonia, including:

> (a) the part of an hydrogen terminal used for storage, excluding the portion used for production operations, and facilities reserved exclusively for hydrogen network operators in carrying out their functions;
>
> (b) large, in particular underground, hydrogen storage, excluding smaller, easily replicable hydrogen storage installations".

The difference between these two definitions is that the Parliament's Proposal aimed at providing a legal basis for developing storage facilities not only for hydrogen but also for ammonia.

The RNGH Directive provides a definition of a **hydrogen storage operator** as

> 'a natural or legal person who carries out the function of storage of hydrogen and is responsible for operating a hydrogen storage facility' (Art. 2.6a),

which was identical to the definitions provided by both the Council and the Parliament.

In addition to specifically defining a hydrogen storage operator and a hydrogen terminal operator, the EC Proposal also defined **a hydrogen undertaking** as

> 'a natural or legal person who carries out at least one of the following functions: hydrogen production, hydrogen transport, supply, purchase or storage of hydrogen, or operating a hydrogen terminal, and which is responsible for the commercial, technical or maintenance tasks related to those functions, excluding final customers',

thus suggesting that a hydrogen undertaking can simultaneously operate a hydrogen transport network (irrespective of pressure), a hydrogen terminal, and a hydrogen storage, while at the same time being active in production, purchase, and supply of hydrogen.

Finally, the RNGH Directive defines **security** as 'both security of supply of natural gas and technical safety' (Art. 2.48) but made no mention of security in respect of hydrogen supply.

2.2. Main principles of operation: unbundling, access, tariffs

2.2.1 Natural gas system

The RNGH Directive and Regulation have largely preserved the main principles, governing the EU natural gas market, as established by the Third Gas Directive and the Gas Regulation 715. They also introduced some additional clauses, aimed at decarbonisation (including a prohibition to conclude long-term supply contracts for unabated fossil gas with an expiry date beyond the end of 2049) and security of supply (including incorporation of some 'emergency' legislation adopted during the 2021-23 energy crisis).[29]

Unbundling and certification

In respect of ***vertical unbundling*** of natural gas networks, the RNGH Directive (Art. 60) mandates an Ownership Unbundling (OU) model, where the Transmission System Operators (TSOs) must own and operate the network, with no simultaneous control over production/supply (including electricity generation) and transmission allowed. The objective is to ensure that no preferential treatment in respect of allocating and charging for transportation capacity is awarded to producers and suppliers. The OU requirement is considered fulfilled in a situation where two or more undertakings which own

[29] For an overview of 'emergency' legislation and its incorporation into the RNGH Regulation, see Yafimava (2023), 'How 'emergency' legislation affected the EU internal gas market?', *Energy Intelligence*, 15 March 2024.

transmission systems have created a JV which acts as a TSO in two or more Member States for the TSOs concerned. No other undertaking may be part of the joint venture unless it has been approved as an ISO or an ITO. Where on 3 September 2009, the TSO belonged to a vertically integrated gas undertaking (VIGU), three other options are also possible: Independent System Operator (ISO) where an ISO operates a network (based on a long term lease) while the network ownership remains with a VIGU (which is also obliged to finance investment decided by the ISO) (Art. 61), Independent Transmission Operator (ITO) where a TSO remains part of the VIGU but its independence from production/supply activities is ensured (Section 3 of the Directive, Art. 63 – 67), and 'ITO plus' (Art. 60.8). Thus, the RNGH Directive outlines the same vertical unbundling options as the Third Gas Directive.[30] As far as natural gas storages are concerned, the RNGH Directive prescribes legal unbundling (Art. 62) and accounts unbundling (Art. 75). Similarly, the Third Gas Directive prescribed legal (Art. 15, Art. 31) and accounts (Art. 31) unbundling. As far as LNG import terminals are concerned, the RNGH Directive prescribes accounts unbundling only (Art. 75), also as the Third Gas Directive did (Art. 31). Overall, unbundling rules in respect of natural gas TSOs, Storage Operators, and LNG operators are largely identical in the RNGH Directive (as well as the Council and the Parliament Proposals) and in the Third Gas Directive.

The RNGH Directive also requires **mandatory certification of TSOs**, confirming compliance with (a) unbundling requirements and (b) security of supply requirements (the latter applies if a TSO or its owner is controlled by a non-EU party, the so called 'TSO Gazprom clause') (Art. 71, Art. 72). Certification was to be granted by a regulatory authority (accompanied by the EC Opinion) whereas the EC was empowered to adopt Guidelines (as delegated acts) specifying a certification procedure. This requirement was already present in the Gas Regulation (Art. 3) and Directive (Art. 10 and 11).

The RNGH Regulation (Art. 13.a) incorporated Gas Regulation 715's requirement on **mandatory certification of Storage Operators** (Art. 3.a), including those controlled by the TSOs (even if already certified), in respect of the security of supply risk assessment: (a) for storages with a capacity of over 3.5TWh that were less than 30% full by 31 March 2021 and by 31 March 2022 (compared to their maximum capacity) – by 1 February 2023 or within 150 days of the date of receipt of a certification re-assessment notification), (b) for all other storages – by 2 January 2024 or within 18 months of the date of receipt of a certification (re-)assessment notification).[31] While the Storage Operator certification requirement has not been part of the original Gas Regulation 715, it was added in 2022 in response to the energy crisis thus becoming permanent. This requirement was largely aimed at preventing Gazprom's ownership/operatorship of European gas storages in the future.

The RNGH Directive requires Member States or undertakings which own natural gas storage or LNG facilities to designate, for a duration determined by Member State themselves, one or more operators for these infrastructures (Art. 73). The RNGH Directive introduces a possibility of having 'a combined operator' for operation of a combined transmission, LNG, storage and distribution system operator (provided compliance with unbundling rules) (Art. 49). Certifying authority would have the power to grant (including conditionally) or refuse certification (and impose remedies).

Access and Congestion Management Procedures (CMP): networks, storages, LNG terminals

The RNGH Directive prescribes **regulated (third party) access to natural gas transmission and distribution networks** (Art. 31), in the same way as the Third Gas Directive (Art. 32).[32] A more detailed

[30] By December 2022, the OU model was used in thirteen Member States, the ITO model – in 6 Member States, and the ISO model was only used in Romania. In those Member where two or more TSOs operate – which is the case in France, Germany, and Spain – two or more unbundling options have been implemented, see ACER (2022a), Opinion on the review of gas and hydrogen network development plans to assess their consistency with the EU TYNDP'.
[31] EC, Gas storage, https://energy.ec.europa.eu/topics/energy-security/gas-storage_en
[32] The Council's Proposal for a RNGH Directive requires the TSOs to have access to the network of other TSOs, if necessary for carrying out their functions for cross-border transmission, Council (2023c).

set of rules, both in respect of existing and incremental (new) capacity, was provided by the EU Capacity Allocation Mechanisms (CAM) Network Code, adopted in 2017. In November 2023, the EU Agency for the Cooperation of Energy Regulators, ACER, responding to the 2023 Madrid Forum's request, launched public consultation aimed at amending and adjusting the CAM NC to the post-crisis environment, with the formal review of the CAM NC expected to be launched in 2024.[33] As far as **congestion management procedures (CMP)** were concerned, the RNGH Regulation (Annex I) listed the same CMP as the Gas Regulation 715 – namely, Oversubscription and Buy-Back arrangements, Firm Day-Ahead Use-It-Or-Lose-It (UIOLI), Long-term UIOLI, and surrender of booked capacity (with minor changes), all of which were applicable only in the event of contractual congestion. It is worth noting that the Enhancing Solidarity Regulation,[34] adopted in 2022 together with other 'emergency' legislation passed to address the 2021-23 energy crisis, had introduced the so called 'long-term capacity confiscation clause' (Art. 14), which would apply regardless of congestion – thus going beyond the Gas Regulation's requirements. However, it allowed the NRAs to provide derogations (and implement Firm Day-Ahead UIOLI procedure and Oversubscription and Buy-Back, as stated in the RNGH Regulation (Annex I) and offer Day-Ahead and Within-Day capacities as interruptible); it is understood that all NRAs granted derogations.[35] As the Enhancing Solidarity Regulation will expire on 31 December 2024, some of its provisions have been incorporated into the RNGH Regulation but the 'confiscation clause' was not one of them. Overall, the existing capacity allocation mechanisms (CAM) and congestion management procedures (CMP), established by the Third Gas Directive and the Gas Regulation 715, have been preserved. However, changes are expected as part of the CAM network code revision, which aims at more efficient utilisation of existing capacity in the view of changed flow patterns in the aftermath of the 2021-23 energy crisis, whereas the incremental (new) capacity allocation procedure could be eliminated altogether. Should this happen, an exemption regime – requiring the national regulator's and ultimately the EC's approval – would become the only route for building new natural gas infrastructure in the EU.

The RNGH Directive requires **regulated access to LNG import terminals** (Art. 31), mirroring the Third Gas Directive (Art. 32). It allows both **regulated and negotiated access to natural gas storages**, subject to a Member State decision (considering the results of the common & national risk assessments) (Art. 33) thus also mirroring the Third Gas Directive (Art 33).

Guided by the RePowerEU Plan, the RNGH Regulation has included some measures directed specifically against Russian gas. One such measure has enabled the national regulators to introduce (pipeline and LNG) import capacity restrictions in respect of Russian gas. Another has excluded Russian gas supplies from the EU Energy Platform for demand aggregation and joint purchasing until 31 December 2025 and potentially beyond. (The Energy Platform had originally been established by the Enhancing Solidarity Regulation and has since been incorporated into the RNGH Regulation).

The 2049 LTC rule

Finally, the RNGH Directive has **prohibited the conclusion of long term contracts for the supply of unabated fossil gas with** with a duration beyond 31 December 2049 **('the 2049 LTC rule')** (Art. 31.3). This was a new provision, absent from both the Third Gas Directive and Gas Regulation 715. In fact, the EU legislation had never previously limited the duration of gas supply contracts, either explicitly or implicitly. While the establishment of the 2050 'deadline' is not surprising given the EU legally-binding 'net zero by 2050' target, it could have an impact on global gas suppliers' willingness to invest in new gas projects. It is worth noting that the '2049 LTC rule' only applies to unabated fossil gas which means that the contracts for fossil gas with Carbon Capture and Storage (CCS) could be concluded for the

[33] ACER (2023d), 'ACER to review the market rules regulating gas capacity allocation in Europe'. Public consultation was held during 14 November 2023 – 5 January 2024.
[34] EC (2023p), Enhancing Solidarity Regulation.
[35] EC (2023p), Report on the main findings of the review of the Enhancing Solidarity Regulation.

period exceeding the 2049 deadline. Both the Council and the Parliament Proposals[36] for a RNGH Directive concurred with 'the 2049 LTC rule' as expressed in the RNGH Directive. Notably while the EC Proposal for a RNGH Directive envisaged a possibility of an exemption from the '2049 LTC rule', neither the Council nor the Parliament did so, and the final RNGH Directive does not envisage an exemption (see *Exemptions* below).

Tariffs

As in the Third Gas Directive, the RNGH Directive requires tariffs (or their methodologies) to be approved and published prior to their entry into force. As in the Gas Regulation 715, the RNGH Regulation mandates 'entry-exit' tariff model (i.e. tariffs must be set separately for every entry point or exit point of the transmission system), transparency, and cost-reflectivity (although without a reference to benchmarking) (Art. 3, Art. 17). The RNGH Regulation **allows regulatory authorities to merge adjacent entry-exit systems to enable 'full or partial' regional integration where tariffs could be abolished at the interconnection points (IPs) between the 'entry-exit' systems**, and to approve 'a common tariff' and 'an effective compensation mechanism' between TSOs for the redistribution of costs (Art. 17.4). The RNGH Regulation does not make it clear whether this provision concerns the entry-exit zones within a Member State as well as the entry-exit zones between several Member States. Although the EC Proposal for a RNGH Regulation did not contain a provision that would allow the regulatory authorities to abolish tariffs at the IPs between 'entry-exit' zones, the RNGH Regulation contains such provision, having accepted the Council Proposal, which included a similar provision (Art. 15.4). The Parliament's Proposal (Art. 5.1a) was more explicit – it proposed the mandation that no tariffs would be charged for access to natural gas transmission network at IPs between Member States unless the regulatory authorities agreed on a tariff regime for such access. In the absence of such agreement, ACER would decide on the tariff regime (Art. 5.1.a). While the Regulation's provision is less radical, it could still potentially enable market distortion. The RNGH Regulation obliges the EC to evaluate, within one year of its entry into force, the impact on the natural gas system of a tariff regime whereby no tariffs would be charged at IPs between Member States or at IPs with non-EU countries whose systems connect two or more Member States and submit a report to the Parliament and the Council.[37] The report could be accompanied by legislative proposals aimed at resolving any problems caused by such regime (Art. 6.2).

It is worth noting that Gas Regulation 715 itself was amended in 2022 to allow NRAs to apply a **discount of up to 100% to capacity-based transmission and distribution tariffs at entry points from, and exit points to, underground gas storage facilities and LNG facilities in respect of natural gas** (Art. 13.3). This was a temporary 'emergency' measure adopted during the 2021-23 energy crisis, aimed at facilitating storage refill and attracting LNG to Europe, and is expected to remain in force until 31 December 2025. Likewise, the RNGH Regulation also **allows the NRAs to apply a discount of up to 100% at entry points from, and exit points to, storage facilities and at entry points from LNG facilities until 31 December 2025** (Art. 17.3). It could continue to be applied **after that date for the purposes of increasing security of supply',** with the NRAs obliged to re-examine the discount and its contribution to security of supply every regulatory period in line with the Tariffs Network Code. The Council's Proposal suggested making this provision part of the Regulation, although phasing out its application by 31 December 2025 (Art. 15.3). The Parliament Proposal also suggested making this provision part of the RNGH Regulation but instead of prescribing any specific phase out deadline, it required the EC to re-examine this provision five years after the Regulation's entry into force and assess whether the level of discount remained adequate, thus prolonging it beyond 31 December 2025 and

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[36] The Parliament Proposal noted that 'the end-date may be revised in order to align with relevant changes in the Union's energy and climate objectives, taking into account the security of supply and without prejudice to long-term contracts that have been concluded' (Art. 27.2), European Parliament (2023a).

[37] This provision would appear to suggest that it would be possible to abolish tariffs at IPs between Member States (as well as between Member States and non-EU countries) subject to regulatory authorities' decisions.

potentially enabling it to become permanent (Art. 15.2a). The final RNGH Regulation reflects a compromise between the Council and the Parliament's positions. Notably the RNGH Regulation does not include the Parliament's suggestion that tariffs 'shall aim to avoid creating incentives for the practice of blending hydrogen into the natural gas system for the purpose of increasing the volume of natural gas transported or stored or of prolonging the lifetime of natural gas infrastructure" (Art. 15).

As far as renewable and low carbon gases are concerned, the RNGH Regulation mandates **a discount for renewable and low carbon gases to be applied to (a) entry points from renewable and low carbon production facilities (100% for renewable gas and 75% for low carbon gas), (b) capacity-based transmission tariffs at entry points from, and exit points to, storage facilities (100 per cent)** in the Member States where the renewable and low carbon gas was first injected (Art. 18.1), with further details on discounts to be set in the Tariffs Network Code. The RNGH Regulation is different from the EC Proposal, which did not differentiate between discounts to be applied for renewable and low carbon gases at entry points from production facilities, stipulating an identical discount of 75% for both. By mandating different tariff discounts to be applied at entry points from production facilities for renewable and low carbon gases, the RNGH Regulation adopted the Council's position, which provided for a higher discount for the former (100%) and a lower discount (75%) for the latter. The RNGH Regulation's discount of 100% to be applied at entry points from, and exit points to, storage facilities, also reflected the Council's position (whereas the EC Proposal envisaged a 75% discount). Unlike the EC and the Council Proposals, the Parliament Proposal for a RNGH Regulation did not require any specific discounts to be applied for renewable and low carbon gases to entry points from production and to entry points from, and exit points to, storage facilities, only requiring the regulators to 'assess whether to offer support to lower grid connection costs and fees for renewable gas and low carbon gas production facilities' (Art. 18).

The RNGH Regulation also stipulates **a discount of 100% on the capacity-based tariff from the TSO at IPs between Member States for renewable gas and 75% for low carbon gas – but not in respect of IPs with non-EU Member States and not in respect of entry points from LNG terminals** as was suggested in the EC Proposal – subject to a sustainability certificate and within one year from the date of the Regulations' entry into force (Art. 18.4), thus reflecting the Council's Proposal. It states that if TSO revenues were to fall by more than 10% because of this discount, an inter-TSO compensation mechanism must be negotiated. The Parliament was against having an ex-post discount for renewable and low carbon gases at IPs of the natural gas networks. ENSTOG was also against, stating that this provision could risk fragmenting the natural gas market. Many national regulatory authorities were also opposed. These concerns were partly addressed by including in the RNGH Regulation a provision **obliging the EC to re-examine all these discounts five years** after the RNGH Regulation's entry into force (2029) and every five years thereafter and assess whether their levels were adequate (Art. 18.3); the EC would be empowered to change the level of discounts through delegated acts. The RNGH Regulation also **allows the regulatory authorities to decide not to apply any of these discounts or decide to set discount rates at lower levels than stipulated by the Regulation**, provided that such derogation is in line with the general tariff principles set by the Regulation, including cost-reflectivity, and its necessity for the efficient operation of the TSO, to ensure stable financial frameworks for existing investments or to avoid undue cross-subsidies, distortion to cross-border trade or ineffective inter-TSO compensation mechanism, or where the application of discounts (or their mandated rates) is unnecessary due to the high roll out of renewable and low carbon gas in the Member State or the existence of alternative support mechanisms for their scale up (Art. 18.5).

Exemptions and derogations

The RNGH Directive and the RNGH Regulation stipulate **exemptions and derogations** from their various provisions. While there are similarities with the Third Gas Directive and Gas Regulation 715, there were also differences. The existing exemption and derogation regime has been established by the Third Gas Directive thus requiring a transposition into national laws of Member States to become binding. The new exemption and derogation regime is being established (mostly) as part of the RNGH

Regulation thus becoming directly applicable in Member States without the need for transposition into national legislation.

Exemptions

The Third Gas Directive stipulated that 'major new gas infrastructure, i.e. **interconnectors, LNG and storage facilities** may, upon request, be exempted, for a defined period of time', from the Directive's provisions on unbundling (Art. 9), access to transmission, distribution, LNG facilities, storages and upstream pipelines (Art 32, 33, 34) and regulated tariffs (Art. 41.6, 41.8, 41.10), subject to Member States/NRA and the EC approvals, with the EC decision being final and binding.[38]

The RNGH Regulation, effectively copying the Third Gas Directive as far as exemptions were concerned, stipulates in its Art. 78 that '[m]ajor new natural gas infrastructure, namely **interconnectors, LNG facilities and natural gas storage facilities**, may, upon request, be exempted, for a set period' from the RNGH Directive's provisions on unbundling (Art. 60), access (Art. 32, 31.1, 33) and tariffs (Art. 78.7, 78.9, 79.1). Like the Gas Directive, it does not stipulate the maximum duration for which exemption could be granted. Exemption is subject to Member States/NRA and the EC approval, with the EC decision being final and binding. Significant increases in, and modifications of, existing infrastructure are also eligible for exemptions if they enable the development of new sources of renewable and low carbon gases.

Importantly, **the RNGH Regulation does not allow for an exemption from 'the 2049 LTC rule'** – although the EC Proposal did – thus reflecting the Parliament and the Council positions, both of which were against an exemption (Art. 78). This suggests that it would no longer be possible to conclude long term contracts for unabated fossil gas beyond 2049.

The RNGH Regulation also stipulates that such infrastructure may be exempted from RNGH Regulation's own provisions, except provisions requiring LNG facilities and natural gas storage operators to publish the amount of natural gas in their respective facilities (Art. 34.5) and information on tariff derivation, the methodologies and the structure of tariffs, or tariffs themselves (Art. 34.6).

An exemption is subject to conditions, largely similar to those stipulated by the Gas Directive, but with a stronger emphasis on their impact on decarbonisation. Specifically, to be granted an exemption, investment:

- must enhance competition in natural gas supply or hydrogen supply and enhance security of supply, contributes to decarbonisation, the achievement of the EU's climate and energy targets, reflects the 'energy efficiency first' principle;
- would not have happened without an exemption;
- must be owned by a person which is legally separate from the system operators in whose systems it will be built;
- must not be detrimental to competition in the relevant markets which are likely to be affected by the investment, to the 'proper' functioning of the internal integrated market for natural gas or hydrogen, to the 'proper' functioning of the regulated systems concerned, to decarbonisation or to security of supply in the EU;
- has not received EU financial assistance for works (construction) under CEF Regulation.

The Regulation requires (all of) these conditions to be assessed taking into account the principle of **energy solidarity**, thus reflecting the Council's position, which also required an assessment of the principle of solidarity, whereas the EC Proposal for a RNGH Regulation was only recommending – as

[38] For detailed explanation of the Third Gas Directive exemptions regime, see Yafimava (2018), 'Building new gas transportation infrastructure in the EU – what are the rules of the game?'

opposed to requiring – such assessment. The RNGH Regulation's requirement that investment must not have received CEF funding to be granted an exemption reflects the Parliament's position as neither the EC nor the Council's Proposals prohibited granting an exemption to such projects, thus making it possible for PCI projects in receipt of CEF funds for construction to be exempted as well.

Derogations

The Third Gas Directive stipulated that derogations from *inter alia* unbundling provisions could be granted by a Member State in respect of isolated and emergent markets (Art. 49). It also stipulated that derogations could be granted by a Member State from the Directive's provisions on unbundling (Art. 9), TSO certification (Art. 10, Art. 11), access (Art. 32) and tariffs (Art. 41.6, 41.8, 41.10) in respect of transmission lines to and from non-EU countries, for a duration of up to 20 years.

The RNGH Directive stipulates (Art. 86.1) that **a derogation could be granted by Member States which are not directly connected to the interconnected system of any other Member State**, from its various provisions (Art. 3, 8, 34, 60 or 31.1), including unbundling requirement (Art. 60), TPA to networks and LNG facilities (Art. 31.1) and an obligation of a Member State to enable undertakings within its territory to supply the eligible customers through a direct line (Art. 34). It also stipulates (Art. 86.2) that a derogation could be **granted by the EC to outermost regions or to other geographically isolated areas** from various provisions (Art. 3, 8, 60 or 31).[39] Notably, the RNGH Directive made a distinction between not interconnected systems and isolated systems, stipulating that derogations in respect of the former could be granted by a Member State and in respect of the latter – by the EC, thus adopting the Council's position. The RNGH Directive also stipulates that Member States, which received the first supply under their first supply contract after the Directive's entry into force may provide a derogation from its various provisions (Art. 3.1 – 3.4, Art. 4.1, Art. 8, Art. 31.1, Art. 32.1, Art. 34, Art. 39.1 – 39.5, Art. 43, Art. 44.6, Art. 46, Art. 60, Art. 61, Art. 75) which would expire within the next ten years (Art. 86.7). Derogations which had been granted under the Third Gas Directive, and either had no expiry date or had no defined period of application, would expire on 31 December 2025 but Member States may decide or apply to the EC (as applicable) for a new derogation. The RNGH Regulation stipulates that its provisions would not apply to natural gas transmission systems in Member States for the duration of derogations granted under Art. 86 of the RNGH Directive (Art. 79).

The RNGH Directive stipulates that derogations could also be granted by a Member State from the Directive's provisions on unbundling (Art. 60), TSO certification (Art. 71, Art. 72), access (Art. 31) and tariffs (Art. 78.7, 78.9, 79.1) in relation to natural gas transmission lines to and from non-EU countries, completed before 23 May 2019,[40] for a duration of up to 20 years, provided that those derogations had been granted by 24 May 2020 (Art. 88). The EC would be obliged to provide a report to the Parliament and the Council on such derogations, assessing their impact on the effective functioning of the internal market, security of energy supply and 'the essential security interests' of the EU and its Member States (Art. 88.4). However, this provision falls short of obliging the EC to revoke the derogation should the report find that derogation posed a threat – a requirement, proposed by the Parliament Proposal (Art. 62).

The Parliament Proposal for a RNGH Directive and RNGH Regulation closely followed the EC Proposal in outlining the derogations regime. However, the Parliament Proposal for a RNGH Regulation required the EC to submit a report (upon the request of at least one Member State) in respect of the **derogations granted in respect of transmission lines to and from non-EU countries**, under Art. 88, assessing their impact on 'the effective functioning of and competition in the internal market […] on security of energy supply and the essential security interests of the Union and the Member States, taking into account the principle of energy solidarity and the REPowerEU Plan objectives' (Art. 62). Should the

[39] Derogation from 'the 2049 LTC clause' is allowed for such systems.

[40] The so called, "Nord Stream 2 clause".

report find that derogation posed a threat, the EC would be obliged to adopt a decision requiring the relevant competent authority **to revoke the derogation.**

The Council Proposal for a RNGH Directive made a distinction between not interconnected systems and isolated systems, stipulating that derogations in respect of the former could be granted by a Member State and in respect of the latter – by the EC (Art. 80). It also noted that derogations granted under the Gas Directive, which had no expiry date or defined period of application, would expire on 31 December 2025, but Member States benefitting from these derogations at the time of the RNGH Directive's entry into force, 'may decide for a new derogation' in respect of not interconnected systems or where Member States received the first commercial supply of their first long term natural gas supply contract after the Directive's entry into force.

2.2.2 Hydrogen system

The RNGH Directive and the RNGH Regulation extended the gas market rules – established by the Third Gas Directive and Gas Regulation 715 – to the EU's nascent hydrogen market. As noted in the Introduction to this paper, neither the Third Gas Directive nor Gas Regulation 715 provided any rules for a hydrogen market.

Unbundling and certification

The RNGH Directive stipulates both vertical and horizontal unbundling in respect of hydrogen networks. For **vertical unbundling**, the RNGH Directive requires Member States to ensure that all hydrogen transmission network operators (HTNO) were unbundled within two years of the Directive's entry into force (spring of 2026) in line with the unbundling rules for (natural gas) TSOs (see Section 2.2.1) (Art. 68). In addition to the OU model, the Directive allows Member States to designate 'an entity under the sole control of the TSO or the joint control of two or more TSOs, or under the sole control of the vertically integrated undertaking active in hydrogen production or supply' as an **integrated HTNO, which would be allowed to operate under the ITO model** (where it would remain part of a VIU but its independence from supply/production activities would be ensured). Furthermore, where a Member State has granted a derogation from horizontal unbundling requirements and where a hydrogen transmission network belongs to one or more certified (natural gas) TSOs unbundled under the ITO model, the Directive allows Member States to designate this entity or an entity under the joint control of two or more TSOs as an integrated HTNO under the ITO model. Where an undertaking includes a (natural gas) TSO unbundled under the OU model and an integrated HTNO, this undertaking may be active in hydrogen production or supply, but not in the production or supply of natural gas or electricity; where such undertaking engages in hydrogen production or supply, the (natural gas) TSO is obliged to comply with the ITO unbundling requirements, and the undertaking is not allowed to book or use capacity rights to inject any hydrogen into the transmission or distribution natural gas system, which it is operating. Unlike the EC Proposal, which suggested to phase out the ITO model by 31 December 2030, the RNGH Directive **does not stipulate any deadline in respect of the ITO model allowing for its indefinite application**, thus accepting the Council and the Parliament positions, which were against any deadline on ITO application. The RNGH Directive also allows Member States not to apply the OU requirement for the hydrogen networks belonging to a vertically integrated undertaking, designating instead an independent HTNO unbundled in line with the ISO model, subject to horizontal unbundling requirements.

As far as **horizontal unbundling** is concerned, the RNGH Directive requires that HTNOs must be 'independent at least in terms of its legal form' from electricity and gas transmission and distribution network operators (so called, "legal unbundling") (Art. 69.1). Nonetheless, the Directive allows Member States to grant derogations to HTNOs from this requirement, subject to a positive cost-benefit analysis and assessment of their NRAs, including the derogation's impact on transparency, cross-subsidies, network tariffs and cross-border trade and the calendar of expected transfers from the natural gas to the hydrogen RABs. Derogation would be withdrawn should the assessment – carried out every seven years – turn negative (Art. 69.2-4). The horizontal unbundling requirement was contentious as the Parliament was strongly against it and only required unbundling of accounts (so called "accounting unbundling"), with separate accounts kept for 'transmission, distribution, LNG, hydrogen terminal, natural gas and hydrogen storage and hydrogen transport' activities, with infrastructure assets to be transparent and 'clearly allocated to the respective accounts and regulatory asset bases separately for natural gas, electricity or hydrogen assets' (Art. 69). ENTSOG was also against horizontal unbundling. On its part, the Council Proposal was in favour of legal unbundling (although Spain wanted to have an exemption for small hydrogen distribution operators[41]). The Directive's Recital 83 reflects that Council's position that the legal unbundling requirement would be considered met with "the creation of a subsidiary or a separate legal entity within the group structure of the natural gas transmission or distribution system operator […] without the need for a functional unbundling of governance or separation of management or staff". The EC explained its insistence on horizontal unbundling by the need to ensure there were no cross-subsidies between (natural gas) TSOs and HTNOs, adding that 'a natural gas network operator will be able to operate on a hydrogen network but within the framework of a separate legal entity'.

Eleven years after the RNGH Directive's entry into force (spring of 2035), the EC will be obliged to publish an assessment of the Directive's HTNOs and HDNOs unbundling provisions, preceded by an earlier ACER report on their impact on hydrogen market functioning, competition, liquidity, hydrogen infrastructure development and transparency (Art. 92).

Comparison between the EC, the Parliament and the Council Proposals suggested a significant rift between the EC position and the Parliament and the Council positions, particularly in respect of vertical unbundling, with the EC Proposal mandating the OU model, while allowing a relatively short (~5 year) transition period during which the ITO model could be used, whereas both the Parliament and the Council called for both OU and ITO models being allowed indefinitely. The Parliament and the Council positions prevailed in the final RNGH Directive. This rift was reminiscent of the differences of positions between the EC on one hand, and the Parliament and the Council on the other, in respect of unbundling models for natural gas networks as part of the Third Gas Directive, where eventually the EC had to succumb to the Parliament and the Council demands, with the Directive allowing for different unbundling options.[42] Horizontal unbundling was also contentious – supported by both the EC and the Council but opposed by the Parliament – ultimately preserved in the final RNGH Directive, with the EC and the Council positions prevailing.

The RNGH Regulation stipulates the establishment of **a European Network of Network Operators for Hydrogen (ENNOH**), consisting of certified HTNOs of Member States, by 1 July 2025[43] to 'promote the development and functioning of the internal market in hydrogen and cross-border trade' and 'ensure optimal management' of the EU hydrogen transmission network – similarly to ENTSOG for natural gas – with a mandate *inter alia* to develop EU network codes for hydrogen (with network codes, establishing rules for determining the value of transferred assets (from natural gas to hydrogen RAB) and the dedicated charge, to be developed jointly with ENTSOG, see Section 4.3) and the EU Ten-Year Network Development Plan (TYNDP) for hydrogen (Art. 57, Art. 59). ENNOH would be obliged to cooperate closely with ENTSOG and ENTSOE. Prior to the ENNOH establishment, ENTOSG will

[41] Spain was presiding over the Council during the RNGH Directive and the RNGH Regulation trilogue, taking place in the second half of 2023, and the Council signalled its willingness to accommodate its demand in respect of hydrogen distribution networks, see Contexte *Énergie (2023b),* 'The Spanish presidency will approach the trilogue on the gas directive with free rein'.
[42] Yafimava (2013), 'The EU Third Package for Gas: major contentious issues inside and outside the EU'.
[43] Procedure of establishing ENNOH is as follows: HTNOs are obliged to submit the documents necessary for their establishment to the EC and ACER by 1 September 2024; ACER Is obliged to provide its opinion within four months (by 1 January 2025), the EC is obliged to provide its opinion within three months after ACER's opinion (by 1 April 2025), with HTNOs to adopt and publish its statutes, list of members and rules of procedure within three months (1 July 2025), following which ENNOH will be considered established (see Section 4.5).

remain responsible for the development of EU TYNDPs for natural gas and hydrogen, built on national Network Development Plans (NDPs) (see Section 4.5).

HTNOs are eligible to join ENNOH from the start of the certification procedure, subject to positive certification within two years and subject to developing hydrogen infrastructure project with an FID within four years of joining ENNOH. A designated HTNO, which has been granted a derogation from the vertical unbundling requirement, is eligible to join ENNOH as a member 'in the exceptional case' of being established in a Member State where no other HTNO is a member of ENNOH. If no HTNO has yet been designated by a Member State, which plans to develop a hydrogen transmission network (according to its National Energy and Climate Plan, NECP), this Member State may nominate an entity as an associated partner to ENNOH.

The RNGH Regulation is based on the Council Proposal, which supported establishment of the ENNOH, and specifies that ENNOH would consist of certified hydrogen transmission network operators (Art. 57.3). The RNGH Regulation rejected the Parliament Proposal, which called for the establishment of 'a joint EU organisation of gas transmission system operators and hydrogen network operators' (ENTSOG&H) 'to promote the completion and functioning of the internal market in natural gas and hydrogen and cross-border trade and to ensure the optimal management, coordinated operation and sound technical evolution of the natural gas transmission network and of the hydrogen network'. ENTSOG&H would be obliged to develop *inter alia* network codes and a non-binding EU-wide TYNDP 'for gas and hydrogen networks', 'including European Plan for Priority Corridors for Hydrogen', 'consistent' with the TEN-E Regulation and 'reinforced by the REPowerEU Plan' every two years.

In respect of certification, just as for (natural gas) TSOs, the RNGH Directive requires **mandatory certification of hydrogen transmission network operators** (prior to their designation as such) confirming compliance with (a) unbundling requirements and (b) security of supply or 'the essential security interests' requirements (Art. 71, Art. 72).[44] Assessment of compliance with security or supply and the essential security interests is required when a hydrogen network operator or a hydrogen network owner is controlled by a non-EU party. While the RNGH Directive requires designation of operators for hydrogen storages and hydrogen terminals (Art. 73), it does not appear to contain a requirement for these operators to be certified. Likewise, while the Directive requires designation of hydrogen distribution network operators, it does not appear to contain a certification requirement (Art. 43).

The RNGH Directive introduced a possibility of having 'a combined operator' for operation of a combined hydrogen transmission, hydrogen terminal, hydrogen storage and hydrogen distribution system operator (provided compliance with unbundling rules) (Art. 49).

Access and CMP

The RNGH Directive mandates regulated access to hydrogen (transmission and distribution) networks based on published tariffs and applied objectively and without discrimination between users (Art. 35.1). It **allows Member States to decide not to apply a regulated access until 31 December 2032** and opt for negotiated access instead. Negotiated access would subsequently have to be replaced by regulated access. Where negotiated access is used, regulatory authorities would be obliged to provide guidance to hydrogen network users on how negotiated tariffs would be affected when regulated access is introduced (Art. 35.5). Overall, as far as the regime of access **to hydrogen networks** is concerned, there were no significant differences between the EC, the Parliament and the Council Proposals, all mandating regulated access but allowing a negotiated access during a transition period until 2030 (the

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[44] Curiously, a provisionally agreed text of the RNGH Directive published in December 2023 as well as the EC Proposal, the Council and the Parliament positions all contained a certification requirement in respect of hydrogen network operators (Art. 65), whereas the final text adopted and published by the Parliament in April 2024 contained a certification requirement in respect of hydrogen transmission network operators (thus excluding distribution network operators).

EC and the Parliament) and 2035 (the Council). The final RNGH Regulation reflects a compromise with the transition period ending on 1 January 2033.

The RNGH Regulation stipulates that from 1 January 2033 – the date from which regulated access becomes mandatory – hydrogen networks would have to be organised as 'entry-exit' systems (Art. 7.6). Further details would have to be provided in the CAM network code for hydrogen. The RNGH Regulation specifies **20 years as the maximum duration of capacity contracts in respect of infrastructure completed by 1 January 2028 and 15 years for infrastructure completed after that date** (Art. 7.3). Regulatory authorities have the right to impose shorter maximum duration if necessary to ensure market functioning, safeguard competition and ensure future cross-border integration. When imposing a shorter duration, the regulatory authorities are obliged to consider commitment from users to secure network financing, negative implications on planning and refinancing possibilities. The Regulation **allowed Member States not to introduce the entry-exit system in respect of geographically confined hydrogen networks** that have been granted a derogation under Art. 52 of the RNGH Directive (see below) and are not connected to another hydrogen network (Art. 7.7).

The Parliament Proposal for a RNGH Directive also mandated regulated access to hydrogen networks while allowing to preserve negotiated access until 31 December 2030, but giving 'priority access to users who can demonstrate the highest potential of GHG abatement' per tonne of consumed hydrogen and where no other, more energy and cost efficient, options were available (except for cases where access has already been granted (Art. 31).The Parliament Proposal for a RNGH Regulation stipulated the same maximum duration of capacity contracts as the EC Proposal, enabling regulatory authorities to impose shorter durations but obliging them to 'take into account, inter alia, commitment from users to secure network financing, negative implications on planning and refinancing possibilities'. It also required priority access to hydrogen networks for users with the highest GHG abatement potential (Art. 6).

The Council Proposal for a RNGH Directive, like the EC and the Parliament Proposals, mandated regulated access to hydrogen networks but in contrast **allowed to preserve negotiated access until 31 December 2035** – i.e. for five years longer. The Council Proposal for a RNGH Regulation specified 20 years as being the maximum duration of capacity contracts for hydrogen infrastructure completed by 1 January 2031 (as opposed to the date of the Regulation's entry into force) and 15 years for infrastructure completed after that date, thus effectively prolonging their duration for ~ five years (Art. 6).

As far as access to **hydrogen storages** is concerned, the RNGH Directive mandates <u>regulated access</u> based on published tariffs (Art. 37). It allowed Member States to decide not to apply regulated access until 31 December 2032, opting to apply negotiated access instead. It also allows Member States to provide that capacity rights, allocated under negotiated access regime not later than 2 years after the Directive's entry into force, would be respected until their expiry date and not affected by the implementation of regulated access (the so called, hydrogen storage 'sunset clause'). In so doing the RNGH Directive has partly reflected the Council's position, which proposed to allow negotiated access until 31 December 2035 (prior to subsequent introduction on regulated access) but shortened the duration of transition period. For its part, the Parliament proposed to mandate regulated access without any transition period (Art. 33).

The RNGH Directive mandates <u>negotiated access</u> to **hydrogen import terminals** used for imports of ammonia and liquid hydrogen and the conversion into gaseous hydrogen for injection into the hydrogen network or the natural gas network, with regulatory authorities to take the necessary measures for terminal users to be able to negotiate access (Art. 36.1). The Council Proposal also allowed Member States to decide to apply regulated access instead (Art. 32).

Tariffs

The RNGH Regulation stipulates that as of **1 January 2033 hydrogen networks would be organised as 'entry-exit' systems** and the requirement of regulated tariffs previously only applicable to natural gas networks (see Section 2.2.1) would also become applicable to tariffs for access to hydrogen networks (Art. 7.6). If Member States were to decide to apply regulated access to hydrogen networks before 1 January 2033, a regulated tariff regime would be applied. The Regulation **allows Member States to decide not to apply the 'entry-exit' requirement to geographically confined networks** that benefit from a derogation under the RNGH Directive's Art. 52. From 1 January 2033 (or earlier, where a Member State decided to apply regulated access to hydrogen networks before that date) capacity allocation and congestion management rules applicable to (natural gas) TSOs would also apply to hydrogen network operators (HNOs), with tariffs for each network point to be published (Art. 7.8). The RNGH Regulation obliges the regulatory authorities to consult regulatory authorities of directly connected Member States before taking a decision on the methodology for setting hydrogen network access tariffs for the entry and exit points at cross-border IPs between Member States, as well as to submit the envisaged tariff methodology to ACER. Notably, the Regulation **allows the regulatory authorities to decide to charge no hydrogen network access tariffs or, when capacity is allocated via auctions, to set the reserve prices to zero** (Art. 7.8) but, unlike the EC Proposal, it does not make a zero tariff mandatory. The RNGH Regulation also confirmed that its **provisions on tariff discounts for renewable and low carbon gas** (see above) (Art. 18) and requirements on TSO revenues (Art. 19) would only apply to natural gas, but not to hydrogen, networks.

While the Parliament Proposal largely followed the EC Proposal, the Council Proposal stated that the requirement of regulated tariffs would become applicable to hydrogen networks and the obligations applicable to (natural gas) TSOs would also apply to hydrogen network operators and prescribed to organise hydrogen networks as 'entry-exit' systems only from 1 January 2036 – five years later than suggested by the EC – to synchronize with the Council's suggested start-date for regulated access to hydrogen networks (Art. 6.6). It also allowed Member States to decide not to apply the 'entry-exit' requirement to those networks that benefit from a derogation for networks which transport hydrogen to a limited number of exit points within a geographically confined area and are not connected to another hydrogen network. Unlike the EC Proposal, which mandated zero tariffs for access to hydrogen networks at intra-EU IPs, the Council Proposal left to Member States to decide whether to apply zero reserve price at intra-EU IPs if capacity is allocated via auctions (Art. 6.7). On its part, the Parliament Proposal stated that no tariffs would be charged for access to hydrogen networks at intra-EU IPs unless the regulatory authorities jointly agree on a tariff regime, whereas in absence of such agreement ACER would decide on the tariff regime, including the possibility of avoiding the application of tariffs. Both the Council and the Parliament Proposals stated that provisions on tariff discounts for renewable and low carbon gas and requirements on TSO revenues would only apply to the natural gas system but not to hydrogen networks.

Exemptions and derogations

<u>Exemptions</u>

The RNGH Regulation (Art. 78) states that '[m]ajor new hydrogen infrastructure, namely **interconnectors, hydrogen terminals and underground hydrogen storage facilities,** may, upon request, be exempted, for a set period' from the RNGH Directive's provisions on vertical unbundling of hydrogen transmission network operators (Art. 68), access to hydrogen networks (Art. 35), access to hydrogen terminals (Art. 36), access to hydrogen storages (Art. 37). It also stipulated that such infrastructure may be exempted from the RNGH Regulation's own provisions, except provisions requiring hydrogen terminal operators and hydrogen storages operators to publish the amount of hydrogen in their respective facilities (Art. 34.5) and information on tariff derivation, tariff structure and methodologies, or tariffs themselves (Art. 34.6). The Regulation does not specify a maximum duration for which an exemption could be granted. An exemption is subject to conditions, identical to those for natural gas infrastructure (Section 2.2.1), including the condition that an exemption could not be granted if it has received the EU financial assistance for construction under CEF Regulation. The principle of energy solidarity must also be assessed. Significant increases in, and modifications of, existing infrastructure are also eligible for exemptions if they enable the development of new sources of renewable and low carbon gases.

The Parliament's Proposal stipulated the same exemption regime (Art. 60) as the EC Proposal but stated exemptions would only be possible if infrastructure contributes towards the achievement of the EU's climate and energy targets and has not received EU financial assistance for works (construction) under the CEF Regulation (thus reflecting the Parliament Proposal). It also added that exemptions granted by the time of the RNGH Regulation's entry into force would remain valid. The Council's Proposal stipulated the same exemption regime as the EC Proposal while adding the requirement of compulsory assessment of energy solidarity (Art. 60).

Derogations

The RNGH Directive (Art. 51) stipulates that Member States may provide for regulatory authorities to grant a derogation from the Directive's provisions **for existing hydrogen networks** that belonged to a VIU on the date of the Directive's entry into force in respect of access to networks (Art. 35), vertical unbundling of hydrogen transmission network operators (HTNOs) (Art. 68), horizontal unbundling of hydrogen transmission network operators (Art. 69), unbundling of accounts of hydrogen network operators (Art. 70), unbundling of hydrogen distribution network operators (HDNOs) (Art. 46), designation and certification requirements for hydrogen transmission network operators (Art. 71) as well as from the RNGH Regulation's provisions on access to hydrogen networks (Art. 7) and regional cooperation of hydrogen transmission network operators within ENNOH (Art. 65). The derogation would expire: (a) where the regulatory authority, upon request by the VIU, decides to end the derogation; (b) where the hydrogen network benefitting from the derogation is connected to another hydrogen network; (c) where the hydrogen network benefitting from the derogation or its capacity is expanded by more than 5 per cent; (d) where the regulatory authority concludes that the derogation would risk impeding competition or adversely affect the efficient deployment of hydrogen infrastructure or the development and functioning of the hydrogen market in the Member State or the EU. The regulatory authorities are obliged to publish an assessment of the derogation's impact every seven years. The Directive suggests that the derogation could be indefinite if the network is not connected to another network and not expanded significantly. This is different from the EC Proposal which required all derogations to be phased out by 31 December 2030.

The RNGH Directive's list of provisions from which derogation can be sought in respect of **existing hydrogen networks** that belonged to a VIU on the date of the Directive's entry into force, included some provisions listed in both the Council and the Parliament Proposals. However, not all Council and Parliament suggestions have been accepted. For example, the RNGH Directive list of provisions from which derogation can be sought includes the HTNO horizontal unbundling requirement despite it being absent in the Parliament Proposal, and also includes the HDNO unbundling requirement despite it being absent in the Council Proposal. The RNGH Directive has also accepted the Council suggestion that derogation could be indefinite. In so doing it departed from the EC Proposal, which stated that a derogation would expire by 31 December 2030 or earlier if the hydrogen network or its capacity was expanded or connected to another hydrogen network. On its part, the Council Proposal suggested that derogation would expire if the hydrogen network was connected to another network or expanded by more than 5 per cent, or if the regulatory authority concluded that the derogation would carry the risk for competition, deployment of hydrogen infrastructure or the development of the hydrogen market in the Member State or the Union.

The RNGH Directive (Art. 52) also stipulated that Member States may provide for regulatory authorities to grant a derogation from the Directive's provisions on vertical unbundling of hydrogen transmission network operators (Art. 68), designation and certification requirements for hydrogen network operators

(Art. 71), unbundling of hydrogen distribution network operators (Art. 46) for **hydrogen networks which transport hydrogen within a geographically confined, industrial or commercial area.** For the duration of the derogation, a network must comply with all the following conditions: (a) it does not include hydrogen interconnectors, (b) it does not have direct connections to hydrogen storage facilities or hydrogen terminals (unless they are also connected to a hydrogen network that does not benefit from a derogation under Art. 51 or Art. 52), (c) it primarily serves the purpose of supplying hydrogen to directly connected customers, (d) it is not connected to any other hydrogen network, except to networks also benefitting from a derogation under Art. 52 and operated by the same hydrogen network operator. The NRAs are obliged to withdraw the derogation if any of these conditions are not fulfilled or where its continued application carries the risk of impeding competition, adversely affecting the efficient deployment of hydrogen infrastructure or the development and functioning of the hydrogen market. The regulatory authorities are obliged to publish an assessment of the derogation's impact every seven years. The Directive obliges Member States to ensure that requests for access from hydrogen producers and requests for connection from industrial customers are notified to the regulatory authorities and published. Notably, as with derogations for existing networks under Art. 51, derogations for hydrogen networks transporting hydrogen within geographically confined areas under Art. 52, could be indefinite.

The RNGH Directive's list of provisions from which derogation can be sought in respect of hydrogen networks which transport hydrogen within a geographically confined, industrial or commercial area includes provisions listed in both the Parliament and the Council Proposals. For example, it includes the HDNO unbundling requirement as suggested in the Parliament Proposal and the HNO certification requirement as suggested in the Council Proposal, both absent in the EC Proposal. The RNGH Directive allows for derogations in respect of hydrogen network transporting hydrogen within a geographically confined, industrial or commercial area irrespectively of the number of entry points through which hydrogen is injected into the network, whereas the EC Proposal and the Parliament Proposal suggested to limit the number of such points to just one.

3. Topology, scale and timing of the European hydrogen network development and its impact on the existing natural gas networks

3.1 Uncertain topology of the future networks

While it is well understood and accepted that there will be two gas networks in Europe (natural gas and hydrogen), their topology – the physical arrangement of future pipeline connections and nodes – is much less clear. The topology of the European hydrogen network is particularly unclear because of significant uncertainty in respect of future demand for, and supply of, hydrogen – both renewable and low carbon[45] – as well as future location of supply (domestic production and imports) and demand centres, which the hydrogen pipelines would be required to connect (Section 3.2). Notably, these factors would determine not only the topology of the future European hydrogen network, but also would have an impact on the future of European natural gas networks (as some of them would have to be re-purposed for hydrogen or de-commissioned).

The EU Hydrogen Strategy acknowledged that the need for hydrogen infrastructure will depend on the pattern of hydrogen demand and supply, as well as transportation costs. The Strategy mentioned three stages for infrastructure development – 2020-2024, 2025-2030, 2031-2050 – linking all of them to the development of renewable hydrogen (6 GW of electrolyser capacity by 2024, 40 GW by 2030, and 500 GW by 2050). The Strategy stated that during *the first stage (2020-2024)* planning of 'medium range and backbone transmission infrastructure' should start, while acknowledging that the need for hydrogen networks during this stage will remain 'limited' as demand will be met initially by production

[45] This paper refers to 'renewable' and 'low carbon' hydrogen as defined in the EC Proposal for a RNGH Directive, EC (2021a).

close to, or on, site (from electrolysis of water by local renewable power or methane reforming) in industrial clusters and coastal areas through existing networks. It is worth noting that as this paper is going into print in April 2024, this plan has not happened and it looks unlikely there will be more than 1 GW of electrolyser capacity and next to no new pipeline infrastructure by the end of 2024. Further 'retrofitting of existing fossil-based hydrogen production with carbon capture' is envisaged to continue during *the second phase (2025-2030)*, while 'the need for an EU-wide logistical infrastructure' is also expected to emerge during this stage, building on the national and regional infrastructure, characteristic of the first phase, noting that while local hydrogen networks would accommodate additional industrial demand, with increasing demand, optimisation of hydrogen production, usage and transportation will be required, thus necessitating longer-range transportation to ensure the whole system efficiency.

The European TSOs' vision for the future European hydrogen network – as expressed in their three consecutive **European Hydrogen Backbone** reports (EHB 2020, EHB 2021, EHB 2022) – builds up on the EU Hydrogen Strategy but is significantly more expansionist. EHB 2020 envisaged an emerging network of 6,800 km of pipelines connecting hydrogen valleys during 2025-30, and a network of 23,000 km of pipelines growing across Europe during 2030-40. EHB 2021 revised the length of the network upwards,[46] envisaging a network of 11,600 km of pipelines connecting hydrogen valleys during 2025-30, growing to become a pan-European network of 39,700 km by 2040. EHB 2022 stated that by 2030 five pan-European hydrogen supply and import corridors could emerge, connecting industrial clusters, ports and hydrogen valleys to regions of abundant hydrogen supply. It revised the length of the network in 2040 further upwards, envisaging a pan-European network of almost 53,000 km (of which over 60% would be repurposed natural gas pipelines). For comparison, currently the total length of hydrogen pipelines in Europe is less than 2,000 km, whereas the total length of natural gas transmission pipelines is over 200,000 km.[47] The EHB effectively envisaged a massive scale-up of hydrogen network, suggesting that by 2040 the pan-European hydrogen network could constitute ~26% of the total length of the current EU gas transmission network (partly through new construction and partly through repurposing), whereas at present it is just ~1%.

Whether the EHB vision will be realised depends on whether the European hydrogen network will remain confined to national and regional industrial clusters ('valleys') or will grow further to become an integrated pan-European network. This ultimately depends on inter alia whether there will be significant additional demand for renewable or low carbon hydrogen in Europe, beyond what is needed for replacing the existing industrial demand for high carbon hydrogen (fossil-based hydrogen without CCS), and whether local hydrogen production will be insufficient to satisfy this demand. If the answer to these questions is 'yes' – which is far from certain, given vastly different hydrogen demand forecasts (Section 3.2) – then the integrated pan-European hydrogen network *could* become a reality, with hydrogen being brought from decentralised hydrogen supply centres to decentralised hydrogen demand centres through new hydrogen supply corridors across Europe. On the other hand, if the answer to these questions is 'no', while there would be some new hydrogen pipelines built and some existing natural gas pipelines repurposed, hydrogen networks will remain largely regional at best, as there would be no need for transporting additional volumes of hydrogen from afar. In this case, the European hydrogen network will consist of several regional hydrogen networks, with no EU-wide integration. Also, even in the event of significant additional demand for hydrogen in the future, it is possible that the pan-European integrated hydrogen pipeline network might not materialize as instead of relying on transportation of hydrogen, some existing and/or new demand centres could (re-)locate closer to hydrogen production – with renewable electricity for producing hydrogen through electrolysis to be transported there by power cables (HVDCs)[48] – thus rendering a pan-European transportation dimension for hydrogen irrelevant.

[46] Due to an increased number of participating TSOs.
[47] Lambert and Schulte (2021).
[48] See Patonia et al (2023).

In summary, while the integrated pan-European hydrogen pipeline network, as envisaged by the EHB (Fig. 2, see *Figures*), could materialize, it is also possible – and perhaps more likely – that a much smaller "no regret" European hydrogen network might emerge instead, and its pipelines would be limited to connecting the existing European industrial clusters (valleys) but not extending much further (Fig. 1, *Figures*). At present, there is no definitive answer on what the future European hydrogen supply and demand will be, and hence what kind of hydrogen network would be needed. Therefore, the EU regulatory framework should be sufficiently flexible to enable the development of any kind of the European hydrogen network – either a smaller scale, regionalized, European network, or a larger scale, integrated, pan-European network.

3.2 Choice of decarbonisation pathways by existing and prospective industrial users of hydrogen and its impact on the network topology

3.2.1 European demand for renewable and low carbon hydrogen: uncertain future

To understand where demand for renewable and low carbon hydrogen could be located in the future – thus influencing the topology, the size and the scale of the European hydrogen network – it is important to understand which sectors of the European economy currently use hydrogen and which sectors could use it in the future.

At present, most of EU hydrogen demand is concentrated in five EU Member States – Germany, the Netherlands, France, Spain and Italy – with Germany having the highest demand of 55 TWh, followed by the Netherlands with 50 TWh, France – 30 TWh, Spain – 17 TWh, and Italy – 16 TWh (Fig. 4, *Figures*). Outside the EU, the UK is the only European country which has significant demand for hydrogen, just behind France with 23 TWh.

Most EU (and non-EU European) hydrogen production (and consumption) is high carbon hydrogen, produced from natural gas through methane reforming process (whereas subsequent CO2 emissions are not captured). Most of this hydrogen is consumed by the industrial sector, mainly in fuel refining and synthesizing ammonia.[49] In 2020, the EU industrial hydrogen demand of 257 TWh was divided between fuel (mostly oil) refining, where hydrogen is used as feedstock (138 TWh), synthesizing ammonia (109 TWh) and methanol (10 TWh) (Fig. 5, *Figures*).

Most of this hydrogen is produced – and consumed – on-site, in large industrial clusters, predominantly located in North-West Europe (Belgium, the Netherlands, Luxembourg, North-West Germany and North-East France), although there are also smaller clusters in the Mediterranean and Eastern Europe. Hydrogen demand varies cluster by cluster, with largest clusters consuming 10-30 TWh and smaller clusters consuming less than 1 TWh.[50] This means that currently the transportation dimension of the European hydrogen value chain is relatively minor as most of existing hydrogen pipelines are located within individual clusters.

The total length of hydrogen pipelines in Europe is currently less than 2000 km, most of them located in Belgium and Germany as well as cross-border pipelines, connecting the Port of Rotterdam in the Netherlands with Belgium and France. There is also hydrogen transport infrastructure in Germany which is operated by industrial gas suppliers Air Liquide and Linde.[51] Most of these pipelines are used to connect industrial clusters, transporting high-carbon hydrogen from producers to large consumers,

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[49] Refineries use hydrogen to lower the sulfur content of diesel fuel. Hydrogen is produced using methane reforming process (using natural gas as feedstock) or as a by-product of other chemical processes. It is produced either by refineries themselves or supplied by industrial plants. Ammonia producers also use methane reforming process using natural gas as feedstock to produce hydrogen, which is subsequently mixed with nitrogen to produce ammonia. A high degree of hydrogen purity is required for both fuel refining and ammonia synthesis processes.

[50] AFRY/Agora Energiewende (2021), 'No regret hydrogen: charting early steps for H_2 infrastructure in Europe.

[51] Lambert and Schulte (2021).

using it as feedstock (refineries, chemical plants) as well as to storages (located close to consumers). These pipelines normally transport a steady high-volume flow of hydrogen on a long-term contractual basis (15-30 years) and are characterised by high degree of capacity utilisation. As such, current hydrogen production is decentralised as each industrial cluster has its own hydrogen production facility.

AFRY/Agora estimates that for 2050 net-zero targets to be met, the EU industrial demand for hydrogen would only have to increase to 270 TWh. Under a “no regret” scenario, industrial hydrogen demand’s division by sector is expected to change significantly, with demand for hydrogen in the refining sector dropping to just 14 TWh in 2040, before disappearing completely by 2050. While demand for ammonia and methanol production is expected to remain almost unchanged by 2050, almost half of demand is expected to be taken by the steel sector, and the rest – by chemical plastics recycling.[52] This indicates that ~270 TWh of renewable or low carbon hydrogen would be required to decarbonize the EU industrial sector. It is worth noting that the Agora estimate of 270 TWh constitutes a “no regret” view and is at the low end of the range. The significant uncertainty existing in respect of hydrogen demand makes it impossible to be definitive about it.

While hydrogen in Europe is mostly consumed in fuel refining and synthesizing ammonia at present, there are various potential applications for renewable and low carbon hydrogen in other sectors. For example, hydrogen could be used as feedstock for products (steel, glass), industrial heat (steel, cement, aluminium, paper) where it could replace natural gas,[53] commercial and residential heating, fuel for transport (heavy duty road transport, maritime, long-haul aviation) and power (for balancing grids with intermittent renewables).[54] Notably, there are limits for using hydrogen in some of these sectors as electrification could be more efficient (e.g. heat for buildings).[55]

Estimates of how much renewable or low carbon hydrogen would be required for decarbonizing the existing high carbon hydrogen use as well as for enabling hydrogen use in new applications differ substantially. For example, the FCH JU study, quoted in Lambert and Schulte (2021), developed various scenarios for several European countries’ hydrogen demand in 2030 (France, Germany, the Netherlands, Spain, the UK and Italy), with significant variations between high and low case scenarios (Fig. 6, Figures).[56] For example, a low case scenario for Germany envisages an overall demand for clean hydrogen of 11 TWh, almost equally divided between refining and steel making, whereas a high case envisages an overall demand of 43 TWh, with refining and steel making taking 1/3 each, whereas heat in buildings and ammonia production also takes significant shares. For the Netherlands, the difference in hydrogen demand for refining is less significant in low and high case scenarios as both envisage a significant role for hydrogen; however, there is a massive difference in respect of demand for hydrogen in heat in buildings and ammonia production. More generally, for all surveyed countries, ammonia production and heat for buildings appear to be the main sources of significant variation between low and high cases of hydrogen demand. Another common feature for all these countries, is a relatively low share of power and transport sectors as potential sources of hydrogen demand – both under low and high case scenarios. Notably, discrepancies between high and low cases are even more significant for scenarios of hydrogen demand in 2050. For example, German hydrogen demand for 2050 is forecast in the range between 150 TWh and 550 TWh.[57]

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[52] AFRY/ Agora Energiewende (2021).

[53] Demand for process heat should be covered by power-to-heat technologies, as the performance factor for electric heating is at least the same or better than for heat produced using hydrogen from electrolysis. 40percent of today’s industrial fossil gas use in Europe is for heat up to 100°C, which can be produced by heat pumps.

[54] Griffiths et al (2021), Industrial decarbonization via hydrogen: a critical and systematic review of developments, socio-technical systems and policy options’.

[55] For example, using hydrogen for decarbonizing industrial heat would be less efficient than using “power-to-heat”.

[56] FCH 2 JU (2020), ‘Opportunities for hydrogen energy technologies considering the national energy and climate plans’.

[57] Lambert and Schulte (2021).

Given that supply and demand for clean hydrogen – both in terms of volume and location – will determine the size of the European hydrogen market and will provide a signal where and when additional hydrogen infrastructure will be needed, significant variations in hydrogen demand scenarios limit their value as a reliable roadmap for developing the European hydrogen pipeline network. However, such scenarios are useful for identifying various sectors (e.g. steel-making) where additional hydrogen demand could come from, as well as for conducting a sensitivity analysis of the impact of additional hydrogen demand on the topology of the emerging European hydrogen network.

3.2.2 Existing and prospective industrial users of hydrogen[58]

a) existing users

While the European power, heat and transport sectors could become new sources of (currently non-existent) demand for hydrogen in the coming decades, at present the European industrial sector – fuel refining and ammonia synthesizing (processes where natural gas is used as feedstock) – is the only definite source of demand for hydrogen. Therefore, conversion of existing industrial users to renewable or low carbon hydrogen is a logical first step towards large-scale use of hydrogen for decarbonisation given the uncertainty about future hydrogen supply and demand.

Retrofitting current hydrogen production (based on methane reforming process) with CCS equipment, enabling CO2 to be captured and stored, would provide a relatively straight-forward way – from an engineering point of view – of decarbonizing existing high-carbon hydrogen production (and consumption) in the EU. From a commercial point of view, this low carbon hydrogen would be more expensive than currently used high-carbon hydrogen. However, as the price of emitting CO2 in the EU is increasing and sectors covered by the Carbon Border Adjustment Mechanism (CBAM) – iron and steel, cement, fertilisers, aluminium, hydrogen production and electricity – are set to lose their free EU ETS emissions allowances over the next 10 years (~40% of free allowances is expected to be phased out by 2030 and 100% – by 2035[59]), the difference will become less pronounced and will eventually disappear. Converting existing high carbon hydrogen consumption to low carbon hydrogen would not require any (significant) new hydrogen pipeline construction as carbon capture would be carried out on-site within an industrial cluster. This suggests that decarbonisation of the existing hydrogen production (and consumption) through low carbon hydrogen would not (at least initially) lead to a rapid growth of the European hydrogen network, as hydrogen pipelines will be confined to individual industrial clusters. However, it would require construction of new CO2 pipelines (or repurposing some existing natural gas pipelines) for transporting carbon to its permanent storage facilities, which would also have to be built. These CO2 pipelines and storage facilities could be located either onshore or offshore.[60]

While it is logical for existing high carbon hydrogen production to decarbonize through low carbon hydrogen by reforming methane and capturing and storing CO2, it is not necessarily the case that all the existing hydrogen production installations will be decarbonised through low carbon hydrogen. Instead, some of them could well choose to decarbonize through renewable hydrogen. In fact, all significant (>100MW) European decarbonisation projects that have taken FID so far, chose to decarbonise through renewable (as opposed to low carbon) hydrogen, either by producing renewable hydrogen for part of the consumption in the nearby refinery (the Netherlands[61] and Germany) or for

[58] Nearly all existing users of hydrogen in Europe are industrial installations. While in the future there could be other users of hydrogen other than the industrial sector, this paper only considers prospective industrial users as potentially having the biggest impact of the hydrogen network topology.
[59] IOGP (2023), 'Creating a sustainable business case for CCS value chains' – webinar.
[60] The EC Proposal for a Net Zero Industrial Act (NZIA) Regulation, expected to be adopted in Q2 2024, mandates the development of 50 mn tons carbon injection and storage capacity by 2030, see EC (2023a). However, the Proposal does not provide a framework for construction and operation of the CO2 transportation network.
[61] Holland Hydrogen 1.

decarbonizing steel-making processes (Sweden).[62] Nonetheless, at present the amount of electrolytic hydrogen produced in Europe is only a small percentage of the total hydrogen use for refining. For example, the Netherlands “Holland Hydrogen 1” project, with capacity of 200 MW, will produce only about 10% of the hydrogen demand for Shell’s Rotterdam refinery. Therefore, it would be possible for a refinery also to add CCS to its existing hydrogen production (from natural gas) and thus have a mixture of renewable and low carbon hydrogen using at the refinery.

Decarbonisation of existing hydrogen production through renewable hydrogen produced close to the source of consumption, combined with on-site production of low carbon hydrogen would not have a significant impact on the European hydrogen network topology as the pipelines required for transporting this hydrogen would be located within the industrial clusters, potentially with a regional but not an EU-wide transportation dimension. However, if locally produced renewable and low carbon hydrogen were to be insufficient for covering demand, a cross-border dimension of the European hydrogen network could become more important as clean hydrogen would have to be brought in from afar. For example, this could be renewable hydrogen produced in areas with high renewable power production potential (e.g. southern Europe, the North Sea area, North Africa, Mediterranean) and transported to European demand centres by pipeline (see Section 3.2.3). However, depending on the volumes of hydrogen required, transporting renewable electricity by power cables (HVDCs) to electrolysers located close to hydrogen demand centres could be more economic than transporting hydrogen by pipeline, as the latter is only economic if hydrogen volumes are sufficiently high.[63]

On the other hand, it could also be low carbon hydrogen if some natural gas producers were to decide to produce low carbon hydrogen by capturing CO2 and transporting low carbon hydrogen by pipeline. This approach would require conversion and utilization of offshore depleted natural gas fields for CO2 storage and conversion and utilization of offshore natural gas pipelines for CO2 transport and subsequent coordination of hydrogen and natural gas networks. One example is provided in Norway by Equinor’s Sleipner project (1996), with CO2 removed from natural gas at an offshore platform and stored underground offshore and natural gas transported onshore by pipeline.[64] Another example is provided by Equinor’s Snohvit project (2008), where CO2 is removed from natural gas prior to liquefaction at Hammerfest LNG plant onshore and transported by pipeline and stored offshore.[65]

Whether these examples would be replicated as the means of producing low carbon hydrogen depends mostly on the costs, as in general it would be less expensive to import natural gas and produce low carbon hydrogen on site, than transport low carbon hydrogen manufactured elsewhere. Sleipner’s commercial rationale was based on the fact that natural gas produced from the Sleipner field had a very high concentration of CO2, which – if not captured and stored – would expose Equinor to significant CO2 tax payments.[66] Snohvit’s commercial rationale was also rooted in CO2 tax exemption from the Norwegian government.[67]

b) new users

Decarbonisation choices made by potential new industrial users of hydrogen – e.g. industries currently not consuming any hydrogen but considering switching their technological processes to hydrogen in the future – such as steel making – could also have an impact on the topology of the European hydrogen network.

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[62] Hybrit and H2 Green Steel.
[63] Patonia et al (2023).
[64] MIT, Carbon Capture and Sequestration Technologies Programme, Sleipner fact sheet, https://sequestration.mit.edu/tools/projects/sleipner.html
[65] MIT, Carbon Capture and Sequestration Technologies Programme, Snohvit fact sheet, https://sequestration.mit.edu/tools/projects/snohvit.html
[66] MIT, Sleipner fact sheet.
[67] MIT, Snohvit fact sheet.

At present, most steel in Europe is produced via either the Blast Furnace-Basic Oxygen Furnace (BF-BOF) route or the Electric Arc Furnace (EAF) route.[68] In 2020, just under 60% of total EU steel production was produced via the BF-BOF route. The BF-BOF process requires coal as an input for producing coke as a reducing agent for an iron ore. Alternatively, the direct reduction (DR) process, where natural gas is used as an input (to provide a high temperature heat), is used for reducing iron without needing a blast furnace; this process is often combined with EAF.

There are various options for decarbonizing steel production.[69] One involves capturing carbon from natural gas in the DR process. At present, there is one commercial project based on this technology – the Emirates Steel CCS plant in Abu Dhabi. The plant uses locally produced natural gas, with CO2 captured and transported by a short pipeline to a geological reservoir, and subsequently used for enhanced oil recovery (EOR). This process is effectively about producing (and consuming) low carbon hydrogen on site through methane reforming with CCS. This model could be replicated in other regions, where access to natural gas is assured and where legal/regulatory conditions are in place allowing for CO2 transport and storage. The attractiveness of this model also depends on the existence of a well-developed natural gas network, which would bring natural gas on site where some of it could be repurposed for building a CO2 pipeline.

Another option would be to use hydrogen instead of natural gas as input material in the DR process, in combination with EAF. As this method does not require natural gas, it avoids carbon emissions associated with its combustion thus not requiring CCS. However, carbon emissions would be incurred in producing hydrogen, as electricity would be needed to power an electrolyser and to power the DR and EAF processes. As the emission intensity would depend on emission intensity of electricity used, the highest potential for decarbonizing steel-making through renewable hydrogen is in regions with a very high share of renewable electricity.[70] The two largest such projects – HYBRIT and H2GreenSteel – are currently located in Sweden, characterised by the highest share of renewable sources in its energy mix in the EU (~65% in 2022, see Fig. 8, *Figures*).

Another alternative, as far as the BF-BOF process is concerned, would be to apply carbon capture at the blast furnace. So far, only small trials have been commissioned for this technology.[71]

Cost is one of the key factors determining whether European steel producers will decarbonise through renewable or low carbon hydrogen (or whether their production facilities will be moved out of Europe). At present, decarbonized steel is significantly more expensive than non-decarbonized steel, and this affects its competitiveness. According to FCH JU, the price of electricity used for electrolysers would be a key factor determining which decarbonisation route would be most economic for European steel makers. It concluded that using low carbon hydrogen (produced from natural gas with CCS) would be beneficial with an electricity price above 44 euros per MWh, whereas lower cost electricity would benefit electrolytic renewable hydrogen.[72] Factors other than cost would also play a role. If the European steel making industry chooses to decarbonize through hydrogen, the sector could become a significant source of additional hydrogen demand. This could potentially have an impact on the hydrogen network topology, depending on whether clean hydrogen for steel making will be co-located with steel making plants or brought from afar.

In summary, the European industries currently using high carbon hydrogen for their technological processes (e.g. refining or synthesizing ammonia), as well as the industries currently not using any hydrogen at all but considering switching to renewable or low carbon hydrogen (e.g. steel-making) have a choice of decarbonizing their technological processes through renewable and/or low carbon

[68] EUROFER, 'What is steel and how is steel made?'
[69] See Muslemani (2023) for an overview and analysis.
[70] Ibid.
[71] Ibid.
[72] FCH 2 JU (2020).

hydrogen. Different factors would likely influence their decisions, including perceived availability and cost of renewable and low carbon hydrogen, location, expected financial and regulatory support from the EU and Member States governments. The choices made will have a significant impact on the topology, the scale, and the timing of the European hydrogen network development, as well as on the status of the natural gas network depending on how much (or how little) of it would have to be retrofitted, re-purposed or de-commissioned. This means that the regulatory framework should be sufficiently flexible and include provisions allowing for decarbonizing through both renewable and low carbon hydrogen.

3.2.3 Decarbonization pathways: renewable and low carbon hydrogen

While the previous sub-section outlined the choices facing European industries about whether to decarbonize their individual technological processes through renewable and/or low carbon hydrogen – and discussed an impact of their choices on the future network topology – this sub-section will discuss the challenges, associated with choosing either renewable or low carbon hydrogen pathways, as these challenges would influence which pathways are taken.

Decarbonization purely through renewable hydrogen presents significant challenges – both in respect of availability of sufficient renewable electricity for producing hydrogen without undermining the priority of grid decarbonisation, as well as the very high costs that make renewable hydrogen uncompetitive at present. It is estimated that the EU RES generation capacity would have to double to enable production of 10 mn tons of renewable hydrogen (as envisaged in the RePowerEU Plan). Currently the share of RES in EU gross energy consumption is 22.5%, while the REDiii Directive (2023) mandated the 42.5% target by 2030 (Fig. 7, *Figures*). Individual Member States' RES shares differ widely (see Fig. 8, *Figures*). Amongst the five Member States with the highest high carbon hydrogen production – France, Germany, Spain, Italy, and the Netherlands – the first four had RES shares at just above 20% in 2022 – in line with EU targets – whereas the Netherlands was behind with 15 per cent. This suggests that decarbonization of these countries' hydrogen production purely by means of switching to renewable hydrogen would be challenging unless their RES shares were to increase rapidly and significantly. Whether the REDiii RES target would be met (and at what price renewable electricity would be available) would have a significant impact on how many industrial players choose a renewable hydrogen decarbonization pathway. Currently the RES power generation plants – onshore and offshore wind farms and solar PV panels/parks – are scattered across Europe, most of them connected to national power grids. As the EU acquis required Member States to ensure 15% interconnection capacity between the national grids by 2030, RES plants also contribute towards decarbonizing the EU grid.[73] While several Member States have very low levels of GHG emissions intensity (Sweden and France being among the least intensive) (Fig. 9, *Figures*), the EU's overall intensity remained relatively high at ~240 gCO2e/kWh which presents a challenge for sourcing electricity from the grid – **"on grid" electricity** – to produce renewable (electrolytic) hydrogen (Fig. 10, *Figures*). At the same time sourcing electricity from the grid has its advantages as an electrolyser can run at higher full load hours, thus resulting in lower production cost of hydrogen. Access to grid electricity could also reduce hydrogen transportation costs as no additional hydrogen pipelines would be needed as hydrogen would be produced close to demand centres (industrial clusters). **"Off-grid" electricity** – electricity produced by a dedicated off-grid RES plant, whose GHG (and carbon) intensity is virtually zero – presents an alternative to powering an electrolyser by grid electricity, with the resulting hydrogen being fully renewable. The main disadvantage of this method is high production cost of hydrogen due to lower capacity factors – at present hydrogen production based on electrolysis from off-grid RES plants is not competitive. However, as costs are expected to decline by the early 2030s, southern Europe (Spain and Italy) solar PVs and North Sea offshore wind (adjacent to Germany, the Netherlands,

[73] Several EU Member States (the Baltic countries) are undergoing synchronisation with the EU grid, whereas some non-EU Member States (Ukraine) have announced their intention to do so.

and the UK) could become large scale producers of renewable hydrogen.[74] This hydrogen could be subsequently transported to demand centres in various industrial clusters thus requiring hydrogen pipelines to be built/repurposed. Alternatively, renewable electricity produced in these regions could be brought to hydrogen demand centres (industrial clusters) by power cables (HVDCs), with hydrogen to be produced within industrial clusters. It is also possible that some industrial installations might decide to shift their production closer to potential large-scale RES generation sites in southern Europe and the North Sea region but, while it could be commercially attractive, it would also be politically fraught with difficulties. These options suggest that while **renewable hydrogen would contribute towards decarbonization of existing and future demand for hydrogen in Europe – although realistically not sooner than the early to mid-2030s – it is not certain that it will lead towards creation of an integrated pan-European hydrogen network as hydrogen networks might remain regional at best.**

Decarbonizing European industrial sector through **low carbon hydrogen** – produced from natural gas through a methane reforming process, with CO2 emissions subsequently captured and stored (CCS)[75] – is also fraught with multiple challenges, including an uncertain trajectory of future natural gas prices (which would impact its competitiveness with renewable hydrogen) and a lack of CO2 transportation and storage infrastructure needed for transporting and storing CO2. Yet, as renewable hydrogen is not expected to become available in significant volumes until the early to mid-2030s, low carbon hydrogen could step in in the interim, particularly in respect of decarbonizing existing hydrogen demand. The key advantage of doing so is that it would not require construction of hydrogen pipelines as carbon capture would take place at the existing hydrogen demand centres. However, it would necessitate construction of CO2 pipelines (or repurposing of the existing natural gas pipelines to transport CO2) as well as CO2 storage. Europe has significant geological potential for CO2 storage, both onshore and offshore. Amongst European countries with significant hydrogen demand, Germany has the biggest potential for onshore CO2 storage, but the lack of public acceptance makes its development challenging. CO2 could also be stored in the offshore storage in the North Sea, as Norway, Sweden and the UK have offshore storage capacity four times that of German onshore capacity and no apparent public opposition. This would require development of the CO2 transportation network, collecting CO2 from various European industrial clusters and transporting it to offshore storage sites; this network would necessarily have a cross-border dimension. An appropriate legal/regulatory framework – currently underdeveloped – would have to be established to make it possible.[76]

All in all, different factors will shape individual choices between renewable or low carbon hydrogen decarbonisation pathways, made by European industrial installations, including perceived availability and cost of hydrogen, location, expected financial and regulatory support from the EU and Member States governments.

Renewable hydrogen vs low carbon hydrogen: an unnecessary race

As supply of both renewable and low carbon hydrogen is expected to be lower than the existing high carbon hydrogen demand at least until 2030 (and likely beyond), renewable and low carbon hydrogen are not 'in competition' chasing limited demand.[77] On the contrary, both would be needed if even the existing – let alone future – hydrogen demand is to be met by clean hydrogen. Thus, as noted in Lambert, there is a scope for accelerated production of low carbon hydrogen. In fact, the EU Hydrogen Strategy acknowledged that low carbon hydrogen would be needed first and foremost 'in the short and medium term', 'primarily to rapidly reduce emissions from existing hydrogen production and support the

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[74] Lambert and Schulte (2021).

[75] Low-carbon hydrogen from natural gas could also be produced via pyrolysis, a technique enabling natural gas to be split into hydrogen and solid carbon, with CO2 emissions.

[76] This author is working on the new OIES paper, analysing the development of EU regulatory framework for CO2 pipelines.

[77] Lambert and Schulte (2021).

parallel and future uptake of renewable hydrogen'.[78] However, the Strategy did not envisage any direct (and only limited indirect) financial support for its development, while envisaging hundreds of billions of euros in financial support for renewable hydrogen (including direct subsidies). Notably, some of the EU support schemes, such as the Hydrogen Bank initiative, are only accessible for renewable hydrogen.[79] Furthermore, while the EU REDiii Directive provided a definition of renewable hydrogen (as part of RFNBOs, see Chapter 1), thus giving investors the necessary certainty, the RNGH Directive did not provide a definition of low carbon hydrogen, deliberately postponing it until the end of 2024 (the decision criticized both by the Council and the European Parliament which asked to bring it forward). The REDiii Directive has also established legally-binding targets for renewable hydrogen (as part of RFNBOs) in industrial and transport sectors, thus effectively 'creating' demand specifically for renewable hydrogen, while one of its Delegated Acts (on additionality) allowed for electricity which was not fully renewable to be counted as renewable (subject to specific conditions) thus allowing for hydrogen produced from such electricity also be counted towards meeting RFNBO targets (see Chapter 1). Mirroring the EU Hydrogen Strategy, the Member States' national Hydrogen Strategies were also focused predominantly on renewable hydrogen.

As noted earlier, the only significant projects, aimed at decarbonisation of existing European hydrogen demand that have taken their FIDs so far, were all based on renewable hydrogen. Investors' enthusiasm for renewable hydrogen is largely based on their expectation and assurance of EU and Member States' political, regulatory, and financial support. At the same time, there are various reasons for potential investors to be hesitant about investing in low carbon hydrogen, including (a) natural gas being politically unpopular and expensive, while its future price trajectory is uncertain, (b) too few CCUS projects making progress, and (c) the EU's unequivocal political preference for renewable hydrogen, which resulted in the lack of adequate regulatory framework in respect of CO2 infrastructure. At present, it appears that whether low carbon hydrogen will play a role in decarbonising the existing high carbon hydrogen demand depends less on the EU and more on the energy policies of individual EU Member States. Those few CCUS projects that are currently under development are all proceeding mainly with financial and regulatory support from the national governments (e.g. the Northern Lights projects in Norway) rather than from the EU. But even those governments and companies that are willing to proceed, are constrained by the lack of a legally binding definition of low carbon hydrogen at the EU level – which is not expected to be provided until the end of 2024 (as part of a separate Delegated Act supplementing the RNGH Directive) – as there is no guarantee that any earlier investments would not be negatively affected.

Yet there is a growing understanding among the EU and Member States' policy makers that renewable hydrogen alone will not be sufficient to meet existing demand for decarbonizing existing high carbon hydrogen demand, let alone additional demand. While the EU remains unwavering in its strong support for renewable hydrogen, the tide might be turning as it starts considering the role of low carbon hydrogen more seriously. In particular, the EC has presented its Industrial Carbon Management Strategy in February 2024,[80] with carbon capture and storage seen as an additional measure needed for reducing industrial carbon emissions. This change appears to be mirrored at the national level as well. In July 2023, the German government – the most ardent proponent of renewable hydrogen (and the most opponent of natural gas-based hydrogen) to date – has updated its national Hydrogen Strategy, which had previously almost exclusively focused on renewable hydrogen, to include low carbon hydrogen as well.

This suggests a strong rationale for developing an adequate regulatory framework that could enable low carbon hydrogen to play a role in decarbonizing industrial hydrogen demand. Although the CCS Directive (2009) did establish a legal framework for the geological storage of CO2 in the EU and the

[78] EC (2020), EU Hydrogen Strategy.
[79] EC (2023n), EC (2023o), EC 'European Hydrogen Bank'.
[80] EC (2024a), Industrial Carbon Management Strategy.

TEN-E Regulation (2022) enabled the cross-border CO2 transport and storage infrastructure to benefit form a PCI/PMI status, overall the EU legal/regulatory framework for CCUS – the key element for scaling up low carbon hydrogen production through retrofitting existing high carbon hydrogen production with CO2 capture – remains woefully underdeveloped. In March 2023 the EC presented a proposal for the Net Zero Industry Act (NZIA),[81] setting a legally-binding target of building 50 mn tons of CO2 injection and storage capacity in the EU by 2030. However, the proposal did not outline any rules governing the operation of the future infrastructure that would be needed for transporting and storing this CO2, thus rendering the injection target largely meaningless. Delaying the development of the robust regulatory framework for CO2 transport and storage infrastructure could result in such infrastructure – which could include onshore and offshore pipelines for CO2 transport, depleted onshore and offshore gas fields converted into CO2 storages, pre- and post-combustion CO2 capture installations – being 'missing' from the EU and Member States network plans. Whether or not such infrastructure develops, in turn would have an impact on the topology of the European hydrogen network.

4. Decarbonisation of the European natural gas networks: EU legislative provisions on network development coordination and financing

4.1 EU regulatory framework governing natural gas network decarbonisation

As European demand for natural gas is expected to decline progressively, existing natural gas networks must decarbonize by becoming able to transport decarbonised gases (e.g. hydrogen, biomethane, synthetic gas) in addition to, and increasingly instead of, unabated methane. While some natural gas networks will continue to remain in operation, others will either be re-purposed to transport hydrogen or de-commissioned. Indeed, as explained in the DNV study for ACER,[82] once natural gas networks reach the end of their regulatory life, decisions would have to be made on individual networks whether to use them for transport of natural gas, biomethane and synthetic natural gas (thus continuing to be part of the natural gas system, as defined in the RNGH Directive, see Chapter 2.2.1), or not – in which case decisions would have to be made on their de-commissioning or re-purposing (thus becoming part of the hydrogen system, as defined in the RNGH Directive, see Chapter 2.2.2) (Fig. 1, see *Figures*). These specific options will differ for different networks in different EU Member States.

The RNGH Directive, the RNGH Regulation and the TEN-E Regulation provide a regulatory framework, governing construction of, and access to, hydrogen networks, as well as re-purposing and de-commissioning of, and access to, natural gas networks. This chapter will examine whether its provisions are adequate for ensuring that the natural gas networks will be phased out and hydrogen networks will be phased in – either through re-purposing or de-commissioning – in a <u>coordinated</u> manner across the EU, without jeopardising <u>security of natural gas supply</u> in the EU. It seeks to understand whether this regulatory framework guarantees that the natural gas networks will not be re-purposed to transport hydrogen at the time when there will be no hydrogen available to flow through them, while leaving consumers previously served through these natural gas networks with no alternative energy supply. This question is especially pertinent given significant uncertainty in respect of the future European hydrogen market and therefore the topology, the scale, and the size of the European hydrogen network, and correspondingly the potential extent of natural gas network repurposing (see Chapter 3).

The Third Gas Directive and Regulation 715 did not contain any regulatory provisions for repurposing or decommissioning the existing natural gas networks. However, the RNGH Directive and the RNGH

[81] As this paper goes to print in April 2024, the draft NZIA is in the final stages of trilogue. European Parliament has adopted its Report on the EC Proposal for an NZIA Regulation on 21 November 2023, see Parliament (2023c). Council has adopted its General Approach on 30 November 2023, see Council (2023g).

[82] DNV / Trinomics (2022), 'Future regulatory decisions on natural gas networks: repurposing, decommissioning and reinvestments'.

Regulation – recast Third Gas Directive and Regulation 715 – stipulated the regulatory treatment of natural gas network re-purposing, de-commissioning, and continued use/re-investing. In particular, the RNGH Directive outlined 'rules for the transport, supply and storage of natural gas and the transition of the natural gas system towards an integrated and highly efficient system based on renewable gas and low-carbon gas' (Art. 1.3), while also proving 'rules for the transport, supply and storage of hydrogen using the hydrogen system' (Art. 1.4). On its part, the RNGH Regulation established rules for the access to natural gas and hydrogen systems (Art. 1.a) (Chapter 2).

The EC presented its Proposals for a RNGH Directive and a RNGH Regulation in December 2021, whereas the Parliament and the Council formed their positions (hereafter referred to as the Parliament and the Council Proposals) in February 2023 and March 2023 respectively.[83] These positions had been reconciled during a 'trilogue' process, which started in June and ended in December 2023, taking two years to finalize this legislation. A provisional political agreement was reached between the Council and the Parliament on 27 November 2023 in respect of the RNGH Directive and on 7 December 2023 – in respect of the RNGH Regulation.[84] On 11 April 2024 the Parliament adopted the RNGH Directive and the RNGH Regulation and published both documents on its website. This chapter analyses relevant provisions of these documents, particularly focusing on natural gas asset transfer for repurposing (Section 4.3) as well as natural gas and hydrogen network planning at national and EU levels (Sections 4.4 and 4.5).

The revised TEN-E Regulation, which entered into force on 23 Jine 2022, also contained provisions relevant for network decarbonisation, enabling and facilitating the access of renewable and low carbon gases – first and foremost, hydrogen – to the European energy system. It made hydrogen pipelines, hydrogen storages, hydrogen (derivative) import terminals, electrolysers, offshore grids, CO2 pipelines and storages – all of which are relevant for the development of the future European hydrogen network – eligible for PCI/PMI status and EU financial assistance. In so doing it facilitated access of renewable and low carbon gases through new hydrogen pipelines and repurposed gas pipelines (both transporting hydrogen) as well as new power lines (transporting onshore and offshore renewable electricity for hydrogen production). The TEN-E Regulation was analysed by this author elsewhere[85] and this chapter summarised its main provisions, relevant for network decarbonisation (see Section 4.2).

The regulatory framework provided by the RNGH Directive, the RNGH Regulation and the TEN-E Regulation must be sufficiently flexible for enabling initially the development of smaller scale hydrogen networks, building on, and connecting, existing national and regional industrial clusters ('valleys'), where demand for hydrogen already exists, before moving towards developing an integrated pan-European hydrogen network associated with large-scale repurposing of the existing natural gas infrastructure, as the prospects of hydrogen demand and supply growth across the EU become less uncertain.

4.2 TEN-E Regulation: enabling network decarbonisation through new hydrogen pipelines, repurposed natural gas pipelines, and CO2 storages

PCI/PMI status eligibility: priority corridors and thematic areas relevant for the future European hydrogen network (hydrogen and electrolysers, offshore grids, CO2 networks)

The revised TEN-E Regulation, adopted in 2022, has amended the list of priority corridors by adding hydrogen and electrolysers, offshore grid and CO2 infrastructure, while removing oil and gas corridors,

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[83] Both the Parliament and the Council taking more than a year to form their positions on the EC Proposal is highly unusual – as this process normally takes around half a year – and can be partly explained by the fact that the Parliament and the Council were preoccupied by addressing the 2021-23 energy crisis.

[84] Council (2023a), Council (2023b). Jerzy Buzek was the Parliament's rapporteur for the RNGH Regulation, Jens Geier – for the RNGH Directive.

[85] See Yafimava (2022), 'The TEN-E Regulation'.

In so doing it has made these added categories – that are relevant for the development of the European hydrogen network – eligible for a project of Common Interest (PCI) status, which, if granted, enables a project to benefit from faster permitting and regulatory approval, rules for cross-border cost allocation (CBCA), and eligibility for EU financial support through the Connecting Europe Facility (CEF). The amended Regulation has also established a new concept of Project of Mutual Interest (PMI), which enabled faster regulatory approval and access to EU funds for projects promoted by the EU in cooperation with non-EU countries, thus recognizing potential importance of imported hydrogen; PMI status can be granted to electricity, hydrogen, and CO2 transport and storage projects but not to electrolysers and smart gas grids. Grant of the PCI or PMI status is confirmed by the project's inclusion in the EU PCI/PMI list.

The TEN-E Regulation made **pipelines for the transport of hydrogen (mainly at high pressure), including repurposed natural gas infrastructure**, alongside with **storage facilities** connected to such hydrogen pipelines, as well as **reception, storage and regasification or decompression facilities for liquefied hydrogen or hydrogen embedded in other chemical substances** (e.g. ammonia), eligible for a PCI/PMI status. (Projects associated with repurposing existing natural gas pipelines to enable them to carry hydrogen will be eligible for PCI status, and hence EU CEF funds, until the end of 2027 and will be allowed to transport blends of methane with hydrogen until the end of 2029.) All of these facilities can be newly constructed or repurposed from natural gas to hydrogen, or a combination of the two. The Regulation also made **electrolysers** (with capacity of at least 50 MW and compliant with the life cycle GHG emission savings requirement of 70% and having a network-related function) and **pipeline connections to the network, eligible for a PCI status.** The Regulation also made **offshore hydrogen grids** (hydrogen pipelines supporting offshore production of renewable hydrogen) **<u>and</u> offshore electricity grids** (power lines supporting offshore production of renewable electricity) eligible for a PCI/PMI status. It also made **CO2 transport infrastructure <u>and</u> CO2 storage infrastructure** facilities eligible for PCI/PMI status, which is important as CCUS constitutes a key element of low carbon hydrogen production in addition to enabling industrial capture of CO2, including dedicated **pipelines**, other than upstream pipeline network, **used to transport CO2** from more than one source, for permanent storage, fixed **liquefaction facilities, buffer storage and converters of CO2**, for further transportation through pipelines and in dedicated modes of transport such as ship, barge, truck, and train, **surface and injection facilities** for permanent storage, where they are necessary for allowing the cross-border transport and storage of CO2.

PCI/PMI eligibility criteria

The revised TEN-E Regulation has amended a set of general and specific criteria that must be met by a PCI and a PMI project,[86] inter alia making sustainability the necessary specific criterion for hydrogen and electrolyser PCIs (as well as for electricity transmission, distribution and storage, smart electricity grids, smart gas grids, CO2 transport and storage PCIs), obliging them to 'contribute significantly'. A positive cost-benefit ratio and a cross-border dimension have remained amongst the key criteria that must be met by PCIs and PMIs alike to be included in the EU list.

The TEN-E Regulation framework largely aimed at supporting the development of cross-border EU-wide – as opposed to national – infrastructure, its cross-border nature being one of the necessary conditions for PCI/PMI status eligibility. To be eligible for a PCI status, a project must involve at least two Member States by directly or indirectly crossing the border of two or more Member States, or to be located on the territory of one Member State, either inland or offshore, and having a significant cross-border impact. To be eligible for a PMI status, a project must be located on the territory of at least one Member State and on the territory of at least one non-EU country and have a significant cross-border impact. Cross-border dimension of eligible infrastructure is emphasised throughout the TEN-E Regulation, which defined eligible hydrogen interconnections as infrastructure 'enabling the emergence

[86] See Yafimava (2022) for a detailed overview of all general and specific PCI and PMI criteria.

of an integrated hydrogen backbone […], connecting the countries of the region and addressing their specific infrastructure needs for hydrogen supporting the emergence of a Union-wide network for hydrogen transport, and […] as regards islands and island systems, decreasing energy isolation, […] solutions involving at least two Member States'. This suggests that a candidate project would have to demonstrate convincingly its cross-border impact to be granted a PCI or PMI status. While this would be easier to do for networks crossing the border of two or more Member States, it would be more difficult – albeit not impossible – to do so for networks located in one Member State, particularly as the Regulation did not make it clear how the significant of cross border impact would be assessed. Ultimately, a certain degree of discretion would be present.

Both PCI and PMI candidates must be characterised by positive cost-benefit ratio to be include in the EU PCI/PMI list. However, significant uncertainty about future European hydrogen supply and demand – where many key factors could not yet be quantified – make any meaningful cost-benefit assessment challenging. If the letter and the spirit of the TEN-E Regulation are to be followed, a project unable to demonstrate its positive cost-benefit ratio could not be awarded a PCI or a PMI status. Also, even if a candidate project demonstrated a positive cost-benefit ratio at the time of its application, such ratio could turn negative as more information about hydrogen demand and supply – as well as the cost – becomes available in the future.

Overall, the TEN-E Regulation provided some regulatory flexibility in respect of cross-border infrastructure development, by enabling EU financial support through the CEF funding for many different categories of infrastructure – such as new hydrogen pipelines, repurposed natural gas pipelines for hydrogen, power lines, CO2 transport and storage facilities – that are supportive of both renewable and low carbon hydrogen. Although the CEF energy infrastructure budget is constrained – 5.84 bn euros during 2021-27 – a project that has received funds under CEF may also receive funds from other EU funding programmes.

4.3 The RNGH Regulation: separation of RABs, asset transfer, and limits on cross-subsidisation

Separation of RABs and asset transfer

The RNGH Regulation requires transmission system operators (TSOs), distribution system operators (DSOs) and hydrogen network operators (HNOs), providing regulated services for gas, hydrogen or electricity, to have **separate Regulated Asset Bases (RABs) for their gas, hydrogen and electricity assets**, as well as unbundled accounts (Art. 5.1).

The aim of this requirement was two-fold. One was to ensure that revenues obtained from the provision of one regulated service can be used only for recovery of (capital and operational) expenditures related to the assets used for the provision of that specific service. For example, service revenues collected from the provision of natural gas transmission service from its users could only be used for recovery of expenditures related to the natural gas pipelines, rather that the hydrogen pipelines. Another is to ensure that when assets are transferred to a different RAB, their value is established – subject to an audit and approval of the NRA – in such a way that no cross-subsidization occurs. An example of such transfer would be transferring the natural gas assets (pipelines) from the TSO or DSO's RABs to the HNO's RAB for repurposing, enabling them to transport hydrogen. The transfer value must be based on methodology approved and published by the NRA or determined by the NRA itself.

The Regulation does not provide any guidance for determining the asset transfer value apart from stating that it should be such 'that cross subsidies do not occur'. As noted in the DNV report, this condition would be met 'if the asset transfer would be set at the residual asset value in the natural gas RAB, plus possibly any additional costs incurred by the natural gas TSO in relation to the repurposing'.[87]

[87] DNV/Trinomics (2022), 'Future regulatory decisions on natural gas networks', p. 11.

In this case, the residual asset value of the natural gas RAB would serve as a reference value, on the basis of which the TSO and the HNO could potentially agree on a transfer value.[88] As the DNV noted further, a deviation from the residual asset value will only be an option, if the asset transfer value is not already set within the regulation of either or both natural gas and hydrogen networks, and the hydrogen network is not owned and operated by an entity affiliated to the natural gas TSO.

Establishing the value of asset transfer, the dedicated charge, and the inter-temporal cost allocation: EU network codes, EC guidelines, NRA guidance

While the RNGH Regulation does not contain any specific provisions for determining the asset transfer value, it empowers (but does not oblige) the EC to adopt supplementing delegated acts,[89] establishing network codes for hydrogen in various areas, including in respect of 'rules for determining **the value of transferred assets and the dedicated charge**' (Art. 72.1.f) as well as 'rules for determining **the inter-temporal cost allocation'** (Art. 72.1.g). These network codes could provide such rules either in form of general guidance or more specific detailed provisions. The RNGH Regulation does not provide a specific timeline as to when any such network codes were to be developed, apart from stating that the EC is obliged to establish a priority list every 3 years identifying various areas in which network codes could be established (Art. 72.3). The first list must be presented one year after the establishment of the ENNOH (as ENNOH is expected to be established in 2025, this list would have to be presented in 2026) (see Section 2.2.2). The EC is obliged to request ACER to submit (within 6 months) non-binding framework guidelines for network code development (Art. 72.4). On its part, ACER is obliged to consult on these guidelines *inter alia* with ENNOH and (where relevant) ENTSOG (Art 72.5). The EC is then obliged to request ENNOH to submit (within 12 months) a proposal for a network code (Art. 72.9). For its part, ACER is obliged to review and revise the ENNOH's proposed code (within six months) to ensure that it complies with the guidelines and submit the revised code to the EC for adoption (Art. 72.11). This suggests that the EU network codes for hydrogen would only be developed by the end of the 2020s, possibly in 2028 at the earliest. The EC is also empowered to amend the adopted network code. Where ACER and ENNOH failed in these tasks, the EC is empowered to adopt a network code on its own initiative, in consultation (at least 2 months) with inter alia ACER, ENNOH and ENTSOG (Art. 72.12 and 72.13). The EC is also empowered to adopt its own binding guidelines in the areas where the network codes could be developed, thus including rules for determining the transfer value and the dedicated charge (Art. 74.1 and 74.2).

The RNGH Regulation permitted Member States to allow HNOs to spread the recovery of hydrogen network development costs over time through network access tariffs, to ensure that future users of the hydrogen network contribute to its initial development costs, subject to the regulatory authority's approval of such **inter-temporal cost allocation** and its methodology. It has also allowed Member States to take measures to cover the HNO's financial risk, associated with 'the initial cost recovery gap' arising from the application of intertemporal cost allocation mechanism, including in form of state guarantees. ACER is obliged to issue biannual recommendations to TSOs, DSOs, and HNOs on the methodologies for setting the intertemporal cost allocation.

In addition to the EU-wide network code and the EC guidelines, rules containing detailed provisions on determining the transfer value and the dedicated charge could also be developed at the Member State

[88] Ibid.

[89] The EC adopts delegated acts on the basis of a delegation granted in the text of an EU law. The EC's power to adopt delegated acts is subject to strict limits: the delegated act cannot change the essential elements of the law; the legislative act must define the objectives, content, scope and duration of the delegation of power; Parliament and Council may revoke the delegation or express objections to the delegated act. The Commission prepares and adopts delegated acts after consulting expert groups, composed of representatives from each EU country, which meet on a regular or occasional basis. Once the EC has adopted the act, Parliament and Council generally have two months to formulate any objections. If they do not, the delegated act enters into force, see https://commission.europa.eu/law/law-making-process/adopting-eu-law/implementing-and-delegated-acts_en

level (either through national legislation or through NRAs' guidelines). Notably, while specificities may differ between different Member States, the key principles for determining the asset transfer value must be identical across the EU whereas national level rules must be compatible with the EU-wide rules (Art. 57).

Limited cross-subsidisation

The RNGH Regulation does not allow Member States to allow financial transfers between separate regulated services – e.g. natural gas, hydrogen and electricity transportation (Art. 5.2). However, it allows Member States to derogate from this provision and allow financial transfers between separate regulated services, if the regulatory authority has established that:

- "the financing of networks through network access tariffs paid by its network users only is not viable" (Art. 5.4),

and if all of the following conditions are also met:

- all revenue needed for the transfer is collected as a dedicated charge;
- the dedicated charge is collected only from exit points to final customers located within the same Member States as the beneficiary of the financial transfer;
- the dedicated charge and transfer (or the methodologies) are approved prior to their entry into force by the regulatory authority and are published no later than thirty days before their date of implementation;
- the EC and ACER have been notified by the Member State that it has allowed financial transfers.

The regulatory authority may grant its approval for a financial transfer and dedicated charge, if (Art. 5.5):

- network access tariffs are charged to users of the RAB that benefits from the transfer,
- the sum of transfers and service revenues collected through tariffs is not larger than the allowed or target revenues, and
- the transfer is valid for no longer than 1/3 of the infrastructure asset's remaining depreciation period.

Thus, **although the RNGH Regulation introduced a separate RAB requirement for natural gas, hydrogen, and electricity assets with a view of avoiding cross-subsidisation between them, it has nonetheless allowed for some limited cross-subsidization, where the financing of networks through network access tariffs paid by its network users alone – i.e. without a cross-subsidy – is not viable**. The Regulation is stricter than the EC Proposal, which suggested to allow financial transfers between separate services (subject to conditions) without making the inability to finance the networks through network tariffs alone the necessary condition for allowing such transfers. As noted in the DNV report, cross-subsidies would 'only be allowed in the form of a temporary dedicated charge, charged from end-users within the same EU Member State subject to ex ante approval by the respective NRA'.[90]

Indeed, the RNGH Directive (also supported in doing so by the Council and the Parliament) grants additional powers and duties to the regulatory authorities, obliging them to fix or approve, in accordance with transparent criteria (Art. 78.1.d):

[90] DNV/Trinomics (2022), 'Future regulatory decisions on natural gas networks'.

- the size and duration of the dedicated charge (revenues needed for the financial transfers between separate regulated services for gas, hydrogen and/or electricity) and financial transfer[91] or their methodologies, or both,
- the value of transferred assets and the destination of any profits and losses that may occur as a result,
- the allocation of contributions to the dedicated charge.

The RNGH Regulation enables (but does not oblige) ACER to issue recommendations (and updating them at least once every 2 years) to TSOs, DSOs, and HNOs as well as to the regulatory authorities on

- the methodologies for determining the value of the assets transferred to another RAB and the destination of any subsequent profits or losses,
- the calculation of the size and maximum duration of the financial transfer and dedicated charge ,
- the criteria for allocating contributions towards the dedicated charge among final customers connected to the RAB (Art. 5.6).

The RNGH Regulation's reconciliation of the Council and the Parliament proposals

The final RNGH Regulation differs from the EC Proposal as it had to incorporate the Council and Parliament suggestions, such as requiring separation of asset bases in respect of both TSOs and DSOs, tightening the requirements for allowing financial transfers between separate services, allowing the HNOs' use of an intertemporal cost allocation mechanism, and limiting the transfers validity to 1/3 of the asset's remaining depreciation period.

Unlike the EC Proposal, the Parliament Proposal prohibited Member States from allowing financial transfers between separate services for gas, electricity or hydrogen, while allowing for derogations, stating that the regulatory authority 'may allow' such transfers 'as a last resort, where no more cost-efficient options are available', subject to an impact assessment. This impact assessment would have to demonstrate the impact of transfers on cross-subsidisation between users of gas networks and users of hydrogen networks, confirm their 'cost-efficiency' and preservation of the level playing field across Member States as well as the fact that the resulting gas networks tariffs 'do not unreasonably distort cross-border trade'. In this case, transfers could be allowed. The Parliament Proposal also required the regulatory authority to 'take the examination of network development plan for hydrogen into account' when deciding on the approval of dedicated charges (Art. 51.6a). It also specified that costs associated with feasibility studies related to the repurposing of the natural gas networks to hydrogen would not be considered being financial transfers (and therefore would not be subject to these requirements) (Art. 4.3.a). The final RNGH Regulation acknowledges in its preamble that costs associated with feasibility studies related to the repurposing of networks to hydrogen should not be considered a cross subsidy (recital 10). The Parliament Proposal also suggested to permit Member States to allow HNOs 'to spread network development costs over time, by ensuring that future users pay part of the initial costs' in order 'to avoid undue and excessive cross-subsidies among first and future users of hydrogen networks'. Such 'inter-temporal cost allocation mechanism' and its methodology were to be subject to approval by the regulatory authority as well as underpinned by a Member State guarantee to cover the operators' financial risk (Art. 4.2.a). The Proposal also required ACER to issue a recommendation on the criteria for allowing and determining this inter-temporal allocation of network development costs among uses of hydrogen network (Art. 4.4).

[91] Unlike the EC Proposal, the RNGH Directive required the financial transfer itself also to be approved by the NRA.

For its part, the Council also made several important changes to the EC Proposal. It extended the scope of RAB separation by stating that separation of asset bases is required not only in respect of transmission but also in respect of distribution system operators as well as hydrogen network operators. It also required that both the dedicated charge and the transfer (or their methodologies) must be approved and published by the regulatory authority not later than 30 days prior to their implementation. (The EC Proposal required those to be approved by the regulator prior to their implementation but did not stipulate any time-period; it also did not require their publication prior to their implementation). Finally, it mandated the sum of transfers and service revenues collected through tariffs must not be larger than allowed and target revenues, thus limiting this sum in both price cap and non-price cap regimes.[92] (The EC Proposal's requirement for this sum not to exceed allowed revenues (but not target revenues) made this requirement applicable under a non-price regime only). The Council Proposal also shortened the period of financial transfer's validity, by specifying that 'in no event' the transfer can be valid for longer than 1/3 of the asset's remaining depreciation period (as opposed to its total depreciation period as the EC Proposal appears to have suggested).

4.4 The RNGH Directive: national network development planning (NDPs)

Separate NDPs for natural gas and hydrogen transmission by default, or a joint integrated NDP by design

The RNGH Directive makes a natural gas transmission operator (TSO) and a hydrogen transmission network operator (HTNO) the main actors in charge of network planning and development. The Directive obliges all TSOs and HTNOs to submit to the relevant regulatory authority and publish at least every 2 years a ten-year network development plan (NDP) based on existing and forecast supply and demand (Art. 55.1), while also considering alternatives to system expansion (Art. 55.3). The RNGH Directive introduces an obligation for all TSOs, irrespective of their unbundling model, to submit their NDPs to regulatory authorities, thus strengthening the latter's oversight over network development.[93] Each Member State will have one single NDP for natural gas and one single NDP for hydrogen, or one joint plan for natural gas and hydrogen. **The Directive mandates separate network planning for natural gas and hydrogen by default**, while also allowing for a joint plan for natural gas and hydrogen. In so doing, it reflects a compromise between the Council – which largely wanted to have separate network planning – and the Parliament – which wanted to have integrated planning. If separate natural gas and hydrogen NDPs are prepared, Member States must ensure that TSOs and HTNOs cooperate closely to ensure system efficiency, 'such as for repurposing'. If one joint NDP for natural gas and hydrogen is prepared, it must be 'sufficiently transparent' to allow the regulatory authority to identify the needs of the natural gas sector and the hydrogen sector, with separate modelling to be performed in respect of natural gas and hydrogen and separate chapters showing network maps for natural gas and hydrogen. In all cases, HTNOs are obliged to cooperate with electricity TSOs and DSOs to coordinate joint infrastructure requirements (e.g. the location of electrolysers and transmission infrastructure).

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[92] Tariffs Network Code defines allowed revenue and target revenue as follows. 'Allowed revenue' means the sum of transmission services revenue and non-transmission services revenue for the provision of services by the transmission system operator for a specific time period within a given regulatory period which such transmission system operator is entitled to obtain under a non-price cap regime and which is set in accordance with Article 41(6)(a) of the Third Gas Directive. 'Target revenue' means the sum of expected transmission services revenue calculated in accordance with the principles set out in Article 13(1) of Gas Regulation and expected non-transmission services revenue for the provision of services by the transmission system operator for a specific time period within a given regulatory period under a price cap regime. 'Non-price cap regime' means a regulatory regime, such as the revenue cap, rate of return and cost plus regime, under which the allowed revenue for the transmission system operator is set in accordance with Article 41(6)(a) of the Third Gas Directive . 'Price cap regime' means a regulatory regime under which a maximum transmission tariff based on the target revenue is set in accordance with Article 41(6)(a) of the Third Gas Directive.

[93] Under the Third Gas Directive, only the TSOs unbundled under ITO and ISO models were obliged to submit their NDPs to the NRAs, whereas the TSOs unbundled under OU models were not obliged to do so. See ACER (2022a).

NDPs to consider infrastructure, facilitating access of renewable and low carbon gases, identify natural gas infrastructure that can or will be decommissioned or repurposed

The Directive requires the NDP(s) to contain ‘comprehensive and detailed information on the main infrastructure that needs to be built or upgraded over the next ten years’, while considering ‘any infrastructure reinforcements needed for connecting renewable and low-carbon gas installations and including infrastructure developed to enable reverse flows to the transmission network’ (Art. 55.2a). In so doing it specifically addresses infrastructure, facilitating access of low carbon and renewable gases to the transmission system (e.g. by enabling biomethane or a hydrogen blend to enter the transmission system), thus reflecting the Council and the Parliament positions. The Directive also requires the NDP(s) to contain ‘information on all the investments already decided and identify new investments and demand-side solutions not requiring new infrastructure investments which have to be executed in the next three years’ (Art. 55.2b).

As far as natural gas is concerned, the Directive requires the NDP(s) to include “comprehensive and detailed information on **infrastructure that can or is to be decommissioned**’, and as far as hydrogen is concerned – ‘comprehensive and detailed information on **infrastructure that can or is to be repurposed for the transmission of hydrogen**’ (Art. 55.2c and Art. 55.2d). It also requires a time frame for all investment and decommissioning projects (Art. 55.2e). In so doing, the Directive incorporates the Parliament position, which called for more clarity on decommissioning and repurposing as part of network planning process.

The Directive requires the NDP for natural gas to contain ‘efficient measures in order to guarantee the adequacy of natural gas system and the security of supply’, including compliance with the SOS Regulation infrastructure standards (Art. 55.1). It contained no such requirement in respect of the NDP for hydrogen. The Directive falls short of obliging Member States to ensure coordinated planning steps of the respective NDPs for natural gas, hydrogen and electricity, stating that Member States ‘shall endeavour’ to do so.

NDPs to be based on a joint scenario for stronger coordination between different energy sectors

The RNGH Directive requires the NDP(s) to be based on **a joint scenario** developed biannually between the relevant infrastructure operators, including relevant distribution system operators, of at least natural gas, hydrogen, electricity and, where applicable, district heating, accompanied by extensive consultation process at an early stage prior to the development of the NDP (Art. 55.2f). The Directive’s requirement for the NDP(s) to be based on a joint scenario provided an instrument for stronger coordination between different NDPs, can be seen as a concession to the Parliament, to compensate for the rejection of its proposal for integrated planning. Similarly, the Directive’s requirement to include not only natural gas and electricity infrastructure operators (as proposed by the Council) but also hydrogen and district heating operators can also be seen as such. Joint scenarios must be based on 'reasonable assumptions about the evolution of the production, supply and consumption […] take into account demand-side solutions not requiring new infrastructure investments […] cross-border exchanges, including with third countries, and the role of hydrogen storage and the integration of hydrogen terminals’ (Art. 55.2). They also must be in line with EU scenarios (under the TEN-E Regulation) and the integrated NECPs as well as support the climate-neutrality objective.

NDPs consistency with TYNDPs, NECP, REDiii Directive RFNBO targets, Climate Law GHG emission reduction targets

The RNGH Directive requires the NDP(s) to be:

- in line with the integrated National Energy and Climate Plan (NECPs) and its updates,
- in line with the integrated National Energy Climate Reports (NECRs) submitted under the Governance Regulation;
- in line with RFNBO targets set by the REDiii Directive;

- to be consistent with the results of common and national Risk Assessments, developed under the SOS Regulation (as far as natural gas is concerned);[94]
- to be consistent with the EU TYNDP for natural gas and the EU TYNDP for hydrogen;
- to take into account the hydrogen (distribution) NDP and the natural gas (distribution) network decommissioning plans; and
- 'support' 2030 and 2050 GHG emission reduction targets under EU Climate Law.

The regulatory authority is also required to examine whether the NDP(s) cover all investment needs identified under consultation and whether it is consistent with:

- the most recent EU-wide ENTSOG's simulation of disruption scenarios under SOS Regulation,
- the regional and national risk assessments, and
- the (non-binding) EU TYNDPs for natural gas, hydrogen and electricity (and is obliged to consult ACER if in doubt).

In addition, the competent national authorities are obliged to examine the NDP(s) consistency with:

- the 2050 GHG net-zero objective,
- the NECPs and their updates,
- the integrated NECRs,

and, in the event of inconsistency, may provide the regulatory authority with a substantiated opinion, which the latter is obliged to take into account.

The Directive's requirement for NDP consistency with various other documents is wider than was originally envisaged in the EC Proposal, thus reflecting both the Council and the Parliament's Proposals. Although **the Directive grants additional powers to the regulatory authorities, it falls short of granting them the power of final planning approval,** thus rejecting the Parliament's suggestion to oblige the regulatory authorities to publish a decision approving the NDP. The regulatory authority is empowered to require the TSO to amend its NDP (Art. 55.5).[95]

The Directive requires the TSOs and the HTNOs to consider the potential for alternatives to system expansion (e.g. demand response) while developing the NDPs, and also obliged them to address a need for integration across electricity, heat and natural gas and hydrogen systems, including information on the optimal location and size of energy storage and power-to-gas assets (renewable hydrogen production) as well as the co-location of hydrogen production and consumption (Art. 55.3). It also obliged the HTNOs to include information on the location of end-users in hard-to-abate sectors so as to target the use of renewable and low-carbon hydrogen.

The Directive requires that in circumstances where the TSO or the HTNO unbundled under ITO or ISO models – thus excluding those unbundled under an OU model – does not make the investment, which according to the NDP was to be executed in the following 3 years, Member States are obliged to ensure that the regulatory authority takes measures ensuring that the investment is made. Such measures include requiring the TSO or the HTNO to execute investment, organising a tender procedure (open to any investors), obliging the TSO or the HTNO to accept a capital increase to finance the necessary investments (Art. 55.7), with the costs to be covered by the relevant tariff regulations. By applying this obligation not only to the TSOs but also to the HTNOs, the Directive reflects the Parliament's position.

[94] EC (2017), Security of Supply Regulation, Art. 17.
[95] The Directive is silent on whether the regulatory authority is empowered to require the HTNO to amend its NDP.

Plans for hydrogen distribution network development and natural gas distribution network decommissioning

In addition to requiring TSOs and HTNO to develop their NDPs, the Directive also requires hydrogen distribution network operators (HDNOs) to develop and submit to the regulatory authority every 4 years their **plan presenting a hydrogen network infrastructure** they aim to develop, including information on hydrogen supply and capacity needs (both in volume and duration, as negotiated between hydrogen distribution network users and operators) and the extent to which repurposed natural gas pipelines will be used for the transport of hydrogen and to which this repurposing is required to fulfil the capacity needs (Art. 56). Such a plan must be in line with both the EU TYNDP for hydrogen and the national ten-year NDPs (for hydrogen where separate NDPs for natural gas and hydrogen are developed, or for hydrogen and natural gas where a joint NDP is developed). It must also be in line with both the integrated NECPs (and updates) and NECRs as well as 'support' the 2050 net-zero objective. The Directive includes the requirement to develop hydrogen distribution network plans in response to the Parliament's Proposal. Furthermore, the Directive requires natural gas DSOs to develop **network decommissioning plans** when 'a reduction in gas demand requiring the decommissioning of natural gas distribution networks or parts of such networks is expected' (Art. 57), listing infrastructure that is to be decommissioned and stating the possible repurposing of such infrastructure for hydrogen.

4.5 The RNGH Regulation: EU-wide network planning (TYNDPs)

Splitting the TYNDP development process between ENTSOG and ENNOH

The RNGH Regulation amends the rules for network development at the EU and Member States level by splitting the responsibilities for developing the EU TYNDP for natural gas and the EU TYNDP for hydrogen between ENTSOG and (yet to be established) ENNOH respectively. Both the TYNDP for natural gas and the TYNDP for hydrogen (as well as the TYNDP for electricity) must be based on one set of joint scenarios and use of an integrated model. The Regulation requires ENTSOG to adopt and publish biannually its EU-wide TYNDP for natural gas, which must include the modelling of the integrated network, scenario development, a European supply adequacy outlook and an assessment of the resilience of the system, including infrastructure to be decommissioned (Art. 26 and Art. 32). It requires the TYNDP for natural gas to be based on national investment plans and to be developed in line with the TEN-E Regulation's cross-sectoral infrastructure planning procedure. (Although the 'national investment plan' is not defined in the Regulation, it is presumed to be inclusive of national NDPs.) It also requires the TYNDP to identify 'investment gaps' (focusing on cross-border capacities), and to build on 'the reasonable needs' of network users and integrate long-term commitments from investors. Importantly, unlike Gas Regulation 715, which contained an explicit requirement for TYNDP to be the subject to a CBA analysis using the methodology in line with the TEN-E Regulation's (Art. 8.10.a), the RNGH Regulation does not contain an explicit requirement for TYNDP for natural gas to be subject to CBA.

Similarly, the RNGH Regulation obliges ENNOH – once it is established, as expected, in 2025 – to adopt and publish biannually the EU-wide TYNDP for hydrogen, including the modelling of the integrated network, scenario development and an assessment of the resilience of the system (Art. 59 and Art. 60). Notably, the TYNDP for hydrogen is required to identify cross-border capacities for implementing hydrogen and electrolyser priority corridors, as defined by the TEN-E Regulation (see Section 4.2). The RNGH Regulation requires the TYNDP for hydrogen to build on the national hydrogen transmission NDPs (Art. 60.a). The RNGH Regulation also requires the TYNDP for hydrogen to be developed in line with the TEN-E Regulation's cross-sectoral infrastructure planning procedure.

Until ENNOH is established, the EU TYNDP for hydrogen will be developed by ENTSOG, alongside the EU TYNDP for natural gas (Art. 58). As this paper goes to print in April 2024, ENTSOG is developing its TYNDP 2024 – which will include both natural gas and hydrogen projects, just as its TYNDP 2022 did – with no separate TYNDP 2024 for hydrogen is expected to be developed. The RNGH Regulation specifically obliges ENTSOG to develop the 2026 EU TYNDP for hydrogen, stating that it must include two separate chapters – one for hydrogen and another for natural gas (Art. 61). ENTSOG is also obliged to develop a TYNDP for natural gas (Art. 32) but it is not entirely clear whether it will develop a separate TYNDP 2026 for natural gas in addition to the TYNDP 2026 for hydrogen. From 1 January 2027, ENNOH will become fully responsible for developing the EU TYNDPs for hydrogen, thus suggesting that the TYNDP 2028 for hydrogen will be the first TYNDP developed solely by ENNOH.

CBA methodologies: no legal obligation for assessment of natural gas projects unless associated with repurposing

The TEN-E Regulation cross-sectoral infrastructure planning procedure – in line with which both the TYNDPs for natural gas and the TYNDP for hydrogen must be developed – established an obligation on ENTSOG to develop single-sector draft cost-benefit analysis (CBA) methodology for a harmonised system-wide CBA analysis at the EU level for hydrogen projects on the EU PCI/PMI list (Art. 11).[96]

The TEN-E Regulation required ENTSOG[97] to publish and submit to Member States, the EC and ACER by 24 April 2023 its single-sector draft methodology for a CBA for projects on the EU PCI/PMI list, failing under hydrogen infrastructure categories (Section 4.2), such as:

- hydrogen pipelines (including repurposed natural gas infrastructure),
- hydrogen storage facilities,
- hydrogen (or hydrogen embedded) import terminals,

with any of these assets could either be newly constructed or repurposed from natural gas to hydrogen, or a combination of the two.

This is the first ENTSOG's CBA methodology, adopted under revised TEN-E Regulation, and it aimed at providing 'guidelines to be applied to the CBA of projects […] and more generally of the overall gas and hydrogen infrastructure'.[98] It is mostly focused on hydrogen infrastructure whereas the previous two ENTSOG's CBA methodologies – adopted in 2015 and 2019 under the old TEN-E Regulation – had considered mostly natural gas infrastructure, with other sectors being 'captured through scenarios'. According to ENTSOG, the objective of its latest CBA methodology was to 'to provide guidelines to be applied to the CBA of projects [project specific] and more generally of the overall gas and hydrogen infrastructure [system assessment].[99]

ENTSOG published its draft methodology in June 2023, however a very tight timeline established by the TEN-E Regulation meant that it was not available in time for assessing hydrogen PCIs/PMIs, and the EC's own – significantly simplified – CBA was used for assessment instead (Section 4.6). According to the TEN-E Regulation, an approved CBA methodology applies for the preparation of each subsequent TYNDP, while it also must be 'updated and improved regularly', with both ACER and the EC empowered to request such 'updates and improvements' (Art. 11.7). It is understood that, as this paper goes to print in April 2024, ENTSOG is updating its CBA methodology, responding to comments from ACER and the EC.[100] It is understood to be used for the development of the TYNDP 2024 although it is unclear whether the same methodology will also be used for TYNDP 2026.

The revised TEN-E Regulation (2022) removed natural gas infrastructure from the list of priority corridors thus making natural gas projects ineligible for a PCI/PMI status and EU funding. Instead, it

[96] Similarly, it obliged ENTSOE to develop single-sector draft CBA methodology for electricity projects on the EU list.
[97] The same requirement also applied to ENTSOE.
[98] ENTSOG (2023c), ENTSOG draft CBA methodology, June 2023.
[99] Ibid.
[100] ACER (2023b), 'Opinion on the draft ENTSOG CBA draft methodology of hydrogen infrastructure projects', No 08/2023. Also see ACER (2023a), 'Opinion on the ENTSOG draft TYNDP 2022', No 06/2023.

added hydrogen infrastructure to the list thus making them eligible (Section 4.2).[101] Therefore, while under the old TEN-E Regulation (2013) ENTSOG was obliged to develop draft CBA methodology for assessing natural gas PCIs (natural gas CBA methodology, which was used for project specific and system assessment),[102] under the revised Regulation it is obliged to develop such methodology for assessing hydrogen PCIs/PMIs (hydrogen CBA methodology). This hydrogen CBA methodology is not applicable to any natural gas projects other than those associated with repurposing for transporting hydrogen. As far as any other natural gas infrastructure projects are concerned, ENTSOG is not obliged to develop CBA methodology for their assessment.

Subsequently, the RNGH Regulation (Art. 86.1) amended the TEN-E Regulation infrastructure planning procedure by relieving ENTSOG of its obligation to develop draft CBA methodology for hydrogen projects and imposing it on ENNOH instead. Thus, once ENNOH is established in 2025 and once the transition period, during which ENTSOG will be obliged to wind down its hydrogen network planning work and hand it over to ENNOH, ends on 1 January 2027, ENNOH (rather than ENTSOG) and ENTSOE will be obliged to develop draft CBA methodologies for hydrogen and electricity PCI/PMIs respectively. ENNOH is obliged to publish its first draft methodology by 1 December 2025, in respect of which the EC and ACER will be obliged to provide their opinions, with final methodology to be approved by the EC by October 2026. Given the tight deadline set by the RNGH Regulation for establishing ENNOH, it would not be surprising if ENNOH's CBA were to be delayed beyond 2026. Even so, it would appear likely that it will be available for using it for the development of TYNDP 2028 – the first TYNDP for hydrogen for which ENNOH will be responsible. It also suggests that ENNOH's methodology would be used for assessing hydrogen projects for the third EU PCI/PMI list (to be developed by 1 December 2027) whereas ENTSOG's CBA methodology would likely be used for assessing hydrogen projects for the second EU PCI/PMI list (to be developed by 1 December 2025).

It is less clear which CBA methodology – the one developed by ENTSOG or the one developed by ENNOH – will be used by for the development of TYNDP 2026. If ENNOH methodology will be delayed and will not be ready by the time of TYNDP 2026 development, the use of ENTSOG's CBA for the TYNDP 2026 would be more likely, particularly as it is ENTSOG rather than ENNOH that would still be responsible for developing the TYNDP 2026.

Importantly, once ENNOH becomes responsible for the development of TYNDP 2028 and all subsequent hydrogen TYNDPs, ENTSOG will no longer be obliged to develop hydrogen CBA methodology. Indeed, **ENTSOG will no longer be obliged to develop CBA methodology either for natural gas projects or for hydrogen.** As noted earlier, the RNGH Regulation did not contain an explicit requirement for TYNDP for natural gas to be subject to CBA. This suggests that the TYNDP 2028 for natural gas will be the first TYNDP in respect of which ENTSOG will have to obligation to develop <u>any</u> CBA methodology. Potentially, this could present a problem for future coordinated gas network development across the EU, if there were to be no analysis of the existing and prospective natural gas infrastructure as part of EU-wide TYNDP.

Lack of clear mechanisms for ensuring consistency between TYNDPs and NDPs: increased importance due to repurposing of natural gas networks

The RNGH Directive requires Member States national NDPs to be developed biannually (both for natural gas and hydrogen NDPs, where a separate planning process is used, or joint natural gas and hydrogen NDPs where an integrated planning process is used) (Art. 55.1) – in sync with the EU TYNDPs (Art. 26, Art. 59)[103] Both the RNGH Directive (Art. 55.2(i)) and the RNGH Regulation (Art. 26, Art, 60) require all national NDPs for natural gas and hydrogen (separate or integrated) to be consistent with

[101] Electrolysers are not eligible for a PMI status, see the TEN-E Regulation.
[102] The 5th EU PCI list was the last one, in respect of which the ENTSOG was obliged to develop CBA methodology for natural gas projects, see EC (2021e), The 5th EU PCI list, 19 November 2021.
[103] The Third Gas Directive required them to be developed annually.

the EU TYNDP for gas and with the EU TYNDP for hydrogen. However, the mechanism for ensuring such consistency is not entirely clear.

The RNGH Regulation states that if ACER identified inconsistences between (a legally binding) national NDP and (a non-binding) ENTSOG TYNDP for natural gas, it is obliged to recommend amending the national NDP or the EU TYNDP 'as appropriate' (Art. 26.9). It also states that if such national NDP is elaborated in accordance with the RNGH Directive's Art. 55 – which stipulated a procedure for national network development of natural gas and hydrogen transmission infrastructure – ACER is obliged to recommend the regulatory authority to amend the NDP. This would appear to suggest that it is the NDP, rather than the TYNDP, that would be liable to being amended in the event of inconsistency. The RNGH Regulation also states that if ACER identified inconsistencies between an NDP for hydrogen and the EU TYNDP for hydrogen, it is obliged to recommend amending the national NDP or the EU TYNDP 'as appropriate' (Art. 60.2). However, ACER's recommendation is not binding thus suggesting that the national regulatory authority may refuse to comply.[104]

While ensuring that consistency between the TYNDPs and the NDPs is important, it would contribute towards coordinated network development only if the TYNDP were to include projects that have already been included in the NDP. However, ACER noted a tendency of progressively decreasing consistency between TYNDPs and NDPs. For example, only about half (49%) of projects included in the draft TYNDP 2022 were also listed in the NDPs, falling from 62% in TYNDP 2020 and 75% in TYNDP 2018.[105] Draft TYNDP 2022 discrepancy was largely caused by the inclusion of hydrogen projects as only 17% of hydrogen projects included in draft TYNDP 2022 were included in the NDPs. Discrepancy was much lower for natural gas projects – 90% of transmission projects included in draft TYNDP 2022 were included in the NDPs – although somewhat higher for LNG import terminals – only 62% of projects included in draft TYNDP 2022 were included in the NDPs.[106] As many of these projects were included in draft TYNDP 2022 without a CBA assessment, it is unlikely that ACER would recommend including these projects in the NDPs and it is unlikely that the regulatory authority would accept such recommendation even if it were to be made.

The RNGH Directive's requirement to ensure consistency between TYNDPs and NDPs is not new, as the same requirement was present in Gas Regulation 715 (Art. 8.11) and the Third Gas Directive (Art. 22.5), both of which also lacked clear mechanisms for ensuring consistency. However, a negative impact of TYNDP-NDP inconsistency would likely be more pronounced in the future as the EU gas system is set to undergo a significant transformation due to decarbonisation. An increasing inconsistency between TYNDPs and NDPs and an apparent lack of clear mechanisms for ensuring consistency, as required by the RNGH Directive, is concerning because it has a potential for distorting the network development and prevent hydrogen networks being phased in and natural gas being phased out in a coordinated manner across the EU – either through re-purposing or decommissioning – without jeopardising the security of supply in natural gas.

4.6 TYNDP 2022 and the RePowerEU Plan intervention

The latest available EU TYNDP – TYNDP 2022 – was published by ENTSOG on 29 September 2023 and included both natural gas and hydrogen infrastructure projects.[107] TYNDP 2022 is the first TYNDP

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[104] ACER is also obliged to recommend amending the TYNDP for hydrogen or the network development report 'as appropriate' in the event of inconsistency between the two. Although the Regulation did not define 'network development report', it referred to the national hydrogen network development reporting as set out in the RNGH Directive's Art. 52, which is concerned with hydrogen distribution (rather than transmission) networks. This suggests that ACER is obliged to recommend amending the TYNDP for hydrogen or the hydrogen distribution network development report. However, it is not clear whether ACER is obliged to recommend amending the TYNDP for hydrogen or the national NDP for hydrogen transmission in the event of inconsistency.

[105] ACER (2022a), 'Opinion on the review of gas and hydrogen national NDPs to assess their consistency with the EU TYNDP', Opinion 08/2022.

[106] Ibid.

[107] ENTSOG (2023d), 'TYNDP 2022: the hydrogen and natural gas TYNDP', 29 September 2023.

where hydrogen projects were included under their own separate category (HYD), whereas in the previous TYNDP 2020 such projects had been included as part of other non-natural gas 'energy transition' projects (ETR). ENTSOG used three different scenarios for TYNDP 2022 network modelling – one that was in line with national policies ('National Trends 2030-40'[108]) and two others that were in line with the EU climate targets (55% GHG emissions reduction by 2030 and net-zero GHG emissions by 2050) ('Global Ambition 2040-50'[109] and 'Distributed Energy 2040-50'[110]).

The latter two were amended in line with the EU REPowerEU Plan in order to incorporate its 2030 objectives (including the target of 20 mn tons of domestic and imported renewable hydrogen and changes in gas supply related to phasing out Russian gas) and assess their impact on (natural gas and hydrogen) infrastructure development.[111] As a result, ENTSOG adjusted both hydrogen supply and demand to align with the politically-driven REPowerEU objectives. In particular, while the pre-REPowerEU Distributed Energy scenario envisaged 181.3 TWh of electrolyser capacity (for domestically produced renewable hydrogen), 21.8 TWh of imported hydrogen, and 87.22 TWh of low-carbon (fossil-based) hydrogen, the amended post-REPowerEU Distributed Energy Scenario envisaged 333 TWh, 333 TWh, and zero respectively.[112]

Previously, ENTSOG had assessed the hydrogen import potential by assuming conversion of natural gas pipelines. As this proved insufficient for meeting the REPowerEU targets, ENTSOG has subsequently used the TYNDP 2022 project collection process, where infrastructure projects enabling hydrogen imports were submitted, which were then aligned with the REPowerEU hydrogen corridors and used for updating the TYNDP 2022 scenarios. For its post-RePowerEU modelling exercise, ENTSOG has preserved hydrogen imports from Norway at the original pre-REPowerEU TYNDP level of 168 TWh, increased hydrogen imports from North Africa to 164 TWh, and introduced two additional routes – hydrogen (or hydrogen embedded) imports by ship (164 TWh) and hydrogen pipeline imports from Ukraine (88 TWh) thus aligning with the REPowerEU target for imported hydrogen (Fig. 11, *Figures*). ENTSOG has also amended hydrogen demand in line with the REPowerEU targets by adding hydrogen demand in industrial and transport sectors (using a 80/20 ratio), subsequently subtracting it from natural gas demand in these sectors.[113] As far as natural gas imports were concerned, ENTSOG excluded additional Russian gas imports (pipeline and LNG) while modelling its TYNDP 2022. Many projects have been added to the TYNDP 2022 without a cost-benefit assessment and not in line with the existing procedures, set by Gas Regulation 715 (see Section 4.7.4).

4.7 TYNDP 2022: an impossible task

4.7.1 ENTSOG's draft CBA methodology: an impossible timeline

Gas Regulation 715, in force at the time when the TYNDP 2022 was under development, required ENTSOG to develop biannually **the EU TYNDP, which must be subject to a CBA based on the methodology developed in line with the TEN-E Regulation.** As noted earlier, the TEN-E Regulation required ENTSOG[114] to publish and submit to Member States, the EC and ACER its single-sector draft CBA methodology by 24 April 2023. ENTSOG published its **preliminary draft CBA methodology on 28 February 2023**, followed by a legally-binding 3-month public consultation period, which lasted until

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[108] Based on national energy and climate plans, national hydrogen strategies, subsequently aggregated at the EU level, see ENTSOG (2023b), ENTSOG TYNDP 2022 workshop, 25 April 2023.
[109] Based on de-centralised approach, envisaging 'higher European energy autonomy, small-scale solutions, prosumer', see ENTSOG TYNDP 2022 workshop.
[110] Based on centralised approach, envisaging 'imports, large scale renewables and decarbonisation', see ENTSOG TYNDP 2022 workshop.
[111] ENTSOG.
[112] ENTSOG TYNDP 2022 workshop.
[113] Ibid.
[114] The same requirement also applied to ENTSOE.

31 May 2023.[115] ENTSOG subsequently submitted its **draft methodology to Member States, the EC and ACER on 30 June 2023** thus missing the 24 April 2023 deadline, possibly due to extra time spent on incorporation of projects, identified by the EC's RePowerEU Plan (see Section 4.6).[116] ACER, as obliged by the TEN-E Regulation, published its Opinion on the ENTSOG draft CBA methodology on 25 September 2023, within a 3-month deadline, during which Member States also had a right to provide their opinions to ENTSOG and the EC.[117] Within 3 months of receipt of ACER's and Member States' opinions, ENTSOG was obliged to amend its draft methodology by taking these opinions into account and submit it (together with ACER's opinion) to the EC, which was obliged to issue its decision within the next 3 months.

This timeline suggested that **if both ENTSOG and the EC were to take all the time allowed by the Regulation, the final ENTSOG CBA methodology would only be ready by the end of March 2024 – and therefore too late for assessing hydrogen infrastructure projects for the first EU PCI/PMI list** under the revised TEN-E Regulation,[118] as the list had to be finalized by 30 November 2023 (Art. 3.4).[119] Furthermore, even had ENTSOG submitted its draft CBA methodology by the 24 April 2023 deadline, with both the EC and ACER taking all the time allowed for issuing their opinions/decisions, the CBA methodology would only be ready by the end of January 2024 – still too late to be used for assessing hydrogen infrastructure PCI candidates for the first EU list. This shows that the TEN-E Regulation had an in-built timeline discrepancy making it impossible to develop such CBA methodology in a timely manner, unless relevant players used significantly less time for its development than was allowed by the Regulation.

The EC appears to have judged as early as November 2022 that ENTSOG's final CBA methodology would not be ready in time for assessing the hydrogen PCI/PMI candidates by 30 November 2023 deadline, as it launched its own 'targeted consultation on methodologies for assessing costs and benefits of hydrogen candidate projects', lasting from 16 November 2022 to 20 January 2023. In its call for consultation the EC asserted that ENTSOG's final CBA methodology would be ready 'no earlier than end of 2023' and tasked its own research institution – the EC Joint Research Centre – to 'elaborate a draft hydrogen CBA methodology' to 'bridge the gap' between the first hydrogen PMI/PCI process under the revised TEN-E Regulation and ENTSOG methodology 'to come in time for the next PCI/PMI process'.[120] In other words, **the EC has developed its own (temporary) hydrogen CBA methodology to be applied for assessing hydrogen PCI/PMI candidates and adopting the first EU PCI/PMI list by 30 November 2023 in (anticipated) absence of ENTSOG's CBA methodology** (see Section 4.7.3).

4.7.2 ENTSOG's draft CBA methodology: "work in progress"

Dual assessment of natural gas and hydrogen Infrastructure levels

In its **draft CBA methodology**, ENTSOG underlined that because at present it was 'unclear […] how and at what pace' future hydrogen infrastructure will evolve in Europe, it was important to build 'a robust assessment framework that will capture the future possible scenarios' through considering several

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[115] ENTSOG (2023a), ENTSOG preliminary draft CBA methodology, February 2023.
[116] ENTSOG (2023c), ENTSOG draft CBA methodology, June 2023.
[117] ACER (2023b), 'Opinion on the draft ENTSOG CBA draft methodology of hydrogen infrastructure projects', No 08/2023.
[118] It would be the 6th PCI list under the old TEN-E Regulation (2013).
[119] The 1st EU PCI/PMI list under the revised TEN-E Regulation (2022) was published on 28 November 2023. The previous list – the last one under the old TEN-E Regulation – was adopted on 19 November 2021 and entered into force on 28 April 2022 (67 electricity, 20 gas, and 6 cross-border CO2 networks PCIs.)
[120] Although the EC JRC study states its methodology was developed 'pursuant to Art. 11.8 of the TEN-E Regulation, the latter does not provide for the EC to develop methodologies for a harmonised energy system-wide CBA at Union level for hydrogen infrastructure, see EC (2023b), EC/JRC, 'Hydrogen system-wide CBA for candidate hydrogen projects – Final', May 2023.

different **reference hydrogen networks**, including the following infrastructure levels (Fig. 12, *Figures*):[121]

- 'advanced' (FID plus advanced, possibly defined as projects on which an FID has been taken, which are part of the NDPs, or which have concluded a market consultation or open season procedure),
- PCI ('advanced' plus remaining PCIs), and
- TYNDP (PCIs plus all remaining TYNDP projects).

In its Opinion, ACER recommended the additional inclusion of 'an existing infrastructure' level that only included existing infrastructure and all infrastructure expected to be commissioned no later than 31 December of the year of TYNDP' (i.e. before 31 December 2023 for the first list of PCI/PMI candidates under the revised TEN-E Regulation).[122] ACER has also noted that the conditions for a project to be considered 'advanced' should be defined in the CBA methodology as the projects included in the last NDP and/or having concluded a market test and/or having reached the FID. ACER has also considered the TYNDP hydrogen infrastructure level as 'overly optimistic' and recommended removal.

While the TYNDP 2022 was focused on hydrogen infrastructure, ENTSOG's draft CBA methodology stressed that it was also important to continue updating the natural gas reference network. Correspondingly**, ACER called on ENTSOG to 'ensure that all relevant information on natural gas projects are (sic) reflected in the TYNDP topology', even when not submitted by project promoters** (as they are not legally obliged to do so).[123] ENTSOG noted that **hydrogen and natural gas reference networks considered in the TYNDP assessment must reflect interlinkage between natural gas and hydrogen** as the former was to be used for producing low carbon hydrogen (e.g. through an SMR process, see Chapter 3), which would be used to satisfy hydrogen demand until production of renewable hydrogen ramps up (so called **dual assessment of natural gas/hydrogen infrastructure**). While commenting on ENTSOG CBA methodology's concept of dual natural gas/hydrogen assessment, the ACER noted that the methodology only included 'natural gas aspects' 'to the extent they are needed to assess hydrogen infrastructures' and recommended to clarify which indicators should be used for assessing natural gas infrastructure needs.

ENTSOG stated that as hydrogen infrastructure will consist of newly built hydrogen infrastructure and hydrogen infrastructure repurposed from natural gas infrastructure, **it was necessary for the modelling and for the natural gas network to 'consider the potential impact of repurposing of natural gas to hydrogen infrastructure'**, calling on the gas TSOs to continue submitting their natural gas projects to the TYNDP.[124]

As noted earlier, once the revised TEN-E Regulation removed the natural gas infrastructure category from the list of Priority Corridors thus making it ineligible for a PCI/PMI status, the ENTSOG was no longer obliged to develop draft CBA methodology for assessing natural gas projects, unless they were associated with repurposing for hydrogen. Potentially this could create a problem for ensuring that security of natural gas supply is maintained as some natural gas networks were repurposed for hydrogen.

ENTSOG stated that **the EU-level topology should at least reflect the following natural gas infrastructure**:

- transmission,

[121] ENTSOG (2023c), ENTSOG draft CBA methodology, June 2023.
[122] ACER (2023b), 'Opinion on the draft ENTSOG CBA draft methodology of hydrogen infrastructure projects', No 08/2023.
[123] Ibid.
[124] ENTSOG (2023c), ENTSOG's draft CBA methodology, June 2023.

- LNG terminals,
- underground storage facilities (UGS),
- domestic production infrastructure (including renewable gases such as biomethane),
- 'reduction of natural gas capacities for transmission, storage and LNG terminals as a consequence of the implementation of hydrogen infrastructure projects from repurposed natural gas infrastructure (including a link to the hydrogen project causing this reduction),
- the gas infrastructure in countries adjacent to the EU in so far as it contributes to European imports/exports.

As far as **the natural gas reference network** is concerned, ENTSOG suggests at least considering the following infrastructure levels:

- **existing infrastructure plus FID projects,**
- '**advanced'** (allowing non-FID projects to be considered).

ENTSOG noted that 'when coupled with a hydrogen infrastructure level, the natural gas infrastructure levels' capacities can differ due to the effect of repurposing projects contained in the respective hydrogen infrastructure level'.

Costs and benefits indicators

ENTSOG's draft CBA methodology specified several **benefit indicators** (for assessing a project's benefits/cost ratio), including inter alia benefits associated with GHG and non-GHG emissions reduction, integration of renewable energy, reduced exposure to curtailed demand (see Table A.1, Annex I, for a full list), together with ACER's comments and recommendations. In addition to these indicators, ENTSOG's draft CBA methodology also required to assess the project's environmental impact whereas ACER recommended all information concerning projects' environmental impact was mandatory and should be collected from project promoters during TYNDP project collection; it has also called for the methodology to 'describe the methodological framework for the assessment of those impacts and specify the unit measures for the data'.

Overall, ACER noted that **the ENTSOG's draft methodology did not fully capture the following benefits**, as required by the TEN-E Regulation:

- contribution to flexibility and seasonal storage options for renewable electricity generation;
- contribution to the integration of market areas and to price convergence;
- contribution to supply diversification and facilitation of access to indigenous sources of hydrogen supply,[125]

and called upon ENTSOG to explore further how to incorporate indicators, which would allow to capture these benefits.

As far as project **cost indicators** were concerned, ENTSOG stated that the CBA methodology must at least take into account capital expenditure (CAPEX), operational and maintenance costs (OPEX), as well as costs 'induced for the related system over the technical lifecycle of the project as a whole, such as decommissioning and waste management costs, including external costs'.

Although ENTSOG stated that only costs 'related to hydrogen infrastructure' should be considered, it also noted that 'additional costs might be required (e.g. in the natural gas system) to enable the hydrogen infrastructure by linking it to natural gas projects' and stated that those must be 'transparently

[125] ACER (2023b), 'Opinion on the draft ENTSOG CBA draft methodology of hydrogen infrastructure projects'.

displayed'. For its part, ACER called on ENTSOG to clarify what was meant by that, stressing that the project's costs must be fully transparent.

Under the TEN-E Regulation ENTSOG was also obliged to identify **infrastructure gaps** as part of TYNDP process. This was a particularly difficult task in respect of hydrogen infrastructure given the uncertainty of hydrogen supply and demand. ENTSOG defined an infrastructure gap as 'a situation where an infrastructure may be needed to meet the criteria defined in the TEN-E Regulation', such as sustainability, security of supply and flexibility, competition, and market integration. ACER noted that ENTSOG's approach for identifying hydrogen infrastructure gaps was 'very similar' to the approach used for natural gas in previous TYNDPs, whereas – unlike natural gas infrastructure – at present there was no hydrogen infrastructure in Europe, except several industrial (national and cross-border) pipelines (see Chapter 3).[126] ACER called on ENTSOG to 'commit to identify' the hydrogen infrastructure capacities 'needed to meet hydrogen demand and supply', using an approach that would ensure 'consistency and interlinkages' with the scenarios process and the electricity TYNDP.

4.7.3 The EC's (temporary) CBA methodology for hydrogen infrastructure: a tool too simple for a complex task

As the ENTSOG's CBA methodology was not ready for assessing hydrogen candidate PCIs/PMIs, **the EC has developed its own (temporary) CBA methodology** – based on methodology previously developed by the EC's Joint Research Centre (JRC) but different from it – to be applied for assessing candidate projects for the 1st EU PCI/PMI list, containing hydrogen infrastructure. Key provisions of this methodology are analysed below.[127]

Key principles

The EC temporary CBA methodology stipulated the following **principles** that were to be used for the assessment of hydrogen infrastructure (pipelines, storages, and import terminals) and electrolyser candidate PCIs (emphasis added), particularly stressing its cross-border dimension:

- a project has a sufficient indication of supply and demand of hydrogen;
- a pipeline intended to cross or reach an interconnection point between two Member States has a matching capacity on the other side of the border;
- an internal pipeline has a significant role in exporting hydrogen from this Member State and/or transiting it via the Member State;
- a storage project aims to supply, directly or indirectly at least two Member States, by being close to an interconnection point and/or a transit pipeline;
- an electrolyser project demonstrates direct or indirect benefits for at least two Member States, taking into account the expected supply and demand of the Member State in which it is located;
- a terminal project demonstrates that it aims to supply directly or indirectly at least two Member States, taking into account the expected supply and demand of the Member State in which it is located;
- a repurposing project offers a pathway to a complete repurposing of the existing infrastructure for exclusive hydrogen use.

[126] Ibid.
[127] EC (2023d), EC hydrogen PCI/PMI methodology, 16 June 2023.

While the EC CBA methodology used the 2030 timeframe (for consistency with the electricity network planning process), it noted that 2040 time could also be considered where relevant 'for a complete picture'.

Assessing costs and benefits under uncertainty

As noted in Section 4.2, the TEN-E Regulation requirement that the potential overall benefits of the project outweigh its costs (within the EU) is one of the main general criteria for assessing all PCI and PMI candidates, including hydrogen projects. Such assessment is complicated by the lack of reliable data in respect of both costs and benefits associated with such projects, due to the absence of European hydrogen market and the (near complete) absence of trans-European hydrogen infrastructure. The EC CBA methodology strives to provide a guidance on weighing highly uncertain costs and benefits and determining whether the cost/benefit requirement is met. There are also specific criteria that must be assessed, such as the project's impact on sustainability, market integration security of supply / flexibility, and competition. While the EC suggested measuring the impact on sustainability by assessing the project's impact on CO2 emissions reduction, it noted that the impact on market integration, security of supply / flexibility, and competition was much more difficult to assess because of the lack of data.

The EC's CBA methodology acknowledged that due to 'fundamental uncertainties' about hydrogen supply (domestic and imports) and demand as well as limited availability of concrete and reliable data about hydrogen suppliers and off-takers, the assessment of candidate PCIs 'needs to rely on certain simplifications', particularly as far as the cost-benefit analysis is concerned.[128] It further stated that the choices made during the assessment of hydrogen and electrolyser candidate PCIs for the first EU list should be 'revisited in the assessment methodology and assessment of future PCI/PMI processes, which will benefit from a clearer market situation and more concrete, impartial and up to date information on volumes and types of supply and demand.' This statement suggested that the EC was aware that its temporary CBA methodology is of limited value for providing an adequate assessment of candidate projects, given significant uncertainty surrounding their costs and benefits. It also implied that some of the hydrogen (and electrolyser) projects, included in the first EU PCI/PMI list based on this CBA methodology, may not be included in subsequent EU PCI/PMI lists, once more information on projects' costs and benefits becomes available.

Benefits

As noted above, **the EC temporary CBA methodology** for hydrogen infrastructure was based on the EC's JRC CBA methodology but differed from it in several important respects, most importantly by having **fewer benefit indicators**, used for assessing candidate projects. Whereas the JRC methodology contained seven benefit indicators (see Box 4), the EC methodology only contained two:

- **variation of CO2 emissions** (tons) through integration of renewable and low carbon hydrogen to measure the impact on sustainability by considering natural gas-based hydrogen[129] as the fuel being replaced by renewable and low carbon hydrogen;
- **improvement of market integration** (qualitative) through assessing the candidate hydrogen project's support for the integration of the EU hydrogen market at the level of interconnections between Member States.

The EC explained its decision to reduce the number of indicators for the first PCI/PMI list assessment by the lack of reliable data that would allow the assessment of other indicators, listed in the JRC methodology (such as security of supply / flexibility and competition inter alia).

[128] Ibid.
[129] Most of hydrogen currently produced and consumed in the EU is natural gas-based hydrogen produced via steam methane reforming (SMR) process.

Box 4. The JRC's CBA methodology benefit indicators

- variation of GHG emissions (euros/a), to assess the impact on sustainability;
- variation of non-GHG emissions (euros/a), to assess the impact on sustainability;
- integration of renewable and low-carbon hydrogen potential into the system (%), to assess the impact on sustainability;
- substitution effect – fuel switching (euros/a), to assess the impact on competition;
- reduction of curtailed hydrogen demand (GWh/a), to assess the impact on security of supply and flexibility;
- improvement of market integration (qualitative), to assess the impact on market integration;
- increase of cross-sectoral flexibility (euros/a), to assess the impact on sustainability.

Source: JRC

Costs

The costs considered under the EC CBA methodology included CAPEX and OPEX, associated with each candidate project, as provided by project promoters. CAPEX represented the cost that was expected to be incurred by the promoter to build infrastructure and start its operation (including the cost of obtaining permits and rights of way, feasibility studies, groundwork, preparatory work, designing, dismantling, equipment purchase and installation). OPEX represented the cost incurred after the commissioning of infrastructure that was not of investment nature (direct operation and maintenance costs, administrative and general expenditures). Inevitably, both CAPEX and OPEX of hydrogen infrastructure were characterised by significant uncertainty and could change significantly during the project's construction and operation.

4.7.4 TYNDP 2022: lack of assessment of hydrogen candidate PCIs/PMIs

The TEN-E Regulation required **hydrogen (and electricity) infrastructure projects to be part of the latest available EU TYNDP to be included in the EU PCI and PMI list.** However, as far as **hydrogen infrastructure is concerned, this requirement only applies from 1 January 2024** (Annex III.2(4)), i.e. one month <u>after</u> the 30 November 2023 deadline for the adoption of the first EU PCI/PMI list (which is also the first EU list to include hydrogen infrastructure). This suggests that the TEN-E Regulation did <u>not</u> require hydrogen infrastructure PCI candidates to be part of the EU TYNDP 2022 in order to be included in the first hydrogen infrastructure EU PCI/PMI list. Therefore, it was possible for candidate hydrogen PMIs and PCIs to be granted a PCI/PMI status and be included in the EU list without having been included in the EU TYNDP 2022 first.

Notably, the TEN-E Regulation did not prohibit the inclusion of hydrogen infrastructure projects in the EU TYNDP 2022. Moreover, it amended Gas Regulation 715, by adding a requirement for ENTSOG to include hydrogen networks in its EU TYNDP modelling (Art. 8.10) thus providing ENTSOG with a right and an obligation to consider hydrogen networks as part of its TYNDP preparation.

It is worth noting that ENTSOG had previously included hydrogen projects in its TYNDP 2020 as part of 'energy transition projects' (ETR) category, alongside with natural gas transmission (TRA), LNG (LNG), and natural gas storage (UGS) project categories, with hydrogen infrastructure candidate projects being 'voluntary submissions'. ENTSOG also decided to include hydrogen infrastructure projects in its TYNDP 2022, which included **seven categories**,

- three of which were natural gas infrastructure projects
    - transmission (TRA),
    - LNG (LNG), and

- natural gas storage (UGS)),[130] and

- four were non-natural gas infrastructure projects
    - new or repurposed infrastructure to carry hydrogen (HYD),
    - projects for retrofitting infrastructure to further integrate hydrogen (blending) (RET),
    - biomethane (BIO),
    - other projects (including conversion of existing pipelines to carry CO2) (OTH)).[131]

Notably, **ENTSOG's TYNDP 2022 project collection process, which had run during 18 October – 12 November 2021, has been subsequently re-opened during 30 May – 24 June 2022**, to collect additional projects, which included *ad hoc* projects aimed at reducing dependence on Russian gas in line with the RePowerEU Plan.[132] It was also complemented with 'new and updated projects from the first PCI/PMI call under the revised TEN-E Regulation'.[133] (The PCI/PMI candidate submission window was open from 17 October to 15 December 2022, with 180 candidate PCIs (147 hydrogen and 33 electrolyser) and 16 candidate PMIs having been submitted.) **ENTSOG published its draft TYNDP 2022 on 11 April 2023 and its final TYNDP 2022 – which included both natural gas and hydrogen infrastructure projects – on 29 September 2023.[134]**

Overall 358 projects were submitted for the TYNDP 2022, of which 152 projects (43%) were hydrogen infrastructure projects (HYD), followed by natural gas transmission projects – 108 projects (30%), other projects (OTH) – 39 projects (11%), LNG – 23 projects (6%), retrofitting projects (RET) – 13 projects (4%), UGS – 12 projects (3%), and biomethane – 3 projects (3%) (Fig. 13, *Figures*).[135]

Hydrogen infrastructure projects clearly dominated the non-natural gas projects landscape. Amongst TYNDP 2022's non-natural gas project categories (HYD, RET, BIO, OTH), hydrogen infrastructure projects (HYD) constituted an absolute majority in more than half of all Member States (with Germany, where all non-natural gas projects were hydrogen infrastructure projects, having the highest share), whereas retrofitting, biomethane and other projects were present in less one third of all Member States (Fig 14, *Figures*).

The European gas industry supported ENTSOG's inclusion of hydrogen networks into its draft TYNDP 2022 to allow network planning to be based on "a comprehensive and consistent assessment of the costs and benefits" to create a European hydrogen backbone at optimal cost. However, the inclusion of hydrogen infrastructure projects in the TYNDP 2022 raised many questions in respect of how the assessment of its costs and benefits has been made. For example, the German association of TSOs, FNB, noted that as far as the first hydrogen PCI list under the revised TEN-E Regulation (the sixth list under the old TEN-E Regulation) was concerned, hydrogen infrastructure projects could 'apparently be included without consideration and evaluation within the TYNDP' and that it was 'completely unclear' which evaluation criteria would apply and whether CEF funding would be possible.

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130 With a caveat that these natural gas infrastructure projects must be "hydrogen-ready or contribute to fuel-switching".
131 ENTSOG used these four new categories – HYD, RET, BIO and OTH – in TYNDP 2022 instead of the ETR category used in TYNDP 2020. In total, TYNDP 2022 included 215 projects in 26 countries submitted under the HYD, RET, BIO, and OTH categories, see ENTSOG (2023d), 'TYNDP 2022: the hydrogen and natural gas TYNDP' and ENTSOG (2023b), ENTSOG TYNDP 2022 workshop.
132 EC (2022), REPowerEU Plan. It is worth noting that the RePowerEU Plan states that its European map of gas infrastructure contains 'PCIs and additional projects identified through REPowerEU, including hydrogen corridors' without mentioning any criteria/methodology on the basis of which these additional projects have been identified/selected.
133 ENTSOG (2023b), ENTSOG TYNDP 2022 workshop.
134 ENTSOG TYNDP 2022. Interestingly, although ENTSOG had published its draft TYNDP 2022 on 11 April 2023, it was only submitted to ACER on 26 May 2023, see ACER (2023c), 'Opinion on the draft regional lists of proposed hydrogen PCIs and PMIs', No 09/2023, footnote 12.
135 ENTSOG TYNDP 2022 workshop.

In April 2023 **ENTSOG confirmed that <u>no</u> eligibility check has been carried out by ENTSOG in respect of hydrogen infrastructure projects submitted for the first EU PCI/PMI list and included in the draft EU TYNDP 2022**, while adding that these projects would 'undergo a thorough eligibility check by the EC', without specifying what CBA methodology would be used.[136] The TEN-E Regulation required hydrogen (and electricity) PCI candidates to be assessed in line with the ENTSOG's CBA methodology. However, as noted earlier, due to ENTSOG's delay in submitting its *preliminary* draft CBA methodology and subsequently missing the 24 April 2023 deadline for submitting its *draft* CBA methodology, the ENTSOG'S CBA methodology for hydrogen infrastructure was understood unlikely to be finalized in time for assessing the candidate projects for the first EU PCI/PMI list. Therefore, the EC developed its own methodology, which has been used for assessing the PCI/PMI candidates for the first EU PCI/PMI hydrogen infrastructure list (see Section 4.7.3).

On 14 July 2023, as required under Gas Regulation 715, **ACER provided its Opinion to the ENTSOG and the EC on the draft TYNDP 2022** within two months of its submission on 11 April 2023. **ACER's main conclusion was that the draft TYNDP 2022 did '<u>not</u> sufficiently contribute to the objectives of non-discrimination and efficient functioning of the market',** due to:

- 'a lack of a complete quantitative needs assessment, doubtful quality of ENTSOG CBA methodology for methane projects […], lack of cost information for a significant number of methane and hydrogen projects';
- 'lack of analysis of the existing and forecasted use of gas [methane] infrastructure', including the expected level of physical congestion, despite the fact that the latter is 'a critical criterion' for analysing the need for additional gas infrastructure;
- 'lack of consideration of the interest of market players to develop transportation capacities to connect hydrogen demand and supply' in the methodology for the identification of hydrogen infrastructure needs;
- 'the asymmetric treatment' of candidate TYNDP projects, as the assessment of some projects was not subject to a CBA whereas and the assessment of other projects was subject to a CBA, thus creating two classes of projects within the same TYNDP.

ENTSOG published its final TYNDP 2022 on 29 September 2023.[137]

4.7.5 Falling consistency between TYNDPs and NDPs: ACER's assessment

When the draft TYNDP 2022 was still under development, **ACER provided an Opinion on the review of gas and hydrogen national NDPs to assess their consistency with the TYNDP**, the integration of decarbonised and low carbon gases into NDPs, as well as the readiness of the natural gas infrastructure to accept blends of hydrogen and biomethane.[138] Notably it expressed concern in respect **of 'a continuous falling level' of consistency between NDPs and draft TYNDP 2022**, compared to earlier TYNDPs, explaining this discrepancy by the inclusion of decarbonised and low carbon gases projects in the TYNDP 2022 which were 'often not part of the most recent gas NDPs' (Fig. 15, *Figures*).

ACER recommended the following **measures to improve consistency between the NDPs and the TYNDP,** such as for the NDPs to 'focus more' on projects allowing for renewable and low carbon gases to be integrated into the networks, 'as part of gas network plans or as dedicated plans for hydrogen' as well as to 'include suitable areas for location of power-to-gas assets in coordination with electricity network planning process'. It also recommended the reconciliation of 'the large number' of (natural gas) projects in the NDPs and the TYNDP with the projected 'downward trend in gas demand' and noted the

[136] ENTSOG TYNDP 2022, see footnote 1. Also see ENTSOG TYNDP 2022 workshop.
[137] There is no requirement under EU law for ACER to provide an Opinion on the ENTSOG's final TYNDP 2022.
[138] ACER (2022a), 'Opinion on the review of gas and hydrogen national NDPs to assess their consistency with the EU TYNDP'.

need for the NDPs to consider 'the possible future need' for (natural) gas infrastructure to be decommissioned. ACER has also called for using compatible scenarios for developing the NDPs and the TYNDP, stressing the need to be aligned with the NECPs. At present, only half of NRAs confirmed that the NDPs are aligned with the latest NECPs). ACER has further called for information on project cost to be provided for all the NDPs and the TYNDP. As far as governance aspects were concerned, ACER recommended consideration of a consolidated NDP for each Member State where several TSOs exist (including not only transmission but also LNG and UGS) and called for strengthening regulatory oversight over, and improving the quality of public consultations in respect of, the NDP development process.[139] Finally, ACER called for the alignment of the NDPs with the REPowerEU objectives, calling for an inclusion of 'soon to be operational' infrastructure projects 'contributing to phasing out the dependency on Russian gas, increasing flows from West to East, and increasing the gas supply import capabilities, including LNG […] to replace missing volumes of Russian gas'.

4.8 The first EU hydrogen PCI/PMI list: reality and aspiration

RePowerEU and new infrastructure rush

It is worth recalling that the REPowerEU Plan[140] established a target of 20 mn tons of hydrogen to be available in the EU by 2030, of which 10 mn tons were to be produced domestically and 10 mn tons imported. The imports were envisaged to arrive through several hydrogen corridors – Iberian, Northern Seas, Nordic – Baltic, Eastern, South – Eastern, Adriatic, and North African (Fig.16, *Figures*).[141]

For these corridors to be implemented, hydrogen infrastructure would have to be built in nearly all Member States. Indeed, hydrogen project promoters from almost all Member States have applied for their projects to be included in the EU PCI/PMI list, despite only a few of them having had even a rudimentary regulatory framework for hydrogen infrastructure.

The EC CBA methodology, together with the final scores and rankings of the candidate projects that were proposed for the inclusion in the draft regional PCI/PMI lists, were presented to the Regional Groups on 16 June 2023.[142] On 28 June 2023 the Groups' decision-making bodies – composed of Member States and the EC – agreed on which projects to include in the draft regional lists. The TEN-E Regulation required the draft regional lists to be submitted six months before the 30 November 2023 deadline for the adoption of the EU list to ACER, which was obliged to issue an Opinion on the draft regional lists – in particular, on the consistent application of the criteria and the CBA across regions – within three months (Annex III.2(14)). The draft regional lists were submitted to ACER by the EC on 12 July 2023.

ACER's de facto refusal to provide an assessment of regional hydrogen PCI/PMI lists

On 29 September 2023, ACER issued its Opinion on the draft regional PCI and PMI lists,[143] also attaching the NRAs' assessments of candidate projects on eligibility criteria and CBA.[144] Importantly, **many NRAs stated their lack of 'competence and jurisdiction over hydrogen projects** within their respective Member States' and acknowledged that **they 'may not be in a position to offer scrutiny' in respect of proposed hydrogen projects.** In particular, only five NRAs – Germany, Lithuania, Malta,

[139] Regulatory oversight is stronger in respect of NDPs (often legally binding) where in many (but not all) cases the governments or NRAs are empowered to approve the NDPs, than it is in respect of TYNDP (non-binding) where ACER is empowered to draft framework guidelines within which TYNDPs are developed as well as to provide an Opinion/recommendations but has no power of approval/rejection).
[140] EC (2022), RePowerEU Plan.
[141] European Hydrogen Alliance has subsequently identified 'the potential and specificities' of each corridor, provided a list of planned hydrogen transmission, distribution, storage, terminal and production/demand projects in each corridor, and identified region-specific bottlenecks, see European Hydrogen Alliance (2023), 'Learn-book on Hydrogen Supply Corridors', March 2023.
[142] ACER (2023b), 'Opinion on the draft ENTSOG CBA draft methodology'.
[143] ACER (2023c), 'Opinion on the draft regional lists of proposed hydrogen PCIs and PMIs'.
[144] Ibid.

Portugal and Romania – reported their competence in respect of hydrogen infrastructure (evaluation, tariff approval) whereas the NRAs of the remaining Member States had 'no competence over hydrogen infrastructure or the legal basis giving competence over hydrogen infrastructure to NRAs has not been established yet' and the legislative framework on how to organise the hydrogen market and system development is 'under discussion' in some Member States.[145] In effect, this meant that the **majority of Member States' NRAs were unable to provide their assessment of hydrogen candidate PCIs and PMIs**, including in respect of the CBA.

ACER's Opinion on the draft regional hydrogen PCI/PMI lists has identified several serious shortcomings and it is fair to say that the Opinion was far from complimentary. Specifically, ACER stressed **'the lack of concreteness of the hydrogen candidate projects'**, while acknowledging that it was related to 'uncertainties' in the emerging hydrogen sector, where 'an applicable revenue model or the applicable regulatory regime' was still under consideration.[146] It recommended that in the early stages of the hydrogen market development, candidate projects should be 'in a more advanced development stage' in order to be eligible for the EU PCI/PMI list. Notably, out of 179 project/project groups submitted for consideration, only <u>one</u> project reached the FID stage, and 19 projects were denoted as 'advanced'. The overwhelming majority of projects were denoted as 'less advanced' (understood as being in the early planning stages and lacking concreteness/maturity).[147] ACER noted that a 'generic emerging corridor covering Ukraine, Slovakia, Czechia, Austria and Germany' has been included in one of the regional lists despite the uncertain hydrogen source, whereas two projects (the Delta Rhine Corridor H2 and Belgium-Germany interconnection) have been included despite their benefits failing short of the required threshold, based on the support from their respective Member States, assuring that the new data was available for these projects.

ACER was also **critical of the timing of the discussions on the methodologies**, noting that they should take place at the beginning of the PCI/PMI selection process, thus adequately guiding and informing it, rather than at the end. Specifically, ACER criticized ENTSOG's late submission of TYNDP 2022, stating that that at the time of the submission of candidate PCI/PMI projects (December 2022) and at the time of the provision of NRAs' assessment (March 2023), TYNDP 2022 had not yet been submitted to ACER and the project-specific CBA results were not available. This has undermined the PCI/PMI selection process as the non-availability of the TYNDP data 'could not allow a proper assessment of projects'.[148] ACER called for ENTSOG to finalise its future TYNDPs before the project assessment starts, including the results of the CBA assessment.

ACER was also critical of **an overly simplified methodology for the identification of hydrogen infrastructure needs in each Member State**, according to which only three needs – market integration, curtailed hydrogen demand and variation of GHG emissions – were assessed, calling for development of a more 'robust' methodology. As far as the EC temporary CBA methodology (see above) was concerned, ACER called for the monetisation of benefits indicators in the future to allow for 'more coherent' outcomes in determining a benefit/cost ratio. While ACER commended the EC for developing the temporary CBA methodology, it also called for its refinement, taking into consideration the hydrogen specific CBA methodology, which was being developed by ENTSOG.[149]

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[145] See Annex II of this paper for a summary of NRAs competences in respect of hydrogen infrastructure in Germany, Lithuania, Malta, Portugal and Romania and for hydrogen infrastructure treatment in all other Member States, where NRAs have no competence in respect of hydrogen infrastructure, see ACER (2023e), 'Report on investment evaluation, risk assessment and regulatory incentives for energy network projects', June 2023.
[146] ACER (2023c).
[147] ACER notes that the conditions for a project to be considered 'advanced' are already defined in the CBA methodology as the projects included in the last NDP and/or having concluded a market test and/or having reached the FID, see ACER (2023c).
[148] Draft TYNDP 2022 was submitted to ACER on 26 May 2023, see ACER (2023c).
[149] Also see VIS (2023), 'Study on requirements and implementation of ENTSOG'S Cost Benefit Analysis for hydrogen infrastructure for ACER'

Importantly, while commenting on the fact that the PCI/PMI selection was ‘primarily based on benefits estimated under the 2030 Distributed Energy scenario’[150] – one of the TYNDP 2022 scenarios consistent with the EU climate law targets – ACER stated **that more scenarios should be taken in consideration during the next PCI/PMI process**, as the failure to do so ‘may result in biased outcomes by missing other possible futures, both in terms of infrastructure needs and assessments of individual projects’. It also called for using a longer-term horizon to reduce uncertainties in the longer assessment period.

In conclusion, ACER stated that it was ‘unable to assess’ the consistent application of the TEN-E Regulation and of the CBA to all the candidate projects because of:

- unavailability of the project-specific CBA results as part of the TYNDP 2022;
- lack of full transparency in the results from applying the PCI/PMI selection methodology;
- inability of the majority of NRAs to scrutinize the candidate projects.

Effectively, the ACER Opinion can be interpreted as a de facto refusal to provide an assessment of the regional PCI/PMI lists because of the lack of data that should have been – but have not been – provided to ACER for assessment.

The 1st EU hydrogen PCI and PMI list

Within one month from receiving ACER’s Opinion, the decision-making body of each Regional Group was obliged to adopt its final regional list and send it to the EC, which was in turn obliged to adopt the final EU PCI/PMI list (as a Delegated Act). The final EU PCI/PMI list was adopted on 28 November 2023, as a Delegated Act.[151] The Act will enter into force on the 20th day after its publication, if no objection has been expressed to it by either the Council or the Parliament within a two-month scrutiny period that could be extended by a further two months, following its adoption. On 5 December 2023, the Parliament requested the initial two-month scrutiny period to be extended by a further two months.[152] As no objection has been raised by 5 February 2024, the EU list was published in the EU Official Journal on 8 April 2024 and entered into force on 28 April 2024 (as an Annex to the TEN-E Regulation).[153]

A small number of benefit indicators (due to the lack of data for assessing other benefit indicators) and significant uncertainty in respect of hydrogen infrastructure costs suggests that the EC CBA methodology only provided a basis for a largely superficial assessment of the first hydrogen PCI/PMI list. Given that the TEN-E Regulation did not specify the upper limit of how many PCIs and PMIs could be included in the EU list, only noting that the number must be ‘manageable’, many projects could be granted such status even though their positive cost/benefit ratio may well change into negative once more information becomes available in the run up to the adoption of the next EU PCI/PMI list in November 2025. As many as 179 hydrogen infrastructure PCI and PMI candidates had been submitted for the inclusion in the regional lists.[154] The EC appeared to have been aware of the dangers of including too many projects in the EU list. This awareness was reflected in the presentation of DG ENER’s Director of Green Transition and Energy System Integration, Catharina Sikow-Magny, who expressed the EC preference for the EU list to be ‘relatively short’, ‘very concrete’ and containing projects that could be implemented by 2030 rather than the projects that would stay on the list for another 20 years.[155]

The process of choosing a 'manageable’ number of hydrogen PCIs/PMIs from 179 candidate projects was bound to be very difficult. With so many projects having been included in the regional lists, which

[150] A scenario, which allies with the EU climate targets.
[151] First PCI/PMI list under the revised TEN-E Regulation, see EC (2023e), EC (2023q).
[152] EC, https://webgate.ec.europa.eu/regdel/#/delegatedActs/2293
[153] EC (2023q).
[154] ACER (2023c), ‘Opinion on the draft regional lists of proposed hydrogen PCIs and PMIs’.
[155] EC (2023m), Meeting of the hydrogen and electrolysers TEN-E cross-regional groups, 17 April 2023.

had undergone only very basic CBA in line with the EC temporary methodology, the process of adopting the first EU list was also bound to be discretionary. Ultimately, 65 projects (~1/3 of all submitted) were included in the EU list, adopted on 28 November 2023, thus suggesting that majority of accepted projects were at less advanced stages of development and therefore highly unlikely to be built by 2030. Given that the inclusion in the EU PCI/PMI list qualifies a project for EU finding (as well faster permitting and cross-border cost allocation), bestowing such status on less advanced projects improves their chances of taking the FID. On the other hand, doing so it could have an adverse impact on the future network development as it could potentially divert limited resources from more advanced projects. Out of 65 projects included in the EU list, 31 were hydrogen pipeline networks, 10 – ammonia import terminals, 17 – electrolysers, and 7 – hydrogen storage facilities (Table 1).

Table 1: The 1st EU hydrogen PCI/PMI list: pipelines, storages, ammonia import terminals, and electrolysers

	Country/Countries	Projects
Pipelines	Ukraine to Slovakia, Czechia, Austria and Germany (generic corridor)	NA
	Portugal-Spain-France-Germany Corridor	Internal - Portugal - Spain - France (HyFen) - Germany (H2 Hercules South) Interconnectors - Portugal-Spain - Spain-France (BarMar)
	Italy-Austria-Germany Corridor	Internal - Italy (Italian H2 Backbone) - Austria (H2-readiness TAG) - Austria (H2 Backbone WAG&Penta West) - Germany (HyPipe Bavaria –Hydrogen Hub)
	Netherlands – Germany Interconnector	Interconnectors from the North-South backbone in East to Oude (NL) - H2ercules North from the North-South backbone in East to Vlieghuis (NL) – Vlieghuis – Ochtrup (DE) Netherlands to Germany (Delta Rhine Corridor H2)
	Denmark – Germany Interconnector	Internal - in Germany [HyperLink III] - in Denmark [DK Hydrogen Pipeline West]
	Czechia – Germany Interconnector	Internal - in Czechia towards Germany - in Germany [FLOW East - Making Hydrogen Happen]
	Greece – Bulgaria Interconnector	Internal - in Greece towards the Bulgarian border - in Bulgaria towards the Greece border
	Sweden – Finland Interconnector	Nordic Hydrogen Route – Bothnian Bay
	Finland, Estonia, Latvia, Lithuania, Poland and Germany Interconnector	Nordic-Baltic Hydrogen Corridor
	Sweden, Finland and Germany Interconnector	Baltic Sea Hydrogen Collector
	France	Internal - to Belgian border (Franco-Belgian H2)
	Germany	Internal - Hercules West
	Belgium	Internal

		- Belgian H2 Backbone
	Netherlands	Internal - Dutch National Backbone
	Offshore	- H2 pipeline Germany [AquaDuctus] - Norway – Germany [CHE Pipeline]* (PMI)
Import terminals (ammonia)	Belgium	Antwerp, Amplifhy Antwerp, Zeebrugge New Molecules
	Germany	Brunsbüttel -Wilhelmshaven (BP), Wilhelmshaven (Uniper)
	Netherlands	Rotterdam LH2, Amplifhy Rotterdam, ACE Rotterdam
	France	Dunkerque
Electrolysers	Portugal	H2Sines.RDAM
	Spain	Tarragona, Bilbao, Cartagena, Valle andaluz del hidrógeno verde, Asturias
	France	CarlHYng, Emil'Hy, HyGreen, H2V Valenciennes, H2Thionville
	Netherlands	Enecolyser, H2-Fifty, SeaH2Land
	Germany	Green Wilhelmshaven, CHC Wilhelmshaven
	Denmark	Jytske Banke
Storage	Denmark	Danish Hydrogen Storage
	Netherlands	Hystock Opslag H2 storage (NL)
	Germany	Salthy Harsefeld, Gronau-Epe
	France	GeoH2
	Spain	North – 1, North – 2

Source: author's compilation based on the first EU hydrogen PCI/PMI list, EC (2023e).

Overall, the first EU hydrogen PCI/PMI list had the following **key characteristics**:

- most of selected hydrogen transmission projects are located in western Europe (Germany, France, the Netherlands, Belgium, Spain, Portugal, Sweden, Finland and Norway), with only a small share of projects (the Greece-Bulgaria IP, the Czechia-Germany IPs, the Nordic Baltic corridor and the Ukraine corridor, for which no specific projects have been identified) located in eastern Europe;
- not only interconnectors but also internal hydrogen transmission (national hydrogen backbones) forming the so called 'hydrogen corridors' have been included;
- all ammonia import terminals (Belgium, Germany, the Netherlands, France), storages (Netherlands, Germany, France, Spain, Denmark), and electrolysers (France, Netherlands, Germany, Denmark, Spain, Portugal) are located in western Europe;
- France, Germany and the Netherlands are the only countries which have all four types of hydrogen infrastructure PCIs (transmission, storage, electrolyser and import terminal) on their territories, whereas Spain has three (transmission, electrolyser and storage), and Belgium has two (transmission and import terminal);
- Norway – Germany offshore pipeline is the only PMI project on the list.

Majority of hydrogen transmission projects and all ammonia import terminals, storages and electrolysers PCIs are located in western Europe – Germany, France, the Netherlands, Belgium, Spain, Portugal – with only a few (transmission) projects located in eastern Europe (Finland, the Baltic states, Greece, Bulgaria, and Czechia). Majority of projects are onshore, with only two offshore pipeline projects (involving Norway and Germany). This geographic distribution of projects on the EU list reflects the current reality of major European industrial clusters – and therefore main sources of industrial hydrogen demand – located in western Europe. As such, it confirms that **the EU hydrogen network will develop on the basis of existing industrial clusters and pipelines**. Some less advanced projects on the EU list appear to reflect the EC willingness to 'fill in' the hydrogen import corridors identified by its Action Plan, more than the genuine readiness of these projects to go ahead.

5. Summary and Conclusions

1. EU regulatory landscape and the paper's rationale

The EU views its future gas system as consisting of two separate systems – one for (progressively decarbonised) methane and another for hydrogen – both developing in parallel and co-existing, as part of ongoing European energy system decarbonisation. This vision is reflected in **the RNGH Directive and the RNGH Regulation**, which were adopted by the European Parliament on 11 April and published on its website on 12 April 2024. Once adopted by the Council, both documents will enter into force on the 20th day following their publication in the EU Official Journal. Together with **the TEN-E Regulation** (adopted in 2022), they will constitute the new EU regulatory framework governing construction of, and access to, hydrogen networks, as well as re-purposing and de-commissioning of, and access to, natural gas networks. This paper sought to understand the impact of this new framework – aimed primarily at the development and operation of hydrogen networks – both on the existing natural gas networks and emerging hydrogen networks.

While it is accepted that there will be two types of gas networks in Europe, the topology, the size, and the scale of the European hydrogen network is currently unknown and will be determined by the actual demand for, and supply of, renewable and low carbon hydrogen – both of which are highly uncertain at present (Chapter 3). These factors will also have an impact on the European natural gas network, some of which will have to be re-purposed to transport hydrogen (or CO2) or de-commissioned. At present, the European industrial sector – in particular, fuel refining and ammonia synthesizing – is the only <u>definite</u> source of demand for hydrogen, and is concentrated in Germany, the Netherlands, France, Spain, Italy and the UK. Additional demand <u>could</u> come from other industrial applications –such as steel-making – as well as from non-industrial sectors, although estimates for this demand differ widely. Industries will have to make a choice whether to decarbonize through renewable or low carbon hydrogen, or both. Infrastructure requirements will differ as renewable hydrogen would require more renewable power generation capacity and electrolysers to be installed, whereas low carbon hydrogen would require CCS facilities and CO2 transportation networks to be built. These choices will determine the first contours of the European hydrogen network, thus also having an impact on its future topology, scale, and timing, as well as on the shape of the natural gas network by influencing how much (or how little) of it would have to be retrofitted, re-purposed or de-commissioned.

Uncertainty about future European hydrogen demand and supply presents a significant challenge for the emergent European regulatory framework, which will govern the construction of new hydrogen pipelines and repurposing of existing natural gas pipelines. The framework **must be sufficiently flexible to enable the development of <u>any</u> kind of European hydrogen network,** whether a smaller scale, regionalized, network, or a larger scale, integrated, pan-European network. It must be sufficiently flexible to allow for a step-by-step adjustment of network planning and development to avoid building new hydrogen networks or de-commissioning existing natural gas networks where no hydrogen supply or demand exists (or will exist). This is true both for hydrogen networks and for other hydrogen-related infrastructure, such as (embedded) hydrogen import terminals and storages as well as CO2 transportation and storage infrastructure. Therefore, this paper analysed whether this framework is sufficiently <u>flexible</u> for enabling initially the development of smaller scale hydrogen networks, confined to regional industrial clusters (‘valleys’), before moving towards the development of an integrated pan-European hydrogen network (which may or may not happen). It did so by examining the RNGH Directive, the RNGH Regulation and the TEN-E Regulation’ provisions, governing the operation of both (existing) natural gas and (emerging) hydrogen networks – namely unbundling, access and tariff regimes – given an intrinsic connexion between the two (not in the least because of the role the repurposing of the latter is expected to play in the development of the former) (Chapter 2).

The paper also examined whether **the new EU framework is adequate for ensuring that the hydrogen networks are phased in and natural gas networks are phased out – either through re-purposing or de-commissioning – in a <u>coordinated</u> manner across the EU**, without jeopardising natural gas security of supply. More specifically, it sought to understand whether this framework provides sufficient assurance that natural gas networks will not be re-purposed to transport hydrogen when there would be no hydrogen available to flow through it, and consumers previously served through this network would be left with no alternative energy supply. It did so by examining the RNGH Directive, the RNGH Regulation and the TEN-E Regulation’s network development provisions, including asset transfer from natural gas to hydrogen RABs and its valuation, and development and coordination of national network development plans (NDPs) and EU-wide ten-year network development plans (TYNDPs), including Project of Common Interest (PCI) and Project of Mutual Interest (PMI) identification and selection, with a view to determining how new hydrogen networks and repurposed natural gas networks will be planned, built and financed in a <u>coordinated</u> manner (Chapter 4).

2. The RNGH Directive, the RNGH Regulation, and the TEN-E Regulation: some, but potentially insufficient, flexibility

RNGH Directive and RNGH Regulation

The RNGH Directive and the RNGH Regulation have preserved the main principles governing the EU natural gas market (OU, ITO, ISO unbundling of transmission networks, regulated access to transmission and distribution networks and LNG terminals, negotiated access to storages, regulated tariffs). They have also added new provisions aimed at <u>decarbonization</u> as well as at <u>security of supply.</u>

As far as <u>decarbonisation</u> measures are concerned, the RNGH Directive has prohibited the conclusion of long-term contracts for the supply of unabated fossil gas with an expiry date beyond the end of 2049 (the “2049 LTC rule”). This provision will have an impact on the European (and global) natural gas market by influencing the global gas suppliers’ willingness to invest in new gas projects.

As far as renewable and low carbon gases are concerned, the RNGH Regulation has mandated (a) a 100% discount to be applied to entry points from renewable and a 75% discount for low carbon production facilities and (b) capacity-based transmission tariffs at entry points from, and exit points to, storage facilities (100%), thus facilitating their access to the system. It has also stipulated a discount of 100% for renewable gas and 75% for low carbon gas at IPs between Member States – but not in respect of IPs with non-EU Member States and not in respect of entry points from LNG terminals – subject to sustainability certificate. At the same time, the RNGH Regulation has allowed the national regulatory authorities not to apply any of these discounts or decide to set their rates at lower levels.

As far as <u>security of supply</u> measures are concerned, the Regulation incorporated a host of measures, originally adopted to deal with the 2021-23 energy crisis. In particular, the Regulation enabled NRAs to apply a discount of up to 100% at entry points from, and exit points to, storage facilities, and at entry points from LNG facilities at least until 31 December 2025, aiming at facilitating storage refill and attracting LNG to Europe – a provision initially adopted to deal with the 2021-23 energy crisis. It has also required mandatory certification of Storage Operators, largely aiming at preventing Gazprom’s ownership/operatorship of European storages. It has also excluded Russian gas from the EU Energy Platform for demand aggregation and joint purchasing until 31 December 2025 and potentially beyond, and enabled Member States to temporarily restrict Russian gas supplies by imposing restrictions on pipeline and LNG import capacity. Additionally, the RNGH Regulation has allowed regulatory authorities to merge adjacent entry-exit systems to enable regional integration where tariffs could be abolished at the interconnection points (IPs) between the 'entry-exit' systems, and to approve 'a common tariff' and 'an effective compensation mechanism' between TSOs. In so doing the Regulation abstained from a significantly more radical (and potentially problematic) European Parliament proposal under which no tariffs would be charged for access to natural gas transmission network at IPs between Member States, and left it for national regulators to decide whether to abolish IP tariffs. The RNGH Regulation has preserved the existing exemption regime, which allowed exemptions from unbundling, regulated access and tariffs for major new (or significant increases in existing) natural gas infrastructure (interconnectors, LNG and storage facilities) for a defined period of time, subject to conditions including solidarity assessment and non-receipt of EU CEF funding and NRA/EC approval. It did not allow for exemptions from the "2049 LTC rule".

While existing capacity allocation mechanisms (CAM) and congestion management procedures (CMP) have been preserved, further changes are expected as part of the CAM network code revision, aimed at more efficient utilisation of *existing* capacity in the light of changed gas flow patterns in the aftermath of the crisis, whereas an incremental (*new*) capacity allocation procedure could be eliminated altogether. Should this happen, an exemption regime (and/or an intergovernmental agreement) – requiring the national regulator's and ultimately the EC's approval – would become the only route to building new natural gas infrastructure. This suggests that while the RNGH Directive and the RNGH Regulation have largely preserved the regulatory framework for the natural gas market, these planned changes appear to introduce some uncertainty in respect of future capacity allocation mechanisms.

The RNGH Directive and the RNGH Regulation have largely **modelled the rules governing the nascent hydrogen market on those governing the mature natural gas market**, while allowing for some in-built flexibility. The RNGH Directive prescribed OU, ITO (integrated HTNO), or ISO (independent HTNO) unbundling of hydrogen transmission networks and regulated access to hydrogen transmission and distribution networks (as for natural gas networks) as well as regulated access to hydrogen storages and negotiated access to hydrogen (ammonia) terminals (thus differing from the rules on LNG terminals and storages). The RNGH Regulation allowed capacity to be booked for up to 20 years in hydrogen network completed by 1 January 2028 and to 15 years – for networks completed after that date. It also required horizontal unbundling of hydrogen transmission networks allowing natural gas networks operators to operate a hydrogen network within a framework of a separate legal entity. At the same time, the RNGH Directive provided some **relaxations of these rules by allowing a transition period** for implementation – e.g. regulated access to networks and storages will only become mandatory from 1 January 2033 and an ITO unbundling model will be allowed to be applied indefinitely.

Both the RNGH Directive and the RNGH Regulation have provided for **exemptions and derogations**. In particular, the RNGH Directive allows NRAs to grant a derogation to existing hydrogen networks that belonged to a VIU on the date of the Directive's entry into force from its provisions on:

- regulated network access (otherwise mandatory from January 2033),
- vertical and horizontal unbundling of HTNOs,
- unbundling of HDNOs,
- certification of HTNOs,

and from the RNGH Regulation's provisions on:

- access to hydrogen networks and
- regional cooperation of HTNOs within the (yet to be established) European Network of Hydrogen Network Operators (ENNOH).

Such derogation will be valid as long as the existing network is not connected to another network, not expanded by more than 5%, and the NRA does not see it posing risk to competition, the efficient deployment of hydrogen infrastructure or the development and functioning of the hydrogen market.

The Directive also allows NRAs to grant a derogation to (existing and new) hydrogen networks transporting hydrogen within a geographically confined, industrial or commercial area from its provisions on:

- vertical unbundling of HTNOs,
- unbundling of HDNOs, and
- certification for HTNOs.

Such derogation will apply as long as the network does not include hydrogen interconnectors, does not have direct connections to hydrogen storage facilities or terminals (unless they are also connected to a hydrogen network that does not benefit from a derogation for existing networks or for existing and new confined networks), primarily supplies hydrogen to directly connected customers, and is not connected to any other hydrogen network (except to networks also benefitting from a derogation for confined networks and operated by the same HNO), and as long as the regulator does not see it as a risk to competition, the efficient deployment of hydrogen infrastructure or the development and functioning of the hydrogen market. In theory both types of derogations could be indefinite.

For its part, the RNGH Regulation allowed for exemptions for major new or significant increases in existing hydrogen infrastructure (interconnectors, hydrogen terminals and underground hydrogen storages) for a defined period of time (with no upper limit defined) from the RNGH Directive's provisions on:

- vertical unbundling of HTNOs,
- regulated access to hydrogen transmission and distribution networks,
- access to hydrogen terminals and hydrogen storages,

as well as from some of Regulation's own provisions, including on regulated access to networks. Such exemption is subject to NRA/EC approval and subject to conditions, identical to those for natural gas infrastructure. Exemptions and derogations serve as another in-built form of regulatory flexibility.

Overall, the RNGH Directive and the RNGH Regulation provide some in-built regulatory flexibility by allowing a transition period for implementing regulated access to hydrogen networks and storages (making it mandatory from 1 January 2033) and allowing an ITO unbundling model to be used indefinitely, combined with exemptions and derogations for existing and new hydrogen networks. Such flexibility is welcome as it could facilitate growth of the hydrogen market by ensuring the required networks are available where and when needed, whereas an overly restrictive framework, as originally proposed by the EC, would significantly constrain its development. However, the allowed transition period until 1 January 2033 – where regulated access to networks and storages becomes mandatory – might prove to be too short for creating a hydrogen market, in which case an avalanche of applications for exemptions for hydrogen infrastructure could be expected.

TEN-E Regulation

The TEN-E Regulation has facilitated the development of the European hydrogen network by making several energy infrastructure categories relevant for its development – such as

- hydrogen pipelines (onshore and offshore),
- natural gas pipelines repurposed for transporting hydrogen,
- hydrogen (ammonia) import terminals,

- CO_2 transport and storage infrastructure,
- electrolysers (with capacity of at least 50 MW and compliant with the life cycle GHG emission savings requirement of 70 % and having a network-related function) and pipeline connections to the network,

eligible for a project of Common Interest (PCI) status.

Such status, if granted, enables a project to benefit from faster permitting and regulatory approval, cross-border cost allocation (CBCA) rules, and eligibility for EU financial support through the Connecting Europe Facility (CEF). The Regulation has also established a new concept of Project of Mutual Interest (PMI), which enabled faster approval and access to EU funds for projects promoted by the EU in cooperation with non-EU countries. This recognizes the importance of imported hydrogen. PMI status can be granted to electricity, hydrogen, and CO_2 transport and storage projects (but not to electrolysers or smart gas grids). Grant of the PCI or PMI status is confirmed by the project's inclusion in the EU PCI/PMI list.

A cross-border dimension and positive cost-benefit ratio are amongst the key criteria that must be met by PCI and PMI candidates alike to be included in the EU PCI/PMI list. The TEN-E Regulation framework largely aimed at supporting the development of cross-border EU-wide – as opposed to national – infrastructure, its cross-border nature being one of the necessary conditions for PCI/PMI status eligibility. A candidate project would have to demonstrate convincingly its cross-border impact to be granted a PCI or PMI status. While this would be easier to do for networks crossing the border of two or more Member States, it would be more difficult – albeit not impossible – to do so for networks located in one Member State, particularly as the Regulation did not make it clear how the significance of cross border impact would be assessed. Ultimately, a certain degree of discretion would be present.

Both PCI and PMI candidates must be characterised by a positive cost-benefit ratio to be included in the EU PCI/PMI list. However, significant uncertainty about future European hydrogen supply and demand – where many key factors could not yet be quantified – makes any meaningful cost-benefit assessment challenging. If the letter and the spirit of the TEN-E Regulation are to be followed, a project unable to demonstrate its positive cost-benefit ratio could not be awarded a PCI or a PMI status. Also, even if a candidate project demonstrated a positive cost-benefit ratio at the time of its application the ratio could turn negative as more information about hydrogen demand and supply – as well as the cost – becomes available in the future.

Overall, the TEN-E Regulation provided **some regulatory flexibility in respect of cross-border infrastructure development, by enabling EU financial support** under the CEF for many different categories of infrastructure – such as new hydrogen pipelines, repurposed natural gas pipelines for hydrogen, power lines, CO_2 transport and storage facilities – that are supportive of both renewable and low carbon hydrogen. Although the CEF budget is quite limited (5.84 bn euros for energy infrastructure during 2021-27), a project that has received funds under CEF may also receive funds from any other EU funding programme, such as InvestEU, the European Regional Development Fund, the Cohesion Fund, REACT-EU, the Just Transition Mechanism, Horizon Europe, and Innovation Fund, some of which could be used for financing renewable and low carbon hydrogen infrastructure.

3. RNGH Directive and RNGH Regulation: natural gas and hydrogen network development coordination is not guaranteed

Asset transfer from natural gas to hydrogen RAB for repurposing: limited cross-subsidization within national borders, subject to NRA approval

The RNGH Regulation requires that the TSOs, the DSOs and the HNOs, providing regulated services for gas, hydrogen or electricity, must have unbundled accounts and separate Regulated Asset Bases (RABs) for their gas, electricity, and hydrogen assets. This requirement aims to ensure that revenues obtained from the provision of one regulated service can be used only for recovery of (capital and operational) expenditures related to the assets used for that specific service. For example, service revenues collected from the provision of natural gas transmission service from its users could only be used for recovery of expenditures related to the natural gas pipelines – rather that the hydrogen pipelines. It also aimed to ensure that the transfer value of assets transferred from one RAB to another – e.g. natural gas assets (pipelines) transferred from the TSO's RAB to the HNO's RAB for subsequent repurposing – is based on methodology approved by the NRA or determined by the NRA itself, in such a way that cross subsidies do not occur. This requirement would be met, as noted by DNV, if the transfer value would be 'set at the residual asset value in the natural gas RAB, plus possibly any additional costs incurred by the natural gas TSO in relation to the repurposing'.

While the Regulation does not provide any guidance for determining the asset transfer value, it empowers the EC to adopt delegated acts, establishing network codes for hydrogen covering various areas, including **'rules for determining the value of transferred assets and the dedicated charge' as well as 'rules for determining the inter-temporal cost allocation'.** These network codes could provide such rules either as general guidance or more specific detailed provisions. While the Regulation does not provide a timeline for the development of these network codes, it obliges the EC to establish every 3 years a priority list, identifying various areas to be included in the codes. The first list must be presented one year after the establishment of the ENNOH. Given that ENNOH should be established in 2025, the list would need to be presented in 2026. Network codes will be developed by ENNOH (in line with the binding framework guidelines, developed by ACER at the EC request) and adopted by the EC. The code, establishing the rules for determining the value of transferred assets and the dedicated charge, is to be developed by ENNOH and ENTSOG jointly. The Regulation suggests that the EU network codes on hydrogen, including the code establishing the rules for determining the value of transferred assets and the dedicated charge as well as rules for determining the inter-temporal cost allocation, would be adopted towards the end of the 2020s. Therefore, it could be expected that the key network codes for hydrogen could be in place by 2030. In addition to the EU network code, rules containing more detailed provisions on determining the transfer value and the dedicated charge could also be developed at the Member State level through national legislation or through NRA guidelines. While details may differ between Member States, the key principles for determining the asset transfer value must be identical across the EU whereas national level rules must be compatible with the EU-wide rules, including the EU network codes for hydrogen.

Crucially, although the RNGH Regulation introduced a separate RAB requirement for natural gas, hydrogen and electricity assets with a view to avoiding cross-subsidisation between them, nonetheless it allowed for conditional cross-subsidization, i.e. where the financing of networks through network access tariffs paid by its network users alone – i.e. without a cross-subsidy – is deemed unviable by the regulatory authorities. Only one type of cross-subsidy would be allowed – a temporary dedicated charge that could only be applied to end-users within the same Member State, thus making it national rather than regional or pan-European. The charge would be subject to approval by the regulatory authorities, which were granted additional powers by the RNGH Directive, to fix or approve the size and duration of the dedicated charge and financial transfer or their methodologies, or both, and the value of transferred assets and the destination of any profits and losses that may occur as a result, and the allocation of contributions to the dedicated charge. The RNGH Directive has also enabled ACER to issue recommendations (updated at least biannually) to TSOs, DSOs, and HNOs as well as to regulatory authorities on the relevant methodologies.

Thus, the RNGH Regulation makes the inability to finance the networks through tariffs alone the necessary condition for allowing financial transfers between separate services. Ultimately, it allows cross-subsidization between separate regulated services – e.g. natural gas and hydrogen transportation – but only in the form of a dedicated charge that could only be applied to end-users within the same Member State, subject to the regulatory authority's approval. As such, cross-subsidization would be limited to the national level, with the regulatory authority approving the size and duration of the transfer charge (methodology), the value of transferred assets and inter-temporal cost allocation, in line with the rules to be stipulated in the EU network codes as well as national legislation.

Amended network development rules at EU and Member State levels and their impact on the network development coordination

The RNGH Directive and the RNGH Regulation amended the high-level rules for network development process both at the EU and the Member States levels, provided by the Third Gas Directive, Gas Regulation 715 and the TEN-E Regulation (2022). The RNGH Directive establishes the rules for national network development process, by making **natural gas transmission operators (TSO) and hydrogen transmission network operators (HTNO) the main actors** in charge of national network planning, obliging each of them to develop a ten-year NDP, based on a joint scenario and an integrated model. It mandates separate network planning for natural gas and hydrogen by default, while also allowing for a joint plan for natural gas and hydrogen, so that each Member State would either have one single NDP for natural gas and one single NDP for hydrogen, or one joint plan for natural gas and hydrogen. It also obliged hydrogen distribution network operators (HDNO) to develop their plans for network development (without specifying a planning horizon) and natural gas DSOs – network decommissioning plans.

The Directive strengthens the regulatory oversight over the network development process. All TSOs and HTNOs, irrespective of their unbundling model, will be obliged to submit their NDPs to the regulatory authorities. **These authorities will have to play a major role in ensuring coordination between hydrogen and natural gas network development**, given that a significant share of new hydrogen pipelines is expected to come from the repurposed natural gas pipelines. NDPs must ensure system efficiency, including for natural gas pipeline repurposing, and be sufficiently transparent to allow the regulatory authority to identify the needs of the natural gas sector and the hydrogen sector. They are required to include 'comprehensive and detailed information' on natural gas infrastructure that can or is to be decommissioned, and on hydrogen infrastructure that can or is to be repurposed, including a time frame for all investment and decommissioning. NDPs are also required to consider any infrastructure reinforcements needed for connecting renewable and low carbon gas facilities thus facilitating their entry in the transmission network.

As far as EU-level network planning is concerned, the RNGH Regulation **split the obligation to prepare the EU TYNDP for natural gas and the EU TYNDP for hydrogen between ENTSOG and ENNOH respectively**, as well as transferring an obligation to develop a CBA methodology for assessing hydrogen PCI/PMIs from ENTSOG to ENNOH. ENTSOG will continue to remain in charge of preparing TYNDPs for natural gas in the future, including TYNDP 2024 (which, as TYNDP 2022 did, will include both natural gas and hydrogen projects). ENTSOG will also be obliged to develop a TYNDP 2026 for hydrogen, which must include two separate chapters – one for hydrogen and another for natural gas, with ENNOH's involvement. ENNOH will be fully responsible for developing the TYNDP 2028 for hydrogen and subsequent hydrogen TYNDPs, while ENTSOG will remain in charge of natural gas TYNDPs.

While the RNGH Directive and Regulation provided high level rules for natural gas and hydrogen network development coordination, more detailed measures – particularly dealing with issues related to repurposing and decommissioning of the existing natural gas infrastructure – were left to be defined by Member States' regulatory authorities with EC guidance and dedicated EU network codes for hydrogen (expected by 2030). These would, for example, include rules in respect of rules for determining the value of transferred assets (from the natural gas to hydrogen RAB) and the dedicated charge as well as rules for determining the inter-temporal cost allocation. As the EU network codes for hydrogen are not expected to be in place before the end of the 2020s, the Member States' regulatory authorities will have significant discretion in drafting the rules, governing the natural gas networks repurposing and decommissioning process.

Lack of legal obligation on ENTSOG to develop CBA for natural gas infrastructure (unless associated with repurposing) could endanger security of natural gas supply

Once the revised TEN-Regulation removed natural gas infrastructure and added hydrogen infrastructure to the EU list of priority corridors – thus making natural gas projects ineligible for a PCI status – ENTSOG was no longer obliged to develop draft CBA methodology for assessing natural gas PCIs. A new obligation was imposed on ENTSOG instead – to develop draft CBA methodology for assessing hydrogen PCIs, which would apply to new hydrogen pipelines, hydrogen storages and hydrogen (ammonia) import terminals as well as natural gas infrastructure repurposed for hydrogen (but not to any other natural gas infrastructure). ENTSOG's first hydrogen CBA methodology was used for developing the TYNDP 2022, providing guidelines for the CBA of projects and 'more generally of the overall gas and hydrogen infrastructure'. It focused on hydrogen infrastructure projects and only included natural gas aspects 'to the extent' they were 'needed to assess hydrogen infrastructures'. Although ENTSOG was under no legal obligation to develop CBA methodology for natural gas projects, its absence made it impossible to assess the needs for natural gas infrastructure not associated with repurposing, as pointed out by ACER, which referred to ENTSOG's methodology being 'doubtful', recommending improvements.

ENTSOG is also responsible for developing hydrogen CBA methodology for its TYNDP 2024 and could be responsible for developing hydrogen CBA methodology for TYNDP 2026 – if ENNOH CBA methodology is delayed. ENNOH will become solely responsible for developing hydrogen CBA for the first hydrogen TYNDP – TYNDP 2028 – as well as all subsequent hydrogen TYNDPs. For its part, ENTSOG will no longer be required to develop either natural gas or hydrogen CBA methodology. However, ENTSOG will still be required to develop its natural gas TYNDPs.

It is not clear how the EU natural gas system will be assessed in the future TYNDPs, particularly as and when the responsibility for developing TYNDPs will be split between ENTSOG and ENNOH. There is **a risk that the EU natural gas system assessment will 'fall through the cracks', as there appears to be no clear legal basis in the EU legislation for developing a natural gas CBA methodology.** Therefore, it is not clear which CBA methodology – if any – will be applied by ENTSOG for its natural gas TYNDP 2028 and all subsequent TYNDPs. Unlike Gas Regulation 715, the RNGH Regulation did not contain an explicit requirement for the TYNDP for natural gas to be subject to CBA. Potentially, this could present **a problem for coordinated network development as well as for ensuring security of natural gas supply across the EU, if there were to be no analysis of the existing and prospective natural gas infrastructure as part of EU-wide TYNDP.** This problem could be overcome if the EC and ACER were to recommend ENTSOG to develop CBA methodology for natural gas projects. Notably, although ENTSOG is not required to develop natural gas CBA, it is not prohibited from doing so.

Growing TYNDPs-NDPs inconsistency poses risks for coordinated natural gas and hydrogen network development

Consistency between EU TYNDPs and national NDPs is of key importance for ensuring a coordinated development of natural gas and hydrogen networks across the EU. The TYNDP 2022 serves as an example of significant and growing inconsistency between EU TYNDPs and national NDPs, mostly (but not exclusively) caused by an inclusion in TYNDP 2022 of many renewable and low carbon gas – mostly hydrogen – infrastructure projects that were not part of the national NDPs. This problem was mostly related to hydrogen infrastructure as only 17% of (new and repurposed) hydrogen infrastructure projects included in draft TYNDP 2022 – many of which without a CBA assessment – were included in the NDPs. Discrepancy was also relatively high for biomethane (36%) and retrofitting (38%) projects. Discrepancy for natural gas infrastructure was significantly lower, although some categories, such as LNG import terminals, were categorized by relatively high level of discrepancy, as only 62% of LNG terminals included in TYNDP were also included in NDPs. The decision to include in TYNDP 2022 many hydrogen and natural gas projects, identified through the RePowerEU Plan, rather than through NDPs – as would be a standard procedure in line with Third Gas Directive and Gas Regulation 715 – was the key reason for TYNDP 2022-NDP inconsistency.

TYNDP-NDP consistency would have to be ensured in the future as both the RNGH Directive and the RNGH Regulation – which are coming to replace Gas Regulation 715 and Third Gas Directive in 2024 – mandated such consistency and indicated that non-binding TYNDPs must be secondary to, and derivative from, the legally-binding NDPs. However, their mechanisms for ensuring consistency are unclear. In the event of inconsistency, ACER is obliged to make a non-binding recommendation to the national regulatory authority to amend the NDP or the TYNDP 'as appropriate'. It is also obliged to recommend amending the NDP if it was developed under the RNGH Directive's network development procedure of natural gas and hydrogen transmission infrastructure. (This would appear to suggest that it is the NDP rather than the TYNDP that would be liable to amendment – at the same time, it would appear to contradict the requirement for TYNDPs to build on NDPs.)

Due to the lack of a clear mechanism, ensuring consistency between national NDPs and the EU TYNDPs could become a challenge. It could be argued that there is a danger that those TYNDP 2022 projects that were not part of NDPs could subsequently find their way into the NDPs as part of ensuring TYNDP-NDP consistency, despite significant uncertainty about their costs and benefits. Should this happen, it could potentially result in including hydrogen infrastructure, in respect of which neither demand nor supply of hydrogen is assured, in the NDPs. Given the NDPs' legally-binding nature, this could potentially lead to repurposing and/or decommissioning of the existing natural gas infrastructure, which currently serves customers whose demand for natural gas could not be readily replaced by other energy sources, thus potentially undermining security of supply. However, some mediation against such a scenario is provided by that fact that given ACER's significant criticism in respect of draft TYNDP 2022, it is as difficult to expect ACER to make such recommendation as it is difficult to expect the national regulatory authority to accept it.

As the regulatory authorities have the powers to ensure coordinated development of natural gas and hydrogen networks at national level and EU level through cross-border coordination with regulatory authorities of adjacent Member States – including in respect of decommissioning and repurposing of existing natural gas networks – it is **paramount that only those projects that have been included in the national NDPs – following regulatory scrutiny – are also included in the EU TYNDPs**, with rigorous CBA applied. Failure to do so could potentially distort coordinated development of the networks across the EU as no clear mechanism ensuring coordination exists at the EU level. In this respect the TYNDP 2022 has established a negative precedent, and it remains to be seen if it will be corrected in subsequent TYNDPs.

If the problem of growing TYNDP-NDP inconsistency is not addressed in subsequent TYNDPs, it could undermine future coordinated development of European gas networks. The RNGH Directive's requirement to ensure TYNDP-NDP consistency is nothing new, as the same requirement was present in Gas Regulation 715 and the Third Gas Directive. Although it had not always been met, inconsistencies were less pronounced and did not have any serious lasting impact. However, a negative impact of TYNDP-NDP inconsistency would likely be more pronounced in the future than in the past, as the EU gas system is undergoing a significant transformation in line with the EU decarbonisation policies. A growing TYNDP-NDP inconsistency – both in respect of natural gas and hydrogen – and an apparent lack of clear mechanisms for addressing it – is a cause for concern. It has a potential for distorting future European network development and preventing hydrogen networks from being phased in and natural gas networks form being phased out – either through re-purposing or decommissioning – in a coordinated manner across the EU, without jeopardising the security of natural gas supply in the process.

The first EU hydrogen PCI/PMI list: (some) reality and (much) aspiration

While the RNGH Directive and the RNGH Regulation amended the rules for the network development process, the EU TYNDP 2022 (which contained both natural gas and hydrogen projects) and the first

EU hydrogen PCI/PMI list had to be developed by ENTSOG under the old rules, provided by the Third Gas Directive, Gas Regulation 715 and the TEN-E Regulation. However, both the TYNDP 2022 development and the PCI/PMI selection deviated from these rules. The TYNDP 2022 scenarios were amended on an ad hoc basis to be in line with the RePowerEU Plan through changes in natural gas and hydrogen supplies related to achieving the EU political objective of eliminating dependence on Russian gas before 2030 – including inter alia by adding hydrogen import corridors. Correspondingly, ENTSOG's TYNDP 2022 project collection process, which ran from 18 October to 12 November 2021, was subsequently re-opened during 30 May – 24 June 2022, to collect additional projects, identified' by the EC (with no explanation of methodology) aimed at reducing dependence on Russian gas as well as PCI/PMI candidates collected during 17 October – 15 December 2022. Many projects were included in the TYNDP 2022 without a proper assessment as no eligibility check was carried out by ENTSOG in respect of hydrogen infrastructure projects submitted for the first EU PCI/PMI list and included in the draft EU TYNDP 2022.

The (unrealistically) tight timetable established by the TEN-E Regulation for the development of ENTSOG's CBA methodology as well as re-opening the TYNDP 2022 project collection window for including additional projects, identified by the EC's RePowerEU Plan, resulted in late submission of the ENTSOG's hydrogen draft CBA methodology in June 2023, which made it impossible to be used for the assessment of hydrogen candidate PCI/PMIs for the first EU list by 30 November 2023. This prompted the EC to develop its own – simplified (using only two indicators) – temporary CBA methodology, which was used for assessment, with significantly less time available for consultation. In addition, the PCI/PMI selection process was undermined by the late submission of ENTSOG's TYNDP 2022, including its project-specific CBA results, in September 2023. (Normally, the TYNDP would have to be finalized and available at the time of the submission of candidate PCI/PMI projects and at the time of the provision of NRAs' assessment, so that it would inform and guide a PCI/PMI selection process.) As a result, ACER was unable to assess consistent application of the CBA to all the candidate hydrogen PCI/PMIs because of unavailability of the project-specific CBA results for the candidate projects as part of the TYNDP 2022, lack of transparency in the results from applying the PCI/PMI selection methodology, and inability of the majority of Member States NRAs to scrutinize the candidate projects. Consequently, these projects were made part of the TYNDP 2022 without ENTSOG's CBA assessment and part of the regional PCI/PMI lists with only a relatively light-touch assessment, based on significantly simplified EC CBA methodology, and with only a limited regulatory oversight and scrutiny. Yet a thorough energy-system wide CBA at the EU level is of key importance for ensuring a coordinated development of natural gas and hydrogen networks in the EU.

The fact that out of 179 submitted candidate PCI/PMIs, only one project has reached an FID stage and 19 projects – an 'advanced' (but not FID) stage, was a testament to the haphazard nature of the first EU hydrogen PCI/PMI list selection process, where many submitted projects were in very early stages of development and characterised by 'the lack of concreteness', where neither demand nor supply sources for hydrogen have been identified. Such vagueness is not unusual for any nascent market – as the EU hydrogen market is – and is explained by significant uncertainty in respect of European hydrogen supply and demand, regulatory framework and revenue model. While the TEN-E Regulation did not prescribe any upper limit in respect of the number of projects on the EU list, it stated that it must be 'manageable'. With so many projects having been included in the regional lists, having undergone only very basic CBA in line with the EC temporary methodology, the process of adopting the first EU list was bound to be discretionary. Ultimately, 65 projects (~1/3 of all submitted) were included in the EU list, thus suggesting that the majority of accepted projects were at less advanced stages of development and therefore highly unlikely to be built by 2030. Given that the inclusion in the EU PCI/PMI list qualifies a project for EU finding (as well faster permitting and cross-border cost allocation), bestowing such status on less advanced projects improves their chances of taking the FID. However, doing so could have an adverse impact on the future network development as it could potentially divert limited resources from more advanced projects.

Out of 65 projects included in the EU list, 31 were hydrogen pipeline networks, 10 – ammonia import terminals, 17 – electrolysers, and 7 – hydrogen storage facilities. The majority of PCIs for hydrogen transmission projects and all ammonia import terminals, storages and electrolysers are located in western Europe – Germany, France, the Netherlands, Belgium, Spain, Portugal – with only a few (transmission) projects located in eastern Europe (Finland, the Baltic states, Greece, Bulgaria, and Czechia). The majority of projects are onshore, with only two offshore pipeline projects (involving Norway and Germany). This geographic distribution of projects on the EU list reflects the current reality that the major European industrial clusters – and therefore the main sources of industrial hydrogen demand – located in western Europe. As such, it **confirms that the EU hydrogen network will develop on the basis of existing industrial clusters and pipelines.** Some less advanced projects on the EU list appear to reflect the EC willingness to 'fill in' the hydrogen import corridors identified by its RePowerEU Plan, more than the genuine readiness of these projects to go ahead.

4. The EU natural gas and hydrogen regulatory framework: "work in progress"

The paper has identified several shortcomings associated with the new EU regulatory framework for renewable and natural gases and hydrogen – constituted by the RNGH Directive, the RNGH Regulation, and the TEN-E Regulation. These shortcomings could restrict flexible step-by-step development of hydrogen networks in the light of significant uncertainty about European hydrogen supply and demand. They could also result in failure to guarantee a coordinated network decarbonisation process – through phasing out natural gas networks and phasing in hydrogen networks – without negatively affecting security of natural gas supply.

Regulatory flexibility, built into the EU regulatory framework by means of establishing a transition implementation period, allowing exemptions and derogations for existing and new hydrogen infrastructure, and enabling financial and regulatory support via a PCI/PMI status, is far from certain to be sufficient for enabling the EU hydrogen market to develop at scale. The allowed transition period – until 1 January 2033, when regulated access to networks and storages becomes mandatory – is likely to prove to be too short, in which case an avalanche of applications for exemptions and derogations could be expected. The EU regulatory framework also does not guarantee that phasing in the hydrogen networks and phasing out the natural gas networks – either through re-purposing or de-commissioning – will be carried out in a coordinated manner across the EU, without negatively affecting the security of natural gas supply.

Overall, **the framework appears to have been built on the premise that the EU hydrogen market will develop fast and at scale, while it lacks the "safety cushion" – including in respect of re-purposing the natural gas networks that could still be needed – should the hydrogen market roll-out be slower and more gradual.** However, as the speed and the scale of the hydrogen market development in the EU becomes more apparent, the regulatory framework could be adjusted accordingly. Should the hydrogen market fail to take off, more regulatory flexibility could be introduced. The framework is not complete yet, as more rules will be established the 2020s in the upcoming EU network codes for hydrogen (and the amended network codes for natural gas) in the 2020s, as the hydrogen market rolls out (or fails to do so) in the EU. Thus, the framework will continue to evolve and remain 'work in progress' at least until 2030 and possibly beyond.

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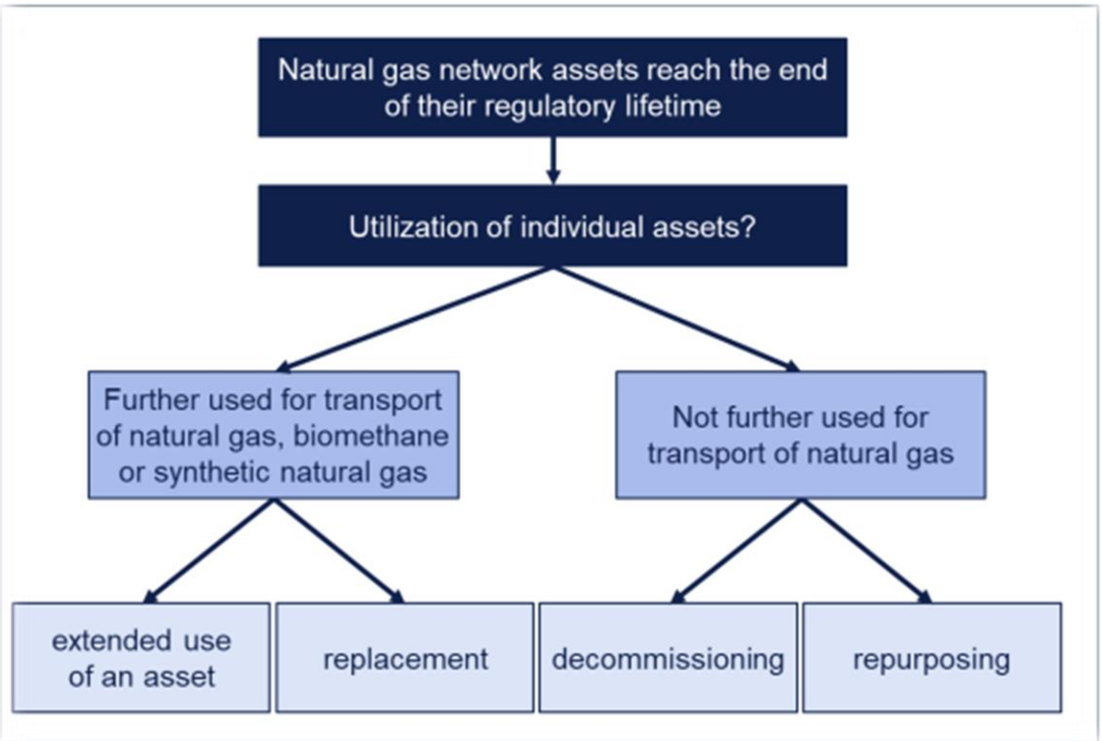
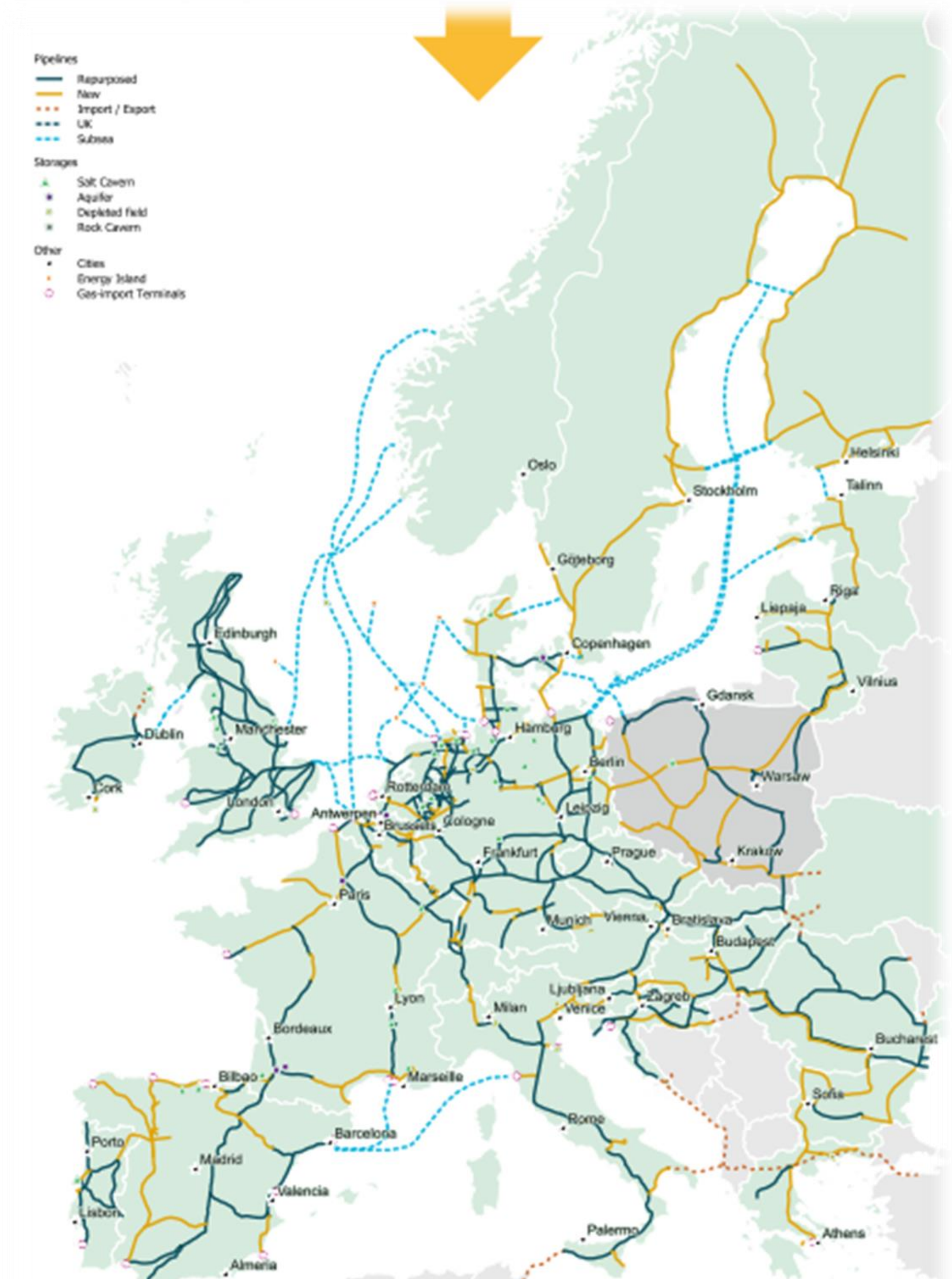
Figures

Figure 1: Decarbonisation of existing natural gas networks: options



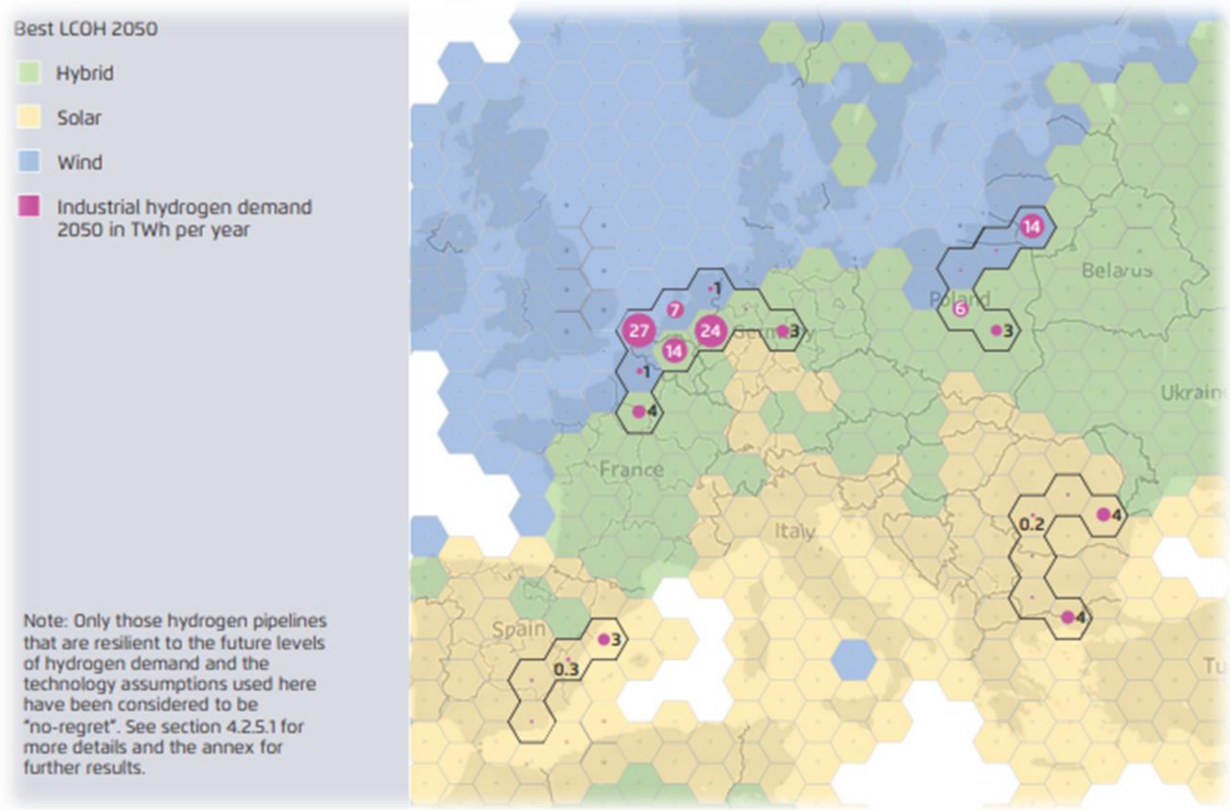
Source: DNV / Trinomics (2022).

Figure 2: EHB Hydrogen Backbone 2040



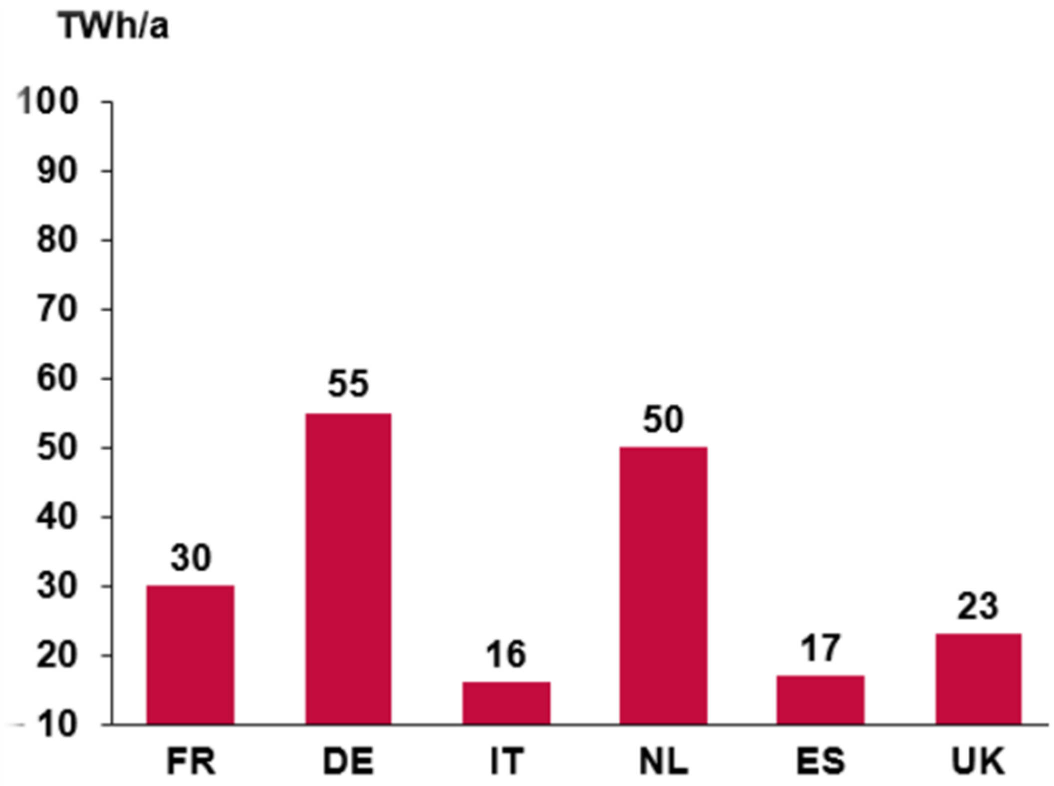
Source: EHB (2023)

Figure 3: No-regret pipeline corridors with industrial hydrogen demand in TWh per year in 2050



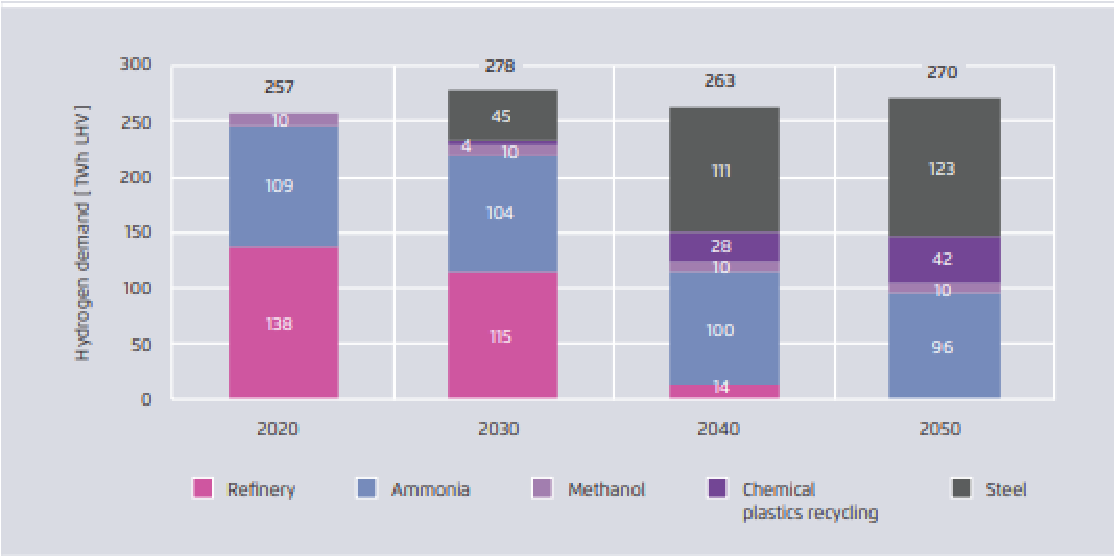
Source: AFRY / Agora Energiewende, No-regret hydrogen

Figure 4: Hydrogen demand by country, 2018



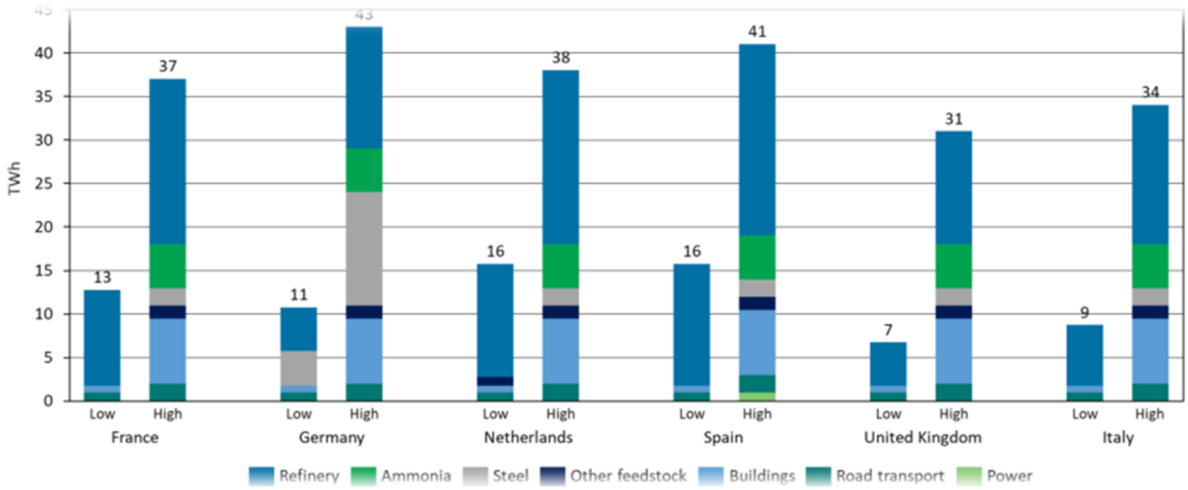
Source: Lambert and Schulte (2021)

Figure 5: Industrial hydrogen demand from 2020 to 2050 within the specific demand sectors, TWh/a



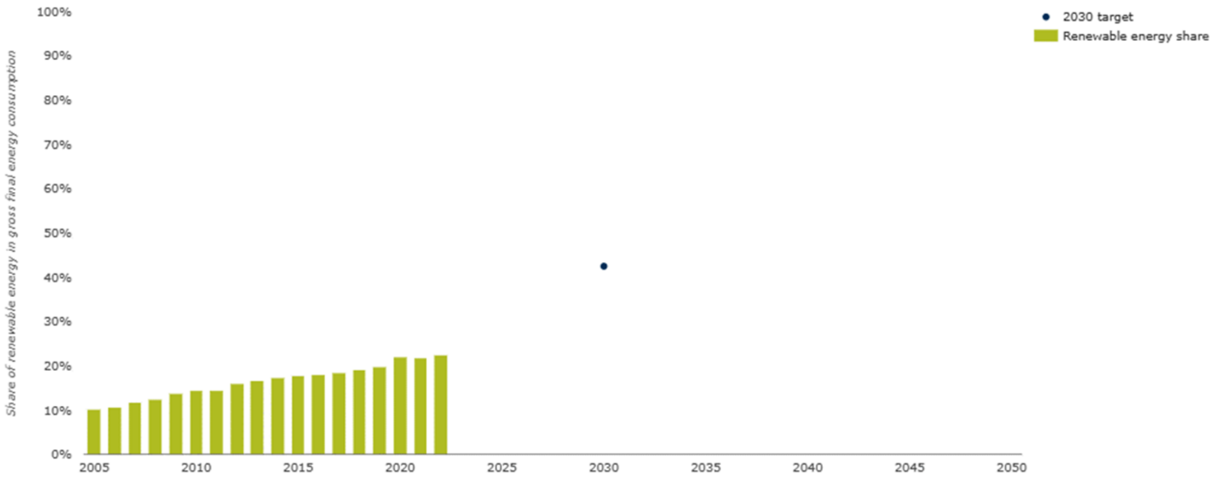
Source: AFRY / Agora Energiewende, No-regret hydrogen

Figure 6: FCH JU low and high scenarios for 2030 (clean) hydrogen demand by sector and country



Source: FCH 2 JU

Figure 7: Share of renewable energy in the EU's gross final energy consumption, %



Source: European Environment Agency, 'Share of energy consumption from renewable sources in Europe', 27 March 2024 (adapted)

Figure 8: Share of renewable energy in European countries, %

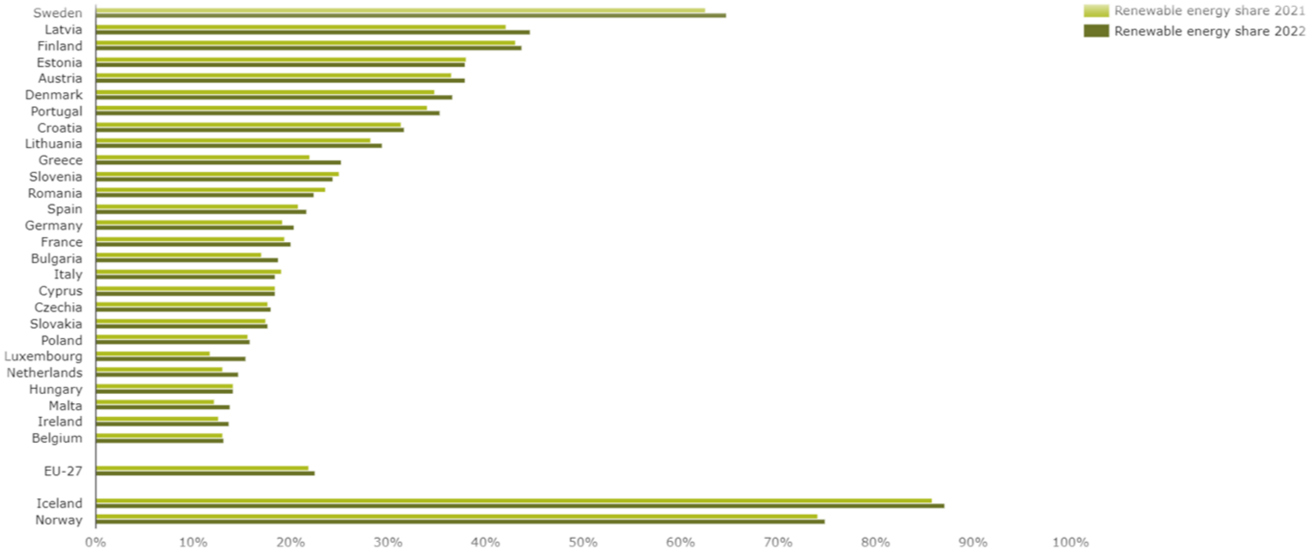


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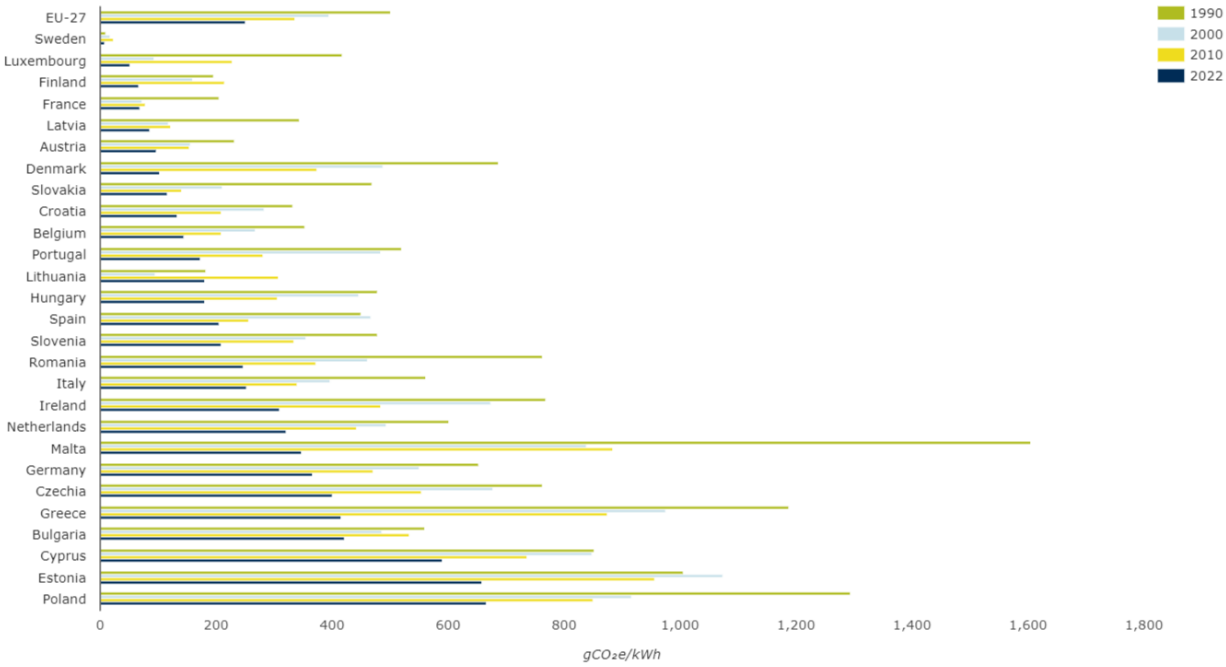
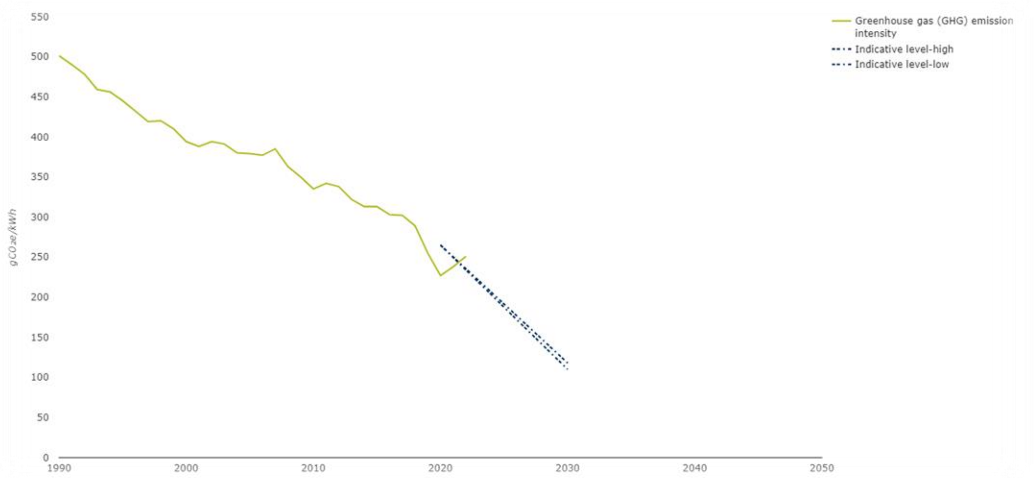
Figure 9: GHG emission intensity of EU electricity generation by country



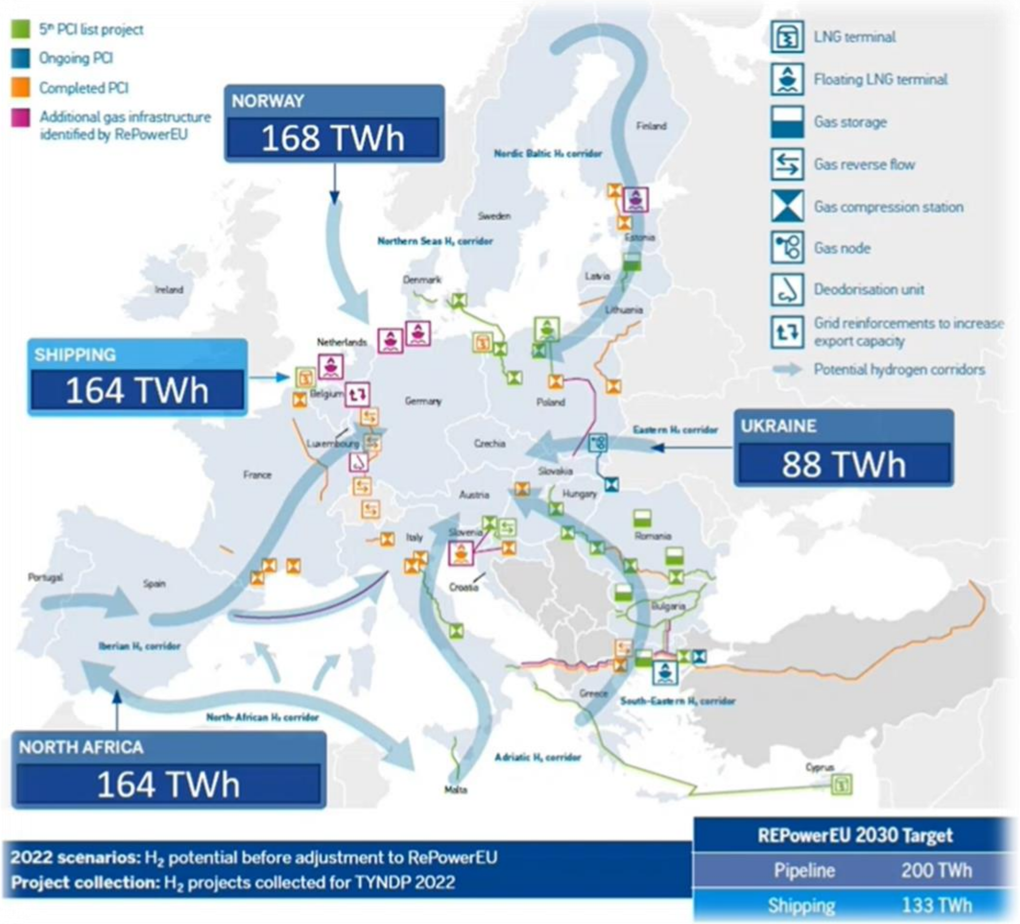
Source: European Environment Agency, 'Greenhous gas emission intensity of electricity generation in Europe', 24 October 2023 (adapted)

Figure 10: GHG emission intensity of EU electricity generation



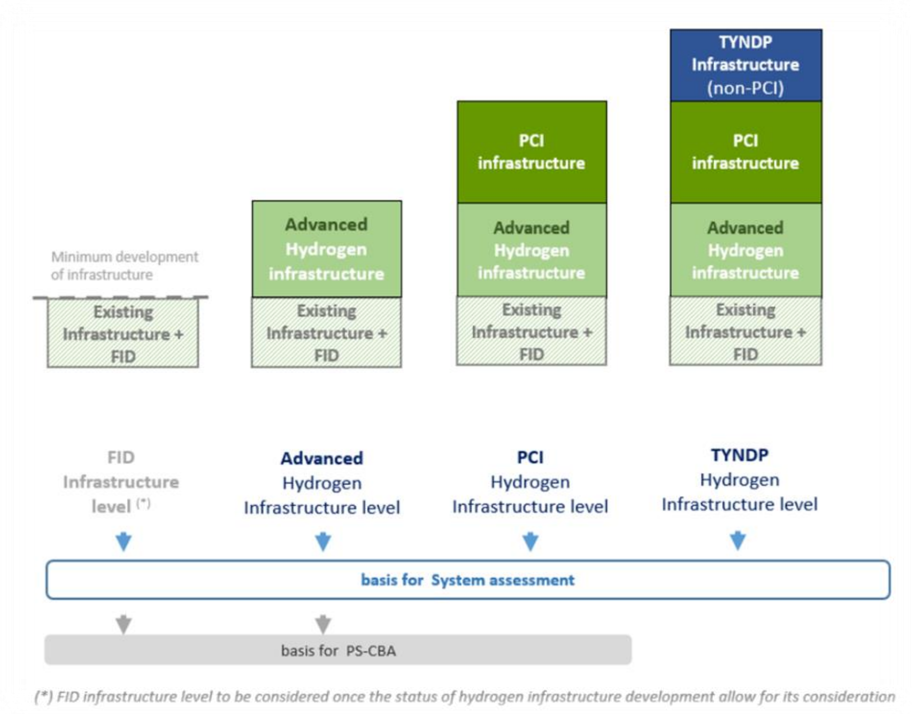
Source: European Environment Agency, 'Greenhous gas emission intensity of electricity generation in Europe', 24 October 2023 (adapted)

Figure 11: EU hydrogen import corridors



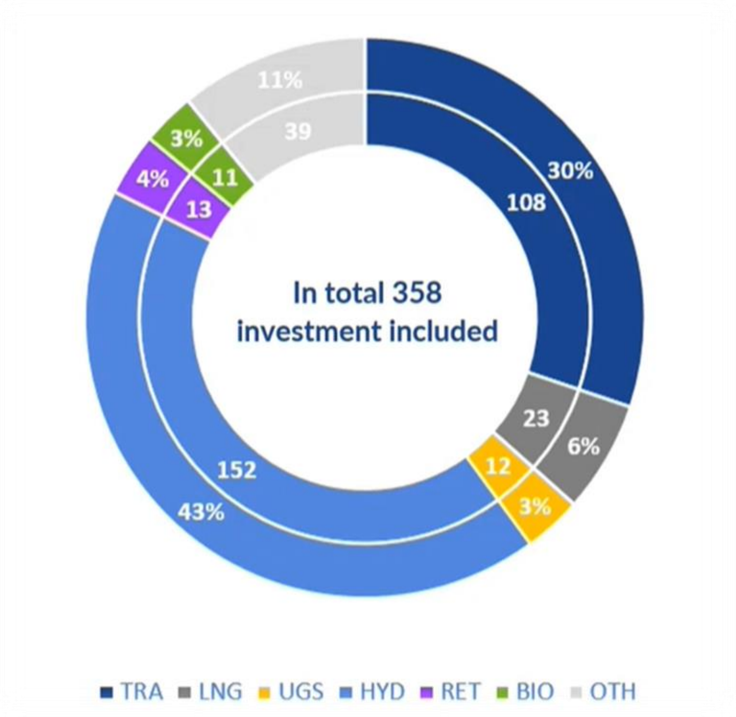
Source: ENTSOG (webinar)

Figure 12: ENTSOG's draft CBA hydrogen infrastructure levels



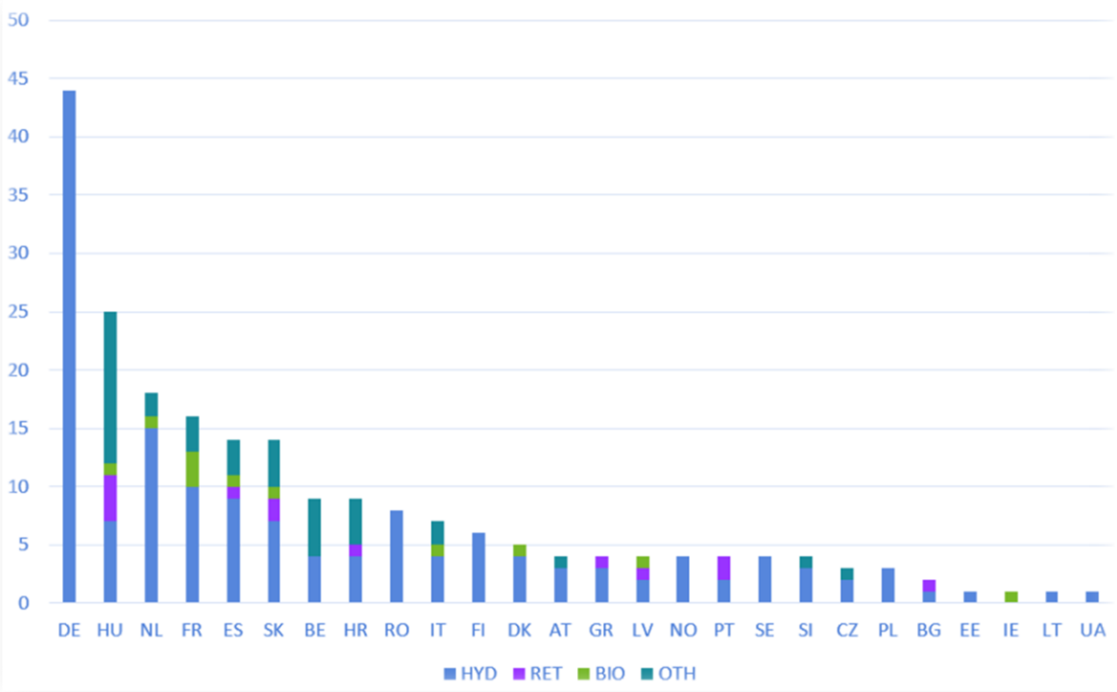
Source: ENTSOG draft CBA methodology, June 2023.

Figure 13: Projects by infrastructure type – TYNDP 2022



Source: ENTSOG TYNDP 2022 workshop, 25 April 2023.

Figure 14: Number of non-natural gas projects per country and type of infrastructure



Source: ENTSOG webinar, TYNDP 2022, 25 April 2023

Figure 15: Consistency of NDPs and draft TYNDP 2022 projects

Country	Included in NDP	Not included NDPs	Total	% of TYNDP projects included in NDPs
Austria	3	3	6	50%
Belgium	4	5	9	44%
Bulgaria	5	2	7	71%
Croatia	11	9	20	55%
Cyprus	0	1	1	0%
Czechia	1	1	2	50%
Denmark	1	5	6	17%
France	2	9	11	18%
Germany	22	23	45	49%
Greece	9	7	16	56%
Hungary	5	17	22	23%
Ireland	0	1	1	0%
Italy	14	2	16	88%
Latvia	0	7	7	0%
Lithuania	2	0	2	100%
Malta	1	0	1	100%
Netherlands	4	15	19	21%
Poland	7	3	10	70%
Portugal	2	0	2	100%
Romania	11	9	20	55%
Slovakia	14	2	16	88%
Slovenia	8	1	9	89%
Spain	1	8	9	11%
Grand Total	130	133	263	49%

Project Type	Included in NDP	Not included NDPs	Total	% of TYNDP projects included in NDPs
Biomethane	4	7	11	36%
Hydrogen	14	70	84	17%
LNG	8	5	13	62%
Retrofitting	5	8	13	38%
Transmission	86	10	96	90%
Underground Storage	8	4	12	67%
Other	5	29	34	15%
Grand Total	130	133	263	49%

Source: ACER (2022b), 'Opinion on the review of gas and H2 NDPs to assess their consistency with the EU TYNDP – charts and maps on selected main findings'.

Figure 16: Potential EU hydrogen supply corridors

Source: EC (2022), REPowerEU Plan, May 2022. NB European map of infrastructure for gas – PCIs and additional projects identified through REPowerEU, including hydrogen corridors.

Annex I

Table A.1 ENTSOG's draft CBA benefit indicators

Indicator	Indicator's purpose	ACER comments / recommendations
B1: societal benefit due to GHG emissions variation	measuring the reduction in GHG emissions resulting from implementing a new project.	methodology is 'partially unclear' in respect of calculation of GHG emissions savings from replacement of alternative fuels in non-power sectors'.
B2: social economic welfare for hydrogen sector	considering the change of total generation costs.	Recommendation to include fuel substitution aspects to allow to identify situations where hydrogen will replace cheaper (as hydrogen could be more expensive) but more polluting fossil fuels.
B3: renewable energy integration	measuring the reduction of renewable generation curtailment and/or the additional amount of RES generation that is connected by the project.	Recommendation to expand its scope to 'capture projects contribution to the integration of low-carbon hydrogen' instead of focusing purely on benefits from reducing curtailed renewable generation or benefits from increasing renewable generation.
B4: societal benefit due to non-GHG emissions variation	measuring the reduction in non-GHG emissions as a result of implementing a new project and considering the change of non-GHG emissions as a result of changing the generation mix of the electricity sector or the supply source used to meet hydrogen demand (including non-GHG emissions savings from replacement of alternative fuels in the industrial, transport and residential sectors).	Call to explain how non-GHG emissions savings are allocated on the basis of which this indicator is calculated.
B5: reduction in exposure to curtailed demand	measuring the reduction on curtailed demand, calculated under climatic stress cases and supply and/or infrastructure disruption cases and covering both hydrogen and natural gas.	As this indicator measured the reduction of curtailed demand under certain stressful scenarios, it could only be considered to cover a security of supply criterion but not a market integration criterion. Call to explain how hydrogen demand in clusters (and hence not connected to the grid) is considered in calculating this indicator.
B6: cross-border impact of hydrogen transmission projects	measuring the cross-border hydrogen capacity increase enabled by the project).	Recommendation to clarify how it allows to 'measure the contribution of projects to supply diversification and to access to indigenous sources of hydrogen supply'.

Source: ENTSOG's draft CBA methodology.

Annex II

Table A.2 NRA competence over hydrogen infrastructure

Country	Description of NRA competence / responsibility
DE	H2 networks are not generally regulated. However, according to the national law the network operators may choose to be subject to regulation by declaration towards the NRA (opt-in declaration). In case that the legal requirements are fulfilled, the NRA determines that the network of a certain operator is subject to regulation. The NRA competence covers unbundling, network connection and access, cost regulation, needs examination and network development. Once a H2 network operator is subject to regulation, its existing and any future infrastructure will be subject to a needs assessment. The focus is on the use of the infrastructure, i.e., on the connection petitioners, possible feed-in and feed-out. Only the hydrogen grid requirements are checked. An evaluation of investment does not take place. These plans also have no binding character. Concerning hydrogen storage facilities, operators of hydrogen storage facilities may declare to the NRA that the relevant provisions shall apply mutatis mutandis to access to their hydrogen storage facilities. Regulated hydrogen network operators are granted a fixed return on equity of 9% pre-tax until 31.12.2027 on their operationally necessary equity. Regulated hydrogen network operators can apply a specific (individual) asset life as regarded suitable when calculating the depreciation.
LT	NRA might approve hydrogen projects only if they are implemented by regulated company and is classified as innovation (sandbox) projects. Moreover, only 50% of CAPEX might be included into regulated prices and the other 50% should be covered by the company. Currently, there are no H2 investments.
MT	The NRA has the duty to regulate, monitor and keep under review all practices, operations and activities relating to energy services and resources in Malta, and it has also the duty to evaluate investments requests and grant licence, permit or other authorisation. No specific regulatory framework in place for hydrogen projects.
PT	The NRA has a non-binding competence on the evaluation of investments in hydrogen projects for the purpose of inclusion in the Union List of PCIs. The Portuguese Government has the binding decision. Once a project is approved by the Government, the NRA considers its cost for the tariff calculation process. Rate of Return regulation for CAPEX and Price Cap regulation for OPEX (4-year regulatory period). Currently, there are no hydrogen investments.
RO	The NRA approves the regulated tariffs and their methodologies for the transmission system operator, the distribution system operator and the hydrogen terminal operator.[44]

Source: ACER Report on investment evaluation, risk assessment and regulatory incentives for energy network projects, June 2023

Table A.3 Treatment of hydrogen infrastructure in each national regulatory framework (in countries with no NRA competence over hydrogen infrastructure)

Country	Description of treatment of H2 infrastructure
AT	• The NRA is not responsible for regulating the H2 infrastructure. • The legal basis is not yet established, but the discussions on principles started.
BE	• H2 investments (transmission, terminal, storage) currently non-regulated activities but a national legislative work is underway to provide a legal framework for H2 market, system development and role to the NRA.
BG	• No NRA competence was reported
CZ	• The NRA is not responsible for regulating the H2 infrastructure. • Implementation of H2 in the national legislation by the Ministry of Industry and Trade is ongoing.
EE	• No NRA competence was reported
HR	• "Croatian Strategy for H2 until year 2050" foresees H2 as a new energy carrier in the transport sector and to build an adequate infrastructure for the production, distribution and supply of hydrogen. • NRA has no competence yet regarding H2 infrastructure. Legislative work will be commenced.
FI	• H2 infrastructure is not existing in Finland. • There is no specific national regulation on H2 or NRA role on the matter.
FR	• There is currently no legal ground for the competence of the NRA (CRE) on H2 infrastructure.
GR	• H2 projects do not fall under the competence of the NRA for the time being, given the fact that the Greek Law has no provisions for renewable gases such as Hydrogen yet[45].
HU	• The NRA is not responsible for regulating the H2 infrastructure.
IT	• The NRA is not responsible for regulating the H2 infrastructure.
LV	• The NRA is not responsible for regulating the H2 infrastructure. • There is no H2 regulation yet.
NL	• The NRA is not responsible for regulating the H2 infrastructure.
PL	• The regulatory framework for hydrogen infrastructure projects is still under establishment, and the role of the NRA is not defined yet
SK	• NRA with competence to set up: Method to set up simulation of the regulated entity´s approved investment in assets used for (among others): connecting gas producers and their equipment using hydrogen technologies, conversion of gas infrastructure to use gases from carbon-free sources, for example H2, biomethane. • Regulatory framework is not defined for CAPEX, Rate-of-return and Revenue Cap regulation for OPEX (5 year-regulatory period); • Regulatory incentives are case by case, with applying the method defined under the regulatory period; • Link to investment and risk evaluation methodology[46]
SI	• A relevant legislation have not yet been adopted, so the NRA does not have the power to regulate hydrogen infrastructure.
ES	• The NRA is not responsible for regulating the H2 infrastructure. • Ministry of Ecological Transition and Demographic Challenge has certain responsibilities on H2.
SE	• The NRA is not responsible for regulating the H2 infrastructure. • There is no specific national regulation on H2.

Source: ACER Report on investment evaluation, risk assessment and regulatory incentives for energy network projects, June 2023