Sector integration – Regulatory framework for hydrogen

Final Report

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EXECUTIVE SUMMARY

The main objective of this study is to develop and assess options for a potential EU regulatory framework for dedicated hydrogen networks and markets. The study provides inputs to pro-actively develop EU regulation that anticipates a significant development of dedicated hydrogen pipeline infrastructure to facilitate large-scale production and use of renewable and/or low-carbon hydrogen in the EU.

Prototype pathways for hydrogen gas infrastructure

In chapter 1, four generic pathways have been developed to describe the potential introduction of renewable and low-carbon hydrogen into the different national (or regional) energy systems in the EU to fulfil the 2050 decarbonisation policy targets. They comprise pathways starting from either a low or high RES-potential and a modestly- or well-established natural gas grid.

The exercise to identify and analyse potential generic development pathways clearly results in the learning that an EU-wide harmonised regulatory approach would enable EU Member States to benefit from higher techno-economic benefits (economies of scale) and infrastructural synergies (cross-border hydrogen exchange) and hence from improved efficiencies and significant cost reductions, compared to a scenario with uncoordinated and hence possibly diverging national regulatory approaches.

Non-exhaustive arguments for an EU hydrogen regulatory framework are:

- **Hydrogen production base:** Member States with significant renewable electricity generation potential could aim to substitute their natural gas use by renewable electricity-based hydrogen and even become net exporters, and consequently have an interest in repurposing their methane networks which would otherwise be decommissioned. This could help to efficiently facilitate the upscaling of hydrogen as an energy carrier in Member States with hydrogen-intensive energy strategies, which would in turn contribute to fulfil some of EC's most important energy and climate policy goals (climate change mitigation, reducing energy import dependency and improve energy efficiency).
- **Hydrogen quality definition:** An EU-wide hydrogen quality harmonisation may facilitate the development of hydrogen end-use equipment and appliances at larger production scales as well as foster the integration of the EU hydrogen market, helping to align national hydrogen pathways.
- **Hydrogen-blending level:** Shared learning as well as an exchange on and testing of concepts will foster a rapid EU-wide implementation of blending hydrogen into the natural gas grid, which is an adequate option to facilitate the deployment of hydrogen. Several EU Member States are already taking initiatives to this end. As far as observed, all concerned grid operators have indicated their willingness for cooperation and EU-wide harmonisation.
- **Conversion of existing methane networks to hydrogen or new-build:** Early analysis has shown that the conversion of existing methane infrastructure to hydrogen operation is significantly cheaper than new-build hydrogen pipelines. Common material standards and operating routines will support conversion activities across the EU. If deemed necessary, this will also help to develop well-defined interfaces to import renewable or low-carbon hydrogen through pipelines from outside of Europe.
- **Today's hydrogen gas pipeline business:** An early European regulatory framework could consider the long-term supply contracts and network assets of existing private hydrogen operators and, at the same time, build on the existing infrastructure to develop the wider energy system use of hydrogen in a stepwise manner.

Pipelines as a natural monopoly?

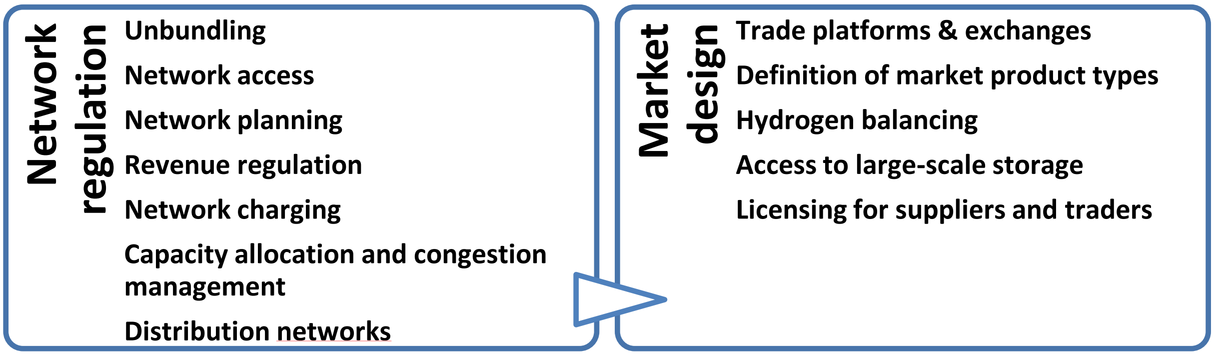
Chapter 2 analyses whether and to what extent dedicated hydrogen networks give rise to a natural monopoly justifying regulatory intervention. Although the hydrogen market development is in very early stages, there are strong indications that hydrogen transmission and distribution networks may constitute a natural monopoly in mature hydrogen markets, where hydrogen becomes or is close to becoming a traded commodity. This would coincide with phase 2 (2025-2030), and more broadly phase 3 (2030 towards 2050) defined in the European Commission's Hydrogen Strategy. Also, in emerging markets, there is a relevant probability of natural monopolies to occur due to the sub-additive investment cost curves of pipelines, and the fact that repurposing methane pipelines to hydrogen will be less expensive than new-build and will hence provide a competitive advantage to the concerned owners/operators.

The views of stakeholders diverge on the exact circumstances and the adequate timing for regulatory intervention with some stakeholders supporting rather early regulatory intervention,

while others prefer late actions. A view voiced rather widely is to apply market tests, and to actively develop regulatory approaches step by step. Starting early with thorough tests and validations accompanied by scientific evaluation support is a robust no-regret approach before implementing any regulation.

Regulatory elements for dedicated hydrogen networks and markets

Chapters 3 and 4 develop a number of options for the different network regulation and market design elements shown in the figure below. The options developed for each regulatory element are either based on the EU natural gas regulatory framework or are developed as a 'greenfield' approach. While an analysis per regulatory element facilitates the development of the options, any EU regulatory framework for hydrogen must be developed and assessed holistically, given the interdependencies between the different regulatory elements. This global analysis is extensively presented in chapter 5 of this study.



Development and assessment of EU hydrogen regulatory framework options

Hydrogen is poised to play an important role in the EU energy transition, as indicated by the EU Hydrogen Strategy, the impact assessment for the 2030 Climate Target Plan, and the Long-term Strategy.

To facilitate the large-scale development of the hydrogen sector according to the pathways identified in chapter 1, adequate policies will be necessary to enable the deployment of hydrogen production, trade, supply, transmission/distribution, storage, as well as of end-use equipment and appliances at the pace required for the energy transition. Given the current absence of economic regulation of the hydrogen sector at the EU and Member State level, this study contributes to determining the appropriate level of EU regulation to facilitate the optimal development of hydrogen infrastructure and markets.

The analysis of chapter 2 indicates that several factors may justify some level of hydrogen sector regulation, including the sub-additive investment costs of hydrogen network assets leading to the need to ensure non-discriminatory third party access to networks (and to large-scale storage), the societal benefits of integrated network planning, and the potential cost savings resulting from repurposing methane infrastructure to hydrogen compared to new-build.

Both regulated and market actors of the EU energy sector highlighted the need for regulatory certainty at both the EU and national levels. EU regulatory action for hydrogen can be based on article 194 of the Treaty on the Functioning of the EU (TFEU), which is also the basis for the EU regulatory framework for electricity and natural gas.

By providing a level playing field for all market participants and technologies across the EU, adequate EU action can provide regulatory certainty, promote integrated network planning and operation of the energy system, facilitate the integration of the future hydrogen market, and minimise the risks of distortion to the overall EU internal energy market. EU action should employ the best practices and lessons learned from the experience in the natural gas and electricity sectors, and also leverage existing EU-level organisations and institutions where appropriate.

The design of a new EU regulatory framework for hydrogen needs to be robust (i.e. perform adequately in any foreseeable transition pathway) and properly take into account the high uncertainty level at this stage, the overall incipient stage of development of hydrogen infrastructure and markets, and the different development speeds across end-use sectors and Member States. Moreover, any hydrogen regulation should be aligned with other developments in energy regulation, particularly regarding the promotion of electricity and gas systems integration, the use of incentive-based network regulation, and the simultaneous provision of regulatory stability and flexibility.

The EU regulatory framework for natural gas has been introduced when the EU gas sector had already developed for several decades, which constrained regulatory options. The future hydrogen sector regulation is comparatively less constrained and must take a number of specific points into account. Repurposing methane infrastructure to hydrogen will facilitate the development of large segments of the future hydrogen networks, which will in particular support hydrogen-intensive scenarios. Hence, there is a significant potential role for methane network operators, but also for existing private hydrogen operators given their relevant assets and expertise. Moreover, trading hydrogen via organised market platforms and exchanges for methane gases can accelerate the development of a well-functioning, liquid hydrogen market. Finally, existing long-term supply contracts and network assets of private hydrogen network operators should properly be considered when implementing a regulatory framework.

The EU regulatory framework options assessed in this study and summarised in the table below range from a *de minimis* intervention to avoid distortions of the internal energy market (the 'EU light' option), to a regulatory framework similar to that for natural gas (the 'Full EU' option), and finally an ambitious regulatory framework further advancing the integration of the internal energy market (the 'Full+ EU' option). Competition *for-the-market* (i.e. tendering hydrogen network concessions) could be used to introduce a competitive element and complement the regulation of hydrogen networks.

There is still strong uncertainty regarding the energy transition pathways, but given the ambitious EU climate and energy targets, competition and energy sector-specific regulation at EU level should accommodate pathways where renewable and low-carbon hydrogen play an increasing role, while also respecting the right of Member States to pursue other decarbonisation pathways.

The Full/Full+ EU options provide, from the start, an adequate regulatory framework for the timely development of an internal hydrogen market, supported by dedicated infrastructure accessible to all network users and coordinated with the electricity, methane, and heat sectors. These options also provide sufficient flexibility through transitional rules and a Hydrogen Target Model for the development of local hydrogen clusters or valleys and allow Member States to develop economies of scale and of scope with the methane sector, while also ensuring a level-playing field and respecting existing long-term hydrogen supply contracts and network assets. By being compatible with the long-term policy targets and providing flexibility to Member States, they minimise the ex-post regulatory costs and provide regulatory certainty.

By fostering integrated network planning and market coupling especially, the Full+ EU regulation would provide an improved level playing field for hydrogen market participants across Europe. However, harnessing the full benefits of the option implies addressing existing differences in the regulatory provisions and structure of the electricity and methane sectors.

Chapter 5 provides a detailed assessment of the options, including the robustness to the pathways and a roadmap for implementation. Whichever regulatory approach is ultimately opted for, a number of key principles should be respected to enable the hydrogen sector to efficiently contribute to reaching the major EU and national energy and climate objectives:

- Non-discriminatory third-party access to hydrogen networks (and large-scale storage) should be guaranteed for all market operators, with only limited and duly justified exemptions;
- Network planning should be integrated across market areas, energy carriers, and network levels, with strong EU and national regulatory oversight and public consultation. It should also be aligned to policy objectives. The risk for stranded assets should be minimised, not only when considering conversion of existing methane infrastructure to hydrogen, but also when considering new investment in fossil gas or fossil-based hydrogen infrastructure. Given the EU decarbonisation targets and the pathways uncertainty, it is necessary to carefully assess the needs for fossil gas-based infrastructure and to apply adequate sustainability requirements to new energy infrastructure investments;
- Member States should be allowed to realise efficiency gains and economies of scope through combined natural gas and hydrogen network operators. But this should not compromise transparency and cost-reflectiveness of grid tariffs;
- The regulatory framework should provide flexibility through transitional measures such as exemption procedures to isolated hydrogen clusters. A Hydrogen Target Model could be defined in order to guide Member States in developing regulation which is aligned with the EU framework and does not hamper the later interconnection of their hydrogen system.

Overview of regulatory framework options assessed

<table>
<tr><th></th><th>No immediate EU action</th><th>Light EU regulation</th><th>Full EU regulation</th><th>Full+ EU regulation</th></tr>
<tr><td>Role of gas TSOs</td><td rowspan="10">Not regulated at EU level</td><td colspan="2">Common operation of methane and hydrogen networks authorised by EU law</td><td>+ EU-level H_2 TSO</td></tr>
<tr><td>Horizontal unbundling from regulated CH_4 infra</td><td colspan="2">Accounts</td><td>Accounts
Variant: legal + functional</td></tr>
<tr><td>Role of private hydrogen networks</td><td>Exemption from unbundling, rTPA, rTariffs for specific cases</td><td colspan="2">Legal unbundling, rTPA and rTariffs
Exemptions requires a market test / sunset clause</td></tr>
<tr><td>TSO network TPA rules</td><td>rTPA / nTPA choice</td><td colspan="2">Regulated TPA</td></tr>
<tr><td>Network tariffication</td><td rowspan="4">No H_2 specific EU regulation</td><td>Harmonised principles and tariff structures</td><td>Market coupling + Harmonised principles and tariff structures</td></tr>
<tr><td>Planning</td><td>ENTSO-H_2
Requirements for national planning</td><td>With EU TSO organisation
Requirements for national planning</td></tr>
<tr><td>CACM</td><td>Rules for cross-market area CACM</td><td>Market coupling
Rules for cross-border and domestic CACM</td></tr>
<tr><td>Balancing</td><td>Individual balancing responsibility for market players
Residual balancing by TSOs
National/multinational balancing zones</td><td>Individual balancing responsibility for market players
Residual balancing by EU TSO
EU balancing zone</td></tr>
<tr><td>Access to storage</td><td colspan="2">rTPA / nTPA choice</td><td>Regulated TPA</td></tr>
<tr><td>Organised market platforms or exchanges</td><td>No H_2 specific EU regulation</td><td>Harmonised market rules
REMIT scope includes hydrogen</td><td>+ market area managers</td></tr>
</table>

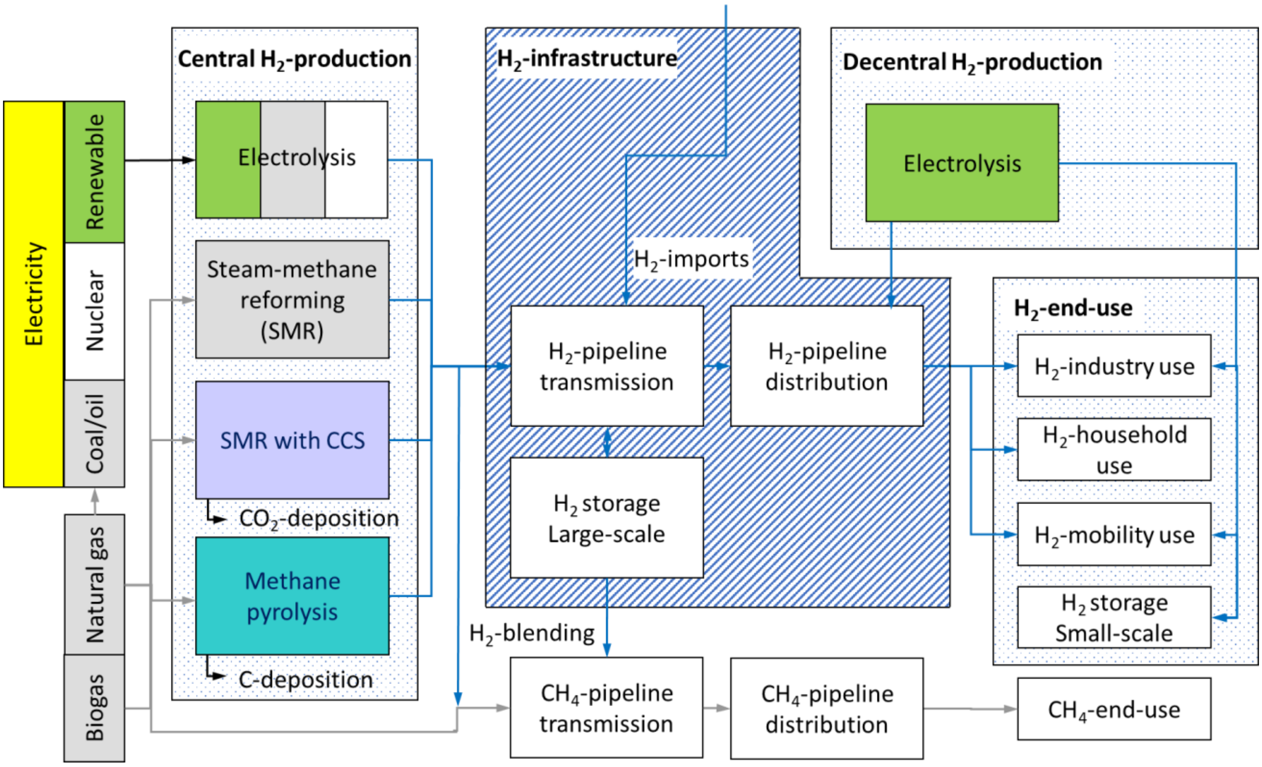
1 PROTOTYPE PATHWAYS FOR HYDROGEN GAS INFRASTRUCTURE

1.1 Approach

To draw up four representative generic pathways that may give rise to the development of a dedicated hydrogen network within the EU, the European hydrogen strategy along with the plans of individual Member States have been assessed. Several plans and strategies have been emerging in the recent past.[1] During the course of the study five national strategies have been published (NL, DE, PT, ES, FR + NO) alongside the European Hydrogen Strategy (July 2020) and further ones are expected in the near future (AU, PO, IT).

In view of a future European hydrogen gas infrastructure[2] the specific focus of this analysis is on hydrogen pipeline infrastructure and seasonal hydrogen storage development. In addition, hydrogen gas strategies developed by national authorities, industry, or associations have been considered. The assessment is based on both desk research and interviews with stakeholders from the gas infrastructure business in various EU Member States. Finally, during the course of work for this study two European key documents have been published[3] to which we have aligned our report in a final adjustment run.

Figure 1-1 Hydrogen gas infrastructure specific assets from well-to-end-use



[1] International Hydrogen Strategies. A study by Ludwig-Bölkow-Systemtechnik (LBST) commissioned by and in cooperation with the World Energy Council Germany, September 2020, https://www.weltenergierat.de/international-hydrogen-strategies/.

[2] Different from the project for the Fuel Cell and Hydrogen Joint Undertaking (FCH JU) [Study on opportunities arising from the inclusion of Hydrogen Energy Technologies in the National Energy & Climate Plans. Study by Trinomics and LBST for FCH-JU, final report, August 2020], the focus of this assessment is on specific national strategies related to hydrogen gas infrastructure. In this respect, Germany has revealed its gas infrastructure ambitions in a consultation process. Other Member States have included specific hydrogen gas infrastructure aspects as part of their national hydrogen strategies or will do so in the near future, such as the Netherlands, Portugal, Spain and Italy.

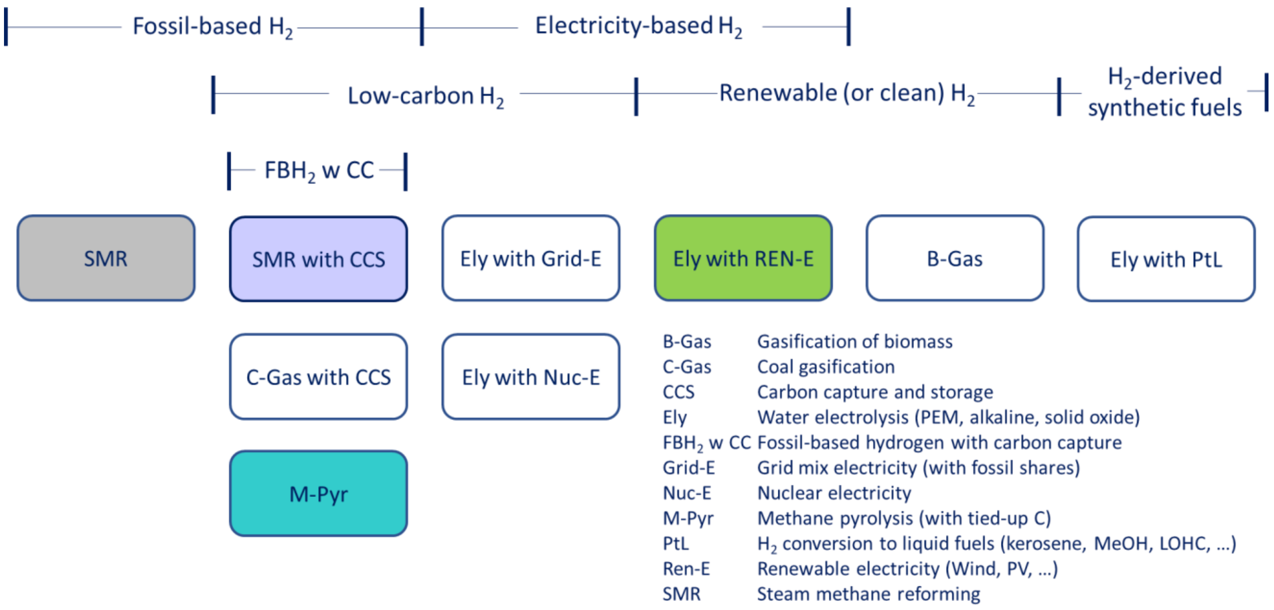
[3] [COM(2020) 301 final]: Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: A hydrogen strategy for a climate-neutral Europe, Brussels, 8th June 2020, https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1594897267722&uri=CELEX%3A52020DC0301 and European Hydrogen Backbone – How a dedicated hydrogen infrastructure can be created. Study report by Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas and Teréga, July 2020, https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone.

In order to structure this approach, relevant and major hydrogen infrastructure assets from well-to-end-use have been defined as presented in Figure 1-1. The dashed box indicates the general scope of this study, the dotted boxes indicate the additional assets considered in this chapter. The relevant technologies (= assets) will become major building blocks of the Member State strategies, covering both central and decentral domestic hydrogen production schemes as well as hydrogen trade across the EU and imports from outside the EU. Other technologies such as hydrogen production by gasification from biogas or from coal, or by other production technologies exist, but have been left out intentionally for the sake of simplicity. The different types of hydrogen have been defined by the European Hydrogen Strategy [COM(2020) 301 final] as 'electricity-based hydrogen', 'renewable or clean hydrogen', 'fossil based hydrogen', 'fossil-based hydrogen with carbon capture', 'low-carbon hydrogen' and 'hydrogen-derived synthetic fuels'. In other strategies a colour coding has been applied to define hydrogen produced from different energy feeds:

- **Grey:** by water electrolysis using an electricity mix[4], including renewable electricity, but also coal, mineral oil, natural gas and nuclear energy, and by steam reforming of natural gas (SMR)[5], partial oxidation of mineral oil (POX) or coal gasification,
- **Green:** by water electrolysis using renewable (i.e. CO_2-free) electricity,
- **Blue:** by steam methane reforming of natural gas (SMR) combined with carbon capture and storage (CCS) (i.e. fossil-based and CO_2-reduced emissions)[6] and
- **Turquoise** by pyrolysis of fossil methane with the by-product carbon deposited or secured against release to the atmosphere as CO_2 any later time (i.e. fossil-based and CO_2-reduced emissions).

The relation of the different definitions is presented in Figure 1-2, headlines representing the European definition. It should however be noted that sometimes additional hydrogen 'colours' are used such as pink for hydrogen produced from nuclear electricity. Also, some sources suggest to also define hydrogen from biomass gasification as green hydrogen. Instead we here have kept to the strictest definition which has e.g. also been suggested by the German Federal Ministry of Education and Research[7].

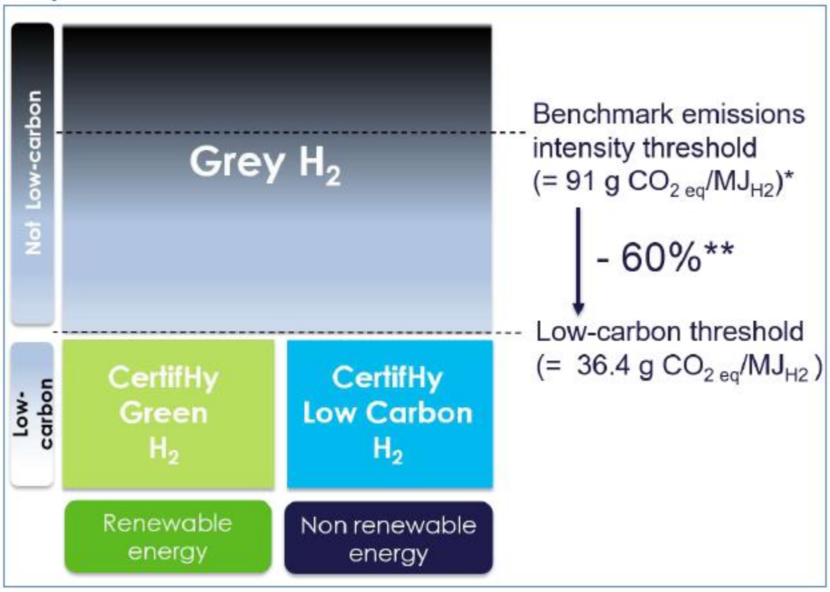
Figure 1-2 Relation of different hydrogen definitions



[4] At growing renewable electricity shares this hydrogen may eventually become "green" depending on the effective share of RES-E in the electricity mix.
[5] The by far highest share of today's hydrogen use is produced by steam methane reforming of natural gas.
[6] Blue hydrogen is strictly speaking no zero-carbon technology, as it comprises residual CO_2-emissions along the energy chain. There is an ongoing debate on the potential sources and means/costs to reduce these CO_2-emissions to a minimum. A wide range of residual CO_2-emissions of less than 10% (without NG provision, study for the UK by G. Allard Reigstad, P. Coussy, J. Straus, Ch. Bordin, St. Jaehnert, S.Ø. Størset, B. Ruff: Hydrogen for Europe Final report of the pre-study, August 2019) and up to 36% (new ATR-based processes according to St. Bukold: Kurzstudie – Blauer Wasserstoff – Perspektiven und Grenzen eines neuen Technologiepfades, study for Greenpeace Germany, January 2020) have been reported by literature for different assumptions, pathways, and cases/locations.
[7] See https://www.bmbf.de/de/eine-kleine-wasserstoff-farbenlehre-10879.html.

In an attempt to avoid ambiguity, the European harmonisation approach for hydrogen certification CertifHy has suggested a differentiation by defining the specific CO_2-emission levels more explicitly as shown in Figure 1-3[8].

Figure 1-3 Differentiation and colour coding for hydrogen from various sources using allowed CO_2-emission levels

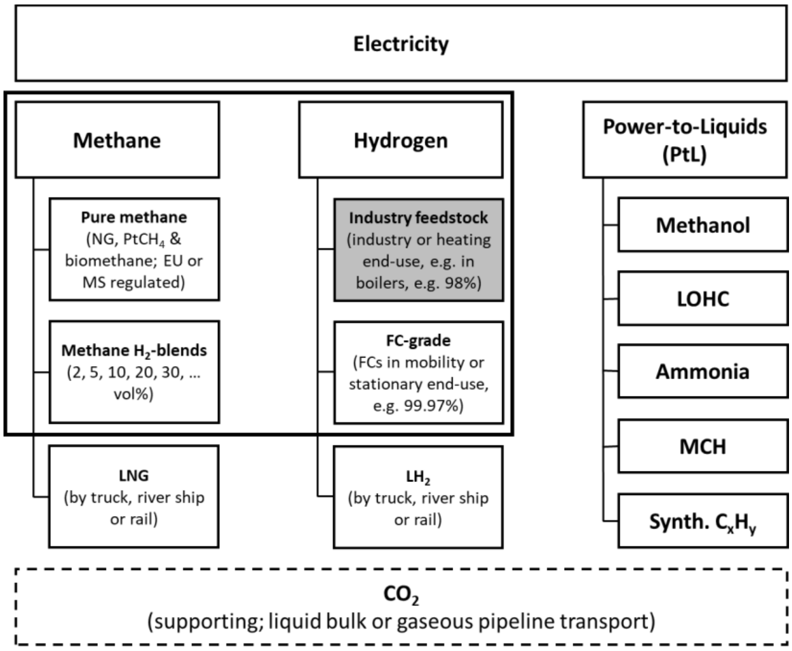


In the CertifHy classification, turquoise hydrogen from methane pyrolysis is not explicitly mentioned but instead part of the (blue) low carbon hydrogen from non-renewable energy. Also, according to this definition, hydrogen produced at a CO_2-emission level of above 91 g_{CO2}/MJ_{H2} is dubbed "grey", which is the current CO_2-reference level from conventional steam reforming of natural gas, i.e. also defined as "not low-carbon" hydrogen. Also, "blue" and "green" hydrogen belong to the same "low-carbon" hydrogen class as they are connected with CO_2-emissions equal or below today's grey carbon emissions by -60%, or with a specific CO_2-emission factor of below 36.4 g_{CO2}/MJ_{H2}.

Figure 1-1 is centred around the development of the future European "Green Gas Grid". This means that other energy carriers, including liquid hydrogen have not been considered. Also, as a third dimension, hydrogen can have different qualities, i.e. highly pure hydrogen as e.g. required by fuel cells for mobility or stationary applications and hydrogen for industrial end use requiring less purity. For completeness sake, Figure 1-4 summarises the potentially relevant energy infrastructures in a renewable based energy system. In addition, the box with the broken line shows the "supporting" gas or liquid CO_2 infrastructure to dispose of CO_2 in CCS schemes (blue hydrogen). Furthermore, the public energy infrastructures relevant for gas transmission and distribution are framed by the bold box, and the shaded box represents the existing hydrogen pipelines operated by industrial gases companies. The issue of hydrogen quality is further discussed in chapter 1.3.3, section "Blended hydrogen users or pure hydrogen users".

[8] RED II in Article 25 requires hydrogen (or more generally RFNBOs) to have a GHG saving of "at least 70 % from 1 January 2021". However, this does not apply to Guarantees of Origin, which are governed by RED II Article 19. Furthermore, the provision in art. 25 does not specify the applicable fossil fuel comparator. CertifHy has communicated that it would adjust the criteria for the two categories (renewable or low-carbon hydrogen) when the applicable fossil fuel comparator is defined as also this value has to be adjusted in CertifHy in order to have an operational definition of the GHG threshold compatible with RED II. Furthermore, CertifHy intends to enlarge its current scope from Guarantees of Origin (governed by art. 19) to also include supply certification demonstrating compliance with the provisions of RED II Art. 25-30 related to contributions to the renewable energy in the transport target for 2030.

Figure 1-4 Large-scale energy infrastructures in an energy system dominated by renewable energies (CO_2 for CCS)



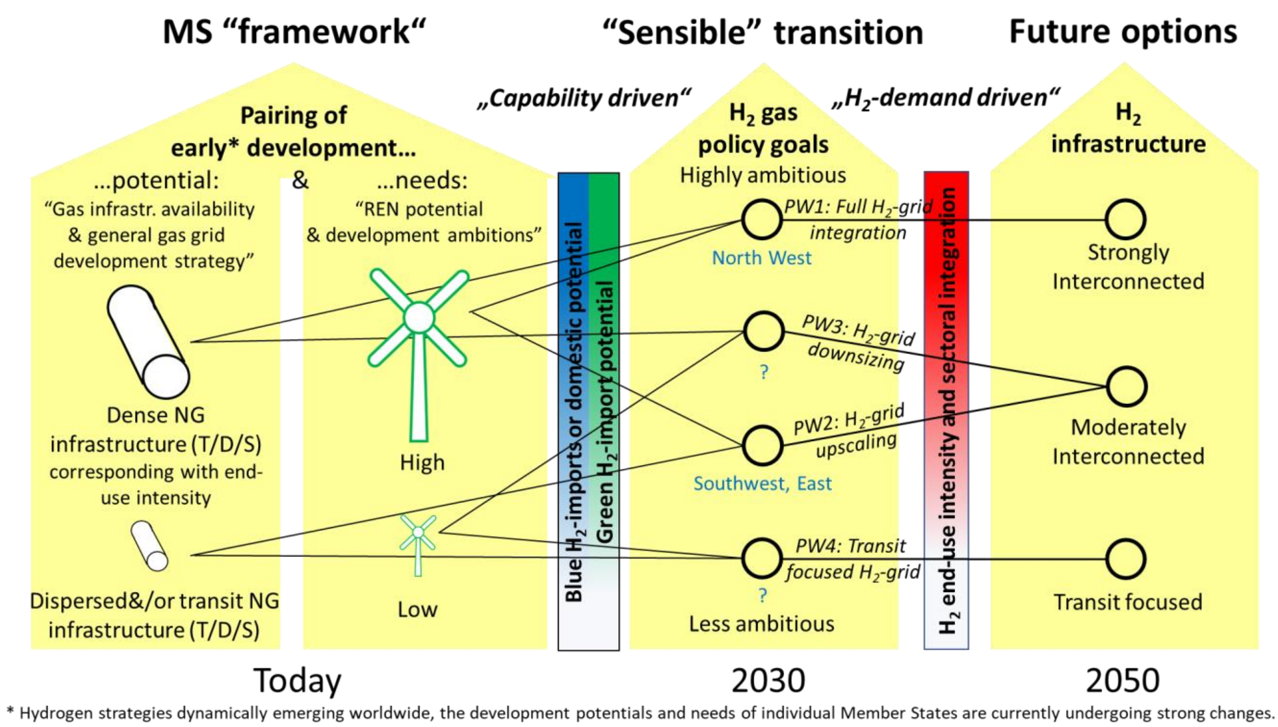
In chapter 2.2, four generic development pathways from today through the transition year 2030[9] to 2050 are defined. In chapter 2.3, the asset-specific considerations are assessed. They address the most relevant hydrogen value chains, from H_2-production to H_2 infrastructure (transmission, distribution, and seasonal storage) and finally H_2-end-use in more detail, also considering their potential impact on the four defined generic pathways. Concluding the pathway considerations, chapter 2.4 highlights the concept of hydrogen imports through existing large-scale gas infrastructures and how they compare to alternative energy carriers import options.

1.2 Hydrogen gas infrastructure development pathways towards 2050

A set of four generic development pathways for integrating hydrogen into the gas infrastructure at large scale are depicted in the scheme presented in Figure 1-5, together with the underlying basic assumptions. The generic pathways have been developed to characterise strategic differences of individual EU Member States or Member State regions and to support the development of a regulatory framework for a future European hydrogen gas transmission infrastructure.

[9] 2030 has been chosen as transition year as it is in focus of many national hydrogen strategies.

Figure 1-5 Tentative generic hydrogen gas infrastructure pathways and their coherence



The definition of the four generic pathways tries to frame the possible general developments of a Member State's transmission and distribution gas infrastructure until 2050 as follows:

- **Pathway 1 (PW1) – Full H_2-grid integration:** This pathway could be typical for Member States with a well-developed gas infrastructure today[10] and understanding its current and future role to support the electricity system in its task to balance fluctuating renewable electricity loads as well as sustaining its economic value. PW1 foresees a continued use of the existing gas infrastructure or even a further build-out by capacity (gas to replace liquid energy carriers) and/or by regional extension (potential relocation of provision-to-demand relations) with a gradual but accelerating shift from fossil (or bio-) methane to green hydrogen by 2050. This pathway typically coincides with the full exploitation of hydrogen as energy vector in all end-use sectors. Therefore, sectoral integration applying hydrogen becomes a key target.
- **Pathway 2 (PW2) – H_2 grid upscaling:** Based on a limitedly developed natural gas infrastructure today but a high potential and/or ambition to utilise the available renewable electricity resources, some Member States may consider to reinforce their gas grid. This decision is typically based on the necessity to adapt the energy system to the renewable electricity load balancing needs and the appreciation of making use of the improving economics of green (and in the transition phase also blue) hydrogen serving multiple end-use sectors from one common infrastructure. Poland can serve as an example for PW2. According to representatives from the gas industry, Poland plans to reinforce its gas grid extending its current transmission focus to gradually replace coal by CO_2-lean or CO_2-free gas serving its growing domestic energy needs. A national Polish Hydrogen Roadmap is expected to announce an important future deployment of hydrogen from wind energy or natural gas with CCS distributed through the gas infrastructure, the extent of which would still have to be developed.
- **Pathway 3 (PW3) – H_2-grid downsizing:** In some EU Member States, the current gas infrastructure is dominated by its use for heating purposes today. PW3 strategies may then be characterised by a shift to more electricity-based (electric heat-pumps) or central heat supply structures, releasing the gas infrastructure from some its current roles. This could in principle cause a devaluation of the existing gas infrastructures. Denmark can serve as an example for PW3; it has announced to reduce its current gas use by about 50% until 2050 and would also for some areas favour centralised district heating-based residential heat

[10] E.g. in some central European Member States parallel transport pipelines are in favour of an early full shift to a full hydrogen transport.

supply[11]. The role of its gas grids would hence change and need to accommodate hydrogen from wind-energy for load-balancing (transport grid) and to collect biomethane (distribution grid). In how far the emerging role of hydrogen as green gas will change this downsizing of the gas grid cannot be foreseen yet.

- **Pathway 4 (PW4) – Transit-focused H_2-grid:** Member States with a limitedly developed or gas transit-focused gas infrastructure and no need to back up the electricity system in its role to balance large shares of renewable electricity will lack the incentive to develop new gas grid infrastructures. These Member States could consider to use alternative energy transmission/distribution means to transport hydrogen (ship, rail, or road) and/or use other CO_2-free energy carriers, still being capable of taking profit from the same efficient end-use technologies. At the same time, they may want to continue the transit and hence transmission task of their existing gas infrastructure.

In this exercise, we have anticipated that in the future the development of transmission and distribution parts of the gas infrastructure will go hand in hand. This may or may not be the case in individual Member States. We are aware of strategies where a continuous strong role of the gas transmission grid is foreseen, while the outreach of the distribution grid is believed to be reduced by distributing heat instead of gas across the last meter[12]. This level of detail, together with many other possible development options and criteria for defining generic hydrogen development pathways would, however, have watered down the strategic proposition of our generic pathways-definition.

Important aspects in developing these generic pathways were:

1. **Today:** Concerning the starting point from which a Member State will consider the strategic development of its energy supply system and the underlying infrastructures, a large number of criteria could be applied to describe an energy system and its specific framework in view of a more or less further developed gas infrastructure. The unifying ambition is to develop green gases taken into account the current energy supply, infrastructures, and the end-users supplied through the gas grid. The ambition was to consider potential major and original as well as early drivers for the development of hydrogen gas. In this respect, two aspects have to be looked at, i.e. the **needs** to shift to hydrogen as molecule-based energy carrier and its most relevant **opportunities**. We understand that the major role of hydrogen in future energy systems will be to (a) universally combine the avoidance of end-use related climate and pollutant emissions, (b) smoothly but increasingly shape the transition from fossil fuels to renewable energy vectors, and (c) deliver economic advantages through a high continuity, including re-utilisation of today's industry structures and hence assets. The two most relevant factors, characterising the present situation as a starting point, are
    1. the availability in most EU Member States of a dense gas infrastructure connecting energy production and user centres as well as dispersed users via a well-developed and interconnected gas transit and transmission grid (opportunity) and
    2. the need to mitigate the economic and technical impacts on the electricity infrastructures from integrating large quantities of short-termed and seasonally fluctuating renewable electricity loads (need)[13].

    Whereas one of the two aspects (opportunity) addresses an important economic asset, the second (need) takes a major EU energy policy target into consideration. In order to keep the pathway definition simple, all other criteria seemed to be of subordinate nature in this context but will be assessed in more detail in chapter 1.3.

2. **Today → 2030:** On the verge of today's energy infrastructures towards less fossil and substantially higher renewable energy shares already in the transition phase (2030), the introduction of green or blue hydrogen may also be eased by other factors, leading to a smoother transition. Therefore, the green and blue columns in Figure 1-5 indicate the opportunities of utilizing the early economic advantages of applying blue hydrogen from steam methane reforming combined with the sequestration of CO_2[14]. This may be either

[11] Energinet.dk: Long-term development needs in the Danish gas system - The green transition calls for new use of the gas system. Report by Energinet. Doc. 20/00788-57, September 2020, file:///C:/Users/buenger/AppData/Local/Temp/Long-term%20develeopment%20needs%20gassystem.pdf.
[12] The Danish energy strategy by 2050 suggests that the gas distribution grid may lose some of its role to distribute energy for heating to individual buildings, but would have 'new' tasks such as biomethane collection and supply to district heating installations [Energiscenarier frem mod 2020, 2035 og 2050, Energistyrelsen, March 2014].
[13] E.g. the use of blue hydrogen pathways does not correspond to a major EU 2050 energy and climate policy goal whereas the deployment of renewable electricity or hydrogen does.
[14] Could as well be the use of biomethane or low-carbon methane pyrolysis.

done by domestic CO_2-disposal or by CO_2-disposal abroad, using a specific CO_2-pipeline or ship transport to other countries within or outside the EU[15]. Another means for rapidly introducing hydrogen into a Member State's energy system is the import of (certified) green or blue hydrogen from outside the Member State or outside of Europe[16]; it is expected that, in this timeframe, hydrogen imports will still be limited.

3. **2030:** Already in the transition target year 2030, the interest in the future role of the green gas infrastructure will become visible in EU Member States; it can be called ambitious (top) or less ambitious (bottom). Therefore, we have dubbed this phase the "sensitive" transition point as the general direction of the future gas infrastructure utilisation will already be decided by then. As a rough indication, the names of European regions have been added to the four hydrogen development pathway "terminal points" in blue font. The allocation of names does not have the purpose to foresee which gas infrastructure strategies will emerge in these regions towards 2050, but rather to indicate the starting point[17].

4. **2030 → 2050:** A major development criterion will then also become the type of hydrogen use, i.e. in which sectors and to which extent green or blue hydrogen will be used, either to cover end-use needs or to exploit potential synergies by intersectoral integration ("sector coupling"). We understand that in the early introduction phase the considerations are rather supply- or capability-driven to reach the required scaling for significant and early cost-reductions in the supply chain, whereas in the longer-term, with key technologies such as fuel cells for mobile or stationary use becoming commercially and widely available, the ramp-up of the infrastructure may become more demand-driven. It is worthwhile noting that for today's hydrogen pipeline operators, i.e. the technical gases industry, all infrastructure investments are solely demand driven.

5. **2050:** By 2050, we imagine three different states of development in the gas grid, probably also reflecting a country's energy intensity as a whole: (a) heavily utilised to supply all energy sectors and in addition providing hydrogen as a base chemical, as well as interlinked with other Member States or for hydrogen imports from outside Europe at large scale, (c) little developed gas infrastructure, possibly with few island grids but lacking interlinkage, and (b) something in between, with gas grids either mostly operated at a national level or with some but limited gas exchange with neighbouring countries.

In principle and due to the highly dynamic strategy development processes in the energy markets, EU Member States have demonstrated different engagement in hydrogen energy. This is well understood, taking into account the two major driving forces behind hydrogen energy as chosen for our pathway selection, i.e. the extent of today's gas infrastructure and the potential or ambition in developing domestic renewable energies. Member States characterised by a PW1 or PW2 pathway typically have an obvious interest in safeguarding existing gas assets in the future whereas other Member States stronger depend on developments in other countries.
To test our selection, we have tentatively applied the 4 pathway types to existing hydrogen strategies, based on our insights from desk research and stakeholder interviews:

- **Netherlands (NL):** With a rather recent strategy to switch from a fossil to a RES based gas supply system and the need to combine the transmission/distribution of electrons and molecules in favour of an efficient RES based energy system[18], the Netherlands are striving to integrate hydrogen into their gas infrastructure. Having pinpointed the re-utilisation of existing (gas) infrastructures, early hydrogen business cases have been earmarked[19]. The Dutch National Hydrogen strategy has recently been published[20]. It combines the (gas) infrastructure

[15] Examples are the H2omorrow (Open Grid Europe with Equinor, DE) https://oge.net/en/us/projects/h2morrow and Magnum (Nuon, Gasunie, Equinor, NL) https://group.vattenfall.com/press-and-media/news--press-releases/newsroom/2017/vattenfall-aims-for-carbon-free-gas-power projects.
[16] Typical examples are the suggested 40+40 GW electrolysis project proposal to import green hydrogen from North Africa or form Ukraine https://www.hydrogen4climateaction.eu/2x40gw-initiative
[17] Eastern European States could decide to import large amounts of renewable electricity by means of hydrogen-based gas infrastructure yet to be developed.
[18] Whereas the traditional energy supply was based on solid, liquid or gaseous energy carriers (i.e. molecules) with 'built-in' storage and flexibility capability (coal dumps, oil tanks, underground gas caverns, linepack) it is believed that the future energy supply system will be dominated by the supply of renewable electricity (i.e. electrons). In order to efficiently and economically combine the best of these two energy worlds, both electrons and molecule handling technologies need to be combined.
[19] J. Koornneef: Offshore wind meets hydrogen - Opportunities on short and long term. Presentation at Global Energy Village 2018 conference, Barcelona, Spain, 17-19th May 2018.
[20] Only recently, ongoing discussions fostering a strong gas grid connection between the Netherlands and Germany have been communicated. The national Dutch hydrogen strategy from 4th June 2020 has phrased: *"The developments in Germany are highly significant to the Netherlands, given that it is likely that a portion of*

availability, large RES potentials, geographical setting as an energy hub, existence of large industrial clusters in need of fulfilling their CO_2 obligations and served by dedicated gas infrastructures, and the capability to unlock RES and fossil based domestically produced as well as imported hydrogen. Finally, a joint political and industrially backing put the Netherlands into the position of making economic use of hydrogen early. The Netherlands are therefore seen as a representative of PW1 with a balanced share of green and blue hydrogen in the transition phase, turning to more green hydrogen in the long-term. Another aspect is the Netherlands's position as energy hub, which will necessitate to develop strong gas infrastructure-based interconnections with its neighbours along the North Sea coast as well as in central Europe.

- **Germany (DE):** The implementation of hydrogen into the national gas grid as part of the emerging national hydrogen strategy is an important element of the German energy strategy, as Germany today benefits from a dense natural gas grid supplying a large share of the final energy end-use in all sectors[21]. Also, it fulfils the criterion of both a large potential and ambition in developing its RES energy base. Even though the RES potential will not be sufficient to cover all of its energy needs given the country's high energy intensity, the combination of both criteria is a sound starting point to integrate hydrogen into all sectors of the energy systems. With strong ambitions to combine early business cases with the fulfilment of the EU GHG targets, the chances are high to more than just substitute natural gas as the molecule-based energy transport and storage vector. Its use is foreseen to be extended to other energy uses such as power generation, mobility, industry, and at the distribution level also buildings (e.g. fuel cells for co-generation). By that, Germany will have the potential for developing along PW1, the future green hydrogen share ambition strongly based on the policy development.
- **Poland (PL):** Being dominated by fossil and specifically coal based electricity generation today, as well as a gas transmission infrastructure developed to transport gas from Russia or Ukraine into central Europe, Poland could be seen as a typical representative of PW4. However, Poland has understood that with its high RES-E potentials (i.e. onshore and Baltic Sea offshore wind) tapped to gradually substitute electricity from coal, the need will increase for load balancing in the electricity system. Next to green hydrogen also blue or turquoise hydrogen sources will be developed further in the transition phase for economic reasons. How this will translate into further gas infrastructure development in detail is open as the national hydrogen strategy is still under development. In addition, continued natural gas imports e.g. from Ukraine or Russia also via Lithuania or the import and exchange of gas with Denmark through the Baltic Pipe after 2022 will provide access to potentially 'cheap' low-carbon hydrogen from Eastern Europe and the North Sea. Thus, the combination of future RES-E transmission (and seasonal storage) business cases and the domestic RES-E potential do support a potential H_2-conversion of today's transit transmission gas grid and the development of the distribution grid much depending on the plans for hydrogen end-use. We therefore suggest to group Poland in PW2. However, the timeframe cannot be foreseen today.
- **Spain (ES):** Representing South Eastern Europe, Spain intends to strongly develop its renewable energy resources, i.e. electricity from solar PV and CSP[22] as well as from onshore wind. Spain intends to in the future produce hydrogen solely from renewable energy, supplying it to all end-users and even for export. Hydrogen from fossil energies is not seen as an option, as it is believed to block future investments in fully sustainable future-proof technologies. Sectoral integration is seen as a means to open economic synergies for the hydrogen businesses. The gas grid, even though tailor-made for today's energy provision can in principle be used to transport hydrogen, blended to methane in the transition phase and converted to 100% operation in the long-term. The awareness has grown that the gas grid should be seen as a valuable asset, worthwhile to be used for green energy transport, extending from islands initially and across European and non-European (North Africa) borders. As such Spain could be grouped in PW3.
- **United Kingdom (UK):** The UK has developed from a natural gas export to a gas import country. Large shares of its final energy end-use are contributed by natural gas today. One important aspect here is the end-use seasonality dominated by the gas-consumption for heating. As a technology change to other heating systems would lead to massive investment needs, it is believed that re-utilising the existing process technology for heating (simple boilers) and gas infrastructure assets will be the most economic approach. In combination with its political and industrial will and its large RES potentials, the UK has developed an outstanding

German demand will have to be met through imports that enter Europe through the Netherlands." https://www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen

[21] In 2017 the contribution of natural gas of final energy use rose to 23.8% [Energy Consumption in Germany in 2017. AGEB, 2018, https://ag-energiebilanzen.de/index.php?article_id=29&fileName=ageb_jahresbericht2017_20180420_englisch.pdf

[22] Concentrated Solar Power: In 2018, Spain accounted for almost half of the world's CSP capacity at 2,300 MW, even though no new capacity has entered commercial operation since 2013.

concept and strategy to utilise the capabilities of hydrogen in the gas grid mainly for heating purposes. As stated, its political ambitions coined by the development of fossil energies will cause a large share of blue hydrogen to be part of the energy strategy still by 2050[23]. Even though being a representative of the PW1 group, the UK will therefore probably tend to a higher share of blue hydrogen over time.

1.3 Pathway justification

In addition to the four generic pathway types, further aspects will need to be taken into consideration to understand the differences between possible hydrogen gas infrastructure development routes which are relevant for elements of a European regulatory framework for dedicated hydrogen gas transmission and distribution infrastructure. Further to the general preparedness or ambition as well as the depth of integrating a hydrogen gas infrastructure as an important part of national energy systems, these criteria address details of the modes by which hydrogen would be

1. produced (fossil versus RES based energy source, share of domestic production versus imports, CH_4 versus H_2 as energy carrier, degree of centralisation),
2. transported, distributed, or stored (dedicated H_2 grid versus admixture, distribution versus transmission grid focus) and
3. used in different energy sectors (type and share of end-use sectors to be supplied).

The structure presented in Figure 1-1 is used as a basis to further explain how the most relevant hydrogen key technologies (= assets) along the hydrogen value chains coincide with the generic pathway types PW1 to PW4. The correlation of assets with pathways will be further explained by examples from individual national hydrogen strategies comprising hydrogen production (also competing technologies), infrastructure (dedicated and blended hydrogen transmission and distribution and storage), and end-use. Where meaningful, also contradicting government and industry strategies have been pointed out.

The structured criterion list in Table 1-1 has been developed to explain potential hydrogen gas infrastructure development pathways of individual Member States in the timeframe until 2030. This chapter follows this criteria sequence. At the end of this chapter, the European regions will be assessed concerning their general position under consideration of these criteria.

Table 1-1 Criteria to explain the assets along relevant hydrogen value chains in more detail

General characteristics
Potentials/ambition in renewable electricity development
Extent of current gas transmission grid
Extent of current gas distribution grid
Hydrogen production
Aspired green and blue/turquoise (SMR/CCS or methane-pyrolysis/C-use/deposition) hydrogen shares
Decentral vs central hydrogen production
Domestic vs imported hydrogen provision
Hydrogen infrastructure (transmission, distribution and storage)
Extent of dedicated hydrogen grid versus H_2-blending at TSO-level
Extent of grids with hydrogen blending versus dedicated hydrogen grids at DSO-level
Existing private hydrogen grids
New hydrogen infrastructure versus methane infrastructure refurbishment
Existing seasonal hydrogen storage potential (salt caverns, other structures)
Opportunity strategy typically through isolated installations vs nationally harmonised gas strategy development
Interest in future transport of biomethane via gas grid
Hydrogen end-use
Share of end-uses served by hydrogen (industry, mobility, heat, power production)
Seasonality of hydrogen demand

[23] By 2050 149 TWh/yr of blue hydrogen and 87 TWh/yr of green hydrogen are foreseen to provide about 28% of UK's total energy demand in the "balanced scenario" [Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain. Study by Navigant for the Energy Networks Association (ENA), 21 October 2019]. In a recent study from Aurora Energy Research, it is claimed that up to 2050 about 480 TWh_{H2}/yr could supply most of UK's energy needs, but also this study concludes that it will be blue hydrogen [Hydrogen for a net zero GB: an integrative energy market perspective. Study by Aurora Energy Research, 24th June 2020, https://www.auroraer.com/insight/hydrogen-for-a-net-zero-gb/

Dispersed small vs central large users
Blended hydrogen users or pure hydrogen users

1.3.1 General characteristics

The first three general characteristics in this table have already been applied in developing the generic pathway graph in Figure 1-5:

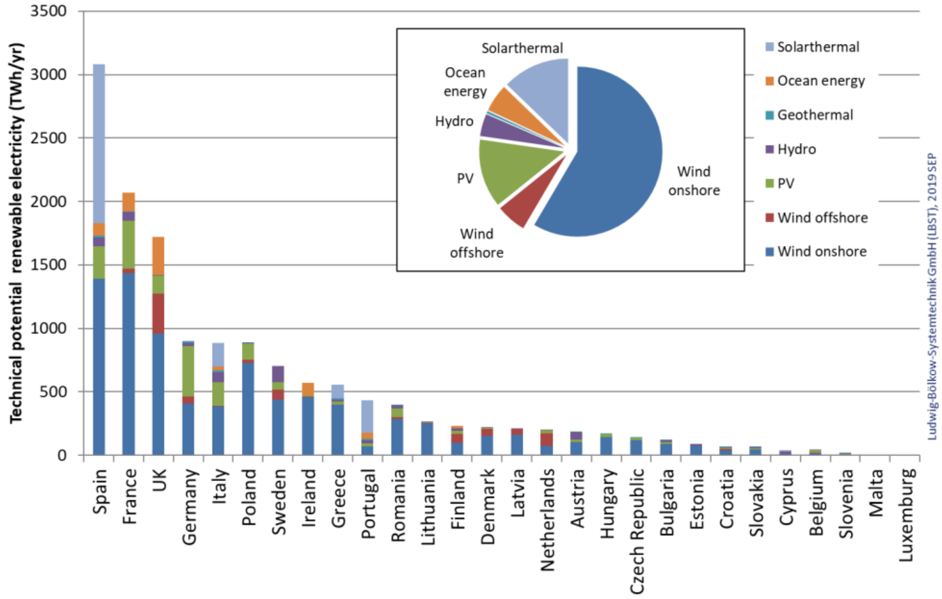
1. Potentials and/or ambition in renewable electricity development,
2. Extent of current gas transmission grid and
3. Extent of current gas distribution grid,

of which 2. and 3. have been combined for the purpose of the pathway graph. All criteria are further explained in this subchapter, without being directly linked to PW1 to PW4. Instead, these aspects have to be considered in addition when considering the potential strategy formulation in an individual Member State.

Potentials/ambition in renewable electricity development

We assume that in fulfilling EU's policy targets by 2030, renewable energies shall become a major element of all Member States energy portfolios[24]. The renewable energy potentials have been recently assessed by various studies[25]. Whereas Figure 1-6 presents the technical production potential for renewable electricity, Figure 1-7 shows the renewable electricity production expected in the METIS 2050 scenario against the firm electricity consumption[26]. A comparison shows significant differences between the renewable electricity production potential and the expected production figures for 2050, demonstrating large electricity potentials in several Member States (such as Germany, Spain or France) for hydrogen production at larger scale[27].

Figure 1-6 EU renewable electricity generation potentials, by Member State (average of ranges per Member State)



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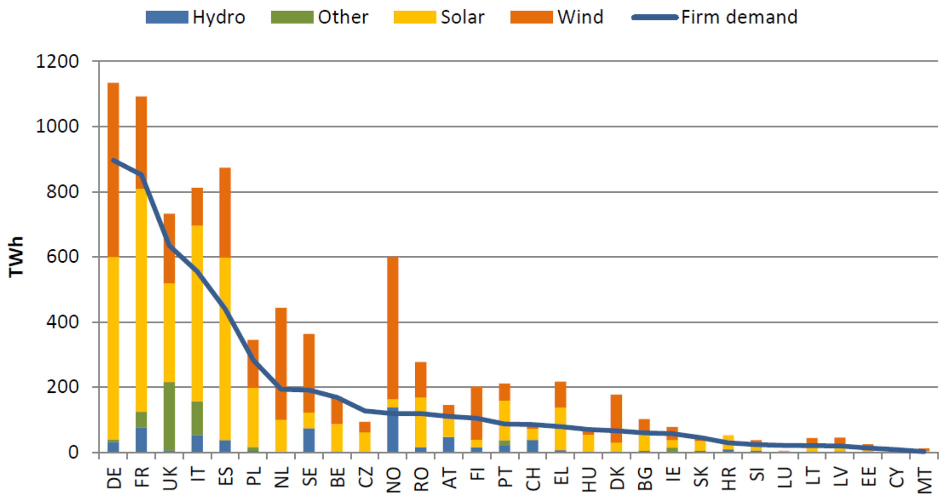
[24] "A binding renewable energy target for the EU for 2030 of at least 32% of final energy consumption, including a review clause by 2023 for an upward revision of the EU level target. The original target of at least 27% was revised upwards in 2018" https://ec.europa.eu/clima/policies/strategies/2030_en

[25] Among others Kanellopoulos, K.; Blanco Reano, H.: The potential role of hydrogen production in a sustainable future power system – An analysis with METIS of a decarbonized system powered by renewables in 2050, JRC study, 2019; and van Nuffel, L; Gorenstein Dedecca, J.; Yearwood, J.; Smit, T.; Bünger, U.; Altmann, M.; Fischer, Ch.; Michalski, J.; Raksha, T.; De Vita, A.; Zerhusen, J.: Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure. Study for DG Energy, September 2019.

[26] The electricity base consumption does not contain the additional electricity consumption for the electrolysis of hydrogen energy.

[27] E.g., the European Hydrogen Strategy states: *"In a third phase, from 2030 onwards and towards 2050, … renewable electricity production needs to massively increase as about a quarter of renewable electricity might be used for renewable hydrogen production by 2050.*

Figure 1-7 Stacked renewable annual production vs firm electricity demand at country level in METIS scenario 2050 (n this case including the additional direct electricity demand by 2050 but excluding demand from the electrolyser fleet)



From the gas infrastructure study for DG Energy, the technical renewable electricity production data per Member State were extracted and linked with the population data; the resulting RES-E potential per million inhabitants is presented in Table 1-2[28].

Table 1-2 Population specific variable technical RES-E production potential by Member State [TWh/ (yr·mio inhabitants)]

Member State	[TWh/(yr. Mio inh]	Member State	[TWh/(yr. Mio inh]
Austria	20.5	Italy	14.7
Belgium	3.3	Latvia	**110.0**
Bulgaria	16.7	Lithuania	**94.5**
Croatia	16.1	Luxemburg	2.4
Cyprus	**47.9**	Malta	4.3
Czech Republic	13.2	Netherlands	11.4
Denmark	37.5	Poland	23.0
Estonia	**64.9**	Portugal	**42.2**
Finland	**41.5**	Romania	20.3
France	30.8	Slovakia	11.5
Germany	10.8	Slovenia	7.8
Greece	**51.7**	Spain	**66.0**
Hungary	17.4	Sweden	**68.1**
Ireland	**116.2**	UK	25.9
		EU	**27.7**

black: low spec. potential (< 20 TWh/(yr. mio inh.); red: high spec. potential (20 … 40 TWh/(yr. mio inh.)) and red+bold: very high spec. potential (> 60 TWh/(yr. mio inh.)).

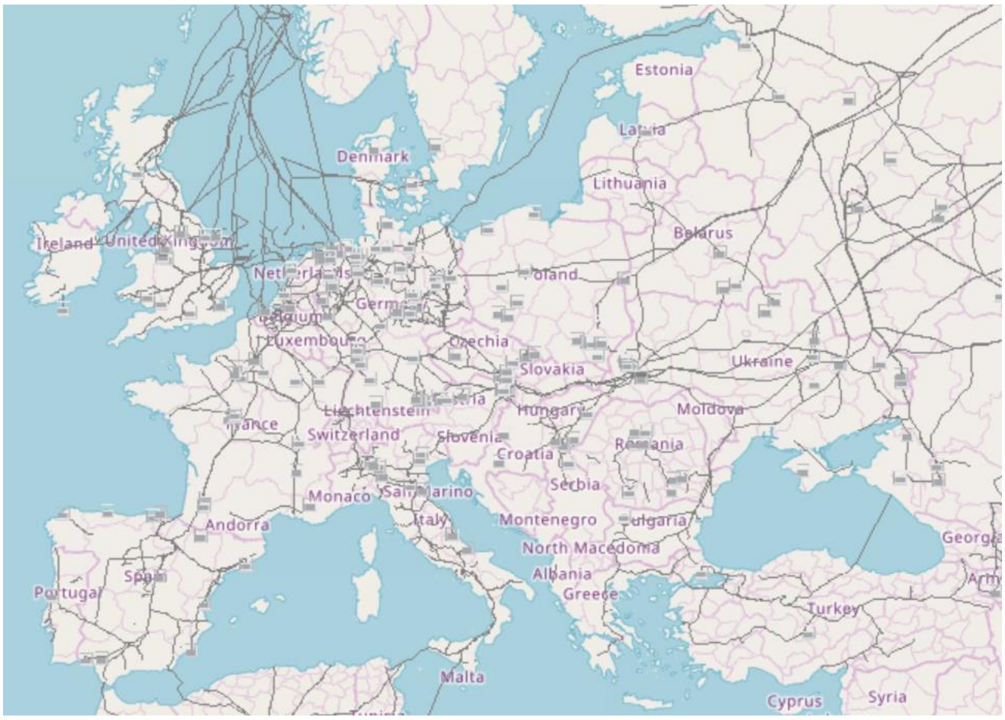
Extent of current gas transmission grid

The extent of the European transmission gas grid is shown in Figure 1-8. It shows the coverage of the EU Member States by a Europe spanning gas transmission infrastructure, specifically illustrating the supply (= network) type character in Northwest and Central Europe as well as the transmission (= line type) character of the grid in Eastern European Member States. In assessing the transmission gas grid density of European regions, this map was taken as a general reference. From this map the high density of the transmission gas grid in the "central Member States" becomes obvious, spanning from France to the Benelux countries and down to Italy in the South to parts of Poland, Austria, and Hungary in the East. In addition, the UK comprises a dense and highly used gas grid. In contrast the "peripheral Member States" are characterised by a gas transmission

[28] The population number is only one criterion whether the technical RES-E of a Member State is specifically high. Another criterion is the specific energy end-use intensity. For simplicity, this level of detail is sufficient for the purpose of this study.

grid of much less density. As pointed out in another study for DG Energy[29], the highest gas end-use intensity is observed in the following five European states: Germany (with a 24.5 % share in total EU gas demand in 2015), the UK (23.0 %), Italy (20.8 %), France (13.1 %), and the Netherlands (10.9 %). Due to their energy intensity, some of these countries may need to import green (or blue) hydrogen from within or outside the EU.

Figure 1-8 EC PCI's European Gas Network map (2019)[30]



Extent of current gas distribution grid

There are no exact figures for the extent of the gas distribution grid across the EU. In its latest gas statistical report, Eurogas reports for 2013 a total pipeline length in all EU Member States, transmission and distribution, of 2,171,002 km but only as a rough estimate (see Table 1-3)[31]. In Germany, the transmission grid is 38,500 km, while the distribution grid comprises a pipeline length of more than 512,000 km, which is about 13 times higher than transmission[32]. In Italy, 200,000 km of distribution grid compare with 33,000 km of transmission grid length[33]. We simply assume that this rough relation also holds for most other Member States, and that the total pipeline length provides a good first order estimate for the distribution grid length, except for the gas transition countries in Eastern Europe.

[29] The role of trans-European gas infrastructure in the light of the 2050 decarbonization targets. Revised Report Tasks1 &2. Specific Tender under Framework Contract MOVE/ENER/SRD/2016-498 Lot 2, Trinomics, LBST, Artelys, E3 Modelling, Rotterdam, 19 June2018, https://ec.europa.eu/energy/sites/ener/files/documents/revised_tasks_1_2_gas_infrastructure_2050_final_clean_2_oct_add.pdf

[30] See https://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html, PCI – Projects of Common Interest. f

[31] Marcogaz presents different numbers for 2013: 217,685 km transmission grid and 1,640,667 km distribution grid, adding up to a total of 1,858,352 km, which is 14.4% off the Eurogas figure for the same year https://www.marcogaz.org/app/download/7719248963/Technical_statistics_01-01-2013_revision_on_15-09-2014_-_WEB_VERSION.pdf?t=1529588711. This reasonably close for the purpose of this study.

[32] Monitoring Report 2019, Bundesnetzagentur (see https://www.bundesnetzagentur.de/SharedDocs/Mediathek/Berichte/2019/Monitoringbericht_Energie2019.pdf;jsessionid=D6D67CFF03E945F87E0CECAAC898CA2A?__blob=publicationFile&v=6, p. 347).

[33] This information was provided in an interview.

Table 1-3 Assets along relevant hydrogen value chains for EU Member States

As of 1 January 2013	Total length of pipelines (in kilometres)	Number of gas customers (in thousands)*	Number of employees	Number of natural gas vehicles**	Gas power generation capacity installed (in megawatts)
AUSTRIA	42 900	1 350	2 949	7 717	5 119
BELGIUM	73 744	3 161	7 194	216	5 998
BULGARIA	6 737	65	1 700	61 256	990
CROATIA	21 055	642	2 053	143	1 185
CYPRUS	0	0	0	0	0
CZECH REPUBLIC	77 419	2 868	3 037	4 300	838
DENMARK	17 924	420	1 400	14	3 110
ESTONIA	2 870	52	340	200	200
FINLAND	3 229	36	450	1 330	2 842
FRANCE	231 627	11 272	32 000	13 000	3 750
GERMANY	477 000	19 678	38 793	95 297	25 640
GREECE	6 930	289	881	800	4 900
HUNGARY	90 784	3 514	2 726	372	4 520
IRELAND	13 309	651	600	2	3 742
ITALY	286 681	22 727	30 000	800 000	54 643
LATVIA	6 110	444	1 275	18	806
LITHUANIA	10 100	557	1 700	200	2 547
LUXEMBOURG	3 034	83	210	249	492
MALTA	0	0	0	0	0
NETHERLANDS	135 229	7 111	9 500	6 025	22 300
POLAND	184 130	6 730	36 000	3 392	1 089
PORTUGAL	17 333	1 251	1 070	442	4 739
ROMANIA	53 666	3 201	41 007	0	4 020
SLOVAKIA	35 349	1 500	4 548	1 245	1 760
SLOVENIA	4 925	153	520	41	308
SPAIN	80 097	7 394	6 615	3 666	26 251
SWEDEN	3 220	40	250	44 319	790
UNITED KINGDOM	285 600	23 003	54 178	559	35 320
EU-28	2 171 002	118 191	280 996	1 044 803	217 899
SWITZERLAND	19 103	430	1 595	11 100	541
TURKEY	82 240	9 177	77 800	2 185	n/a

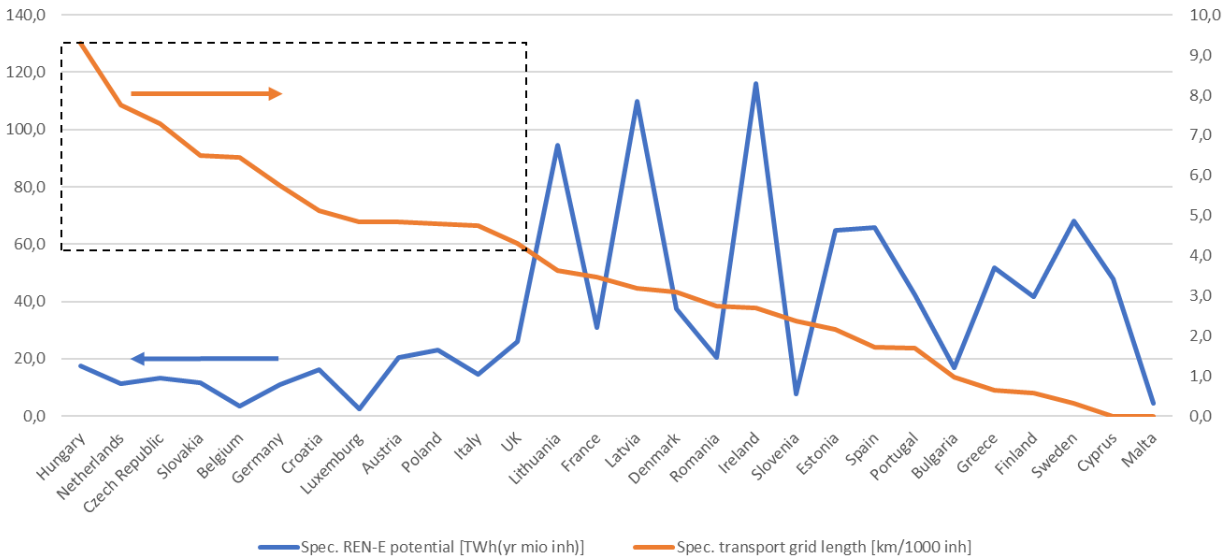
** Number of gas customers are counted by number of meters, and include domestic as well as non-domestic (industrial, commercial and other) customers, except Germany for which the number of domestic customers is equivalent to the number of dwellings supplied with natural gas for heating.*

*** Eurogas and NGVA Europe.*

Note: Figures are best estimates available at the time of publication; n/a: not available.

From Figure 1-9 it can be concluded that the countries with the most extensive gas distribution grids in Europe are Germany, the UK, Italy, France, Poland and the Netherlands based on total numbers, and Hungary, the Netherlands, the Czech Republic, Slovakia, Belgium, Germany, Croatia, Luxemburg, Austria, Poland, Italy and the UK (dashed box), on a population specific basis[34]. Summing up, both the renewable electricity production potential and the total gas pipeline length across all EU Member States and the UK are shown in Figure 1-9. As expected, the comparison demonstrates little correlation between gas pipeline infrastructure and renewable electricity potential.

Figure 1-9 Population specific variable technical renewable electricity production potential and transmission grid length for all EU Member States + UK (sorted for pipeline length)



[34] Population density is not the only specific energy indicator for the gas grid density. Others are energy intensity to reflect energy intensive industries as well as climate conditions to reflect the heating needs. These factors have been skipped here for reason of simplicity.

1.3.2 Hydrogen provision

Three hydrogen production specific criteria have been assessed in more detail:

- Aspired green versus blue (SMR/CCS or methane-pyrolysis/C-use/deposition) hydrogen shares,
- Decentral vs central hydrogen-production and
- Domestic vs imported hydrogen provision.

Aspired green versus blue (SMR/CCS or methane-pyrolysis/C-use/deposition) hydrogen shares

The most prominent and published green gas strategies demonstrate an obvious colour-ranking of the hydrogen production pathways of choice:

1. **Green hydrogen:** Two motivations for an early introduction of green hydrogen have been identified from the hydrogen strategies or the interviews:
    a. Member States with a high renewable electricity production potential (or with obvious green hydrogen import opportunities) and the perspective of low production costs. Obviously, these are Southern European countries taking profit from high solar irradiation.
    b. Member States with a visible technology development strategy for innovative technologies along the green hydrogen value chain. E.g. Germany has explicitly stated a combined sustainability and value creation focus of its national hydrogen strategy.
2. **Blue hydrogen:** A strong motivation for an early blue hydrogen provision can have two motivations:
    a. Natural gas producers (outside the EU): The UK collaborates with Norway on the exploitation of combined autothermal reforming (ATR) and CCS technologies to provide cheap hydrogen at costs of 1.85 £/kg_{H2} down from 2.1 £/kg_{H2} today[35], based on the availability of large natural gas resources. But, also EU Member States with a cost-efficient access to NG and the plan to export CO_2 for storage (e.g. in Norway) such as Germany are currently discussing the inclusion of blue hydrogen in their gas strategies[36].
    b. Access to CO_2 storage sites: With a focus on the transition period (2030), the availability of cheap and abundant NG as well as high CO_2 taxes in Norway coincides with available storage sites under the North Sea.
3. **Turquoise hydrogen:** Specific interest for turquoise hydrogen has been prominently raised by the Russian gas industry to provide CO_2-reduced (medium-term) and CO_2-free (long-term) hydrogen. This has also recently provoked industrial interest by the European gas industry, specifically in Austria[37] as it is believed to be simpler to dispose of solid carbon than CO_2. It also appears in the German and European hydrogen strategies. The potential success for this type of hydrogen depends on the development success of the technical options, also timewise and how the target can be reached to provide the by-product carbon in qualities relevant for competitive C-sales prices. Turquoise hydrogen will compete with the rather robust SMR process which has the advantage of a lower technical complexity and no by-product to be sold into the market at unknown economic consequences[38]. Given the early state of R&D and technical development, it is not clear yet, how large the contribution of turquoise hydrogen will be by 2030.

Depending on the share of green hydrogen to be produced in the medium to long-term, electrolysers for PtX-schemes are posed to becoming one of the key technologies in RES-E-dominated energy systems. Their contribution would be severalfold as they would not only provide hydrogen as an energy carrier, fuel, and base chemical for industry, but as well provide system services, in particular to balance the electricity system with increasing RES-E shares. Its success will therefore depend on hydrogen strategies building on one or several of four success factors:

[35] It is interesting to note that the authors of [Hydrogen for a net zero GB: an integrative energy market perspective. Study by Aurora Energy Research, 24th June 2020, [https://www.auroraer.com/insight/hydrogen-for-a-net-zero-gb/] at the same time claim lower costs for electrolytic hydrogen of 1.6 £/kg_{H2} by 2050 down from 2.6 £/kg_{H2} today.
[36] Other EU Member States such as the Netherlands have their own CO_2 sinks.
[37] [St. Petters: Rebalancing our Planet's Carbon & Water Cycle at no extra Cost. Carbotopia, December 2018].
[38] Today's carbon markets are much smaller in scale than if carbon is produced at energy market specific scale and would have a soon to be expected economic impact on the whole carbon market with unpredictable outcome.

- An ambitious RES-E development goal supported by a relevant policy framework (mainly supply driven) much beyond the early discussions of surplus electrical energy[39], such as in Southern Europe, where green hydrogen may not only be used for own end-use but also for export,
- The need of providing seasonally fluctuating energy, such as for heating purposes in various Northern European countries[40],
- The role of hydrogen to decarbonise end-users, providing hydrogen to more than one of the energy users such as industry, buildings, mobility, and the power sector, mentioned by all emerging hydrogen strategies in central Europe[41], and
- The comprehension of potential value creation in an innovative new technology segment, typically exploitable by all technology innovation focused Member States.

Conditions for these success factors may therefore be met across all of Europe with shifting focus for each Member State, specifically as studies have indicated electrolyser cost reduction potentials which will eventually render green hydrogen cheaper than blue or turquoise hydrogen, depending on the region, i.e. from Southern (solar) or Northern (wind) regions[42].

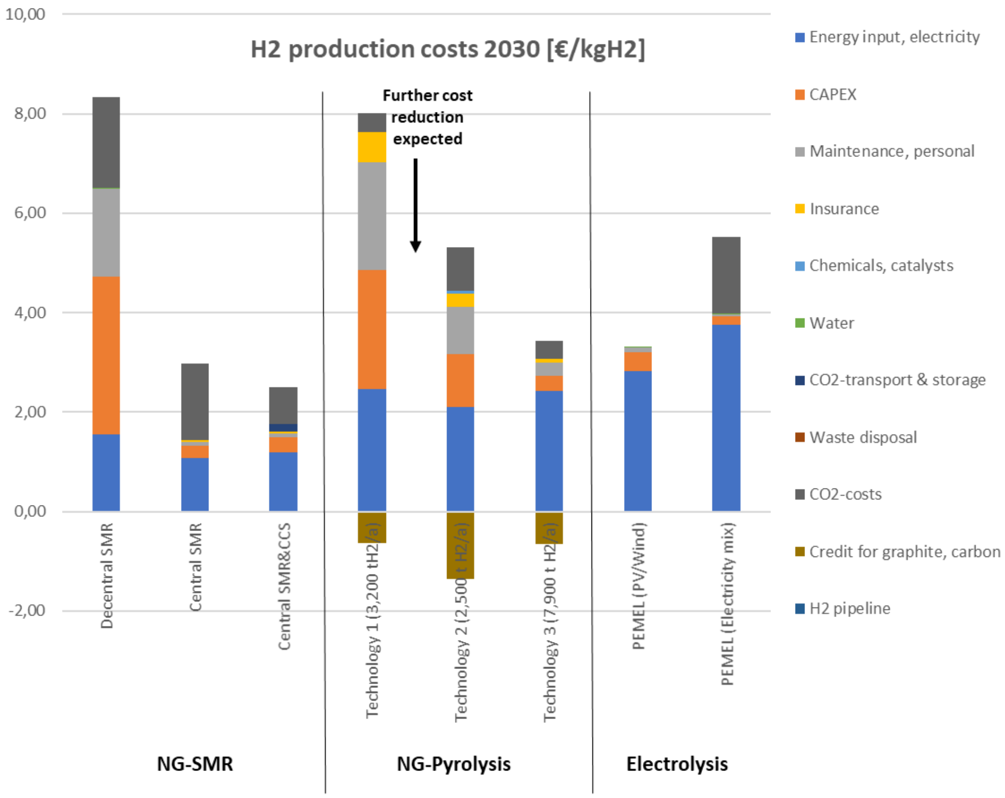
With still abundant and cheap natural gas available in parts of Europe, also CCS- or C-deposition schemes can in combination with steam reforming or pyrolysis of natural gas support load-levelling in the transition period until 2050. Even though the positive contribution of electrolysers to single European electricity markets has been found to be beneficial, further studies will need to assess the parameter driven economic viability of the extensive use of RES-E for hydrogen production for individual Member States[43].

Concerning the costs of hydrogen production by different technologies, recent analysis for the time horizon 2030 and a set of realistic assumptions (see Figure 1-10) have shown that by today hydrogen costs from fossil natural gas with or without CCS are still lowest (2.5 / 3.0 $€/kg_{H2}$), followed by hydrogen produced from electricity directly connected to renewable energy plants (3.5 $€/kg_{H2}$)[44] and from grid electricity (5.5 $€/kg_{H2}$), by NG from pyrolysis (3.5…8 $€/kg_{H2}$, with the large bandwidth in this case caused by large development uncertainties and based on cost estimates from literature w/o practical experience) and finally onsite NG-SMR plants (8.5 $€/kg_{H2}$).

[39] The idea of producing hydrogen mainly from surplus electricity emerged from the need to produce green hydrogen at least costs and as driven mostly by operating, i.e. electricity, costs. As surplus electricity would however only be available during a limited number of hours, this would drive up the annuity related costs due to the low load factor of the electrolyser.
[40] This factor would also drive the provision of other non-green hydrogen technologies in the short-term.
[41] ditto
[42]

E.g. [Path to hydrogen competitiveness: A cost perspective. Study by McKinsey for the Hydrogen Council, 20 January 2020, download at: www.hydrogencouncil.com].
[43] Bossmann, T.; Fournié, L.; Peña Verrier, G.: METIS Studies – Study S14- Wholesale market prices, revenues, and risks for producers with high shares of variable RES in the power system. Study by Artelys, December 2018; Trinomics, Artelys and Enerdata: Energy Storage Study - Contribution to the security of electricity supply in Europe, 2020; and M. Roach, L. Meeus: The welfare and price effects of sector coupling with power-to-gas, 2020.
[44] i.e. to avoid grid related fees

Figure 1-10 Production costs for hydrogen from NG-SMR, NG-Pyrolysis and water electrolysis[45]



These results have to be interpreted with a great level of care. The data may change by climate region across Europe (costs of RES-E), by the fulfilment of technology development goals by 2030 (pyrolysis and PEM electrolysis), by the CO_2-price assumed[46], as well as by other uncertainties of electricity prices for renewable electricity and the regulatory framework, which may change in general with potential regional spreads. In addition, the cost of hydrogen from NG-pyrolysis also depends on the by-product carbon price, which is currently serving rather small C-markets and may be significantly disturbed by large amounts of C entering these markets. Furthermore, there is a range of currently suggested pyrolysis processes, producing different types of C-structures (production costs!) and at different operating conditions (energy use, …). As a working hypothesis, the cost for hydrogen from electrolysis will further decline (technology development, renewable electricity costs, favourable framework) and the cost for hydrogen from natural gas will tend to rise by 2050 becoming a strong argument for the more sustainable technology earmarked for the future. Yet, a smooth transition from natural gas today to hydrogen gas in the future can be adjusted by the growing share of hydrogen versus methane gas over time.

Decentral vs central hydrogen-production

There is evidence from both national and industry-specific hydrogen strategies, that driving the green hydrogen production cost down will require to significantly scale up production technologies, less from a per-plant scale, but more from a production capacity perspective:

- **Scaling by plant size:** The electrolyser developers' and industry's claim by tradition was that electrolysers are an intrinsically decentral energy technology with little energy efficiency differences related to the scale. In other words, from an energy resource utilisation perspective there is no reason to necessarily scale up a hydrogen production plant as it is the case with thermal power plants which typically take profit from an efficiency increase the volume-effect, combined with the advantage of low hydrogen transmission costs for decentral electrolysis plants[47].
- **Scaling by electrolyser production level:** Most Power-to-Gas (PtG) projects have been put into operation at small scale, i.e. until today in the 1…20 MW range, caused by the fact

[45] Taken from studies for industry by LBST (2020) and based on assumptions for central Europe.
[46] Here, a price of 180 €/kg$_{CO2}$ has been applied as suggested by the German Environmental Agency UBA (see: https://www.umweltbundesamt.de/sites/default/files/medien/376/publikationen/factsheet_co2-bepreisung_in_deutschland_2019_08_29.pdf).
[47] Instead of gas, electricity then needs to transported across long distances, rendering the degree of (de-) centralisation one of techno-economic optimisation.

that at this plant scale investment risks are still low for the aspired technical/operational learning. According to the European Hydrogen Roadmap, scaling by production level from today's European capacity of 1 GW to 40 GW by 2030 is expected to bring down specific electrolyser investment costs from 900 €/kW today to 450 €/kW or less in the period after 2030, and 180 €/kW after 2040. With rising CO_2 prices and increasing availability of renewable electricity at low prices in several EU Member States, green hydrogen would cut the cost curve of natural gas with CCS based hydrogen by around 2030.

However, taken into account the ambitions of the industry and the authorities, it is expected that, next to the prototype scale projects, larger electrolysis plants will already be developed in the next decade. A clear signal of this development is also the interest in the development of hydrogen for

- **Mobility:** the focus on hydrogen as a fuel for passenger cars has been scaled down in Europe in favour of applications for heavy-duty transport, with the effect of upscaled and better utilised refuelling stations (trucks, buses, trains, or even ships),
- **Stationary applications:** the focus on small decentral PtG plants for load balancing to take profit from cheap and otherwise curtailed renewable energy has shifted towards larger hydrogen industry applications. This has raised industry expectations that central hydrogen production schemes and continuous and large quantity hydrogen supply with e.g. dedicated hydrogen pipelines will become economically viable soon specifically for hydrogen for applications in industry, assuming that favourable policy framework conditions are provided for by politics[48].

From the stakeholder consultation process for this study we have learnt that by 2030 both approaches may coincide:

- The installation of decentral plants in regions with a dispersed gas grid to kick-start hydrogen markets in islands, i.e. by the distribution grid, serving one or more end-uses, which is typically the case in peripheral Europe[49] and
- The development of large-scale dedicated hydrogen pipelines, mainly for large industrial consumers, specifically when the option of parallel grids allows to continue the transport of methane and the refurbishment of the grid taking place at low costs[50] rapidly allowing to extend the hydrogen gas grid, typically to happen in dense gas grid regions, i.e. in central Europe (Northwest).

To improve the interoperability of European energy infrastructures, the specifications of gas infrastructures of central and peripheral Europe will need to converge, as load balancing renewable energies across Member State borders and green hydrogen imports across European borders will require accommodating a growing supranational hydrogen trade. The backbone for a Europe-spanning hydrogen transmission pipeline infrastructure has in July 2020 been presented by 11 large European TSOs from Belgium, the Czech Republic, Denmark, France, Germany, Italy, Spain, and Sweden[51]. For 2040 a dedicated hydrogen pipeline system of about 23,000 km[52] has been devised to connect Eastern with Western and Southern with Northern Europe.

Domestic vs imported hydrogen provision

The interest in domestic or imported hydrogen goes hand in hand with the choice of green or blue/turquoise hydrogen. In principle, the following ambitions have been identified:

- **Domestic hydrogen:** Typically, Member States with ample renewable electricity potentials (e.g. Spain, Portugal, Italy) foresee to exploit their domestic resources to both supply their own energy demand (e.g. Italy) and furthermore to supply renewable hydrogen to other Member States (e.g. Spain). But also Member States with limited renewable energy potentials but a high ambition to exploit these potentials for own purposes (e.g. Austria,

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[48] Industry has understood this urgent upscaling need and approached politics to develop an adapted regulatory and financially viable framework allowing the operation of large-scale hydrogen supply chains, e.g. expressed by the recent consultation document of the German Gas Transport Association (FNB), collecting as many as 31 industry proposals for reasonably sized PtG plants to be installed by 2030 the latest. The German National Hydrogen has now addressed the issue of electricity price support http://www.bmz.de/en/press/aktuelleMeldungen/2020/juni/200610_pm_031_Federal-Government-adopts-National-Hydrogen-Strategy-and-establishes-National-Hydrogen-Council/index.html

[49] In these Member States, hydrogen transport pipelines will only be built after 2030 when the hydrogen demand will grow significantly.

[50] For their comprehensive consultation document, the German FNB has earmarked 1,284 km of transport pipelines to be converted to 100% hydrogen operation, the majority of which shall be refurbished methane pipelines at investment costs of no more than 10% as compared to new-built dedicated hydrogen pipelines.

[51] European Hydrogen Backbone – How a dedicated hydrogen infrastructure can be created. Study report by Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas and Teréga, July 2020, https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/.

[52] 6,800 km by 2030.

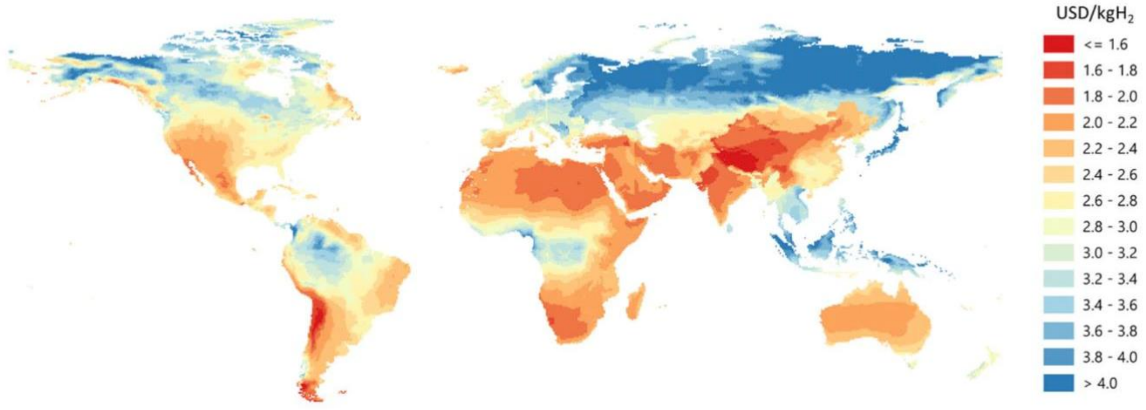
Germany and the Netherlands) have flagged their interest in domestic hydrogen production, typically but not limited close to the renewable energy sites[53].
- **Imported hydrogen:** We have not identified a current or emerging hydrogen strategy which solely focuses on import of (green) hydrogen. Yet, for Member States with limited own renewable energy resources, most hydrogen would have to be imported unless produced from fossil-based energy (natural gas) with CCS or methane pyrolysis. In this respect, Member States such as Belgium, Luxemburg or Slovenia are typical future hydrogen import candidates. They are counterbalanced by Member States which explicitly view themselves as potential green hydrogen exporters such as Spain and Portugal.
- **Combination of domestic and imported hydrogen:** As far as national hydrogen strategies are emerging, most of them understand the future potential of domestic production in view of economic value creation, if competitive. For economic reasons and the lack of sufficient own renewable electricity potentials, hydrogen imports are understood as a realistic option towards a CO_2-free energy system. Depending on production costs, these imports can be from within Europe (e.g. Spain) or from outside of Europe (e.g. North Africa and Ukraine[54]).

Also, the ambition in hydrogen import varies across the European regions:
- **Energy intensive Member States:** hydrogen supply costs are the most important decision point, independent from the hydrogen source (from within EU, neighbouring countries by gas infrastructure or from international sources such as Saudi Arabia or Southern Africa[55]).
- **Member States with an obvious interest in domestic value creation:** options for the provision of hydrogen from within the EU or neighbouring regions will develop from Member States offering their own domestic renewable energy sources for export (e.g. Spain or Portugal) or from providing hydrogen transmission services (e.g. Spain or Italy), favourably using their gas infrastructures.

To demonstrate the differences in hydrogen costs per World region, IEA has reported hydrogen production costs from hybrid solar PV and onshore wind as shown in Figure 1-11. As can be seen, the only European Member States which may produce hydrogen at large scale at costs of as low as 1.6 US$/$kg_{H2}$ or below, are Spain, Portugal, and Southern Italy. This compares to much higher hydrogen production costs of 3-4 US$/$kg_{H2}$ in most other parts of the EU. This gives rise to a general idea of the principal future hydrogen flows, i.e. from South (ES, PT, North Africa) to central EU (including East and West), partially also from North (North Sea neighbour countries, NO) to Central Europe as well as from East (Russia, Ukraine) through eastern to central Europe. Adding transport costs via pipeline (as gas) versus ship (as cryogenic liquid) is treated in a separate chapter. Here, it should only be added that for shorter transport distances (e.g. from within the EU or from neighbouring countries) hydrogen imports as a gas by pipeline would be cheaper by up to a factor of 10 than by cryogenic liquid via ship.

[53] For the case of northern Germany, the five northern German (= coastal) states have claimed in a separate regional hydrogen strategy to offer their on- and offshore wind production and its further distribution to other parts of Germany in the form of hydrogen, the electricity transport grid soon reaching its acceptable capacity ceiling. If the target of the federal German 5 GW_{H2} production capacity will be reached by 2030 the total German green hydrogen claimed by the national German hydrogen strategy will be provided from the north. The gas grid will need to provide the required transport capacity by then. [Norddeutsche Wasserstoff Strategie. Wirtschafts- und Verkehrsministerien der norddeutschen Küstenländer Bremen, Hamburg, Mecklenburg-Vorpommern, Niedersachsen und Schleswig-Holstein, 7th November 2019].
[54] E.g. [https://www.hydrogen4climateaction.eu/2x40gw-initiative].
[55] E.g. African Hydrogen Partnership project, https://www.afr-h2-p.com/; or K. Westphal, S. Doge, O. Geden: The International Dimensions of Germany's Hydrogen Policy. Comment 2020/C 32 by Stiftung Wissenschaft und Politik (SWP), June 2020, https://www.swp-berlin.org/10.18449/2020C32/.

Figure 1-11 Hydrogen production costs from solar hybrid PV and onshore wind systems in the long-term[56]



1.3.3 Hydrogen infrastructure

Concerning hydrogen infrastructure, the following seven criteria are assessed further:

- Extent of dedicated hydrogen grid at TSO-level
- Extent of grids with hydrogen-blending at DSO-level
- Existing private hydrogen grids
- New hydrogen infrastructure versus methane infrastructure refurbishment
- Existing seasonal hydrogen storage potential (salt caverns, other structures)
- Decentral, opportunity strategy vs national, harmonised gas strategy development
- Interest in future use of biomethane in gas grid

Extent of dedicated hydrogen grid at TSO-level

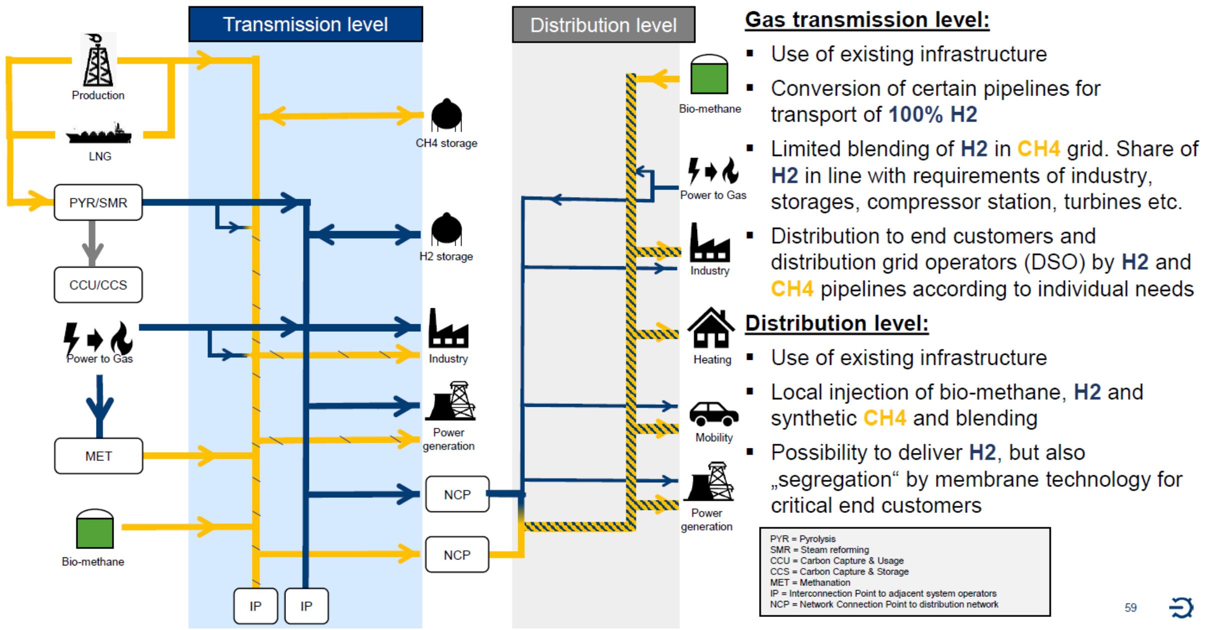
This topic has partially already been addressed in chapter 1.3.1. When it comes to the issue of transporting hydrogen via the transmission grid, two basically different strategies have been observed. They depend on the intrinsic differences of Member State transmission grid structures and type of gas in the high-pressure transmission grid:

- **Dedicated TSO H_2-grid:** For Germany the FNB-report authored by the TSOs [57] (see Figure 1-12) argues that that the admixture option in the transmission grid will be limited, as (a) sufficient parallel gas grid capacity would be available to operate methane and hydrogen grids in parallel in the transition phase and (b) the detrimental effects (materials, process equipment, end-user compatibility, …) of an admixture should be avoided. A 100% H_2 conversion is therefore the preferred option.
- **H_2-blending at TSO-level:** For Spain with (a) a gas transmission grid of less density and (b) the use of a high share of biomethane injected into the transmission grid today and in the future, blending of hydrogen with methane in the transmission grid has been mentioned as an option. For other peripheral Member States such as Italy the situation is believed to be similar.

Whereas with a growing share of hydrogen in the methane grid, also the second type of Member States will start to build or to convert to dedicated hydrogen pipelines, but later. Member States will need to develop plans striking the right balance between keeping methane-rich transmission grid sections for the uptake of biomethane as well as developing an interconnected dedicated hydrogen grid. For this reason, it has been communicated in different stakeholder consultations for this study, that the gas industry in individual Member States foresees a period of focused national gas grid development, driven by individual gas regulatory regimes. Even though, the need for early harmonisation of specifications to ensure the interoperability of the European gas grid has been flagged in our stakeholder interviews in the interest to avoid later trade barriers for an EU spanning fully integrated hydrogen gas markets towards 2050.

[56] The Future of Hydrogen - Seizing today's opportunities. Technology report — June 2019, https://www.iea.org/reports/the-future-of-hydrogen#key-findings.
[57] See [Gas Development Plan 2020-2030, draft. FNB, 4th May 2020, https://www.fnb-gas.de/media/fnb_gas_2020_nep_entwurf_en.pdf].

Figure 1-12 Suggestion for a future German gas grid infrastructure with close to zero hydrogen admixture at TSO level[58]



Extent of grids with hydrogen-blending at DSO-level

The opportunities and challenges of admixture/blending of hydrogen to the methane distribution grid at medium and low pressures have also been described in a recent study commissioned by DG Energy[59]. Yet, in contrast to the challenges as reported for the transmission grid these appear to be less fundamental and can be overcome specifically for the transition period by the following approaches:

- **Incompatibility with end-users:** (a) (stepwise) adapt end-use appliances and instrumentation or (b) limit admixture to grid sections with no or only few challenges and (c) apply de-mixing equipment for H_2-critical end-users in a grid section.
- **Missing regulatory framework:** develop adapted national framework
- **Continuously constant admixture rate:** regionally connect distribution grids to transmission grids which transport pure hydrogen as well as methane in parallel with sufficient (seasonal) storage capacity, allowing to level out any locally or seasonally fluctuating distribution grid gas blends and gas demand.

Until now, practical experience with the blending of hydrogen to natural gas has been gathered in different Member States[60]. Admixture rates of 5, 10, 20 or even 30 vol%$_{H2}$ have been mentioned. With 30 vol% of hydrogen admixture being the equivalent to a 10% CO_2-emission reduction, the achievement towards the fulfilment of EU's climate goals is however limited. This may be one of the reasons why beyond a 30 vol% H_2-admixture a full hydrogen conversion seems the preferred solution. However, other than the 100% conversion strategy for the UK[61], no single national strategy for a H_2-blending pathway has yet been developed as the local conditions vary from distribution to distribution grid.

Existing private hydrogen grids

A limited number of hydrogen pipeline grids for industrial purposes have been developed over time, in areas with large chemical industry clusters. These investments are solely market-driven by hydrogen end-use and hydrogen production economics. Today, these grids, limited in size and

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[58] See [GEODE Webinar, Towards the new age of gas networks. Presentation by J. Bergmann, Open Grid Europe, 5th May 2020].
[59] Van Nuffel, L; Gorenstein Dedecca, J.; Yearwood, J.; Smit, T.; Bünger, U.; Altmann, M.; Fischer, Ch.; Michalski, J.; Raksha, T.; De Vita, A.; Zerhusen, J.: Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure. Study for DG Energy, September 2019.
[60] See [Nitschke-Kowsky, P.; Weßing, W.; Dörr, H.; Kröger, K.: Praxiserfahrungen mit der Wasserstoffeinspeisung in das Gasnetz, energie / wasser-praxis, 10/2015]; and [Snam: hydrogen blend doubled to 10% in Contursi trial: 8th January 2020, https://www.snam.it/en/Media/news_events/2020/Snam_hydrogen_blend_doubled_in_Contursi_trial.html]; or [Alter, L.: UK Pilot Project Mixes 'Green' Hydrogen With Natural Gas, 17th June, 2020, https://www.treehugger.com/uk-pilot-project-mixes-green-hydrogen-natural-gas-4856218].
[61] See H21 Leeds City Gate: https://www.h21.green.

capacity compared to the natural gas grids[62], are operated by industrial gases companies, with no Third Party Access and are transporting hydrogen qualities governed by industry specific safety rules and hydrogen purities[63]. The hydrogen price is set by the relevant pipeline operator (monopoly, no unbundling), infrastructure hardware depreciation is coined by industrial rules, i.e. at different time-scales than for natural gas grids today.

The most extensive industrial hydrogen grids crossing public land in the EU are situated along the North Sea Coast, connecting conventional fossil-based hydrogen producers[64] and industrial hydrogen users in France, Belgium, and the Netherlands (843 km, operated by Air Liquide), close to Rozenburg (the Netherlands, 50 km, operated by Air Products), in North Rhine-Westphalia (Germany, 24 km, operated by Air Liquide) and in the Bitterfeld-Leuna chemical industry triangle (Germany, 139 km, operated by Linde). In addition, some further but minor dedicated pipeline sections, such as one connecting the DOW with the Yara industrial sites (the Netherlands, 21 km, operated by a Gasunie subsidiary) and one connecting the chemical industry cluster in Brunsbüttel with a refinery in Heide (Germany, 38 km, operated by Linde) are in operation. Finally, several pipelines or systems are operated on private industry grounds. In total, the existing European industrial hydrogen pipeline grids comprise a length of ca. 1,500 km. Concerning the transported energy, the industrial hydrogen grids' capacity is dwarfed by the quantity of natural gas transported through Europe today. With industrial pipeline diameters of 100-300 mm and gas transmission pipelines of 600-1,000 mm, the hydrogen transport capacities of the private industry pipelines are a factor of at least 10 lower and limited in regional outreach.

In principle, the industrial gas industry would be open for an extension of its existing private grids, mainly focusing on the end-use development in different sectors. This could be the supply of hydrogen to further industry sites with emerging hydrogen energy or feedstock needs or to supply hydrogen to refuelling stations for mobility. Yet, due to the different hydrogen purity levels, in the latter case, hydrogen purification technology would have to be planned onsite the refuelling stations.

Today, it is not clear whether and how the existing hydrogen pipeline grids could be connected to the to-be-developed dedicated hydrogen grids that would provide open access to multiple grid users. Major issues for discussion are of technical (hydrogen purity, delivery pressure, capacities, …) and regulatory nature (third party access/monopoly, regulation/unbundling, …).

New hydrogen infrastructure versus methane infrastructure refurbishment

The comparison of refurbished and new-built hydrogen pipeline systems to stepwise grow the amount of hydrogen in the gas grid, has been developed by gas industry on the basis of existing know-how:

- In the early phase of the gas grid, synthesis gas from coking processes has been applied with a high hydrogen content of 50 to 60 vol%.
- Also, the idea of introducing hydrogen as green gas to substitute methane in the gas grids is more than 30 years old. Since the late 80s several studies and measurement campaigns have assessed materials and processes for operation in both methane and hydrogen environments.
- With the idea of admixing hydrogen in increasing percentages new studies have been launched[65].
- Finally, and as presented in chapter 1.3.3 private industry-based grids have been in multi-year operation within large industrial centres across the world.

[62] Typical hydrogen industry pipeline sizes are 100-300 mm in diameter and medium pressure of 2-3 MPa, carry hydrogen at different purity levels which may even contain synthesis gas components such as CO, comparing with natural gas transport pipelines of 600-1,000 mm diameter and pressures of 8-10 MPa with much higher transport capacities by at least a factor of 10.
[63] Industry type hydrogen is considered as too impure for use in mobility and stationary hydrogen applications involving fuel cells. Industry type hydrogen is much cheaper than hydrogen that is suitable for fuel cells.
[64] Typically, from steam methane reforming but also hydrogen as by-product from industrial processes such as chlorine-alkaline electrolysis.
[65] See e.g. M. Henel, H. Bauer, M. Simm, E. Wanzenberg, O. Huising: Energiewende mit Wasserstoffrohren „H2Ready" und Umstellung existierender Erdgasnetze. gwf-Gas + Energie, 03/2020, pp. 32-45] or [Appraisal of Domestic Hydrogen Appliances. Report by Frazer-Nash Consultancy, prepared for the Department of Business, Energy & Industrial Strategy, February 2018, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699685/Hydrogen_Appliances-For_Publication-14-02-2018-PDF.pdf]; or [Heating with hydrogen: World's first domestic hydrogen-powered boiler – pilot project in the Netherlands, https://fuelcellsworks.com/news/heating-with-hydrogen-worlds-first-hydrogen-powered-domestic-boiler-pilot-project-in-the-netherlands/, 15th January 2020].

According to a German stakeholder, the recently presented NEP 2020 consultation report by the German Association of Gas Transmission Operators FNB[66] has carried out a detailed calculation for the 1,294 km of pipeline to be operated on 100% hydrogen by 2030. For this purpose, the association members have been asked to provide data on the announced hydrogen project plans (a total of 31 PtG-plants) and the required hydrogen gas infrastructure has been modelled based on concrete existing or to-be-built hydrogen pipeline for transmission stretches. The result was a suggestion of 1,142 km of refurbished pipelines and 94 km of new hydrogen pipelines[67]. For these specific pipelines, the total refurbishment costs were estimated at 310 M€ and the new-built pipeline costs at 220 M€, resulting in specific refurbishment costs of 271 €/m of pipe and new-built costs of 2,340 €/m, i.e. a factor of almost 9 higher than the refurbishment costs. As a result, we can assume that refurbishing exiting methane infrastructure may offer a huge economic benefit compared to building new hydrogen pipelines. This result amplifies the understanding that the existing gas grid is a high value asset the use of which can be prolonged also in a hydrogen gas infrastructure.

The European Hydrogen Backbone (EHB) report provides slightly different figures. Of the 22,900 km total hydrogen pipeline grid envisioned for Europe, 18,000 km (75%) are assumed to be retrofitted NG pipelines, comprising about 50% of the total costs. The cost per km of refurbished hydrogen pipelines would hence amount to 33% of the cost of new-built hydrogen pipelines. As no further cost details are provided, we anticipate that part of this difference is based on the costs for compression which may have been accounted for in different ways in both calculations. As the current analysis has to be seen as preliminary with no experience from the field, a 9-33% bandwidth is taken as a reasonable initial cost differential range.

Existing seasonal hydrogen storage potential (salt caverns, other structures)

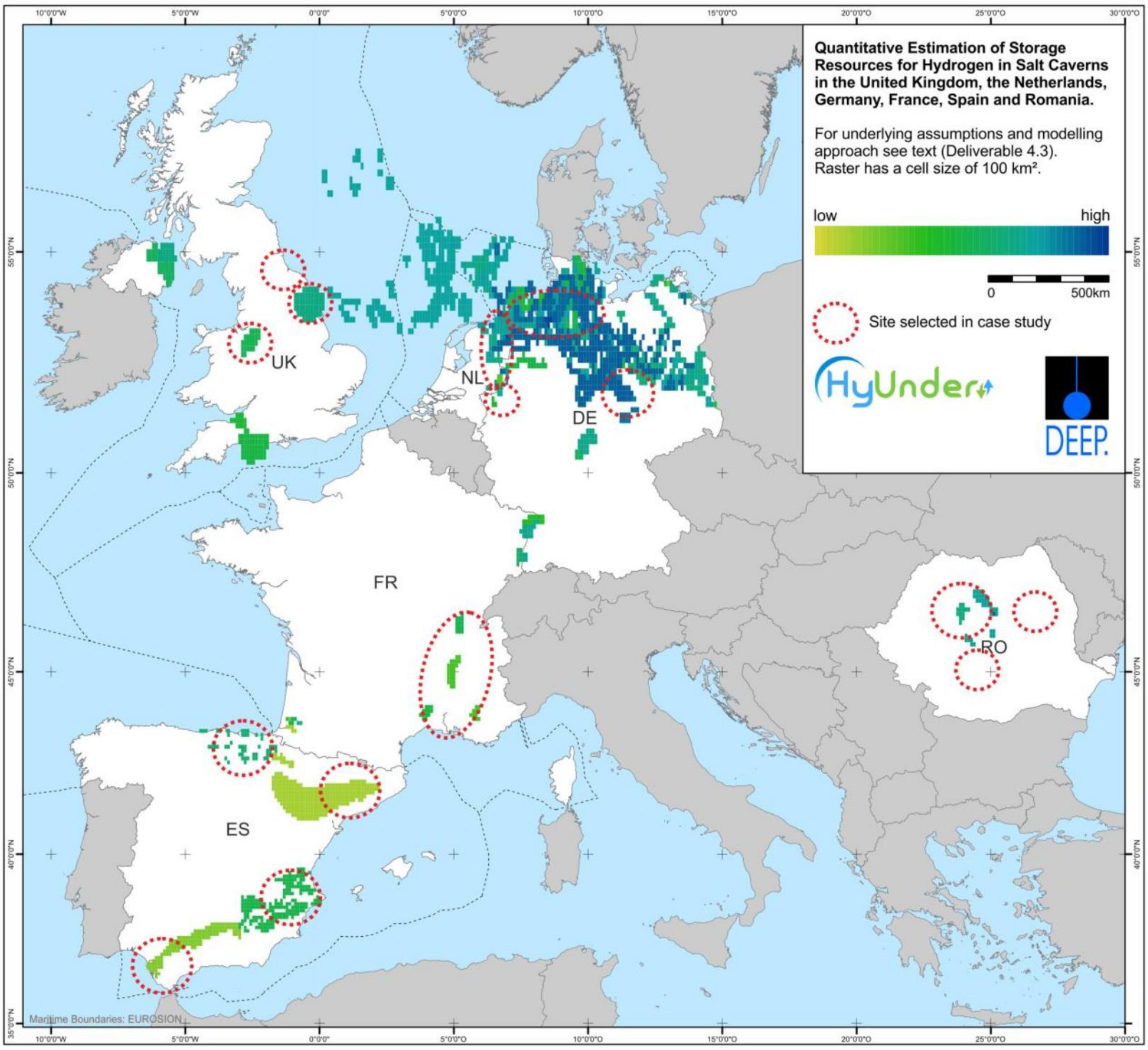
Seasonal underground storage of natural gas today uses large to very large porous or hollow below ground structures, which are limited to geologically relevant sites:

- aquifers,
- depleted gas fields,
- salt caverns and
- rock caverns.

So far, safe hydrogen storage has only been confirmed and also mapped across the EU for salt caverns (see Figure 1-13), depleted gas fields and aquifers have been in the focus of recent studies and pilot test activities[68]. Currently, the FCH-JU has called for a research and mapping activity for Europe to better understand the potential of other than salt cavern hydrogen storage across all of Europe[69]. Even though not covering all of EU27, a view at the map shows that underground storage in salt caverns is limited to rather few locations and Member States. The largest potential is under the southern North Sea and its bordering countries. Therefore, if Europe's salt cavern storage potential could be extended by storage in porous underground caverns, the applicability of hydrogen to cope with the seasonality of the heating demand and to support the electricity system in integrating high volumes of variable renewable electricity could be greatly enhanced.

[66] NEP – Netzentwicklungsplan: see [Gas Development Plan 2020-2030, draft. FNB, p. 148, 4th May 2020].
[67] The balance was 57 km of new built H-gas pipelines.
[68] Estudio de Impacto Ambiental, Proyecto Piloto Almacenamiento, Subterráneo de Gas Natural e Hidrógeno. Project by Hychico S.A., Argentina, 2013; St. Bauer: Underground Sun Conversion: Erneuerbares Gas zur Speicherung von Sonne und Wind. 7.03.2019, https://www.innogy.com/web/cms/mediablob/de/3950142/data/3880198/2/esk-im-ueberblick/vortraege-zum-download/Underground-Sun-ConversionStephan-Bauer.pdf.
[69] Annex to FCH-GB-2019-14.Fuel Cells & Hydrogen 2 Joint Undertaking (FCH 2 JU)2020 Annual Work Plan & Budget, p. 49, https://www.fch.europa.eu/sites/default/files/AWP%202020_final29112019_clean%20%28ID%207481618%29.pdf.

Figure 1-13 Map of European salt cavern structures across Europe[70]



In brief, the regional coincidence of seasonal hydrogen storage potential and the availability of renewable electricity potentials at large scale is a good prerequisite for avoiding expensive electricity grid extensions. This is the case for Spain, Denmark, the UK, the Netherlands, and Germany. Though not explicitly mapped, also Austria and Poland offer large underground storage potentials for hydrogen[71].

Cavern-based gas storage on a system level is one of the cheapest long-term energy storage options, specifically apt to cover seasonal imbalances which are typical for today's and potentially also future gas markets (heating, electricity load balancing). Based on a full-cycle storage and re-electrification, costs for seasonal electricity storage in hydrogen/salt cavern-based systems were found to be 0.1…0.3 €/kWh for central European conditions[72].

[70] [J. Simón; D. Albes; M. Ball; A. Becker; U. Bünger; S. Capito; L. Correas; R. Evans; A. Ferriz; I. Iordache; O. Kruck; H. Landinger; J.-C. Lanoix; A. Le Duigou; J. Michalski; H. Mozaffarian; T. Rudolph; D. Schitea; P. Speers; M. Weeda: Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe. Study for FCH-JU by partner group, Deliverable No. 6.3 - Joint results from individual Case Studies, 14th July 2014, http://hyunder.eu/wp-content/uploads/2016/01/D6.3_Joint-results-from-individual-case-studies.pdf].
[71] R. Tarkowski, G. Czapowski: Salt domes in Poland e Potential sites for hydrogen storage in caverns. Int. J. Hydrogen Energy, 43 (2018), pp. 21414-21427.
[72] These costs include conversion and re-conversion of electricity to gas. F. Crotogino, S. Donadei, U. Bünger, H. Landinger: Large-Scale Hydrogen Underground Storage for Securing Future Energy Supplies. 18th World Hydrogen Energy Conference 2010 - WHEC 2010.

Decentral, opportunity strategy vs national, harmonised gas strategy development

Background for this criterion was the question whether a national hydrogen strategy and – as part of it – the hydrogen gas infrastructure strategies are currently based on a local, company or industry sector-based strategy or whether a comprehensive national hydrogen strategy has already been formulated and published or is at the development stage. As the role of hydrogen as an energy carrier is currently gaining much interest combined with high learning gradients, this criterion is one of momentary nature. Nevertheless, it tells about the impact of a Member State's ambition in having understood the potential contribution of hydrogen and its universal contribution as an energy carrier across all energy sectors (sectoral integration) and the implementation of a decision process. In our interviews we have learnt that a number of Member States foresee the development of a national hydrogen strategy to be published soon, even though so far only France (2018) Germany (2020), the Netherlands (2020) and Portugal (2020) have published their national strategies[73].
Screening the national hydrogen strategies or related recent publications, a strong interest in inter-regional or supra-national cooperation within the EU and also international cooperation becomes apparent at this early stage of development going beyond the formulation of regional and national hydrogen strategies. The following examples underpin the different facets of cooperation anticipated:

- **Inter-regional cooperation:** The regional Northern German hydrogen strategy[74] explicitly points at a cooperation beyond their own territory within Germany (Brandenburg, North Rhine-Westphalia) as well as outside of Germany with the Northern Netherlands (region of Groningen) or Scandinavia and on a technology basis with countries like China, Japan, South Korea, and USA/Canada. For potential imports of hydrogen, North Africa, the Middle East, and Australia are mentioned.
- **One-sided cooperation proposal by one Member State:** Spain offers to cooperate on the export of renewable electricity and green hydrogen on economic grounds[75].
- **Bi-lateral cooperation between Member States:** Both national hydrogen strategies of the Netherlands and Germany raise the need for bi-lateral cooperation on the basis of at least balancing energy supply and demand and the development of hydrogen infrastructures.
- **Multi-Member State cooperation:** At EU level, multi-lateral cooperation initiatives have been published such as the "Joint Political Declaration of the Pentalateral Energy Forum on the role of hydrogen to decarbonise the energy system in Europe" between Austria, Belgium, France, Germany, Luxembourg, the Netherlands, and Switzerland[76].

Interest in future use of biomethane in gas grid

As documented in the green gas study for DG Energy in 2019[77], assessing the future role of hydrogen and biomethane in the European gas infrastructure, it was found that the interest in the use of the gas grid for transporting biomethane varies across EU Member States. Whereas e.g. in Spain much of the biomethane is admixed to the NG grid at transmission level, it is fed into the gas distribution level in most other Member States. The impact of accommodating both green hydrogen and biomethane in the future, might hence be different depending on the Member State. As a general approach, stakeholders have argued that three options may be applied to accommodate both green gases:

- Blending hydrogen and methane to methane grids, and – also depending on the local situation – in general with a higher focus on hydrogen over time (mostly at distribution but for the example of Spain also at transmission level),
- Keeping or developing parallel methane and hydrogen grids depending on local production capacities and end-use development, hand in hand with the production of synthetic

[73] **France:** https://www.ecologique-solidaire.gouv.fr/sites/default/files/Plan_deploiement_hydrogene.pdf, **Germany:** http://www.bmz.de/en/press/aktuelleMeldungen/2020/juni/200610_pm_031_Federal-Government-adopts-National-Hydrogen-Strategy-and-establishes-National-Hydrogen-Council/index.html
[74] See https://www.hamburg.de/contentblob/13179812/f553df70f865564198412ee42fc8ee4b/data/wasserstoff-strategie.pdf
[75] See https://www.dw.com/de/spanien-braucht-neue-industrien-setzt-auf-grünen-wasserstoff/a-54035381
[76] See https://www.bmwi.de/Redaktion/DE/Downloads/P-R/penta-declaration-signed.pdf?__blob=publicationFile&v=4
[77] Trinomics, LBST, E3M (2019): Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure, **the Netherlands** https://www.government.nl/binaries/government/documents/publications/2020/04/06/government-strategy-on-hydrogen/Hydrogen-Strategy-TheNetherlands.pdf; **Portugal:** [Portuguese Government approves hydrogen strategy, €7b investments, 24th May 2020, https://fuelcellsworks.com/news/portuguese-government-approves-hydrogen-strategy-e7b-investments/].

methane from hydrogen in cases this is deemed a suitable and competitive transition option and
- Gradually reducing the methane operated grid share[78].

Also, mixed approaches of the above options could be possible. E.g. for Spain with its central biogas schemes mostly for upgrading to biomethane and feeding it into the transmission grid, also characterised by a dedicated and well utilised gas infrastructure today, a 100% conversion to hydrogen is not in view in the short- or medium term. Therefore, a methane transmission grid needs to remain in place, unless alternative local end-uses will be identified or – with adapted technology and regulation – methane may be blended with H_2-rich gas flows of 80 vol%. This situation would only change in the long-term, if additional and possibly parallel dedicated hydrogen transmission pipelines were built, e.g. to import green hydrogen from North Africa in the South or export it to central Europe in the North.

1.3.4 Hydrogen end-use

For better understanding the hydrogen strategy end-use specific considerations by EU Member States, the following four criteria were considered in more detail:

- Share of end-use sectors served by hydrogen (industry, mobility, heat, power production)
- Seasonality of hydrogen demand
- Dispersed small vs central large users
- Blended hydrogen-users or pure hydrogen users

Share of end-use sectors served by hydrogen (industry, mobility, heat, power production)

The majority of all hydrogen used today, is used as chemical feedstock for industry and typically produced from fossil energy, i.e. by steam reforming of natural gas (SMR). When Member States developed their early hydrogen energy strategies, these hydrogen quantities – equivalent to an annual EU market size of 325 TWh_{H2}/yr. or 9.75 Mt_{H2}/yr. in 2015 – were not within the scope. Instead, the initial focus of future hydrogen end-use was on its use as a vehicle fuel or for mobility, and the inclusion of industry has happened only lately.

This extended perspective to a wider use of hydrogen as universal energy carrier may be a consequence of understanding its potentially strategic role in the energy system. Major arguments in favour of applying hydrogen energy in the future include its use for load-levelling of variable renewable electricity, the need for sectoral integration to unlock economic synergies, the potential of the gas infrastructure (transmission and distribution) to transport/store energy in molecules efficiently, and its capability for long-distance energy transport, including for imports, etc. Based on their energy system structures today, individual Member States have recently begun to communicate different interests in which end-use sectors they envision hydrogen to be introduced at large scale. The following four fundamental drivers for an introduction of hydrogen energy in one or more sectors have been identified, with the initiating sector mentioned in parenthesis[79]:

- **Ample RES-E potential or ambitions as well as seasonal hydrogen storage potentials:** apply hydrogen for load-levelling of fluctuating renewable electricity supply or for hydrogen export (power sector)
- **Technology innovation:** develop opportunities for value creation from innovative technologies along the hydrogen value chain which can serve one or possibly simultaneously several end-use sectors (e.g. fuel cells or hydrogen storage equipment for transport and stationary applications[80]) (mobility and or residential heating end-use as well as manufacturing/processes for industry)
- **Existing gas infrastructures:** sustaining existing high value energy assets of the Member States' gas infrastructures refurbished for CO_2-free gases (gas sector)
- **Existing hydrogen use in industry:** transfer existing know-how in hydrogen process technology and safe operations to other energy applications (industry sector)

78 For **Germany** an extreme position is the option that with hydrogen becoming the dominant gas in the gas grid towards 2050, biomethane injection may become limited and available biogas could rather be locally used for decentralised power (and heat) production.

79 Naturally, EU Member States are unified by their ambition to fulfil their EU energy policy obligations across all end-use sectors. This ambition has therefore not been added to the drivers list.

80 Only recently Daimler has announced a refreshed interest in the development of fuel cell technologies for mobile applications, e.g. in cooperation with Volvo, and for stationary CHP plant development in cooperation with Rolls-Royce Power Systems ([Jetzt aber Vollgas. Süddeutsche Zeitung, 30th June 2020]).

The four drivers cannot be fully separated; the mix of hydrogen end-uses in any Member State will vary based on its existing energy (hydrogen energy) as well as industry structures (hydrogen as base chemical). The **UK** is an obvious example of a (former) Member State that focuses on the use of hydrogen for heating based on the strong traditional role of natural gas for this sector. As a consequence, hydrogen is posed to play an important role for this sector applying similar technologies (boilers)[81]. Residential energy supply being in focus in the UK, studies have indicated its use also for industry and mobility. The end-use profile for hydrogen is much less obvious in other countries with little or no hydrogen tradition. **Portugal**, much like **Spain** currently takes a fresh look at the potential contribution of hydrogen in their energy systems, starting from serving as energy carrier for the export of RES-E[82] and rather open for its application mostly in mobility or industry (e.g. ammonia production). Flagging its interest in value creation from innovative green hydrogen technologies, the **German** national hydrogen strategy has put its economic ambitions high on the agenda, the second major ambition to fulfil its GHG targets across all energy sectors[83]. Germany's hydrogen strategy is much facilitated by its tradition as largest user of hydrogen in the industry sector. So far, **Austria** and **Poland** have been unspecific concerning their future ambition for hydrogen end-use. From interviews and recent studies, it is understood that hydrogen might be applied across all end-use sectors but that industrial hydrogen use will stand out for both Member States until 2030 to reach economies of scale, and therefore obviously in early clusters[84]. The injection of hydrogen into the gas grid to also serve mobility and the residential sectors would be addressed in a consecutive step. More details are to be expected in the national hydrogen strategies of both Member States, expected to be published by the end of 2020.

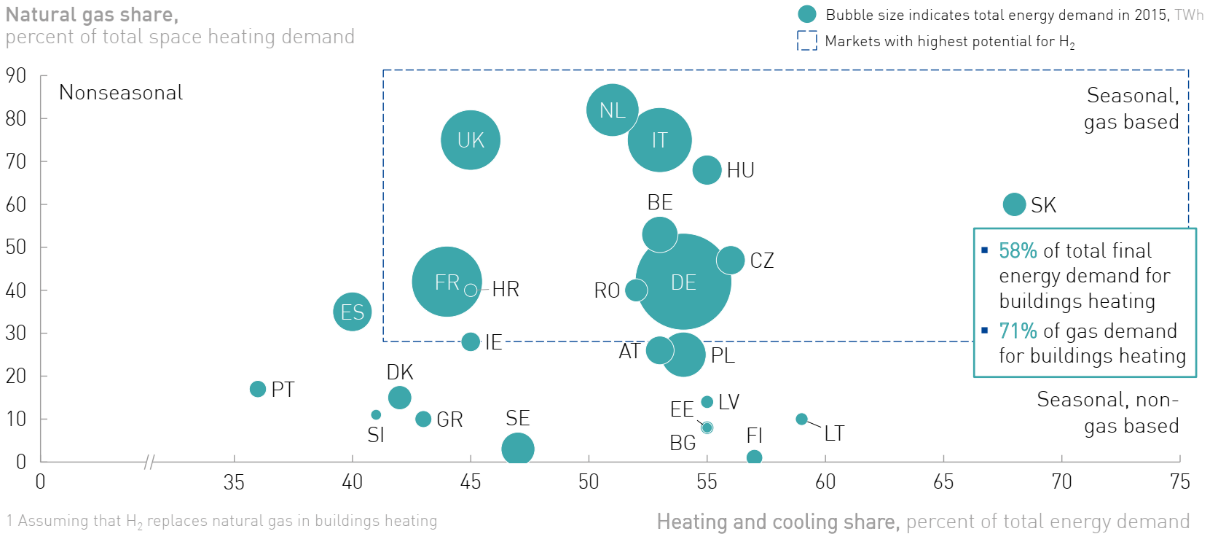
Seasonality of hydrogen demand

The major driving force behind the seasonal variation of energy demand is the demand for space heating, typically representing a fourth of all energy use, and mostly covered by fossil energy today (natural gas, mineral oil, coal)[85], and hence one of the major GHG emission sources. The seasonality in energy demand varies by region (North or South), the North suffering from the typically strong winter/summer variation, only partially buffered by higher building standards in some Member States. This dependency has recently been analysed for the FCH2-JU[86] and is displayed in Figure 1-14. The graph does not necessarily represent the future energy demand for heating/cooling, possibly to be partially contributed by hydrogen, as other options have not been addressed such as behavioural energy savings, technical and operational efficiency, and electric heat pumps.

The figure groups the prime candidate countries for the use of hydrogen for space heating/cooling, and shows the natural gas share in the heating sector versus the combined heating & cooling share as percent of total final energy demand, also indicating the total energy demand in 2015 as a third dimension by bubble size. According to this graph, the following Member States have a high potential for using hydrogen for heating/cooling purposes: Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Italy, the Netherlands, Romania, Slovakia, and the UK, the underlined ones coinciding well with those countries having the densest natural gas grids today (chapter 1.3.1). Out of these Member States, only France, Germany, and the Netherlands have published national hydrogen strategies while Belgium, Italy, and the UK are in the process of preparing one, NL however with little ambition in using hydrogen for heating purposes, insulation, energy efficiency and electrification apparently being the preferred options.

[81] See [Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain. Prepared by Navigant for Energy Networks Association, 21st October 2019].
[82] Pedro Furtado (REN) and Christian Pho Duc (SmartEnergy): [World Hydrogen Congress, Green Power Global Webinar: Greening the gas grid, 11th May 2020].
[83] Die Nationale Wasserstoffstrategie, Bundesministerium für Wirtschaft und Energie (BMWi), Juni 2020, http://www.bmz.de/de/zentrales_downloadarchiv/wasserstoff/Nationale-Wasserstoffstrategie.pdf.
[84] Wasserstoffstrategie für Österreich. Konzeptentwurf Sektion VI, Wirtschaftskammer Österreich (WKO), Wien, Mai 2020, https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwinwNqnzI7tAhXODOwKHQB1B2EQFjADegQIAhAC&url=http%3A%2F%2Fwko.at%2Fooe%2FBranchen%2FIndustrie%2FZusendungen%2FKonzeptentwurf%2520Sektion%2520VI%2520Wasserstoffstrategie%2520f%25C3%25BCr%2520%25C3%2596sterreich.pdf&usg=AOvVaw3xOpJIn7ZhWxxwwqbz6ve3; Andreas Veigl: Energiezukunft Österreich - Szenario für 2030 und 2050. Study commissioned by GLOBAL 2000, Greenpeace and WWF, June 2015.
[85] Exceptions are France (nuclear electricity) and the Nordic countries (hydropower) for space heating.
[86] Hydrogen Roadmap Europe - A sustainable pathway for the European energy transition. McKinsey study for the Fuel Cells and Hydrogen 2 Joint Undertaking, February 2019, https://www.hydrogeneurope.eu/news/hydrogen-roadmap-europe-has-been-published.

Figure 1-14 Seasonality of the energy demand for heating and cooling by Member States in Europe[87]



Dispersed small vs central large users

Across EU Member States' strategies both central and decentral ramp-up schemes have become apparent. A major decision criterion for emerging hydrogen energy applications in central schemes is the ambition for scaling up, which in turn is driven by the goal to drive down specific hydrogen production and infrastructure costs. The awareness of the necessary economies of scale has developed only recently in the growing interest of installing cheaper hydrogen refuelling infrastructures for mobility[88] or building new or refurbishing existing NG transmission pipelines for full hydrogen operation[89]. The central concepts typically apply for Member States with existing large-scale energy infrastructures for energy production/provision and end-use. This is typically the case for central, i.e. North West Europe (including Italy).

The major aspect behind decentral hydrogen supply schemes are missing opportunities to scale-up applications, such as the absence of large central potential short-term hydrogen users, i.e. large industry clusters (chemical industry, fertiliser industry, steel industry or large refineries). The other missing link is existing large-scale infrastructure to be readily converted from natural gas today to hydrogen in the near-term, as is e.g. the general case for the peripheral EU Member States. Whereas in central Europe gas transportation corridors comprise parallel pipelines, lending themselves for a stepwise conversion from methane gas to hydrogen, the transition is more difficult for transmission gas grids relying on single pipeline corridors, as the choice may then be either to apply H_2-blending or otherwise converting from methane to hydrogen in one big leap. In contrast, the challenges for the distribution grid are similar for central and peripheral Member States, which typically supply dispersed customers. They have various options, from reducing the distribution grid extent, H_2-blending or full H_2-conversion. An example for a full conversion of distribution grids to hydrogen is the Leeds 21 City Gate project, whereas in Germany, some municipalities may opt for the blending option, supported by a stable H_2-supply from the transmission grid. Denmark has stated in its national energy strategy, that with biomethane having a major role also in the future, a basic methane grid needs to be kept in operation for biomethane collection at distribution level. Also, hydrogen will only be transported in the TSO grid and "last meter" connections to individual houses will be given up in favour of electric heat pumps and district heating systems.

Relevant examples for the different approaches are the hydrogen gas strategies in central Europe (**Germany, the Netherlands**, …) which target a mixed central/decentral hydrogen end-use development scheme to supply both large central hydrogen users (industry) and likewise dispersed users (heating, mobility). Supplying large users with hydrogen can then be achieved by direct

[87] Hydrogen Roadmap Europe - A sustainable pathway for the European energy transition. McKinsey study for the Fuel Cells and Hydrogen 2 Joint Undertaking, February 2019, https://www.hydrogeneurope.eu/news/hydrogen-roadmap-europe-has-been-published.

[88] E.g., hydrogen refuelling stations for rail applications tend to be better utilised and are more concentrated than the dispersed hydrogen refuelling stations for road vehicles.

[89] One medium transport pipeline has a capacity of 10 GW_{H2} or 300 t_{H2}/h and therefore requires to develop one or several large industry consumers or a large number of dispersed users (heating, refuelling stations). In the latter case the simultaneous development of a gas distribution grid is required, such as proposed for the H21 Leeds City Gate project [https://www.h21.green/projects/downloads/].

hydrogen imports through the transmission grid or hydrogen from electrolysis in central plants close to the RES-E locations or by imports of natural gas, for hydrogen production combined with CCS schemes for CO_2-disposal in other locations[90]. For both schemes the transmission grid has to be accommodated, either for hydrogen or for additional natural gas supply, the second option also in need of a new CO_2 transport infrastructure (see Figure 1-4). A decentral hydrogen supply option is onsite-electrolysis at small scale to e.g. supply remote hydrogen end-users, such as e.g. refuelling stations for rail applications[91].

Likewise, **Italy** with industry clusters to use large quantities of hydrogen both in the South (refinery in Sicily) and the North (steelworks in Dalmine close to Milano[92]) has presented ideas of the future role of its transmission gas grid for transporting hydrogen produced from domestic RES-E or imported from North Africa via Sicily[93]. But also decentral PV- or wind based electrolysis projects have been suggested for Italy[94]. Concluding, also Italy could develop a mixed central / decentral hydrogen use and provision approach, even though not formulated in its national hydrogen strategy yet.

In contrast and documented in its national hydrogen strategy from July 2020[95], **Spain** foresees its hydrogen roll-out to emerge in a rather decentralised way to supply a few local industry clusters (refinery, fertiliser production) and to collect hydrogen from solar energy clusters for export to other EU Member States through the gas grid (blended to the existing gas grid in small amounts or as dedicated hydrogen through re-furbished or new-built pipelines)[96]. A conversion of the transmission grid to accommodate more than 2 vol% of hydrogen is therefore difficult to foresee before 2030. Instead, it is part of Spain's vision to build/re-furbish distribution type hydrogen pipelines in local clusters for the decentral supply of hydrogen end-users from RES-E operated electrolysis. In its national hydrogen strategy, Spain foresees to invest ca. B€ 8.9 in hydrogen development activities over the next 10 years, large shares of which are expected to come from the private sector and supporting projects for value creation. By 2030, Spain aims to install 4 GW_{H2} of electrolysers, one tenth of the EU's target of 40 GW_{H2}.

Blended hydrogen users or pure hydrogen users

In the ongoing discussions about the impact of hydrogen development on the gas infrastructures, the following potential approaches could be identified:

- **Pure hydrogen end-use:**
    - high purity fuel for fuel cell vehicles and stationary fuel cells
    - fuel for 100% H_2 heating boilers
    - combined chemical feedstock and energy carrier/fuel for industry (fertiliser production, refineries, steel industry)
- **Admixed hydrogen end-use:**
    - Up to 2 vol% max for use in CNG combustion engine operated vehicles[97]
    - Fuel for heating boilers adapted to specific H_2-blending-rate
    - Fuel for the industry, max H_2 concentration level to be agreed individually case by case

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[90] In the case of the H2omorrow project, the plan is to convert the natural gas to hydrogen onsite and close to the hydrogen end-users, with CO_2 produced to be liquefied onsite and shipped by river and ocean ship to the CO_2-disposal site underneath the North Sea [https://oge.net/en/us/projects/h2morrow].

[91] As e.g. announced in https://www.evb-elbe-weser.de/aktuelles/detail/?tx_news_pi1%5Bnews%5D=61&tx_news_pi1%5Bcontroller%5D=News&tx_news_pi1%5Baction%5D=detail&cHash=6e5e8d0cd09d51672de5298e259a9936 for the first FC rail pilot project in Bremervörde in northern Germany.

[92] See presentation [TENARIS, techint and tenova: Zero CO_2 emissions – EAF and Hot Rolling mill plant as presented at the IPCEI workshop in Brussels, 15th January 2020].

[93] See [The hydrogen challenge: The potential of hydrogen in Italy, SNAM report, 10-11th October, 2019, https://www.snam.it/it/hydrogen_challenge/repository_hy/file/The-H2-challenge-Position-Paper.pdf].

[94] See [P. G. Muraa, R. Baccolia, R. Innamoratia, St. Mariottia: Solar energy system in a small town constituted of a network of photovoltaic collectors to produce electricity for homes and hydrogen for transport services of municipality 6th International Building Physics Conference, IBPC 2015, [https://doi.org/10.1016/j.egypro.2015.11.002].

[95] Hoja de Ruta de Hidrógeno: Una apuesta por el hidrógeno renovable, Gobierno De España, Ministerio Para La Transición Ecológica Y El Reto Demográfico, July 2020, https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&cad=rja&uact=8&ved=2ahUKEwirjKf30o7tAhUEGuwKHdtVBCQQFjACegQIAxAC&url=https%3A%2F%2Fwww.miteco.gob.es%2Fes%2Fprensa%2Fultimas-noticias%2Fel-gobierno-aprueba-la-hoja-de-ruta-del-hidr%25C3%25B3geno-una-apuesta-por-el-hidr%25C3%25B3geno-renovable%2Ftcm%3A30-513814&usg=AOvVaw0Q7lHdt_GUROH9fbJRA0Te.

[96] Based on information from stakeholder discussions by the authors.

[97] Limitation currently imposed by existing CNG tank specifications.

All options have been mentioned within individual national hydrogen strategies, but only few Member States have specified their priorities, except the UK with its outstanding H_2-for-heating conversion approach. The impact of the hydrogen specifications on the gas infrastructure both at transmission and distribution level is determined by the specific end-uses and end-use technologies in each Member State. It may also result in alternative hydrogen infrastructures to be developed, such that the gas industry needs to respect the individual frameworks (e.g. specifying hydrogen quality) as imposed by the individual end-use sectors.

One specifically critical example is the potential use of hydrogen for fuel cell vehicles typically requiring high purity hydrogen which may be difficult to be provided through the gas grids. Should this become a major option, very pure hydrogen needs to be delivered at large scale, which requires the hydrogen gas specification to follow the harmonised hydrogen standards as a vehicle fuel[98].

The gas industry has been discussing the issue of hydrogen quality for two years. An apparently well-agreed gas industry opinion is that a two-quality hydrogen pathway needs to be aspired[99]:

- **Industry-grade hydrogen[100]:** The dedicated hydrogen gas grid should only carry one single hydrogen quality, well specified by the Member State's and later European regulations/standardisation to avoid the necessity of parallel grids of different quality as used to be the case for natural gas. The agreed level would be minimum 98% purity. This is justified by two major reasons: (a) the fact that it will be difficult to respect a higher H_2-quality specifically in converted natural gas grid sections[101], and (b) that higher grade hydrogen will be much too expensive for the average bulk hydrogen industry customer[102]. Through a tentative and informal comparison of internal research work, some European gas companies already agree that European harmonisation of hydrogen gas quality can be achieved in principle, e.g. through the support of EASEE-gas. As the international and European hydrogen gas requirement standards have served as guidance, the gas industry believes that barriers for reaching a European agreement are small.[103] Also, the recent research results by the gas industry on impurity types and their maximum allowable levels in industry grade hydrogen undertaken so far can be seen as universally applicable.
- **Fuel cell-grade hydrogen:** In the future, fuel cell vehicles may also be served by fuelling stations connected to the dedicated gas grid taking profit from the advantages of gas grid hydrogen delivery (cost, safety, public acceptance, …) compared to delivery by trucks. Also, some Member States might want to build on the application of fuel cell CHP units in the heating market. As both FC applications will require a significantly higher H_2-quality of 99.97% than served by the grid (98%), decentral or on-site, local gas purification units would be needed to separate the most relevant impurities, such as CO, H_2O or O_2. Other inert constituents, not harmful for the FC operation, such as N_2 or Ar might just remain in the gas. These purification units will have to be built according to the H_2 gas grid delivery specifications on the hydrogen-from-grid feed-side and to the FC operational requirements on the hydrogen-to-vehicle product-side. The responsibility for hydrogen purification could be in principle be in- or outside the scope of the gas grid operators.

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[98] This specification is being developed in ISO 14687:2019 (Hydrogen fuel quality - Product specification for cars and stationary applications), ISO FDIS 19880-8:2019 (Gaseous hydrogen - Fuelling stations — Part 8: Fuel quality control) and EN 17124:2018 (Hydrogen fuel - Product specification and quality assurance - Proton exchange membrane (PEM) fuel cell applications for road vehicles). For Europe, the EC has ushered implementing agreement M533 (ANNEX 2 of the Alternative Fuels Directive (AFID) for hydrogen refuelling stations) to safeguard unified technical specifications and standards across Europe.

[99] The information is based on a discussion with a large European TSO in August 2020.

[100] As fuel cells will also be operated by industry, the term "industry-grade quality" has been used by the European Hydrogen Backbone study for a higher quality type of hydrogen. In this study "industry-grade hydrogen" is considered as the type of gas used by large-scale industrial end-users (e.g. chemical industry, refineries, steel production). As the quality level for this use can be significantly lower, it may also be significantly cheaper. It is suggested that an unambiguous definition will be aspired soon at European level. According to the current German rules & standards it has been dubbed "Group A" (98%) in contrast to "Group D" (99.97%) for the "fuel-cell grade" hydrogen.

[101] It is believed that all converted NG grids to dedicated hydrogen operation can fulfil this specification.

[102] The industry interviews carried out by the gas industry have considered aspects of 3 peer groups: **(a) H_2-consuming industry** : Specification of the type of impurities and their allowable maximum levels acceptable by the end-use applications; **(b) H_2-production processes:** type and quantity of impurities from the known production processes (e.g. Cl_2 from Chlor-alkali processes, to be confirmed), CO from SMR, H_2O or O_2 from electrolysis); **(c) emerging as necessity from pipeline supplied gases to public users:** operational safety (e.g. explosion limits) and environmental or human impact (e.g. max. allowable workspace concentration (MAC)). With this information the 98% specification envelope was further detailed for the allowance/limitations of individual constituents.

[103] For the H_2 quality used in FCEVs (ISO 14687 Grade A) the DIN 17124 has been built on ISO 14687 almost one by one.

From the above it can be concluded that to allow the development of a supra-national interconnected hydrogen grid and to facilitate cross-border trade, a process will need to be established to agree on a robust H_2-quality definition[104]. This will then allow to fulfil the requirement which was expressed by the European Hydrogen Backbone report as follows: "A mature European hydrogen backbone assumes well-functioning interoperability across borders…".

1.3.5 Application of criteria to EU regions

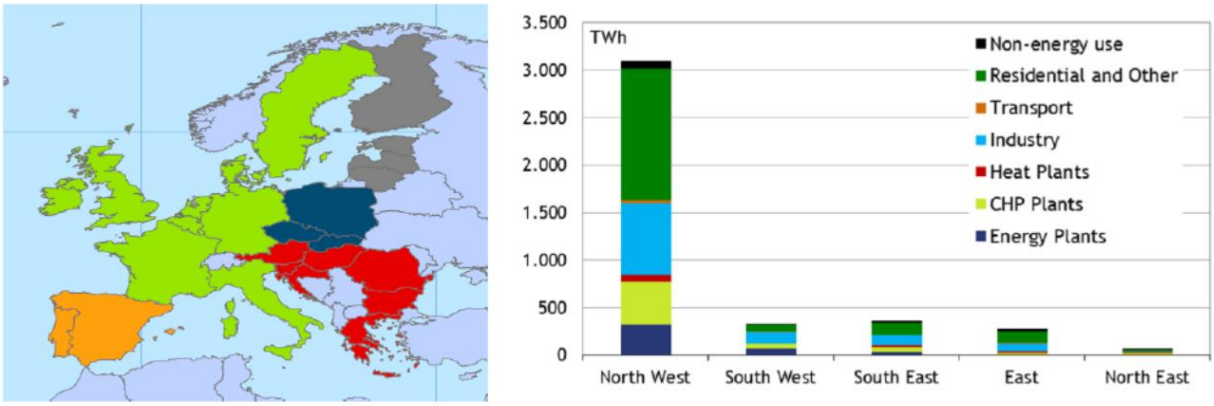
For a better understanding of how EU regions are preparing themselves for the introduction of hydrogen as green gas into their energy systems, a method has been developed comprising the following steps:

- Definition of regions
- Evaluating Member States' situations
- Graphical presentation of results
- Interpretation of results

Simplifying the graphical presentation, the most suitable approach was by grouping individual Member States into European regions reflecting their current gas infrastructure intensity. For reasons of consistency, we have chosen the definition from the green gas meta study for DG Energy and presented it in Figure 1-15:

- Northwest: BE, DE, DK, FR, IE, IT, LU, NL, SE, UK
- Southwest: ES, PT
- Southeast: mainly Balkan countries and AT
- East: CZ, PL, SL
- Northeast: Baltic countries and FI

Figure 1-15 Definition of five EU regions with differing interests in gas infrastructures



Green: Northwest; Orange: Southwest; Red: Southeast; Blue: East; Grey: Northeast.

As the effort should not cover all single Member States, but instead provide a principle view to the development situation as "snapshot", we have identified one or more Member States to be representative for each group for desk research. The interest in developing a hydrogen gas infrastructure currently being highest in central and Southwest Europe, the number of Member States assessed in these two regions has been higher, simply for the reason of sufficient information available.

For these Member States we have then assessed their approach to the 17 asset related criteria from above. As single Member States can deviate from their Member state group, the conclusions drawn are of general nature. It is specifically pointed out that this evaluation of criteria represents the differences between regions and by no means a ranking, i.e. a "1" is not equivalent to "poor performance" and a "5" not equivalent to "excellent performance". Instead the individual evaluation bandwidth (not "ranking") is provided in Table 1-4.

The result from the Member State specific evaluation has been aggregated for individual Member States to the umbrella region respecting an average for the Member States by own judgement[105]

[104] This will be the role of CEN, to be included in CEN TC 234/WG11, possibly in collaboration with JTC-6.
[105] The figures generated do not present a calculated average taking into account statistical figures (extent of gas grid, population or final gas demand) but is based on our personal evaluation.

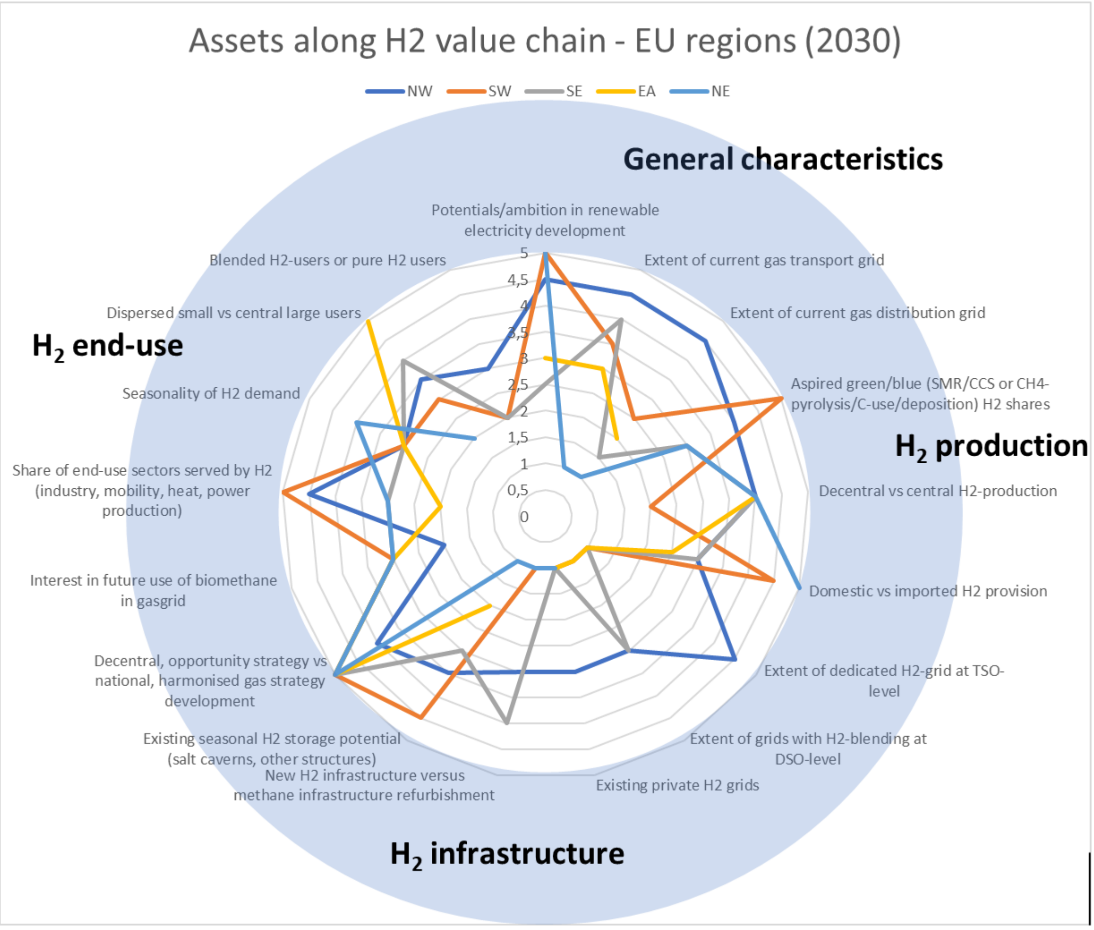
and the result is documented in Table 1-4. As this table is difficult to interpret, the data has been incorporated in the spiderweb graph in Figure 1-16.

Table 1-4 Member State specific evaluation of asset-based criteria list ("blanks" denotes no evaluation possible)

	NW	SW	SE	EA	NE
Potentials/ambition in renewable electricity development	4.5	5	2.5	3	5
Extent of current gas transmission grid	4.5	3.5	4	3	1
Extent of current gas distribution grid	4.5	2.5	1.5	2	1
Aspired green or blue (SMR/CCS or CH_4-pyrolysis/C-use/deposition) H_2 shares	4	5	3		3
Decentral vs central H_2-production	4	2	4	4	4
Domestic vs imported H_2 provision	3	4.5	3	2.5	5
Extent of dedicated H_2-grid or H_2-blending at TSO-level	4.5	1	1	1	
Extent of grids with H_2-blending or dedicated H_2 grids at DSO-level	3	1	3	1	
Existing private H_2 grids	3	1	1	1	1
New H_2 infrastructure versus methane infrastructure refurbishment	3	1	4		1
Existing seasonal H_2 storage potential (salt caverns, other structures)	3.5	4.5	3	2	1
Decentral, opportunity strategy vs national, harmonised gas strategy development	4	5	5	5	5
Interest in future use of biomethane in gas grid	2	3	3	3	3
Share of end-use sectors potentially served by H_2 (industry, mobility, heat, power production)	4.5	5	3	2	3
Seasonality of potential H_2 demand	3	3	3	3	4
Dispersed small vs central large potential hydrogen users	3.5	3	4	5	2
Blended H_2-users or pure H_2 potential users	3	2	2		

(light blue: general aspects, light green: H_2-production, light red: H_2-infrastructure, light yellow: H_2-end-use)

Figure 1-16 Spiderweb graph of criteria valuation for five EU regions



A careful interpretation of this evaluation results in the following conclusions:

- **General characteristics:** As suggested by Figure 1-16, central (i.e. Northwest) Europe and Southwest Europe currently stick out concerning the combination of their dense gas grid and high potentials or ambitions to develop domestic renewable electricity as a basis for green hydrogen production, making them candidates for the PW1 approach. In the other three regions this criteria combination is less obvious and they are candidates for any of the other three PW types. Exceptions from this general approach are obvious, with e.g. Austria possibly also being a candidate for PW1.
- **Hydrogen production:** Currently, no obvious correlation between the three H_2-production specific criteria exists. They all stand for themselves. However, it is obvious that the "peripheral regions" in the Northeast, East, and South (Italy as outlier belonging to central Europe) have a significant interest of potentially importing green hydrogen from outside Europe with some interest also from central Europe in blue hydrogen.
- **Hydrogen infrastructure:** The variation for most infrastructure related criteria is high across single regions[106]. One criterion however sticks out, the one concerning the strategy level at which hydrogen pathways or infrastructures are planned. It could be observed that a growing number of national authorities have identified hydrogen as an important energy carrier and fuel, going hand in hand with the increased production of variable renewable electricity. Among these, e.g. Portugal, which has recently released its national hydrogen strategy and Poland, which showcases that hydrogen is up on the current energy agenda, could be pointed out.
- **Hydrogen end-use**: The regional four-criteria based analysis shows that the interest of the Member States assessed could support the hypothesis that by 2030 the introduction of hydrogen is not yet demand driven. In contrast to today's hydrogen pipeline business, solely being demand-driven, the gas industry is in the process of identifying its position to make the most out of the existing gas infrastructure assets, i.e. capability-driven. Most of the Member States assessed, seem to tend for a mixed dedicated and blended-H_2 hydrogen approach, the supply of a mix of large- (continuous for industry) and dispersed (fluctuating for heating, mobility) users supporting the assumption of a cost-driven ramp-up phase. The emerging supply infrastructure would thus need to supply hydrogen at a high level of flexibility (storage), both at small-scale (local, e.g. refuelling stations) and at large-scale (seasonal for space heating) storage capabilities.

1.4 Hydrogen import pathways

In various industry-based analyses over the years as well as recently, the authors have compared different transport modes for hydrogen import from North Africa. The probably most important insight from these exercises is that the import costs strongly depend on a large number of key and therefore influential parameters, some of which are presented in the following list:

- Import (= transport) of compressed hydrogen via pipeline (CGH_2) versus liquefied cryogenic hydrogen (LH_2) (versus LOHC, methanol, etc.)
  - Transport distance (x km vs y km) and routes (pipeline vs ship routes vs …)
  - Capacity scaling (x ton/yr. vs y ton/yr.)
- Local/regional distribution via pipeline (CGH_2) versus road transport (CGH_2 or LH_2)
  - Distribution distances (x km vs y km)
  - Dimensioning (diameter, pressure, flow velocity) and design of pipeline system (new-built vs refurbished)
- Hydrogen end-use
  - High versus low H_2-demand per site
  - Required H_2-supply pressure (high vs low pressure)
  - Type of hydrogen end-use (CGH_2 vs LH_2)
- Other
  - Seasonality or fluctuation of hydrogen demand per day, week, month, year

Some of these parameters can be of game changing nature, i.e. a general contents unspecific assessment can result in misleading conclusions, with the potential consequence of high sunk capital investments. Hence, a general comparison of global energy transport vectors is possible but potentially misleading, and a parametric and algorithm-based generic comparison of competing PtL-based energy transport with hydrogen by gas infrastructure will always be only general and indicative in nature. To understand the details, a regionally focused analysis will have to take multiple parameters into consideration, such as: source-to-target, relevant and non-relevant transport modes by road (rail, truck) or maritime paths, energy transfer quantities and their seasonality and daily/weekly fluctuations, direct versus real transport distances respecting possible and typical routes, end-use- vs energy carrier-based, pathway hurdles (political, …), and finally also a potential re-utilisation of otherwise stranded assets (e.g. LNG terminals).

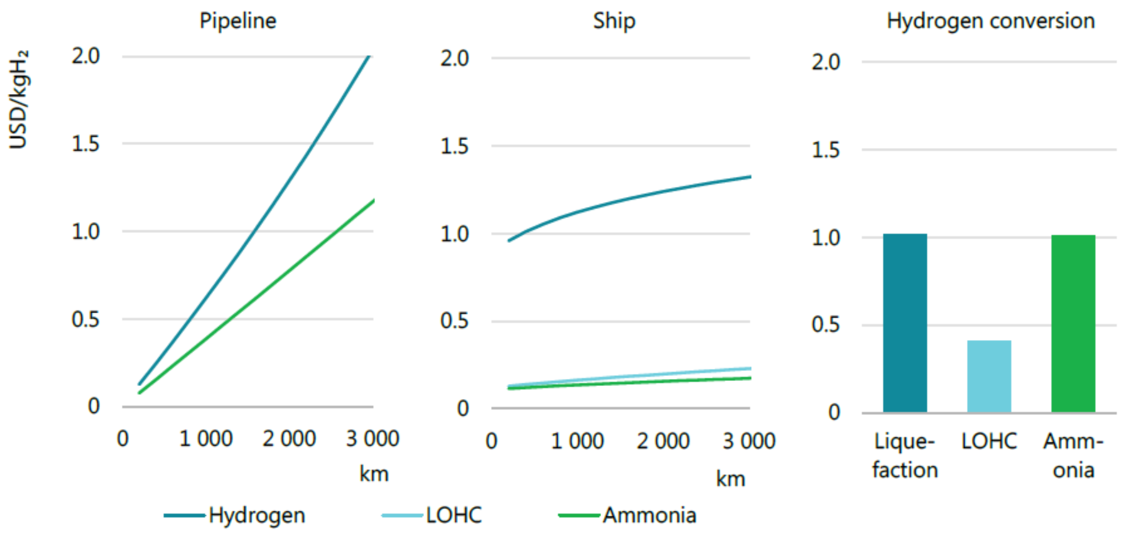
[106] The analysis has shown that the variations are even strong within the five EU regions.

For this report, we therefore present an analysis carried out by the international energy agency (IEA) which has compared the transport and conversion cost for importing hydrogen as gas or chemically embedded in ammonia (NH_3) by pipeline, as hydrogen cryogenic liquid, and as ammonia or absorbed in the liquid energy carrier LOHC by ship.

Figure 1-17 shows that the hydrogen pipeline related transmission costs scale strongest with the transmission distance, about a factor of 3 from 1,000 to 3,000 km[107]. As the two left graphs show the costs for transporting the energy carrier and not hydrogen as such, the conversion costs from the right graph need to be added. I.e. for a transport distance of 1,500 km, the specific hydrogen pipeline transmission costs are about 1.0 US$/$kg_{H2}$ and 1.5 US$/$kg_{H2}$ for ammonia. It should also be noted, that if the respective energy carrier needs to be re-converted to hydrogen gas if required by the specific end-use, then the additional re-conversion costs need to be added as well[108]. Hence, even at 3,000 km distance the hydrogen pipeline transmission costs are less than for piped ammonia. The economy of scale is less distinct for ammonia than for hydrogen transport by pipeline beginning at the same order of magnitude of transport costs.

Both LOHC and ammonia transport by ship result in low specific transport costs for all transport distances whereas the cost for liquid hydrogen via ship comes out highest, specifically if the high conversion costs are accounted for. For all distances the transport costs of LOHC appear to be lowest. But, taking the potential re-conversion costs into account, connected to energy losses of about 15% of the transported energy, the gap at least for liquid hydrogen and ammonia closes. The economy of scale of specific transport costs is little for all three energy carriers.

Figure 1-17 Cost of hydrogen storage and transmission by pipeline and ship and cost of hydrogen liquefaction and conversion [109]



Notes: Hydrogen transported by pipeline is gaseous; hydrogen transported by ship is liquefied. Costs include the cost of transport and any storage that is required; costs of distribution and reconversion are not included. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

This analysis concludes with a few general statements all having an impact on the development of future hydrogen import options:

- **Hydrogen import**:
  - Pipeline transmission requires an initially incrementally large source for hydrogen production and a high demand source simultaneously, which will require strategical (i.e. nationally backed) investment decisions[110].
  - The import of liquid cryogenic hydrogen (LH_2) (and other liquid energy carriers in general) is more flexible as several import routes can be used from one

[107] Reason are the operating costs for hydrogen compression along the pipeline. According to IEA, other drawbacks are the high capital costs entailed and the need to acquire rights of way.
[108] This specifically holds for the use of hydrogen as a vehicle fuel or for heating and many other industrial applications (refineries, steel production, …).
[109] The Future of Hydrogen. Report prepared by the IEA for the G20, Japan, June 2019.
[110] As an example, the German gas transmission infrastructure development is agreed in a national development plan (NEP), based on real capacity development and investment plans.

export location (e.g. for LH_2 about 1/3 of the production quantity and 1/10 of the import capacity as compared to hydrogen pipeline transmission) and

- The subsequent **hydrogen transmission and distribution** option is of relevance when evaluating a full hydrogen import value chain. i.e., whether a transport and distribution grid is available or can be refurbished from methane operation at moderate costs or whether hydrogen will have to be distributed via road transport. Therefore, the share of distribution has a high impact on the full value chain economics and a seemingly cheaper import path can turn out to be an expensive one if road distribution cannot be avoided (not even considering the advantages of an LH_2 refuelling station (no onsite compression, station footprint and hence site development costs, …).
- Finally, also **hydrogen end-use** considerations will have an impact, e.g.:
    - Who will be the major hydrogen customers, e.g. industry with a demand of gaseous hydrogen, ammonia, methanol, … or the heating sector in need of low to medium pressure gaseous hydrogen?
    - Hydrogen refuelling stations: liquid cryogenic hydrogen (LH_2) versus compressed gaseous hydrogen (CGH_2): if LH_2 would be stored on board of vehicles (trucks, trains, ships), the LH_2 transport vector would have significant economic benefits.

As a consequence, for further analysis and planning import pathways, the ambition may have to be adapted to e.g. read "how much of what energy carrier" instead of "either energy carrier A – or energy carrier B". Also, the opportunity of refurbishing existing natural gas pipelines to hydrogen at reduced costs (9-33% of new-built pipeline costs) is an important asset in comparing transporting hydrogen as a gas through pipelines versus as a secondary liquid energy carrier by ship or truck.

2 PIPELINES AS A NATURAL MONOPOLY?

Similar to natural gas, the viability of competition must generally be assessed separately for each segment of the envisioned hydrogen industry, i.e. for (i) production, (ii) storage; (iii) transport (pipeline/ grid including both transmission and distribution level, or other transport), (iv) trading and (v) supply to end-users. The focus of this analysis is on hydrogen transmission/distribution by pipelines.

The ultima ratio for regulating network operations is to ensure that the natural monopoly that a network may represent does not foreclose downstream and/or upstream markets. Not all dedicated networks necessarily qualify as natural monopolies conferring market power, e.g. based on a sub-additive cost curve, or depending on the number and type of connected users and market contestability.

This chapter analyses whether and to what extent and under what circumstances the development of a dedicated network under the pathways for the transport of hydrogen gives rise to a natural monopoly justifying regulatory intervention.

"It is generally assumed that monopolies and certain forms of market power (for example, created by cartels, switching barriers, barriers to entry) are harmful to social prosperity because they lead to sub-optimal production from a social perspective and therefore to welfare losses."[111]

Therefore, natural monopolies and further situations of imperfect markets described here justify regulatory intervention.

As an example of the growing concrete interest of industry including regulated gas grid operators in pure hydrogen pipeline systems and the regulatory aspects related to it, the German initiative GET-H2[112] aiming at building up a national hydrogen transmission grid has recently commissioned and published a legal study on the German legal framework for such an endeavour.[113]

2.1 Approach

The development pathways of hydrogen network systems developed in Task 1 are the basis for analysing the 'natural monopoly' topic. The results derived here are based on literature on the one hand, and on input provided by stakeholders in interviews on the other hand.

While dedicated primary research with detailed quantitative analyses of e.g. subadditive cost curves are beyond the scope of this assignment, cost structures of hydrogen pipelines will be compared to natural gas pipelines quantitatively. In order to establish a relative comparison between hydrogen and natural gas network systems, further aspects such as number and type of network users (injection and take-off) etc. are assessed qualitatively.

2.2 Natural monopoly assessment

"The natural monopoly situation may have different sources […]. It may be associated to strong scale economies (due to the importance of fixed costs, average costs decrease following the increase of the production); […] and network economies (related to interconnection and system control) […].[114]

The first source of a natural monopoly is commonly known as a 'sub-additive cost curve' characterised by a situation where "a single company produces with lower costs than a combination of smaller companies"[115] (see section 2.2.2). The second aspect relates to the advantages of an optimised grid based on integrated planning for an optimised coverage of a given geographical area by a pipeline grid (see section 2.2.3). A third cause for natural monopolies is notably a

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[111] Ecorys and TNO: Waterstoftransport – verkenning marktordeningsalternatieven; commissioned by Dutch Ministry for the Economy and Climate; Rotterdam/Delft, 31 May 2018; translation by LBST

[112] www.GET-H2.de

[113] IKEM: Rechtsrahmen für ein H_2 – Teilnetz – Nukleus einer bundesweiten, öffentlichen Wasserstoffinfrastruktur; September 2019

[114] Bento, N.: Building and interconnecting hydrogen networks: insights from the electricity and gas ex-Perience in Europe. Energy Policy, Elsevier, 2008, 36(8), pp.3009-3018. 10.1016/j.enpol.2008.04.007. halshs-00266304

[115] Bento, N.: Building and interconnecting hydrogen networks: insights from the electricity and gas experience in Europe. Energy Policy, Elsevier, 2008, 36(8), pp.3009-3018. 10.1016/j.enpol.2008.04.007. halshs-00266304

consequence of a situation where the market is not well developed and in a well-functioning 'steady state', but is building up based on a low (but growing) number of consumers and producers. Here, market power, market contestability and market inefficiencies are relevant aspects to consider (see section 2.2.4).

One cannot speak of a natural monopoly for hydrogen transmission and distribution until pure hydrogen becomes or is close to becoming a traded commodity, meaning that in a defined space, a large number of buyers start to compete to acquire it and a certain number of producers compete for access to transport means. This would coincide with phase 2 (2025-2030), and more broadly phase 3 (2030 towards 2050) defined in the European Commission Hydrogen Strategy[116].

Pipeline transport may be characterised by a natural monopoly as a result of the large economies of scale resulting from the high fixed costs of pipeline construction. However, the other elements of the value chain (production and consumption) need to exist as well. The market should be in a situation where hydrogen production and hydrogen consumption become widespread, contrary to the current situation which is characterised by a very small number of sellers and a limited number of buyers. Developments as described in detail in Task 1 may be anticipated to take place until such a situation is in place. However, once this (expected long-term) situation has been reached, hydrogen is very similar to natural gas in terms of natural monopoly situations in gas grids.

In essence, the development of a hydrogen market is interlinked with the development of the transport infrastructure and possible natural monopoly situations related to it. The evolution of the market for hydrogen will not be uniform, but different markets may develop, e.g. hydrogen for industry, hydrogen for transport, hydrogen for heating and cooling, etc., with different characteristics in terms of the infrastructure required, number of market players, number of consumers, volumes to be transported and even, potentially, the quality of the hydrogen required.

In a scenario where hydrogen is a commodity in a liquid competitive market, "the hydrogen transmission network would need to be regulated in a similar way to the methane transmission network today, given its natural monopoly characteristics."[117] Such a liquid competitive market may develop earlier in some EU regions than in others, and thus EU level regulation would have to be available for the early regional markets. Also, the development of liquid markets and of regulation may go hand in hand. The most appropriate timing for the development of rules is difficult to define at this stage.

Existing assessments for natural gas grids can be transferred to hydrogen grids as long as market conditions are similar: "In contrast to other grid-based industries such as for example telecommunications, the existence of an unquestionable natural monopoly in the area of transport and distribution gas grids is seen as empirically proven. […] Reasons for such a monopoly are advantages because of size and interconnectivity in pipeline transport of natural gas."[118]

At the moment, the business case for large scale hydrogen deployment beyond the current demand level is not yet positive. Public intervention is still necessary to support production and market uptake before the market described above (many producers and many buyers) will be established. While many stakeholders believe that business cases, based on competitive markets at upstream and downstream levels based on favourable and predictable market conditions (potentially including enabling regulatory regimes) are needed and are anticipated to develop, a significant increase in supply/demand driving the development of a liquid market should take place justifying regulation and the choice of the most effective regulatory regime.

It should also be noted that the hydrogen market may be quite different from today's natural gas markets in the production segment. While natural gas production consists of the large set of operations necessary to deliver natural gas to the wellhead, such as exploration, drilling, production, and gathering, potentially the approach for hydrogen production could well be more diversified and agile, and allow for a much higher number of producers (if the market conditions are set to allow for this; see point above regarding the existence of competitive business cases

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[116] European Commission (2020): Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions – A hydrogen strategy for a climate-neutral Europe. COM (2020) 301 final Brussels, 8.7.2020.
[117] Frontier Economics (2018): Market and regulatory frameworks for a low carbon gas system"; contracted by the UK Department for Business, Energy & Industrial Strategy; https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699678/Final_BEIS_low_carbon_gas_070318_clean-STC.pdf
[118] Sondergutachten der Monopolkommission Strom und Gas 2007: Wettbewerbsdefizite und zögerliche Regulierung. https://www.monopolkommission.de/images/PDF/SG/s49_volltext.pdf; Translation by Matthias Altmann

based on stable market conditions). Natural gas production, furthermore, is limited to geographies with relevant natural resources, while hydrogen can be produced from different primary or secondary energies, notably renewable energies, which makes it superior to natural gas in a global strive for climate protection, and which allows for hydrogen production at many different locations depending on many factors.[119] This may require a more decentralised grid, but does not change the fundamental consequences of a natural monopoly. Also, while natural gas production is linked to the geography of the natural resources and may require longer-term commitments for transport capacity, hydrogen producers may be less willing to enter into long-term commitments, which would increase the importance of third party access.

While there are major differences between the production characteristics of natural gas and hydrogen, pipeline/ grid transport of hydrogen, which requires a significant investment and enables very high economies of scale, would have similar characteristics. This shows that a natural monopoly on hydrogen pipelines/ grids can develop. And it shows that having hydrogen pipeline/ grid transport regulated could secure the investments necessary, both for transport and for production (and also for consumption).

2.2.1 Different situations in pipeline transport of hydrogen

In terms of pipeline transport of hydrogen, it is important to distinguish between four different situations:

1. Blending of hydrogen in existing natural gas pipelines
This situation is not relevant in the present context, and is covered by the current regulatory regime for natural gas grids.

2. Retrofitted natural gas pipelines, converted to be used for pure hydrogen
Future hydrogen transmission pipelines will in many cases be developed from existing natural gas pipelines by refurbishing them for hydrogen operation. This option has proven to be technically feasible and will in several EU regions be economically justified because the demand for fossil gas will as of 2030 decrease significantly.[120] To a certain extent, the current switch of low calorific natural gas to high calorific gas in the Netherlands, Belgium and Germany is an analogy for the switch to hydrogen. This reduces additional investment needs significantly, lowering average costs of transported hydrogen compared to newly built hydrogen pipelines. This makes it even more difficult for new entrants in transportation to compete, thus extending the monopoly situation from natural gas to hydrogen.

When retrofitting a natural gas pipeline and preparing it to be used for the transportation of pure hydrogen, the asset is, in effect, taken out of the natural gas market and out of the regulatory scope of natural gas. As a result, the question of what regulatory regime should apply to it becomes immediately relevant, together with the economic and legal consequences of this shift from a regulated to a (currently) non-regulated asset.

As retrofitting natural gas pipelines to hydrogen, according to the current status of knowledge[121], is much cheaper than newly built hydrogen pipelines, the hydrogen pipeline/ grid "inherits" the natural monopoly from the natural gas pipeline/ grid (see section 2.2.2).

Many stakeholders believe that, similar to transmission and distribution of natural gas, a natural monopoly could exist in relation to hydrogen retro-fitted natural gas pipelines/ grids for pure hydrogen.

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[119] Natural gas supply is only driven by demand and mainly imported via long-term contracts from non-EU countries, while hydrogen is expected to be to a large extent domestically produced, and driven by the availability of (renewable) electricity, short-term energy market conditions and hydrogen demand. Moreover, natural gas production is characterised by a rather limited number of fields and operators, while for hydrogen a large number of producers and installations are expected to emerge. Natural gas production spans a wide range of capacities: the very large Groningen field in the Netherlands had a capacity beyond 100,000 MW in the first decade slowing down thereafter. At the lower end, the small German gas fields had on average a capacity of some 10 MW per field in 2019 down from 22 MW a decade earlier. Hydrogen production, in contrast, can be done at scales from kW to GW with first installations beyond 10 MW in place.
[120] Trinomics, LBST, E3M (2019): Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure; contracted by the European Commission DG ENER; https://op.europa.eu/en/publication-detail/-/publication/10e93b15-8b56-11ea-812f-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search
[121] Trinomics, LBST, E3M (2019): Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure; contracted by the European Commission DG ENER; https://op.europa.eu/en/publication-detail/-/publication/10e93b15-8b56-11ea-812f-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search

However, there is no natural monopoly yet in hydrogen pipelines, and a market test and more in-depth analyses would be useful to determine the specific market situation in each case.

3. Newly built pipelines for pure hydrogen
The assessment with respect to newly built hydrogen pipelines is similar to retrofitted natural gas pipelines with the exception that investment costs are higher. Here, it depends on the regulation both for natural gas pipelines (as the to-be-retrofitted pipelines are in the regulated asset base) and for hydrogen pipelines as well as on the actual cost differential between retrofit and new build. It may, however, be assumed that retrofit will in most cases be significantly less costly than new build, which implies a market entry barrier for new entrants. However, also competition on hydrogen transport may be different with truck transport (hydrogen either in gaseous or in liquid form), rail or ship transport being potentially more relevant competitive options. Also, on-site production of hydrogen is a competing option (see also section 2.2.5).

4. Existing pipelines serving existing hydrogen consumers
Existing hydrogen pipelines (see section 2.2.5) are in general not open for third party access and are thus not an option to the hydrogen transport market in their current structure.

2.2.2 Sub-additive cost curve

Economic theory defines a natural monopoly as a situation where an industry is characterised by a sub-additive cost curve.[122] Or in other words, a natural monopoly exists where total costs of production are lower for a single firm than for two or more companies with the same total production. This is frequently the case if initial investments are high creating economies of scale. While electricity and gas grids are typical examples of natural monopolies, telecommunications generally is not a natural monopoly: Gas pipeline operation is a "'typical' natural monopol[y] with a high degree of network synergies. By contrast, long-distance telephone networks ("backbones") have been transformed from monopolistic to competitive structures over the last decades due to i) a large surge in demand, and ii) decreasing costs. Since neither can be expected in natural gas transmission, the emergence of competition is unlikely in the future as well."[123] In more detail: "The cost structure of a pipeline network is characterised by high capital intensity and low variable costs. The majority of investment costs are 'sunk' costs (in the true sense of the word). Transmission pipelines have long lives (35-60 years). Technical progress is slow, particularly when compared with the ever-evolving telecom industry. Thus, the gas sector is characterised by a low degree of innovation and relatively modest modernisation requirements. Total costs are composed of fixed costs (pipeline, compressor stations, metering) and operational costs (maintenance, variable fuel costs of compressor stations). Pipeline costs are mainly fixed costs, whereas in compressor station costs are mainly variable costs."[124]

However, gas pipelines do not under all circumstances represent a natural monopoly, and the situation can change over time: "A natural monopoly can dissolve notably in those elements of the value chain where the sub-additivity of the cost curve is not very strong, investments are only partly irreversible and possibility for innovation exists. […] This does not exclude a situation where in the long-term a very dynamic demand growth could lead to a competitor building pipelines in parallel where demand cannot be satisfied by the incumbent alone."[125] Independent of how realistic such a situation may be for hydrogen, this argument shall only serve to highlight the limitations of the sub-additive cost curve criterion.

Structurally, hydrogen pipelines are very similar to natural gas pipelines in mature markets.

A rough estimate may illustrate semi-quantitatively the sub-additivity of the cost curve for hydrogen pipelines: At a diameter of 400 mm, one meter of transmission pipeline at 100 bars requires an investment of some 1.000 €; for 700 mm diameter pipelines, an investment of 1500 € per meter is required[126]. Assuming that hydrogen flows through a pipeline are proportionate to the cross section of it (pi times the radius squared), then the investment per meter of length and per

[122] von Hirschhausen, Neumann, Ruester: Competition in Natural Gas Transportation? Technical and Economic Fundamentals and an Application to Germany; Dresden, July 2007
[123] Ibidem
[124] Ibidem
[125] Sondergutachten der Monopolkommission Strom und Gas 2007: Wettbewerbsdefizite und zögerliche Regulierung. https://www.monopolkommission.de/images/PDF/SG/s49_volltext.pdf; Translation by Matthias Altmann
[126] Trinomics, LBST, E3M (2019): Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure; contracted by the European Commission DG ENER; https://op.europa.eu/en/publication-detail/-/publication/10e93b15-8b56-11ea-812f-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search

square millimetre of cross section is a measure of the investment per cubic meter of gas transported. With the numbers above, the investment for three 400 mm pipelines is double that of one 700 mm pipeline, while the gas throughput is roughly the same.[127] Actually, it is lower in the smaller pipeline as the flow resistance of smaller pipelines is higher that that of larger pipelines. The situation is very similar for distribution pipelines, which, due to the lower pressure, have lower investment costs per meter of length at the same diameter. Other cost elements are operation & maintenance costs, investment and operation & maintenance costs for compressor stations for transport pipelines (not required for distribution pipelines), and metering & instrumentation costs. Annualised investment costs are typically at a similar level as the other cost elements, which are, furthermore, proportionate to the initial investment. As a consequence, in this hypothetical case, the annual costs including all cost elements, are very roughly double as high for two smaller pipelines of similar hydrogen throughput as for one large pipeline. This rough estimate shows very clearly that hydrogen pipelines typically have a sub-additive cost curve.

Where a natural gas pipeline is retrofitted for transport of pure hydrogen, one-off retrofit costs are much lower than investment costs for new pipelines. Depending on the age of the pipeline and the depreciation already taken place, pipeline retrofit is much cheaper than building new pipelines. So in a hypothetical situation where a regulated natural gas TSO converts a natural gas pipeline to pure hydrogen operation, this would have the double cost advantage compared to new investments in two smaller pipelines of the same throughput of lower investment costs (even if the natural gas pipeline is not fully depreciated yet), and of economies of scale (lower CAPEX and total costs of one large pipeline compared to two smaller pipelines).

In view of overall cost optimisation, it should be kept in mind that regulated assets are in general depreciated over longer periods of time than assets in competitive activities, and that in principle profit margins should be lower because of the reduced commercial risk.[128] As a consequence, regulated assets represent lower costs than commercially operated assets (all other aspects kept equal).

2.2.3 Network planning and operation as underlying cause for a natural monopoly

ACER and CEER in their recent conclusions paper on decarbonisation and decarbonised gases note a "growing recognition that the 'natural monopoly' element of TSOs lies really in network planning and operation. Current trends in the industry such as digitalisation and decentralisation allow bypassing of some networks or of network components."[129] The natural monopoly arising from the need for integrated planning and operation is a complementary aspect to the economic perspective described above.

In any case, ACER and CEER emphasise the need for a system perspective, which goes beyond economic theory in including the geographical dimension, both within the geographical area of a monopoly, and more importantly in the collaboration of the various geographical monopoly areas across the European Union.

Network planning for electricity and gas grids has been unified in the course of recent years at European level. Integrated planning for grids including electricity, natural gas and hydrogen could be beneficial from several perspectives, but may also present risks.

Integrated planning of natural gas and hydrogen would provide for a process where the decline of natural gas consumption and the growth of hydrogen consumption could be anticipated by the relevant stakeholders, and could thus be managed in an optimised way. However, there could both be tendencies to block or slow down the development of hydrogen in order to protect the existing business, or to unduly accelerate it in order to create new business under lower risks. Also, there would have to be a process to define who would participate in the integrated planning for the hydrogen side. One of the challenges would thus be to design a process of selecting incumbents from the regulated natural gas sector, and/or of selecting new players interested in becoming hydrogen grid operators. A regulatory environment, in any case, would and should not only define rights of monopoly holders, but also obligations including the building-up of hydrogen grids based

[127] 400 mm diameter is equivalent to a cross section of 125,664 mm², roughly 3 times lower that the cross section of a 700 mm diameter pipeline (384,845 mm²). Three 400 mm pipelines have a CAPEX of 3,000 €/m, double that of one 700 mm pipeline at 1,500 €/m.

[128] In company valuation, higher risks are taken into account in the so-called beta factor, which is used to calculate the appropriate rate of return for an investment into that company. Higher risks lead to higher return targets by investors into the company. Therefore, the business carried out by that company needs to generate these higher returns. In regulated markets, the rate of return is defined by the regulator, which takes into account the lower risk level of the regulated market.

[129] ACER, CEER: The Bridge Beyond 2025 – Conclusions Paper; Ljubljana, Brussels, 19 November 2019

on thorough planning based on clear principles such as security of supply, non-discriminatory third-party access, congestion avoidance/ minimisation, etc.

Operation of gas grids has seen innovations related to market-based instruments complementing and partly eliminating physical gas flows. In this sense, gas grid operation has developed from a pure technical operation to a combined technical and market-based operation, partly disconnecting gas grids from the physical reality. These aspects need to be taken into account in the assessment of natural monopolies. This may not be fully possible today in a situation where an open hydrogen energy market does not exist yet, but anticipated to develop.

2.2.4 Market power, contestability and inefficiencies

The economic perspective of the sub-additive cost curve (see section 2.2.2) is qualitatively confirmed by [Ecorys and TNO, 2018], but extended to more general aspects of market power and market inefficiencies or failures: "In sectors where a physical network plays an important role (such as gas, electricity) there is often market power as a result of the existence of a natural monopoly, economies of scale and scope, vertical integration and asymmetrical information."[130]

In addition to the cost structure characterising natural monopolies, a lack of real or potential competition is a related criterion for natural monopolies justifying regulation. With respect to natural gas transmission pipelines, a "necessary, but not sufficient, condition for workable competition is that a dominant part of the exit points must be accessible to more than one subsequent market network or that such access can be established under 'reasonable business conditions'"[131]. In other words, if there is a liquid integrated market served by several transmission pipelines, then there is also competition between transmission pipelines.

As a fundamental basis for the development of a natural monopoly in hydrogen transport pipelines/ grids, hydrogen must be a traded commodity, i.e. there must be production and demand in large quantities for hydrogen of a defined quality. As mentioned above, this would coincide with phase 2 (2025-2030), and more broadly phase 3 (2030 towards 2050) defined in the European Commission Hydrogen Strategy. A further pre-requisite is that the number of sellers and buyers is high, or has the potential to grow to a level allowing for a liquid market (see also the introduction to section 2.2).

Competition for hydrogen transport is not only between several (potential) pipelines or grids, but also with road, rail or ship transport. And there is the option of onsite production (notably from electricity). Hydrogen as a facilitator of system integration thus opens up new possibilities, which on the other hand make the situation more complex, and due consideration should be given to this additional complexity.

2.2.5 Existing hydrogen pipelines and pipeline systems

In the EU countries where hydrogen is produced and used in large quantities by a limited number of companies, pipeline systems have been established to transport it. The following Table 2-1 shows hydrogen pipelines and pipeline systems in operation in Europe, some of them since many decades. The hydrogen pipeline system in the German Ruhrgebiet, for example, has been operated safely since 1938.

Table 2-1 Hydrogen pipelines and pipeline systems in operation in Europe[132]

Network	Country	Length (km)	Operator
North Europe (BE+NL)	BE, NL	949	Air Liquide
Dunkerque	FR	14	Air Liquide
France East	FR	37	Air Liquide
France Centre East	FR	57	Air Liquide
France South East	FR	42	Air Liquide
Le Havre	FR	4	Air Liquide
Ruhrgebiet	DE	240	Air Liquide
Monthey	CH	2	Air Liquide

[130] Ecorys and TNO: Waterstoftransport – verkenning marktordeningsalternatieven; commissioned by Dutch Ministry for the Economy and Climate; Rotterdam/Delft, 31 mei 2018; translation by LBST
[131] von Hirschhausen, Neumann, Ruester: Competition in Natural Gas Transportation? Technical and Economic Fundamentals and an Application to Germany; Dresden, July 2007
[132] Own data collection based on various publications and sources.

Network	Country	Length (km)	Operator
Priolo	IT	6	Air Liquide
Rozenburg	NL	50	Air Products
Teesside	UK	5	Air Products
Porto Marghera	IT	2	Air Products
Leuna-Bitterfeld	DE	135	Linde
Teesside	UK	35	Linde
Stenungsund	SE	18	
Heide	DE	30	
Burghausen	DE	8	
Hoek-Sluiskil	NL	12	
Total		***1 646***	

The Hoek-Sluiskil pipeline in the Netherlands, which was the subject of agreements signed in March 2018 between Dow, Yara, ICL-IP and Gasunie Waterstof Services, has been commissioned in late 2018. It stands out from the hydrogen pipeline systems as the pre-existing natural gas transport pipeline was modified at a few points making it suitable for transporting hydrogen, while the other pipeline systems have been purpose-built as hydrogen pipelines. The Hoek-Sluiskil pipeline is now being used commercially for transporting more than four kilotons of hydrogen per year. Transporting hydrogen to ICL-IP at a later stage is also part of the plan.

The existing hydrogen pipeline networks are not regulated. A recent study concludes: "Given the current market context, this type of market failure [market power leading to access limitations, unfair conditions, discriminatory or improper use of information, or price-related competition problems, such as excessively high rates and price discrimination] has limited relevance for additional government intervention. The current pipeline networks for hydrogen transport are primarily aimed at supplying large industrial parties and often have limited geographical coverage. When constructing these networks, long-term agreements were made by (industrial) parties with sufficient knowledge. If competition problems arise, the Competition Act (…) is in principle the appropriate instrument for intervention. Neither have any concrete cases emerged from the interviews in which there is clearly abuse of market power."[133] In other words, the market does not seem to be distorted as there are long-term contracts and no information asymmetries, at least in the current Dutch hydrogen transport pipeline system, where the number of market operators is still very limited.

It should be noted that the current hydrogen pipelines in general do not offer third-party access. The business model is based on economies of scale from centralised production of hydrogen for some large industrial users; transport is done by pipelines as this is the cheapest option to transport the relatively large quantities of hydrogen from the supply to the consumption sites. This competes with large-scale on-site hydrogen production through natural gas steam methane reforming, or in the future through electrolysers using electricity. Therefore, current hydrogen pipelines are in general competitive where by-product hydrogen is available in large quantities. For smaller quantities of hydrogen, road transport is in general cheaper than pipeline transport, in particular if customers are located at large distances from each other to render pipelines uneconomical. This competes with onsite hydrogen production based on electrolysis or natural gas steam methane reforming, where the competitive advantage depends on transport distances, competition, quantities, contract duration, and further parameters.

However, a future hydrogen transport system may be expected to have different characteristics than today's commercial hydrogen pipelines: "This does not alter the fact that, as the hydrogen transport market grows, competition problems may indeed arise in the future. When the supply of and demand for hydrogen increase, the importance of transport via pipeline networks also increases, and with it the risk of access-related or price-related competition problems. The protection of the various interests may then be better regulated through a specific set of regulatory instruments […]. When hydrogen becomes more widely used by consumers, for example in the built environment, the importance of consumer protection increases." [134]

[133] Ecorys and TNO: Waterstoftransport – verkenning marktordeningsalternatieven; commissioned by Dutch Ministry for the Economy and Climate; Rotterdam/Delft, 31 mei 2018; translation by LBST
[134] Ecorys and TNO: Waterstoftransport – verkenning marktordeningsalternatieven; commissioned by Dutch Ministry for the Economy and Climate; Rotterdam/Delft, 31 mei 2018; translation by LBST

2.3 Conclusions

ACER and CEER come to the key conclusions that "decarbonised gases should be able to be integrated into existing gas markets […] New assets and activities should be facilitated through regulation, including a sandbox model at EU level for pilot, small scale projects and appropriate differentiation between competitive and monopoly activities. […] While it is too early to be definitive, large-scale hydrogen networks could be expected to provide regulated third party accessing."[135] It needs to be taken into account here that decarbonised gases may be physically different products: decarbonised methane based on biogas or based on Power-to-Hydrogen with subsequent synthesis to methane on the one hand, and pure hydrogen on the other hand. Nonetheless, the same or similar market platforms and processes may be used for the different products.

A number of stakeholders have expressed similar views. There is a general tendency to assume natural monopolies to exist for transport and distribution in mature hydrogen markets, and also in emerging markets there is a relevant probability of natural monopolies to occur. However, mature markets are not there yet, but are anticipated to develop. Where the number of market players, both on the production side and on the demand side, is low, there is a lower chance of having a natural monopoly. In contrast, high numbers of market players relate to a high probability of natural monopolies. Thus, the critical, and difficult to answer, question is under which circumstances exactly natural monopolies emerge, and when exactly regulatory intervention would be justified. Learnings from natural gas grids can be applied to hydrogen, with the limitations discussed above. The views diverge on the exact circumstances and the exact timing of regulatory intervention with some stakeholders supporting rather early regulatory intervention, while others prefer late actions. A view voiced rather widely is to apply market tests, and to actively develop regulatory approaches step by step starting early with thorough tests and validations along the way with scientific support as a robust no-regret approach to regulation.

While existing hydrogen pipeline infrastructure is currently not characterised by a natural monopoly, it is expected to represent in the future market situation a natural monopoly, based on the following elements which would justify regulatory intervention:

- Pipelines have a subadditive investment cost curve, and other transportation means would for most uses not provide suitable or competitive alternatives;
- Hydrogen is expected to become a traded commodity with a high number of producers/sellers and buyers;
- Refurbishing natural gas pipelines to hydrogen operations will be less expensive than new-build pipelines, and will hence offer a competitive advantage to the concerned owners/operators.

[135] ACER, CEER: The Bridge Beyond 2025 – Conclusions Paper; Ljubljana, Brussels, 19 November 2019

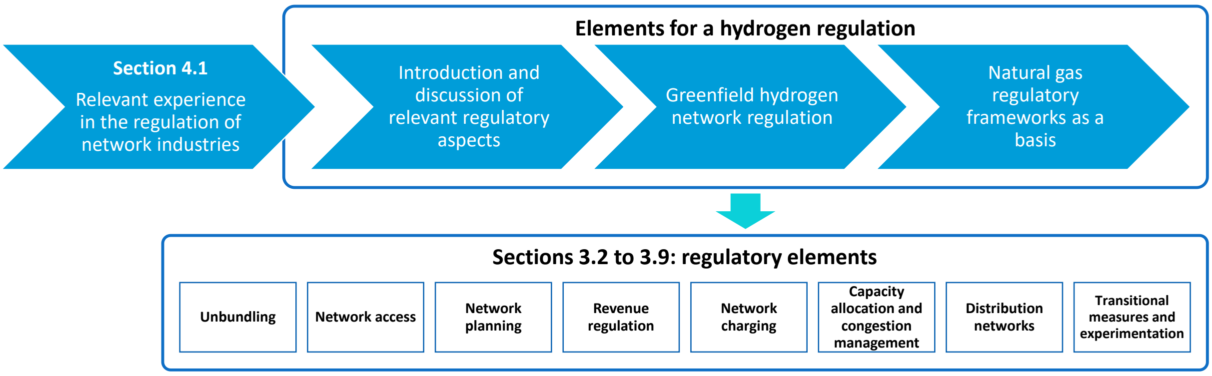
3 HYDROGEN NETWORK INFRASTRUCTURE REGULATION

The aim of this chapter is to develop options for the regulation of hydrogen infrastructures at the EU level, with a focus on networks, for a range of regulatory elements. This chapter is separated into the following sections:

- Section 3.1 reviews relevant experience in the regulation of natural gas, electricity and telecom industries to identify encountered barriers and measures relevant for hydrogen networks regulation and market design (the latter is further analysed in chapter 4);
- Sections 3.2 to 3.7 analyse regulatory elements for hydrogen network infrastructure, with the following structure for each element:
    1. An introduction and discussion of the regulatory aspects relevant to hydrogen networks;
    2. The analysis of regulatory options for a greenfield hydrogen network regulation, that is, without assuming current natural gas regulation would be applicable to hydrogen networks also;
    3. The analysis of regulatory options assuming the current EU and national regulatory frameworks for natural gas were applied to hydrogen networks (with necessary modifications), to enable efficient investments and operation, and incentivising the conversion of methane networks when optimal from a societal point of view.
- Section 3.8 analyses the potential regulation of hydrogen distribution networks;
- Section 3.9 discusses transitional measures and regulatory experimentation.

Figure 3-1 presents the structure of the chapter and the main network infrastructure regulatory elements which are analysed in detail. Balancing of hydrogen systems is addressed in chapter 4.

Figure 3-1 Structure of this chapter and relation to regulatory elements



The main options for each regulatory element are presented in the respective section, without each option forming a coherent ensemble – for example, option A for unbundling and option A for network access are not linked. Coherence between the options for each regulatory element is considered in the assessment of regulatory frameworks conducted in chapter 5.

The focus on the EU level means that the options for each regulatory element may provide overall guidelines to Member States (to be implemented through EU directives) or regulate more specifically hydrogen networks in the EU (through EU regulation). Hence, certain options may leave significant room for Member States if regulation at the EU level is not warranted.

Box 3-1 Current regulation of hydrogen networks in the EU and US

Currently, dedicated transport and distribution of hydrogen in the EU are covered by different legislative acts:[136]

- Directive 2008/68/EC on the inland transport of dangerous goods, based on and further specifying provisions of UN agreements, addresses transport by road, rail or inland waterway within or between Member States;
- Directive 2010/35/EU on transportable pressure equipment, setting requirements for manufacturers, importers, distributors and owners for the conformity of such equipment, used in road, rail or inland waterway transport;

[136] Floristean et al. (2019). HyLAW Deliverable 4.4 EU regulations and directives which impact the deployment of FCH technologies.

- Directive 2014/68/EU complements the Directive on transportable pressure equipment, establishing essential safety requirements for stationary pressure equipment and assemblies with a maximum allowable pressure greater than 0.5 bar;
- Commission Regulation (EU) No 453/2010 amending Regulation (EC) No 1907/2006 on the Registration, Evaluation, Authorisation and Restriction of Chemicals (REACH);
- Regulation (EC) No 1272/2008 on classification, labelling and packaging of substances, establishing rules for the harmonised classification and labelling of hydrogen
- The ATEX directives 2014/34/EU address equipment, protective systems intended for use in potentially explosive atmospheres, and work in such atmospheres.

Hence, only technical aspects of hydrogen transport and distribution are specifically regulated in the EU. The situation is the same for the US, which counts with the longest hydrogen pipeline network in the world, and where technical aspects related to hydrogen transport are regulated at the federal level especially by the Title 49 of the Code of Federal Regulations.[137] Therefore, **the current hydrogen network regulation has limited relevance for the potential regulation of TPA and other elements to existing or future hydrogen energy networks**.

The following elements are not addressed in this study, except where punctually relevant:

- Public support to hydrogen production and demand, such as target setting and economic support;
- Consumer protection;
- Safety aspects;
- Standardisation of gas quality, equipment and appliances;
- Interoperability of energy networks;
- Conversion or replacement of end-use equipment and appliances;
- Legal status of energy conversion.

New EU-level regulation for hydrogen should avoid the risk of foreclosing regulatory and technological innovation. There is currently no experience with the regulation of hydrogen networks and markets in any Member State (or non-EU countries, for that matter), and EU-level legislation will inevitably set boundaries to the available options for Member States to regulate hydrogen networks and markets.

By focusing on the regulation of hydrogen network infrastructure, the present chapter complements the analysis of chapter 4 on the design of hydrogen markets. The following assumptions base the analysis:

- If hydrogen networks and markets are regulated to some extent, the present European and national energy regulators will also be tasked with the oversight of the hydrogen sector – no separate hydrogen regulator would be set-up, given the synergies with electricity and methane sectors, even if the regulatory framework would be separated. Hence, at the EU level it is assumed that new regulatory tasks would be assigned to ACER;
- Energy conversion (e.g. power-to-gas) is considered primarily a competitive activity;
- The regulatory choices should be stable and unforeseen changes should not undermine the viability of assets and business models of regulated and market actors.

Box 3-2 The importance of regulatory certainty and timing of EU and MS-level legislation

Deploying large-scale hydrogen projects in 2025-2030 as planned by some Member States and suggested by the European Commission in its Hydrogen Strategy[138], requires experimentation by actors now in order to develop the necessary knowledge, as well as adequate regulatory frameworks already in the coming years. Kick-starting the deployment of hydrogen systems at a larger scale will require 1) the clear demarcation of what are considered competitive or regulated activities, and 2) adequate regulation to foster efficient infrastructure development.

While EU legislation on the regulation of hydrogen networks is not expected to enter into force before 2023, some countries are already taking steps to adapt their national regulation to foster deployment of dedicated hydrogen infrastructure.

[137] CFR Title 49, Part 192: Transportation of natural and other gas by pipeline: minimum federal safety standards.

[138] European Commission (2020). A hydrogen strategy for a climate-neutral Europe

In the Netherlands, the Energy Transition Act of 2018[139] allows network companies, *netwerkbedrijven* to be involved in alternative energy carriers infrastructure (hydrogen, biogas, heat and cold). These companies are part of the same group as network operators, *netwerkbeheerders,* but may not exert regulated electricity and gas network nor energy trade and supply activities. The government can assign to the network companies temporary tasks in that regard. The Dutch NRA closed a stakeholder consultation in April 2020 on a guidance establishing what the network companies are effectively allowed to do in the domain of these alternative energy carriers.[140] Specifically *netwerkbedrijven*:

- May establish and manage infrastructure for alternative energy carriers;
- May transport alternative energy carriers in that infrastructure, but are not allowed to supply or trade in alternative energy carriers;
- May establish and manage, but not exploit production and storage facilities for alternative energy carriers.

Following an agreement with the Dutch NRA, the *netwerkbedrijf* Gasunie Waterstof Services changed its name to Hynetwork in order to avoid any confusion with the regulated TSO (*netwerkbeheerder*) Gasunie Transport Services.[141] Netwerkbedrijven can manage electrolysers and provide conversion services.

The German Hydrogen Strategy also foresees regulatory experiments ('sandbox') in order to enable hydrogen projects. German branch organisations have also requested for regulatory changes in the current parliamentary term.[142]

Hence, certain Member States such as Germany and the Netherlands are considering to or have already regulated aspects concerning hydrogen networks and associated infrastructure, ahead of any EU legislation on the matter. Some national stakeholders argue that this is necessary to provide certainty for hydrogen investments in front-runner Member States. While national developments allow for regulatory experimentation and increase certainty, it will be necessary to minimise the risks of ex-post regulatory changes to national frameworks due to EU measures. Also, other Member States may see significant deployment of hydrogen networks only after 2030. Therefore, the target regulatory framework and market design for hydrogen should be agreed upon at EU level allowing action by front-runners and flexibility for different energy strategies, while minimising the risk of national regulatory divergence:

- Continuous discussion by EU institutions and Member State policy makers and regulators for sharing best practices and agreeing on established principles for network regulation, such as use of objective criteria, transparency, non-discrimination and cost-reflectivity;
- Early identification of regulatory aspects where EU action is warranted to promote market integration and avoid distortions, such as regarding cross-border issues (an important objective of the present study);
- Employ experimentation mechanisms such as regulatory sandboxes, further discussed in section 3.9, to promote projects without extensive regulatory changes.

Stakeholders' opinions on general aspects of hydrogen network regulation

Stakeholders are divided on the suitability of the current natural gas regulatory framework for hydrogen networks in general and regarding unbundling and third party access provisions in particular. GEODE supports a single gas definition comprising both methane and hydrogen gases,[143] and others also noted that most mentions to natural gas could be changed rather easily to expand the scope to other gases. Otherwise, they argue that network operators would have to comply with two sets of regulation, which would considerably complicate the operation of the respective networks.

However, multiple other stakeholders favour a separate approach (either through new chapters in the Gas Directive and Regulation or through new legislative pieces). For example, a national regulator argued that for the sake of transparency it would be more appropriate to define hydrogen as a separate gas, with regulation in a dedicated chapter in the national gas law or with an altogether new law, even if the regulatory approach for natural gas is deemed to be generally

[139] Wet tot wijziging van de Elektriciteitswet 1998 en van de Gaswet (voortgang energietransitie)
[140] ACM (2020). Consultation on "Leidraad netwerkbedrijven en alternatieve energiedragers"
[141] ACM (2020). Toezeggingsbesluit GTS over gebruik naam en beeldmerk. Available on https://www.acm.nl/nl/publicaties/toezeggingsbesluit-gts-over-gebruik-naam-en-beeldmerk
[142] Federal Ministry for Economic Affairs and Energy (2020) The National Hydrogen Strategy. FNBGas et al. (2020) Auf dem Weg zu einem wettbewerblichen Wasserstoffmarkt Gemeinsamer Verbändevorschlag zur Anpassung des Rechtsrahmens für Wasserstoffnetze
[143] GEODE (2020) Towards the New Age of Gas Networks: Proposal on the Regulation of a European Hydrogen Infrastructure

adequate for hydrogen. Gas TSOs argue that the regulatory framework should adhere, as far as possible, to the regulatory principles and technical rules that underpin the Internal Energy Market for gas.

Stakeholders are consensual on the need for the speedy definition of the hydrogen regulatory framework in order to provide certainty to regulated and market actors, and to avoid divergence of the national regulatory frameworks. Private hydrogen network operators, however, favour later regulatory intervention, as this would, it is argued, allow for these operators to realise the necessary investments to meet the decarbonisation needs of industrial customers.

Stakeholders are also unanimous on the need for transitional measures which phase in requirements according to the different stages of the hydrogen market development in the (groups of) Member States. Taking this into account, setting a Hydrogen Target Model would be beneficial, drawing on best practices from the methane sector. Multiple stakeholders also highlight the need for room for regulatory learning and adaptation of the regulatory framework according to new lessons learned.

3.1 Experiences in the regulation of natural gas, electricity and telecom industries

This section briefly reviews relevant experiences in the regulation of natural gas, electricity and telecom industries to identify encountered barriers and measures relevant for hydrogen networks regulation and market design.

The review of the barriers and measures in the natural gas and electricity sectors is focused on the 3rd Energy and the Clean Energy for All Europeans packages, and the associated studies and evaluations which served to identify the barriers and justify the measures of the packages. The barriers and measures are presented in Table 3-1. Market aspects are also indicated in the table and analysed further in chapter 4.

The 2005-2007 inquiry on the energy sector identified important barriers which were not adequately addressed in the 2nd energy package. While the 3rd energy package managed to significantly overcome multiple barriers, progress is still on-going with e.g. network codes and guidelines development. Moreover, the 3rd Energy Package did not adequately address issues which became apparent with the acceleration of new developments, such as the increasing share of (variable) renewable energy in the energy system, the associated deployment of uncoordinated capacity remuneration mechanisms, and further technological developments such as demand response, storage and power-to-X.

Attention has been increasing to the need for regulators to accompany fast-changing market conditions, technological developments and increased decarbonisation of the energy system, providing flexibility to new business models while assuring the transparency, predictability of the regulatory framework.[144] To this end, regulators have been employing different mechanisms for regulatory experimentation (discussed in section 3.9).

The reform of and technological developments in the telecom sector provide further lessons which can be considered for the regulation of hydrogen networks:

- **Telecom equipment has become increasingly decentralised, modular and mobile.** A similar development will occur with energy technologies, such as electrolysers and fuel cells, to varying extents, depending on the scenario and speed of R&D efforts and development of market designs enabling 'new' business models. Regulation of hydrogen infrastructure will need to account for the possibility of rapid upscaling of equipment and appliances connected to the network, as well as increased interaction (and arbitrage) with the methane and electricity systems;
- Competing technologies for conventional telecom services, especially mobiles and the internet, along with sector reform, have led **to a sharp reduction in the number of fixed phone users and to the entry of new market actors**, while incumbents were reticent to risk their core business activities; [145] The roll-out of hydrogen networks could lead to rapid migration of users from methane networks (as long as other necessary elements such as hydrogen appliance technologies are also in place) and to the entry of new actors, eroding the customer base of methane network operators.

[144] See for example CEER (2019) 3D Strategy (2019-2021) - Digitalisation, Decarbonisation, Dynamic regulation
[145] Munns (2017) What the US Electricity Sector Can Learn from the Telecom Revolution http://blogs.edf.org/energyexchange/2017/02/28/what-the-us-electricity-sector-can-learn-from-the-telecom-revolution/

Table 3-1 Selected barriers and measures in the regulation and market design of EU electricity and natural gas sectors

Barrier type	Causes	Measures	Potential hydrogen measures
Vertical foreclosure	• Low level of unbundling, discrimination by operators for access to electricity and gas networks (and gas storage and LNG terminals) [1] • Vertical integration of production/import and supply [1]	• Effective unbundling of network and production/supply activities • Regulated access at non-discriminatory conditions • Enhanced powers for NRAs • Active competition policy in foreclosure cases	• Non-discriminatory and transparent access to networks (and large-scale storage) will be required • Ownership unbundling may be required for networks (and large-scale storage), but well-designed requirements for legal unbundling may be sufficient • Some unbundling options have high (regulatory) cost and might hinder hydrogen deployment • Competition policy can complement sector regulation after its implementation
Lack of or distorted competition	• Market concentration in forward and spot markets [1] • Bias in connection conditions [1] • Price regulation below market prices [1] • Legacy long-term contracts on import/transit pipelines not subject to TPA [1] • Legacy long-term contracts on energy markets [1] • Ineffective congestion management mechanisms [1] • Insufficient indication of the origin of electricity [2] • Slow deployment of innovative retail products [3] • Market design focused on centralised generation [3] • Distortive effect of RES support mechanisms [3]	• Capacity and/or commodity release / contract swap • Contract / gas release as condition for approving mergers / acquisitions • Ceilings on ownership of electricity generation / long-term upstream gas contracts • UIOLI and other provisions • Incentivise investment in generation / infrastructure • Implicit capacity day-ahead auctions • REMIT • Enhanced TPA requirements and Commission oversight on exemptions • Binding guidelines for transparency	• Legacy commodity and capacity contracts may foreclose competition • GOs important for development of renewable and low-carbon hydrogen • Renewable hydrogen support must be market-oriented • Binding transparency guidelines relevant for any market development • Implicit hydrogen transport capacity allocation is preferred
Limited cross-border market integration	• Different market designs [1] • Insufficient/unavailable physical and/or contractual cross-border capacity [1,3] • Bias in network planning [1,5] • Contractual restrictions on re-sale of energy [1] • TSOs and regulators focus on national concerns and on reducing system risks rather than on optimising market integration [2-3] • Uncoordinated capacity remuneration mechanisms [2,3] • Failure to address emergency aspects [3]	• Enhanced consistency of regulation in cross-border issues • Regional initiatives • Network codes and guidelines process • Binding guidelines for transparency • TYNDP process	• Establish network codes / guidelines • Leverage regional initiatives for experimentation in front-runner regions, sharing of best practices and then upscaling to EU level • Enable cross-border trade (forward, spot and balancing) • Develop regional/EU level network planning, with bi-annual process leading to gradual improvements.

Barrier type	Causes	Measures	Potential hydrogen measures
Inadequate regulatory oversight	• Uncoordinated actions by MS and voluntary EU guidelines not able to promote harmonisation of e.g. CACM [6] • Insufficient competences of the regulators [2]	• Enhanced powers for NRAs • Reinforced coordination between NRAs (ACER) • Reinforced cooperation between TSOs (in ENTSOs and at regional level) • Reinforced cooperation of DSOs (in EU DSO entity and regional) • Enhanced consistency of regulation in cross-border issues	• Assign regulatory powers to NRAs and cooperation through ACER and new hydrogen EU TSO or ENTSO and EU DSO entity
Insufficient transparency	• Lack of network availability data, especially cross-border [1] • Lack of generation and storage data [1] • Little harmonisation on transparency requirements [1] • Information asymmetry between incumbents and others [1] • Lack of regulatory framework for data protection and exchange [3] • Lack of information regarding assets for which waivers apply	• Binding guidelines for transparency • ENTSOs transparency platforms • Further TSO unbundling • Antitrust regulation • Monitoring of cross-subsidies, tariffs and access to customer data	• Binding transparency guidelines relevant for any market development • Consider at least accounts unbundling for transparency of networks with TPA • Ensure publication of relevant information by incumbents (data quality included) • Include hydrogen in EU monitoring procedures (MMR, others) and potentially REMIT
Lack of adequate price formation	• Limited trust in price formation mechanisms [1] • Gas contract indexing to oil derivatives [1] • Lack of gas hub liquidity [1] • Lack of liquid DA and/or ID markets • Price regulation, including setting price caps [1-3]	• Assessment and removal of distortions due to regulated supply tariffs • De-linking gas and oil commodities • Increase of interconnection capacity	• Forbid regulated supply tariffs • Enhance market liquidity to have representative wholesale prices • Prohibit indexing to other commodities • Support interconnection capacity development
Lack of enabling balancing rules and inexistence of liquid balancing markets	• Small size of balancing zones [1] • Strict balancing rules (e.g. hourly balancing for gas, lack of re-nomination possibility) • Requirement to book capacity at every interconnection point [1] • Non-transparent charges, clearing costs and (unjustified) penalties [1] • Lack of liquid balancing market, e/g/ due to electricity generators and/or gas supply market concentration [1] • Lack of cross-border harmonisation [1]	• Widening of balancing zones • Regional initiatives • Network codes and guidelines process	• Avoid small balancing zones / integrate where possible • Leverage regional initiatives for experimentation in front-runner regions, sharing of best practices and then upscaling to EU level
Inadequate TPA access to gas storage and LNG terminals	• Ownership by incumbents [1]	• Unbundling rules • Regulated TPA at non-discriminatory conditions	• Set minimum TPA requirements and unbundling

Sources: [1] DG COMP (2007) Report on energy sector enquiry; [2] EC (2007) communication – Prospects for the internal gas and electricity market; [3] EC (2016) Evaluation of the EU's regulatory framework for electricity market design and consumer protection in the fields of electricity and gas; [4] Talus (2016) Introduction to EU energy law; [5] ACER/CEER Bridge beyond 2025; [6] stakeholder inputs

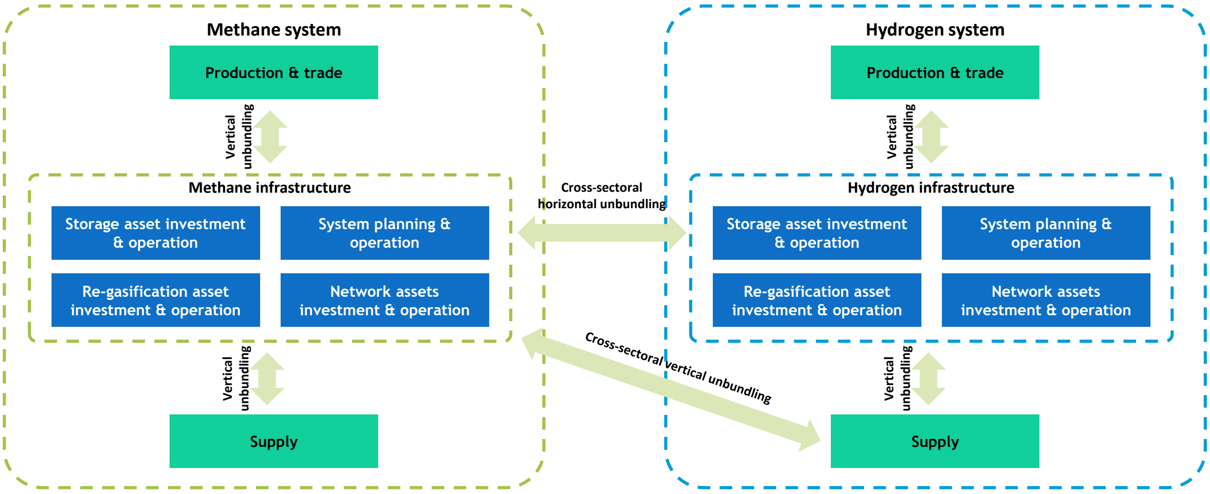
3.2 Unbundling

Unbundling regulation aims achieving partial or total separation between the regulated and unregulated activities of an economic operator, as well as in some cases between different regulated activities. Regulated activities in the gas sector may include, besides the investment and operation in transmission & distribution assets, and planning and operation of the system, also gas storage and liquefaction/re-gasification. Unregulated activities comprise energy production/conversion, trade and supply, as well as gas activities/assets (e.g. transmission, storage, LNG terminals) for which an exemption from regulated TPA has been granted or negotiated TPA applies.

Unbundling may apply not only to vertically integrated undertakings active in a sector, but also those active in multiple sectors, such as the electricity, natural gas and hydrogen sectors. Figure 3-2 illustrates the possible dimensions of unbundling:

- Vertical unbundling, between the regulated and unregulated activities. Can be either intra- or cross-sectoral;
- Cross-sectoral horizontal unbundling, between regulated activities for two or more different energy carriers;
- Infrastructure activities unbundling, i.e. separation of some of the regulated activities of system planning & operation, and investment & operation in storage, terminals and/or network assets.

Figure 3-2 Illustration of dimensions of intra- and cross-sectoral unbundling



Without effective unbundling and adequate oversight, there is a risk that network operators discriminate third parties regarding connection and/or access to the network in favour of their own (including affiliated) production and supply activities, cross-subsidise certain activities, and/or over- or under-invest in their energy network leading to higher overall system costs.

With the increasing implementation of energy technologies such as electricity storage and demand response, which provide flexibility services to the system and, to a certain extent, substitute the need for investments in energy networks, it is necessary to adequately consider the costs and benefits of network investments vs competing alternatives across different energy sectors. To optimise the overall network configuration, one could consider unbundling network planning from network investment and operation, or at least organise a strong oversight with the necessary powers to e.g. verify correctness of data provided by regulated operators.

Unbundling may be achieved, in decreasing order of the extent of unbundling, through: ownership, legal, functional or accounts separation of regulated and non-regulated activities. With ownership separation, the same company is not allowed to own both regulated and unregulated assets, although e.g. the ownership of minority shares without rights to vote or appoint board members may be allowed. Legal separation involves the separation of the regulated activities in a distinct legal entity, which may nonetheless be owned by a parent company with interests in production or supply. Functional unbundling is achieved by the effective separation of the decision making rights between unregulated and regulated activities, and of the human, technical (e.g. IT infrastructure), physical (such as buildings) and financial resources, as well as possibly the use of a separate corporate identity and/or assigning an unbundling compliance officer. Finally, accounts unbundling involves the use of separate accounts for the regulated activities, while the remaining activities may make use of consolidated accounts. This allows to apply cost-reflective tariffs while avoiding cross-subsidisation between regulated and non-regulated activities.

Unbundling and dedicated hydrogen networks

The issue of whether to unbundle or not the functions related to hydrogen networks is influenced by a number of factors:

- For pathways and countries/regions with an important hydrogen development, significant investments will take place;
- An important share of these investments may occur through conversion of methane networks to hydrogen. In the biomethane and hydrogen study,[146] investment annuities in the hydrogen scenario for the EU28 were estimated at 4.7 billion €/a until 2050, split between 1.4 billion €/a for converted hydrogen pipelines and 3.3 billion €/a for new ones. The cost of repurposing networks from methane to hydrogen transport can be as low as 10% of the cost of building new hydrogen pipelines.[147] This would mean that in the study, for the EU28, converted pipelines would account for more than 50% of the hydrogen network length in 2050. It is very likely that also new network assets will be required, e.g. to connect specific converted pipeline sections or to connect hydrogen production plants;
- The type and number of hydrogen network users (national producers/importers on the one hand and consumers on the other hand) will evolve over time, not only as a result of the specific national strategies (focusing initially for example on production and imports of fossil-based low-carbon hydrogen and its use in industry and transport), but also depending on the efficiency of the regulatory framework (including unbundling measures) to incentivise new hydrogen producers and users;
- The planning, investment, and system and asset operation of regulated, large-scale hydrogen and natural gas systems would be to a significant extent similar. The expertise of existing natural gas system operators would be relevant for implementing these functions, but operators of existing private hydrogen networks have of course also relevant expertise;
- The development and operation of dedicated hydrogen systems will need to be realised in conjunction with the natural gas and electricity systems in order to minimise the overall energy system cost. There are hence important synergies in the planning and system operation of hydrogen, natural gas and electricity (and heat) systems.

The central question regarding unbundling concerns the application of unbundling measures to owners/operators of future hydrogen networks. The following unbundling dimensions should be addressed:

- Vertical unbundling within the hydrogen sector: this would address the separation of hydrogen production, trade and supply activities from network-related activities;
- Unbundling between hydrogen network-related functions: the functions of planning and or operation of the hydrogen system could be separated from the functions of investment in and operation of the network assets;
- Cross-sectoral vertical unbundling: could be required for undertakings active both in hydrogen-network related functions and in production, trade and supply activities in the natural gas or electricity sectors;
- Cross-sectoral horizontal unbundling: could be required between the electricity, natural gas and hydrogen sectors, with legal or accounts separation between the network operators for each or a combination of those sectors.

The possible unbundling of private hydrogen networks is a related, but secondary question. As presented in chapter 2, important hydrogen networks already exist in Belgium, Germany and the Netherlands, operated by a handful of companies. There is at present no unbundling of these networks, with each company owning and operating production and transport assets. Specific unbundling exemptions for private hydrogen networks are considered in the development of the different options below.

Stakeholders' opinions

Stakeholders largely support vertical unbundling provisions for network infrastructure in the hydrogen sector, coupled with non-discriminatory third-party access. Stakeholders highlighted that unbundling provisions (and related third-party access) would be necessary at the European level and in the short-term (three to five years) in order to provide the investment certainty necessary for the development of hydrogen networks. One actor noted that if unbundled network operators would have a legal monopoly (where, by law, they would be the only ones authorised) or factual monopoly in a certain area of operation, this could be counterbalanced by them being assigned a

[146] Trinomics, LBST and E3-M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure
[147] European Commission (2020) Hydrogen generation in Europe: Overview of key costs and benefits.

number of responsibilities regarding e.g. regulation of revenues and tariffs, security of energy supply standards.[148]

Nonetheless, one national regulator indicated that, while adequate third party access and tariff regulation could be sufficient to provide non-discriminatory, transparent access to the network, unbundling requirements could allow the third party access and tariff regulation to be less strict. This would be based on the well-established rationale that actions such as unbundling that directly alter the market structure can reduce the market power of operators as well as their interest to abuse it, thus reducing the need for more strict regulation and monitoring.

Concerning horizontal unbundling, multiple stakeholders (including incumbent natural gas TSOs) support that the incumbent natural gas TSOs would be responsible for the planning, investment and operation of future hydrogen networks. They did not specify whether this role should be assigned through a legal initiative or would result from a factual monopoly. Arguments include the benefits of an integrated planning of natural gas and hydrogen infrastructure, the fact that the conversion of natural gas infrastructure is the lowest-cost option for developing hydrogen infrastructure, and the overall experience of gas TSOs with planning, investing and operating regulated networks.

Other stakeholders indicated that while natural gas TSOs should be allowed to invest in and operate hydrogen networks, they should not necessarily be granted a legal monopoly with unjustified ex-ante exclusion of other interested parties, as e.g. existing private hydrogen network operators also have significant expertise that might be valued in future hydrogen systems. Private hydrogen network operators themselves indicated to be interested in investing in renewable and low-carbon hydrogen solutions. A stakeholder noted that there could be a conflict of interest for incumbent natural gas TSOs to also own and operate hydrogen networks. Nonetheless, no stakeholder argued for the co-existence of parallel hydrogen networks, although there could be competition with other means of transport – by road, rail or water.

A gas TSO expressed his opposition to accounts unbundling between hydrogen and methane assets, noting that TSOs are already planning the repurposing of methane networks. This would be complicated by mandatory accounts unbundling, and moreover joint accounts would promote an efficient and rapid development of hydrogen infrastructure.

3.2.1 Greenfield hydrogen regulation: unbundling

The options developed for the unbundling requirements for hydrogen networks consider two dimensions:

- Whether hydrogen networks planning, investment and operation is considered a competitive or regulated activity, or a combination of both (i.e. where regulated and non-regulated actors are allowed to co-exist), and to what extent some form of unbundling (ownership, legal, functional or of accounts) is required between hydrogen networks and hydrogen production/trade/supply activities;
- Whether some form of unbundling (ownership, legal, functional or of accounts) is required between methane and hydrogen networks.

In the future, four types of operators for new hydrogen networks could exist, depending on unbundling and TPA rules (structured in Table 3-2):

1. **Vertically integrated undertakings (VIUs),** combining hydrogen production/trade/supply activities with hydrogen networks investment and operation. Would be allowed only in case hydrogen networks are not considered a regulated activity;
2. **Hydrogen network operators**, exerting only hydrogen network activities. Requires that hydrogen networks are considered a regulated activity;
3. **Combined gas network operators**, exerting both hydrogen and methane network activities. Requires that hydrogen networks are considered a regulated activity;
4. **Merchant operators**, developing specific transmission interconnectors in case hydrogen transport is considered an exclusively regulated activity and upon authorisation from regulators.

[148] Currently, energy network operators in EU MSs have a factual monopoly, but also in some cases a legal monopoly, such as the Finnish electricity TSO.

Table 3-2 Unbundling for different future hydrogen network operators

<table>
<tr><th>Hydrogen network operator</th><th>Vertical unbundling</th><th>Unbundling to methane networks</th></tr>
<tr><td>1. Vertically integrated undertakings</td><td>None / any</td><td>None / any</td></tr>
<tr><td>2. Hydrogen network operators</td><td rowspan="3">Preferred: Ownership
Variant: Legal</td><td>Ownership / legal</td></tr>
<tr><td>3. Combined gas network operators</td><td>Preferred: Accounts
Variant: None</td></tr>
<tr><td>4. Merchant operators</td><td>Ownership / legal</td></tr>
</table>

Further exemptions or waivers could be granted in national regulatory frameworks to operators of existing hydrogen networks and to direct pipelines. These are discussed below.

Considering these dimensions, the main options are:

- **Option A:** Hydrogen network-related activities are considered of a competitive nature and thus no vertical/horizontal unbundling is required;
- **Option B:** Hydrogen networks are regulated, but the sector entry by non-regulated actors is allowed (represented here by VIUs). Vertical unbundling is required;
- **Option C:** Hydrogen networks are regulated, excluding the participation of non-regulated operators. Horizontal and vertical unbundling are required;
- **Option D:** Hydrogen networks are regulated, excluding the participation of non-regulated operators. Vertical unbundling only is required.

Table 3-3 Unbundling options

	Option A	Option B	Option C	Option D
Hydrogen networks regulation	Competitive activity	Non-exclusive regulated activity	Exclusive regulated activity	Exclusive regulated activity
Unbundling to methane networks	No vertical/horizontal unbundling required	Vertical unbundling required	Horizontal and vertical unbundling required	Vertical unbundling required
Allowed operators	1. VIUs	1. VIUs 2. H_2 network op.	2. H_2 network op. 4. Merchant	2. H_2 network op. 3. Combined gas network op. 4. Merchant
Advantages	• Enables private investment in networks • MS may still regulate at national level • Allows for innovation by private actors • Low regulatory costs	• Enables private investment in networks • May leverage knowledge of CH4 / H2 network operators • Allows for innovation by private actors	• Entrants allowed • Lower cost of capital • Increased certainty for network users • May leverage knowledge of CH4 / H2 network operators	• Facilitates conversion of NG infrastructure • Lower cost of capital • Reduced administrative burden compared to option C • Increased certainty for market actors • Leverages knowledge of CH4 network operators
Disadvantages / risks	• Potential for market power and welfare loss due to sub-additivity • Difficulty to quickly upscale hydrogen networks, including across borders • Uncertainty due to competition of regulated and non-regulated activities in certain MSs	• Uncertainty due to competition of regulated and non-regulated activities • Potential for market power • High regulatory costs	• Requires transfer of NG infrastructure assets for conversion • Medium regulatory costs	• Competitive advantage to incumbent methane network operators • Complicates cost allocation between hydrogen and NG infrastructure • May incentivise excessive repurposing by combined gas network operators • Medium regulatory costs
Mitigation measures	• Competition law enforcement	• Require a positive cost-benefit analysis for regulated NG TSO • Tender concessions for regulated hydrogen network operation	• Tender concessions for hydrogen network operation	• Require accounts unbundling. • Require a positive cost-benefit analysis for authorising a combined gas TSO.

For option A, regulated electricity and methane network operators could be involved with hydrogen networks, if allowed by their national regulatory framework and hydrogen activities were legally unbundled, at least.

The advantages and disadvantages of the options are indicated in the Table 3-3. The following main aspects should determine the adequacy of each option:

- It is expected that, due to the natural monopoly characteristics of hydrogen networks, private and regulated networks will not co-exist in the same geographic area (although specific merchant pipelines could co-exist with a regulated network). Hence, allowing both non-regulated and regulated hydrogen networks should consist in a competition *for* the sector rather than *in* the sector, possibly through a cost-benefit analysis (CBA) by policy makers or regulators in order to consider a specific area as (un)regulated (see Box 3-3);
- Even if hydrogen transmission/distribution was defined as a competitive activity, methane network operators authorised in certain Member States to be involved in certain unregulated activities could still compete as a non-regulated actor;
- Incumbent regulated natural gas network operators and private hydrogen system operators can both bring significant expertise to the planning, investment and operation of hydrogen networks. The first regarding not only technical expertise but also familiarity with network regulatory models and aspects such as stakeholder consultation in planning processes;
- While market parties may have an interest in developing limited hydrogen networks for their local clients or own end-uses, they are unlikely to be interested in developing and operating large scale hydrogen networks per se. This may be the case of existing private hydrogen network operators, that may wish to devolve their networks to regulated network operators. Specific exemptions/waivers to unbundling can be considered in options B-D;
- Predictability of the regulatory framework should be guaranteed. Regardless of whether hydrogen network-related activities are considered a regulated or competitive activity, this should not be subject to posterior change, unless clear conditions are set ex-ante, in order to provide certainty for developing the network;
- Third-party access, revenue and network charging regulation would to some extent need to be imposed to regulated network operators, in order to ensure non-discrimination of network access and charges.

Box 3-3 Competition *for-the-market* and the regulation of hydrogen networks

A distinction can be made between competition in-the-market, where economic operators compete to supply a certain share of the market, and competition for-the-market, where economic operators compete to be able to be the sole supplier for a specific market. Energy networks are generally considered a natural monopoly and thus there is no competition in-the-market. However, the right to own and operate an energy network in a specific territory can be seen as a market for candidate network operators, if such right is tendered by the authorities. Competition for-the-market "may be the only option for creating a competitive incentive" for economic operators of natural monopolies.[149]

Competition for the hydrogen network "market" does not preclude network regulation – they could be combined to ensure networks are allocated to the most suitable operator, providing a level playing field and addressing potential competitive advantages of incumbent regulated methane network operators or pre-existing hydrogen network operators, if it would be socially beneficial.

Policy makers could consider to tender the hydrogen network investment and operation for a determined period of time, refraining from regulating the network afterwards (only re-tendering the right to invest in and operate the network at the end of the concession period). If hydrogen networks are not further regulated after the tendering of the concession, the only recourse available would be general competition policy, potentially making use of the Essential Facilities Doctrine. This has a number of disadvantages for hydrogen networks in hydrogen-intensive pathways, as discussed in Box 3-7 below. Such an approach would have risks associated with auction design - badly designed tenders may for example maximise public revenues from the tender, but network operators will recover their additional costs from network users, leading to higher tariffs.

Generally, competition for the market is not seen as a substitute for regulation of an activity with natural monopoly characteristics. Network tariff and third-party access regulation are often still necessary to avoid the abuse of dominant position by the concessionary.[150] Competition for-the-

[149] OECD (2019) Global Forum on Competition - Competition for-the-market. Executive Summary - Key findings from the discussion held during Session IV of the 18th meeting of the Global Forum on Competition on 5-6 December 2019.

[150] OECD (2019) Global Forum on Competition – Competition for-the-market. Background note by the Secretariat

market can nonetheless be an interesting complementary approach to introduce an element of competition.

Unbundling type

Options B-D imply some form and extent of unbundling of the hydrogen network operators. Vertical unbundling of the hydrogen network activities from production, trade and supply activities in the hydrogen and other energy sectors is considered to be applied to all options.

Cross-sectoral unbundling of network activities could be achieved through ownership, legal, functional and accounting unbundling. Here, functional unbundling is considered only in combination with legal unbundling, as a more effective and efficient way to separate network from unregulated functions, minimising regulatory costs compared to only functional unbundling. While ownership and legal + functional unbundling represent the strongest forms of unbundling, they would require additional administrative costs for existing hydrogen system operators.

There is a possible risk that a significant fall in methane gases demand would incentivise incumbent methane network operators to over-invest in hydrogen networks (i.e. ‘gold plate’ them), if allowed to, including through repurposing methane pipelines, even where not optimal from the social perspective. While repurposing methane networks will be, in hydrogen-intensive pathways, an efficient way to facilitate hydrogen development, there will be cases where decommissioning of methane pipelines is a more appropriate option from a societal perspective. Accounts unbundling between hydrogen and methane networks would not address this moral hazard of methane network operators. Even legal unbundling could prove to be insufficient given the 2007 sector inquiry found third-party access rules and legal unbundling requirements of the 2^{nd} energy package were not sufficient to prevent network operators of discriminating against other network users in certain cases.[151]

The remaining unbundling option to eliminate the moral hazard for methane network operators to over-invest in repurposing existing assets is separate ownership of methane and hydrogen networks. However, this option has a number of negative impacts and implications not related to the moral hazard of incumbent network operators. Enforcing ownership unbundling for hydrogen networks would not have as high administrative costs as for natural gas networks when the 2^{nd} and 3^{rd} energy packages were introduced but would limit the knowledge transfer from existing methane and hydrogen system operators.

Non-discriminatory and transparent planning, network access and charging can be achieved by less strict unbundling requirements coupled with other means. While the moral hazard of incumbent methane network operators is a legitimate concern, it should preferably be addressed through other regulatory elements. Ownership unbundling can reduce over-investment risks, but this does not constitute as such a sufficient reason for enforcing it.

Some form of H_2-CH_4 unbundling as required in options B and C would nonetheless facilitate proper cost allocation between the two networks, which would be complicated in case Member States choose to implement single accounts for combined gas network operators under option D. Simplified (i.e. accounts) unbundling requirements between hydrogen and methane networks would have a similar effect of facilitating conversion, while improving the transparency of cost allocation compared to no account unbundling.

Methane assets could also be transferred, upon fair compensation based on the residual asset value (residual accounting value), to the hydrogen network operator, in case of ownership or legal + functional unbundling. This would involve higher administrative and regulatory costs, to realise the transfer and determine the fair residual value but would not restrict *ex-ante* the development of hydrogen networks to incumbent NG network operators due to administrative reasons. It would be compatible with the introduction of a competitive element with *competition-for-the-market*.

Methane network operators would foreseeably oppose to sell infrastructure assets, or to sell them at the residual accounting rather than market value. Property laws could affect the possibility of EU provisions to enforce the sale of assets or legal or ownership unbundling of gas networks. The third energy package, enforced OU, but offered less intrusive alternatives to pre-existing undertakings (the ISO and ITO models).[152] Moreover, the energy sector-wide enforcement of unbundling was

[151] Jones (2016) EU Energy Law, Volume 1: The Internal Energy Market
[152] Diathesopoulos (2010) Ownership Unbundling in EU & Legal Problems

based on a thorough sector inquiry and later supported by competition cases which led to further divestiture by incumbent operators in certain Member States.[153]

Lowe et al. (2007)[154] indicates that "the right to property is not an absolute right but must be viewed in relation to its social function. Consequently, its exercise may be restricted, provided that those restrictions in fact correspond to objectives of general interest pursued by the Community and do not constitute a disproportionate and intolerable interference, impairing the very substance of the rights guaranteed".

Olesiewicz (2015)[155] lists a number of criteria that EU energy sector unbundling measures should satisfy regarding property rights:

- The EU must have the competence to regulate on energy sector as well as property rights allocation matters;
- The measures must be proportional with the expected social benefits;
- Owners must be suitably compensated.

The author argues that the ownership unbundling provisions of the 3rd energy package probably satisfied the first two principles, but that it is unclear whether 'suitable compensation' can be provided merely by the assets sale price (even if case law indicates that sale under the market value could still be considered 'fair'). Again, the existence of the ITO and ISO alternatives facilitated the compatibility of the 3rd energy package with national property laws.

EU provisions imposing ownership or legal unbundling to the hydrogen sector could face a number of additional difficulties compared to the 3rd energy package OU provisions. First, there are no demonstrated market failures yet, given the incipient development stage of the hydrogen sector and the lack of any competition inquiries. Second, demonstrating that ownership or legal horizontal unbundling are socially beneficial may be more difficult, as alternatives exist to ensure social welfare, such as accounts unbundling and strong planning oversight. This can be further complicated as in certain cases there may be synergies in having combined (accounts-unbundled) ownership and operation of methane and hydrogen networks. Third, it is unclear whether selling assets at the residual accounting value would be considered a 'fair compensation', even though the RAB model remunerated the depreciation of the assets and the capital cost. The alternative of selling assets at market value would be socially unfair, as TSOs would be compensated for depreciated regulated assets which would lead to higher hydrogen network tariffs.

If provisions on ownership or legal unbundling from methane networks were established for the hydrogen sector, the risk of legal challenges could be reduced by providing an alternative allowing Member States to opt for accounts unbundling, if a cost-benefit analysis demonstrates this option would be socially beneficial. In case such a test would have a negative outcome, it would support the proportionality of the unbundling measures.

Exemptions and waivers to unbundling requirements

In the case of options B-D, private hydrogen network operators existing at the time of entry into force of the new regulatory framework, could be exempted (or not) from unbundling requirements through an exemption procedure, or waivered automatically.

As discussed above, in order to regulate on the unbundling of pre-existing hydrogen networks, the EU needs to have the competence to regulate on energy and property rights matters, and any unbundling provisions need to be proportional to the expected social benefits. There is a strong parallel between unbundling provisions in the 3rd energy package and potential new ones for pre-existing hydrogen network operators. Similar to the 3rd energy package, it can be argued the EU does have the competence to act in this new matter, at least for cross-border hydrogen networks (as energy is a shared competence between the EU and Member States) and as long as the principle of neutrality is respected (that no privatisation or nationalisation of property is enforced).[156]

The unbundling of private hydrogen networks, and more broadly their regulation, could be implemented if this would increase social welfare resulting from 1) the integration of private and new hydrogen networks, 2) the elimination of discriminatory treatment of network users (new

[153] Talus (2016) Introduction to EU energy law
[154] Lowe et al (2007) Effective unbundling of energy transmission networks: lessons from the Energy Sector Inquiry. Competition Policy Newsletter no. 1 2007
[155] Olesiewicz (2015) Property Law and Free Movement of Capital Limits to the Implementation of the Ownership Unbundling in the Energy Sector. Aberdeen Student Law Review vol. 6.
[156] Olesiewicz (2015) Property Law and Free Movement of Capital Limits to the Implementation of the Ownership Unbundling in the Energy Sector. Aberdeen Student Law Review vol. 6.

and/or existing), and/or 3) addressing under-investment in private hydrogen networks (due to a potential lack of interest from the private operators, or difficulties in acquiring right of way, as expropriation based on public interest is in principle not possible. Hence, the proportionality principle could be respected even if unbundling is enforced.

Suitable compensation would need to be provided to pre-existing private hydrogen network owners that have property rights. This could possibly be satisfied by the revenues received from the sale of the assets at a market price. However, this specific point deserves further attention.

It must be considered that existing hydrogen networks have limited transport capacity compared to the planned future hydrogen networks. For example, the energy content of hydrogen production in Germany is equivalent to only 1.5% of the national natural gas consumption in 2018.[157] Therefore, in countries such as Germany, Belgium and the Netherlands, existing hydrogen networks would, without expansion, not provide a significant contribution to large-scale hydrogen deployment. Also, although existing private networks have a single supplier, they supply large industrial consumers, and therefore the hydrogen transport system owner has not necessarily significant market power.

In case private hydrogen networks are exempted or waivered from certain regulatory elements such as third-party access, measures could be taken to increase transparency, facilitate monitoring by competition authorities and reduce costs for posterior regulatory intervention. Such measures could include requirements for transparency on supply contracts (e.g. via REMIT), or at least accounts unbundling of network activities.

Furthermore, measures could be put in place to incentivise private hydrogen network operators to place their transport activities under a regulated regime. This could be done either by unbundling or by selling their network assets to an existing regulated operator. Incentives could include streamlined permitting for regulated networks (as some private operators may have difficulties in obtaining right of way or providing them preferential access through long-term capacity contracts to meet existing or new supply contracts. As the new hydrogen regulation could trigger a faster development of the hydrogen market, this could be in the interest of the existing private network operators as their primary business is rather hydrogen supply.

For the case of Germany, Benrath (2019)[158] proposes an alternative: the demarcation of legislation between energy and feedstock pipelines. In this proposal, existing private hydrogen networks would not be covered by the new regulation as they mainly serve to transport hydrogen used as feedstock. Future pipelines supplying hydrogen to be used exclusively as feedstock would also not be regulated, while pipelines that supply hydrogen as feedstock as well as for energy purposes would be considered as energy pipelines and would hence be regulated. The existence of unregulated feedstock pipelines could worsen the business case for regulated energy pipelines. Moreover, such an approach might lead to a suboptimal grid configuration, as potential economies of scale resulting from the sub-additive cost curve of gas pipelines might not be valued.

Some form of unbundling (at least accounts) should be imposed for new direct pipelines linking small groups of hydrogen producers and consumers in options B-D where unbundling is enforced to network operators – as these direct lines would constitute transmission or distribution pipelines much like the rest of the system, and in order to avoid the proliferation of direct lines which would compromise the development of an interconnected system. Direct pipelines could be exempted by national regulators from unbundling and other requirements (especially third-party access) for a defined period of time (i.e. with a sunset clause) and with the possibility of renewal of the exemption (this is not foreseen in the current EU natural gas regulatory framework). A similar regulatory test could be applied like for existing private hydrogen network operators, but subject to additional conditions such as the refusal or impossibility to connect to the regulated hydrogen network, or that this would not unduly affect security of supply, or the regularity, quality and price of supplies to other hydrogen users (similar to art. 9 of the current Electricity Directive).

These provisions are similar to the existing EU natural gas regulatory framework for direct lines, except for the potential exemptions foreseen and the right of Member States to refuse to authorise a direct line due to public service obligations considerations (the latter does exist in the Electricity Directive).[159] The direct line provisions and exemptions in the EU natural gas regulatory framework are considered to achieve an adequate balance between the rights of suppliers to develop direct lines and the broader interests of all system users.

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[157] Based on IEA (2020) World energy statistics indicating a natural gas consumption of 813.6 TWh_{lhv}.
[158] Benrath (2019) Applicable law to hydrogen pipelines for energy purposes in Germany. Journal of Energy & Natural Resources Law.
[159] Jones (2016) EU Energy Law, Volume 1: The Internal Energy Market

3.2.2 Natural gas as a basis for hydrogen network regulation: Unbundling

The current regime regulating separation of gas infrastructure assets is set out in the Gas Market Directive (2009/73/EC). There are three vertical unbundling regimes allowed. Firstly, the option of legal unbundling with full separation of asset ownership is the standard option. The two other options allow legal and functional unbundling through separation of network assets from the system operation function (creating an Independent System Operator, ISO) or through full management separation (where the vertically integrated company is mandated to create a subsidiary Independent Transmission system Operator, ITO). The ISO and ITO models are only possible if the transmission system operator was part of a vertically integrated undertaking at the time of entry into force of the Gas Directive. According to a Commission interpretative note, new transmission systems will have to follow the ownership unbundling regime[160]. Reviewing a number of studies, Meletiou et al. (2018) indicate that "OU and ISO models are considered more stringent unbundling forms when compared to the ITO model".[161]

From the 58 gas transmission system operator certifications, there were, in 2015, 23 operators under OU regime, 26 under ITO regime and 6 under ISO regime[162]. Since the implementation of the 3rd energy package, the European Commission has until 2019 issued 139 opinions regarding the certification of TSOs. During this period, 4 TSOs changed their unbundling model, including 2 gas TSOs and one gas interconnector operator. All four changed their regime to the ownership unbundling model[163].

Box 3-4 Energinet as a regulated multi-vector operator in Denmark

The Danish TSO Energinet is ownership unbundled. It combines the activities of electricity and gas transmission with that of gas storage and distribution. It took over gas distribution activities from DONG Energy as part of government plans to consolidate the gas sector. The government plans also included the use of incentive regulation to improve the efficiency of regulated companies.[164] In 2018 Energinet restructured itself around independent business units, "to improve transparency around decision-making and allow the Energinet group to perform its many and varied functions in a more focused and efficient way".[165]

The Act on Energinet indicates that the company should undertake electricity and gas transmission activities "*on the basis of coherent and holistic planning*".[166] Energinet's 2018 System Plan puts an emphasis on the holistic planning aspect and indicates that the company is developing, in cooperation with policymakers, a process for developing multi-annual investment plans with increased transparency.[167] This includes the approval of the development plans by competent authorities.[168]

In its PtX Strategic Action plan of 2019,[169] Energinet again highlights the need for integrated energy infrastructure planning as well for independent hydrogen infrastructure operators. It furthermore notes that the Danish regulatory framework does not address whether hydrogen transport should be a regulated activity, and does not affirm that Energinet should necessarily be tasked with this activity – proposing to collaborate with policymakers in defining the conditions which would require third-party access regulation for hydrogen networks.

[160] EC (2010). Interpretative note on unbundling in the electricity directive and the natural gas directive. Available at https://ec.europa.eu/energy/sites/ener/files/documents/2010_01_21_the_unbundling_regime.pdf.
[161] Meletiou et al. (2018). Regulatory and ownership determinants of unbundling regime choice for European electricity transmission utilities.
[162] EC. List of certification notifications received (2011-2015). Available at https://ec.europa.eu/energy/topics/markets-and-consumers/market-legislation/third-energy-package_en
[163] CEER (2019). Implementation of TSO and DSO Unbundling Provisions. Available at: https://www.ceer.eu/documents/104400/-/-/f69775aa-613c-78a5-4d96-8fd57e6b77d4.
[164] Energinet (2018). Energy across Borders – Strategy 2018-2020.
[165] Energinet (2018). Energy across Borders – Strategy 2018-2020.
[166] Act on Energinet No. 1384/2004. Consolidated version LBK nr 118 of 06/02/2020. Available on https://www.retsinformation.dk/eli/lta/2020/118
[167] Energinet (2018). System Plan 2018– Electricity and Gas in Denmark
[168] Trinomics, LBST, Artelys and E3Modelling (2018). The role of trans-European gas infrastructure in the light of the 2050 decarbonization targets.
[169] Energinet (2019). Winds of Change in a Hydrogen Perspective - PtX Strategic Action Plan.

These considerations highlight a number of interconnected aspects at play for the regulation of energy infrastructures:

- The use of incentive-based revenue regulation and sector consolidation to achieve efficient investments and operation;
- The need for transparency in electricity and gas transmission, including regarding planning processes;
- The importance of integrated network planning across energy sectors, and the potential role of regulation in establishing planning requirements;
- The lack of regulation for the hydrogen sector and the current consideration by Member States whether and how to regulate it.

Extending the current regulatory approach to (newly built or converted) hydrogen networks would not change the situation for incumbent transmission system operators if the hydrogen networks were considered as an extension of the already existing gas (methane and hydrogen) system. Only completely new hydrogen transmission systems would have to be subjected to the ownership unbundling regime if they were considered separate from the natural gas system. For each TSO/NRA, this approach offers the continuation of the freedom to choose the unbundling model most suitable to its particular situation.

This approach would also avoid the transactional cost of adapting to a new regulatory regime and possibly enable the transition of established natural gas system operators to hydrogen infrastructure. On the other hand, this approach would decrease the transparency of network infrastructure management, as it would not allow for distinguishing between natural gas and hydrogen networks accounts.

The Gas Directive contains provisions for the exemption of unbundling requirements for new natural gas infrastructure built after the entry into force of the Directive, but not for existing natural gas infrastructure. Hence, without further adaptation, the application of this regulatory framework to hydrogen would require the unbundling of existing private hydrogen system operators.

Options formulation

It is assumed that:

- All currently available unbundling options (OU, ITO, ISO) are sufficiently effective;
- Cross-sectoral horizontal hydrogen/NG network activities are allowed;
- Cross-sectoral vertical unbundling is enforced;
- Only existing gas TSOs that currently operate under one of the functional unbundling regulatory models, can keep this model also for hydrogen networks.

Thus, the central question is the legal status of hydrogen pipelines – are they considered a new infrastructure? Or are they an addition to an existing gas network and can currently existing natural gas operators build and operate hydrogen networks with their legal status unchanged? If hydrogen is included in the definition of gas in the Gas Directive and Regulation, new hydrogen infrastructure can be considered as an extension of existing methane networks, and the currently existing network companies operating under a functional unbundling regime, might be allowed to keep their current ownership structure. A regulatory test could be used to check whether the social benefits of such an approach outweigh its costs. In case hydrogen and natural gas are considered as separate gases, tenders could be employed to award the networks to the most suitable operator, taken into account the competitive advantage of methane network operators. This approach is further discussed in Box 3-3 above regarding competition for-the-market.

Table 3-4 Unbundling options for hydrogen based on natural gas regulatory frameworks

Unbundling	Option A	Option B	Option C
Hydrogen gas definition	Hydrogen and natural gas are separate gases	Hydrogen is a separate gas	Methane gases and hydrogen are defined as a single gas
Hydrogen networks are new networks?	New	May be considered as extension of methane grid	Extension of methane grid
Unbundling from methane networks	Ownership unbundling obligatory	Legal+functional / accounts / none	None / accounts
Advantages	• Improved level playing field for entrants • May not leverage knowledge of NG TSOs.	• Facilitates conversion of NG infrastructure • Allows entrants	• Facilitates conversion of NG infrastructure • Reduced administrative burden
Disadvantages / risks	• Conversion of NG infrastructure entails administrative burden and potential compensation • Increased transactional costs of adapting to new regulatory regime	• Incumbent methane network operators have competitive advantage.	• Entry of new network operators very difficult • Complicates cost allocation between hydrogen and NG infrastructure.
Mitigation measures	• Tender concessions / require a positive CBA for awarding operation to NG TSO	• Tender concessions / require a positive CBA for awarding operation to NG TSO	• Require accounting unbundling. • Require a positive CBA for authorising a combined gas TSO

In Germany, the gas TSOs as well as other energy associations have recently proposed to change the national legislation so that current natural gas network operators are able to also operate hydrogen networks with accounts unbundling.[170]

In the Netherlands, a study on the regulatory framework for hydrogen networks indicates that if current natural gas network operators were to be assigned a mandate to develop and operate hydrogen networks, existing private hydrogen operators could wish to devolve their networks to the regulated operators as their core busines is hydrogen supply rather than network operation. Nonetheless, specific exemptions could be foreseen from unbundling, third party access and tariff regulation.[171]

Box 3-5 Emergent and isolated markets provisions in the Gas Directive

Article 49 of the 2009 Gas Directive includes a number of provisions related to emergent and isolated markets. Emergent markets may exist in 'Member States in which the first commercial supply of its first long-term natural gas supply contract was made not more than 10 years earlier' (art. 2(31)). Isolated markets are 'Member States not directly connected to the interconnected system of any other Member State and having only one main external supplier […]. A supply undertaking having a market share of more than 75 % shall be considered to be a main supplier' (art. 49(1)).

The provisions include derogations on unbundling of TSOs, direct lines provisions, and DSO obligations (including unbundling), which expire when Member States cease to qualify to the conditions above.

The emergent and isolated markets provisions may be an interesting solution for making the applicability of certain regulatory elements such as unbundling and third-party access conditional to the interconnection of national hydrogen systems. This would provide clarity for Member States on the requirements once their hydrogen systems develop, without imposing restrictions to local hydrogen clusters.

The application of the derogation provisions to the hydrogen sector would at least need some adaptations, e.g. as the more domestic and decentralised nature of hydrogen production would reduce (external) suppliers' dependency and thus make it more difficult to qualify to the 75% threshold, while multiple national hydrogen systems could remain isolated for a long period.

[170] FNBGas et al. (2020) Auf dem Weg zu einem wettbewerblichen Wasserstoffmarkt Gemeinsamer Verbändevorschlag zur Anpassung des Rechtsrahmens für Wasserstoffnetze
[171] Ecorys and TNO (2018). Waterstoftransport – verkenning marktordeningsalternatieven

3.3 Network access

Third-party access (TPA) rules aim to guarantee to network users non-discriminatory access to the transmission and distribution network, by forbidding network operators to refuse or favour access to certain network users, without reasonable technical or economic justification. This includes the obligation to allow for the non-discriminatory connection of users to the network.

Third-party access rules are intrinsically linked to unbundling requirements, with both having the ultimate goal of facilitating fair competition amongst network users. Third-party access rules and functional vertical unbundling are generally considered insufficient to guarantee that incumbent network operators do not discriminate other network users versus their own or affiliated undertakings. The 2007 sector inquiry found that the third-party access and legal unbundling requirements in the 2nd energy package were insufficient to ensure non-discriminatory third-party access.[172]

Third-party access is in the current EU legislation not required for all energy networks. Existing private energy networks (such as existing hydrogen networks) are not regulated, and regulators may furthermore provide (partial) exemptions to natural gas direct lines (connecting one producer to one or a group of specific customers) or to merchant interconnectors, due to considerations on the economic feasibility of the investment.

Under regulated third-party access, infrastructure operators are required to provide non-discriminatory access to users on the basis of published terms and conditions, including tariffs, set or approved by the regulator. Negotiated third-party access constitutes an alternative to regulated third-party access; under this regime the infrastructure operator and users negotiate in good faith the access to the infrastructure, with terms and conditions being published ex-post or not published.

In the case of transmission networks, third-party access may require, for specific corridors and cross-system interconnection points, the establishment of rules on booking (i.e. reservation) and nomination (i.e. actual use) of the transport capacity: so-called capacity allocation rules. Additionally, it is necessary to define rules for the management of eventual physical or contractual congestion which may take place in such corridors and interconnection points. Capacity allocation rules are not necessary within entry-exit systems which should theoretically be characterised by the absence of internal (structural) congestion, although congestion management rules are still necessary for transitory, non-structural congestion which may take place. Capacity allocation and congestion management are described in more detail below.

Network access and dedicated hydrogen networks

Network access for new dedicated hydrogen networks could range from a fully regulated to an unregulated approach. The ultimate criterion to establish the adequate level of third-party access regulation is that the system benefits should outweigh the costs. Whichever the choice, TPA requirements (or their absence) have a direct impact on the business case of network investments since they determine how capacity should be contracted to network users, and would have to be defined early on as they would affect hydrogen networks of all scales, including initial hydrogen clusters.

As hydrogen networks are expected to constitute a natural monopoly, TPA requirements are essential to enable the development of a liquid hydrogen market, with multiple network users having access to hydrogen networks as a pre-condition to participate in the market. This would need to be combined with effective vertical unbundling to assure that network operators do not discriminate other network users in favour of their own or affiliated undertakings.

As a trade-off for being granted a factual or legal monopoly in a given area of operation, an obligation could be imposed to hydrogen network operators to connect all hydrogen network users that request so, in addition to providing access at tariffs that reflect their actual costs and a regulated market-based margin to remunerate their equity. This would provide increased certainty for the migration of users from natural gas networks and increase the protection of end-users connected to the distribution grid, which would have less available alternative options than large industrial consumers. Therefore, such a legal obligation to connect all users at their request could be considered depending on the expected uptake of hydrogen.

As it is expected that long-term hydrogen supply agreements may be a main driver of investments in production capacity and of the shift of end-users to hydrogen, third-party access to networks should be coupled to some degree with long-term network capacity contracts. Conversely, such

[172] Jones (2016) EU Energy Law, Volume 1: The Internal Energy Market

long-term supply contracts would signal demand for network transport capacity and thus minimise the risk of stranded hydrogen network investments. This must be outweighed by the (low) risk of foreclosure of capacity and the impact on the development of a liquid hydrogen market. A mechanism similar to the current incremental capacity procedures in the CAM network code[173] could be employed to provide long-term capacity contracts for new or repurposed hydrogen networks (see section 3.7 for further details).

The existing private long-distance hydrogen networks supplying industrial customers have been developed without regulated third-party access, with hydrogen suppliers and consumers freely agreeing integrated long-term supply and transport tariffs. No evidence was indicated by stakeholders of abuse of the position of hydrogen suppliers in the past. However, the suitability of such an approach needs to consider the profile of the customers, exclusively composed of large industrial consumers, and the size and capacity of the networks, with are extremely limited compared to the regulated electricity and gas networks.

Exemptions could be foreseen from regulated third-party access for a number of cases, including for previously existing private hydrogen systems (when it is demonstrated that the social benefits of TPA rules would not outweigh its social costs. Some private operators could for commercial or economic reasons be interested to provide third-party access (with unbundling) to their networks, or even to devolve their networks to another party (further analysed in section 3.2). Potential exemptions to TPA are further detailed in the next section.

Priority connection to and use of the network could also be foreseen for renewable and/or low-carbon hydrogen, in order to incentivise them and foster the substitution of fossil fuels or hydrogen with a high-carbon footprint. This has been proposed by a number of studies to facilitate the development of dedicated hydrogen systems, and there are precedents in the electricity and natural gas sectors.[174] The impact of such a measure would however be very limited, as grid congestion is not expected to be a major issue.

Stakeholders’ opinions

As noted in the unbundling sub-section above, stakeholders, including natural gas network operators and market actors, overwhelmingly support non-discriminatory third-party access (and associated vertical unbundling) for new hydrogen networks. A stakeholder highlighted that such measures would be necessary at the European level and in the short-term (three to five years) in order to provide the investment certainty necessary for the development of hydrogen networks.

Some gas infrastructure operators argued that regulation at the EU level should allow both regulated and negotiated TPA for hydrogen infrastructure. The principles of unbundling, non-discrimination, transparency and fair competition should always be met. A network operator proposed that initially a single operator or at least mutually controlled operators (at the national level) with uniform non-discriminatory access and transport conditions would be necessary, with later on uniform tariff setting and socialisation of costs among users of the different network clusters being an option – i.e. some conditions can be set from the start, but further measures such as regulated TPA and tariffs should be implemented at a later stage. In contrast, another natural gas network operator affirmed that regulated TPA should be the default approach to networks.

A network operator indicated that the lack of regulated TPA for future hydrogen networks would make it impossible for grid operators to develop, as network growth would lead to increasing complexity of need for negotiating terms and tariffs with each new network user. Lack of regulated TPA would at least slow down network development below the speed required for the energy transition.

One market actor indicated that, similar to closed natural gas distribution systems and direct lines, upstream (i.e. gas production-related) infrastructure and some new infrastructure (interconnectors, storage and LNG terminals) will require some flexibility for regulated TPA in specific cases. Although favouring the consideration of exemptions, two natural gas network operators indicated that the mere fact they already exist should not automatically lead to the provision of waivers to the current hydrogen system operators. Generally, gas TSOs indicate that, while requirements such as for unbundling and TPA may be waivered or exempted for direct pipelines, they should be enforced once additional consumers are connected to the network.

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[173] Where network operators develop new capacity based on a market demand assessment (e.g. open season) and then firm commitments from market parties

[174] CEER (2018) Status Review of Renewable Support Schemes in Europe for 2016 and 2017
EurObserv’ER (2017) Biogas Barometer

Another stakeholder raised the option of requiring TPA only for specific groups of network users, such as hydrogen producers and industrial consumers, which would most likely be the early adopters of hydrogen. But the stakeholder added that this option would be discriminatory and thus easily be contested in court by other potential network user groups. A natural gas network operator supported the consideration of exemptions, but indicated that in the long-term, all hydrogen networks should be regulated. Another stakeholder was of the opinion that existing hydrogen networks are mainly used to supply feedstock for the chemical industry, and that market power issues should remain to be managed by the competition authorities and by guaranteeing that entry barriers are removed by offering non-discriminatory access.

The opinions regarding the treatment of existing hydrogen networks are not consensual. A stakeholder commented that, while exemptions could be considered, existing customers should have the right to terminate their supply contract, after a transition period, and migrate to another energy network. One natural gas network operator indicated that minimum requirements on unbundling, TPA and transparency should also be imposed on existing private hydrogen networks, while market actors opposed in general the imposition of legal requirements on existing hydrogen infrastructure. A gas TSO supported the application of a sunset clause to exemptions to private network operators, noting that it would have various effects on both existing and new hydrogen network operators, which need to be better understood. Some energy exchange operators also supported a transition pathway for initial exemptions to existing private hydrogen network operators. Private hydrogen network operators, on the other hand, highlighted the need not to put existing long-term commercial contracts at risk and not to impair existing assets.

3.3.1 Greenfield hydrogen regulation: Network access

The options developed for the unbundling requirements for hydrogen networks consider two dimensions:

- The need for regulating third-party access to some extent;
- The type of third-party access regulation.

Considering these dimensions, the following are the main options, as detailed in Table 3-5:

- **Option A:** No harmonised TPA requirements at the EU level;
- **Option B:** Choice for Member States between negotiated TPA (nTPA) and regulated TPA (rTPA);
- **Option C:** Obligatory application of regulated TPA networks in all Member States.

TPA requirements would only apply to regulated networks, while other operators could be exempted or subject to only nTPA. Other specific exemptions on TPA requirements could be granted and are detailed below.

Table 3-5 TPA options for hydrogen / combined network operators

	Option A	Option B	Option C
Options	No harmonised TPA requirements	nTPA / rTPA choice	Obligatory rTPA
Applies to	-	Hydrogen / combined network operators	Hydrogen / combined network operators
Advantages	• Low regulatory cost related to EU legislation • Flexibility for national/local conditions	• Increased transparency • Non-discrimination of users • Flexibility for national/local conditions	• Increased transparency • Non-discrimination of users • No competition distortion between nTPA and rTPA networks
Disadvantages / risks	• Potential for discrimination and market power • Potential for cross-border distortions	• Potential for cross-border distortions	• Increased regulatory cost • Potential impact on business case
Mitigation measures	• Competition law enforcement	• Regulatory test for nTPA choice • Transparency requirements on terms & conditions and ex-post negotiated tariffs • Sunset clause (expiration date) for nTPA	• Provide rTPA exemptions

Box 3-6 Regulatory tests for nTPA/rTPA regimes

As indicated in chapter 2, regulatory tests are broadly viewed as an appropriate way to decide whether and when regulation of hydrogen networks should be introduced. If Member States are allowed to choose between negotiated and regulated TPA for hydrogen networks as proposed in option B, harmonised principles should be set at the EU level for these regulatory tests.

Similar principles can be applied to defining access to existing private hydrogen networks, to new networks as well as in eventual exemption procedures to the chosen access regime. Potentially, different access regimes (nTPA/rTPA) could be foreseen for existing and new hydrogen networks – and even different regimes for different categories of new networks (direct pipelines, closed distribution systems, etc). However, the choice of different regimes will need to be duly justified and the interaction and risk for unequal competition between the networks assessed.

Different access regimes could in principle be imposed to the same network, with part of the transport capacity being offered under a regulated TPA regime. However, regimes should not discriminate between types of network users.

Based on the analysis of this study as well as the criteria for decision on TPA regimes for gas storage,[175] the following minimum regulatory test criteria are suggested for hydrogen pipelines:

- **Effective competition between networks and alternatives**: are there other options for hydrogen transport (through networks or other modes – by rail, trucks, ships) or is competition by on-site hydrogen production feasible?
- **Effective network access**: is/will a significant capacity of the network (be) booked with long-term contracts without non-discriminatory procedures?
- **Upstream or downstream concentration**: is/will transport capacity be booked by a restricted number of network users?
- **Barriers to entry**: are there economic or technical barriers to the development of new hydrogen networks, alternative transport modes or on-site hydrogen production? For example, a planning process which is discriminatory and does not consider alternatives to network development;
- **Relevance of repurposing of methane pipelines**: does the potential repurposing of methane pipelines form barriers to investments in new pipelines, and if so, does the regulatory regime provide non-discriminatory rules for repurposing? Or are only incumbent methane TSOs allowed to repurpose their methane pipelines (i.e. they cannot be transferred to other parties)?

Both regulated and negotiated TPA would require that network operators provide non-discriminatory access to network users, based on transparent criteria and processes. Regulated third-party access would involve the definition or approval of network tariffs by the regulator. Negotiated TPA could be chosen by Member States based on a regulatory test, and would need to impose a number of requirements:[176]

- Publication of terms & conditions for access, such as ex-ante publication of standard contracts, as well as the available capacity;
- Transparency requirements for nTPA with the ex-post publication of the negotiated tariffs;
- Market-based procedures for allocating capacity, such as open seasons or auctions;
- Use-it-or-lose-it and other mechanisms to manage congestion (addressed in the CACM section);
- At least legal unbundling from other energy infrastructure activities (addressed in section 3.2).

Moreover, a number of additional requirements to nTPA could be considered, if deemed necessary to guarantee non-discriminatory access to the network, such as to:

- Establish a cap on the capacity share allocated to dominant downstream users;
- Sunset clause (expiration date) for nTPA or at least the test of market conditions to re-confirm the nTPA regime.

Refusal of connection to or use of the network (including curtailment) should be allowed only in case of proven lack of network capacity. Moreover, the regulatory framework could foresee mechanisms to expand network capacity to accommodate new network users, as long as this is

[175] European Commission (2010). Interpretative Note on Directive 2009/73/EC Concerning Common Rules for the Internal Market in Natural Gas

[176] Some of the suggestions are derived from: Trinomics, REKK & Enquidity (2020). Study on Gas market upgrading and modernisation – Regulatory framework for LNG terminals.
Frontier Economics (2020). Modernisation of the regulatory framework for LNG terminals – A report for GATE terminal.

technically and economically feasible. Member States could decide on whether connection costs should be recovered from the concerned users through specific connection fees and/or (partly) through the general network access tariffs.

Regulated TPA would be suitable where a fast upscaling of the hydrogen system is expected to take place. In such cases, it is unlikely that, in the absence of regulated TPA, network operators would be able to negotiate and provide access to a significant number of new users in time. Access agreements with existing users would complicate the definition of available capacity and tariffs for new users, slowing down their connection. Network planning and investment would also be significantly more complex, especially in the absence of a network development plan based on policy objectives for hydrogen deployment.

Box 3-7 The essential facilities doctrine and its application to hydrogen networks

An essential facility is a "facility or infrastructure which is necessary for reaching customers and/or enabling competitors to carry on their business. A facility is essential if its duplication is impossible or extremely difficult due to physical, geographical, legal or economic constraints".[177]

The application of the essential facilities doctrine (EFD) is based on Article 102 (on abuse of dominant position) of the Treaty on the Functioning of the EU (TFEU) and on competition case law. In the EU, an operator of an essential facility may be obliged to enter into an agreement with competitors regarding access to the facility if "(i) refusing to do so could remove all competition from the market; (ii) the product, such as access to infrastructure, is necessary for the business in question; and (iii) in practice the product could not be replaced by another" as well as if (iv) there is no objective justification for refusing access. The EFD has been applied not only to electricity and natural gas infrastructure but also others such as railways and ports.[178]

Electricity and natural gas infrastructure are traditional examples of essential facilities. The EFD could be employed to guarantee third-party access to dedicated hydrogen networks, if those were also deemed to be essential facilities. In Germany, existing hydrogen networks must already observe the Act against Restraints of Competition (Gesetz gegen Wettbewerbsbeschränkungen, GWB) antitrust regulations.[179] Section 19(2) no.4 of the GWB classifies refusal by a dominant company to grant another company access to its own network as abusive behaviour, unless "the dominant company proves that the shared use is not possible or unreasonable for operational or other reasons".

Competition law in general and the EFD in particular can be important complements to sector-specific regulation, as has been demonstrated in the EU electricity and natural gas as well as other sectors.[180] However, the use of competition law to address eventual market failures in the hydrogen sector can demand significant resources from the competition regulator, face resistance from market participants which slows down sector inquiries, be complicated by information asymmetry, and last but not least may fail to provide the regulatory certainty necessary for investments, given the possibility for eventual market inquiries and ex-post regulation of the sector.[181]

Exemptions and waivers to third-party access requirements

In the case of options A-C, private hydrogen network operators existing at the time of entry into force of the new regulatory framework could be exempted (or not) from TPA. TPA requirement exemptions for pre-existing operators should be allowed only when it is demonstrated that the social benefits of TPA rules would not outweigh its social costs. This could be the case when for example the residual available transport capacity of a private pipeline is rather small and could not make a relevant contribution to the overall hydrogen system. A market test could be conducted to identify the interest of third-parties in accessing the pre-existing network, or absence of such interest. Considerations similar to for unbundling exemptions apply (see section 3.2), including that incentives could be given for pre-existing operators to provide third-party access. TPA requirements could also be phased in gradually, entering into force only once existing supply contracts expire.

New direct pipelines between one producer and some individual hydrogen consumers could be exempted from TPA requirements, possibly for a defined period of time (i.e. with a sunset clause).

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177 DG COMP (2002) Glossary of terms used in EU competition policy – antitrust and control of concentrations
178 Talus (2016) Introduction to Eu Energy Law
179 https://www.gesetze-im-internet.de/gwb/BJNR252110998.html
180 Talus (2016) Introduction to Eu Energy Law; Tapia et al. (2013). The Regulation/Competition Interaction. Handbook on European Competition Law-Substantive Aspects
181 Ecorys and TNO (2018). Waterstoftransport – verkenning marktordeningsalternatieven; commissioned by Dutch Ministry for the Economy and Climate

A similar regulatory test could be applied as for existing private hydrogen network operators. However, as indicated in section 3.2, direct line provisions and exemptions in the EU natural gas regulatory framework are considered to achieve an adequate balance between the rights of suppliers to develop direct lines and the broader interests of all system users. Exemptions to TPA rules should be applied sparingly and only after a regulatory test.

Closed distribution systems could also be exempted from TPA. A similar definition for closed distribution systems as in the art. 28(1) of the Gas Directive could be employed, i.e. 'for specific technical or safety reasons, the operations or the production process of the users of that system are integrated' or the system 'distributes gas primarily to the owner or operator of the system or to their related undertakings'. Closed distribution systems developed with significant public subsidies could be required to provide TPA, and only exempted after a regulatory test similar to new direct lines.

Refurbished natural gas pipelines should in principle not be able to apply for an exemption from TPA, in order to ensure that the economic advantages of using existing assets benefit to the network users and facilitate the deployment of hydrogen.

3.3.2 Natural gas as a basis for hydrogen network regulation: Network access

The non-discriminatory third party access has in principle to be allowed in all gas networks, but exemptions might be granted under the conditions set out in the Article 30 of the Regulation on the Conditions of Access to Natural Gas Infrastructure (2009/715/EC) and Article 36 of the Gas Market Directive. The current regulatory framework thus offers a degree of freedom not to apply TPA rules on interconnectors, LNG and storage facilities (new, of increased capacity or modified) that:

- Enable the connection of new sources of gas supply, or enhance gas competition and security of supply; and
- Entail high level or risks that would otherwise prevent the realisation of such project; and
- The exemption does not negatively affect competition, the internal gas market or the gas system.

The limitation of the possibility of exemptions only to new interconnectors, LNG and storage facilities means that "national" hydrogen transport pipelines would not be eligible for exemption from TPA requirements. Exemptions could be used however to interconnect these systems, if needed to improve the business case of the project.

Table 3-6 Network access options for hydrogen based on natural gas regulatory frameworks

Network access	Option A	Option B
Option	Network TPA requirements, exemptions and waivers apply to hydrogen systems	Network TPA requirements apply to hydrogen systems, with exemption to existing networks
Advantages	• Guarantees effective TPA for existing and future hydrogen networks	• Guarantees effective TPA for future hydrogen networks • Provides regulatory stability to existing hydrogen networks
Disadvantages / risks	• Exemptions limited to interconnectors, storage, LNG/LH_2	• TPA for some existing hydrogen networks may be socially optimal
Mitigation measures	• TPA requirements for pre-existing networks enter into force only once long-term supply contracts expire	• Regulatory test for granting exemption or for imposing TPA to existing hydrogen network • Provide incentives for existing networks offering regulated TPA

3.4 Revenue regulation

Due to the specific characteristics of energy networks highlighted in chapter 2, the revenue regulation of TSOs/DSOs is usually centred on the use of a regulated asset base (RAB). Hence, the revenue of network operators is determined through the building blocks of operational costs (related to O&M and required system services), depreciation of the RAB (allowing to recover the investments) and capital remuneration of the RAB (i.e. return on investments).[182] Figure 3-3

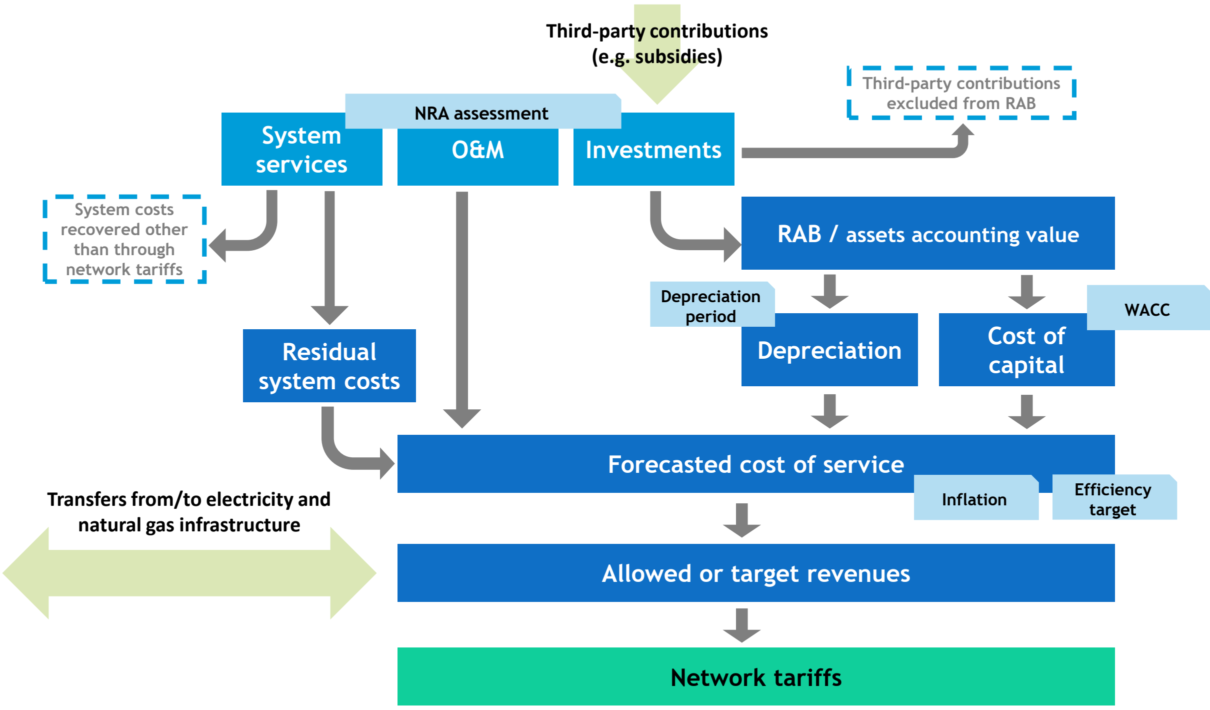
[182] ECA (2018) Consultant report for ACER - Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)

further details the determination of the allowed / target revenue based on these building blocks and associated parameters.

The regulatory framework should incentivise network operators to take socially-optimal decisions regarding the planning, investment and operation of the system and physical assets,[183] while guaranteeing the long-term economic security of the asset owners/operators. Regulators as well as policy makers have an important role in guaranteeing that these two objectives are met, as they are critical to providing long-term certainty for network operators to take decisions which are aligned to energy policy and decarbonisation strategies, thus facilitating the energy transition and reducing the risks of stranded investments.[184]

As discussed in the network charging section, a number of principles guide the design of tariffs which serve to recover the allowed revenues of network operators, including that of cost reflectivity. Cost reflectivity implies that there should not be cross-subsidisation between network users, i.e. tariffs should reflect the actual network costs caused by each network user (reflecting also eventual system externalities).

Figure 3-3 Regulation of the allowed / target revenues of network operators[185]



Box 3-8 CEER's note on stranded assets in distribution networks[186]

In July 2020 CEER published a document on stranded assets in distribution networks. Noting that there is not a clear and harmonised definition of stranded assets in national regulatory frameworks, CEER indicates that "regulated gas or electricity assets can be considered to be stranded when it is expected that regulated companies, as owners of those assets, cannot recover their efficient investment costs under the conditions for allowed revenues given the changes between the current and expected environment. One of the main reasons for such a situation is underutilisation of assets, due to low demand, technical/environmental constraints, or policy decisions, among others".

Stranded assets could lead to an increase in tariffs, the need for subsidies, and ultimately to the decommissioning of assets. Responding to a CEER survey, most NRAs indicated that stranded assets are not a problem yet, with only a few cases identified and with varying causes.

The NRAs identify a number of risk mitigation measures for stranded assets, namely:

[183] These functions may not be assigned to the same organisation, especially that of planning and/or of system operation (which may be assigned to an ISO), as discussed above.
[184] Trinomics, LBST and E3-M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure
[185] Adapted from ACER (2018) Report on the methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators
[186] Available at https://www.ceer.eu/documents/104400/-/-/cbe00257-ab09-c1b2-91bf-b6081032f322

- Incentives for efficient investments;
- Alternative use for the grids;
- Change in depreciation policies and adjustments to the cost of capital.

At present, most NRAs are involved to some extent in the planning and development of distribution networks. They also examine and confirm the assessment of project demand volumes by the regulated network operators.

Hence, NRAs play some role in the development of distribution network development plans including in the setting of projected demand volumes, and have a number of instruments to incentivise efficient investments by the DSOs.

It must be noted that most instruments, except the re-purposing of networks, should be adequately applied regardless of the risks of stranded investments – i.e. incentives for efficient investments as well as adequate depreciation policies and remuneration of capital should be in place.

Revenue regulation and dedicated hydrogen networks

Regulating the revenues of network operators is a complex task which needs to consider holistically all the building blocks and parameters, so that decisions of network operators are socially optimal, while providing reasonable remuneration of their capital. Inefficient regulatory frameworks can lead to structural over-recovery (i.e. excessive profits) or under-recovery (i.e. revenue deficits) of the cost of service, through risks such as: [187]

- Lack of robust planning scenarios;
- Capex bias / gold-plating;
- Inadequate asset depreciation rules;
- Misestimation of the WACC;
- Inadequate economic efficiency incentives (such as the x-factor);
- Inadequate re-evaluation of the RAB;
- Incorrect remuneration of working capital, assets under construction or leased assets;
- Inclusion of third-party contributions (e.g. EU grants) to the RAB.

Therefore, revenue regulation is directly related to the transparent, non-discriminatory network planning and investments based on scenarios. In the case of hydrogen, scenarios reflecting energy policy targets (ideally approved by policy makers) will be particularly important to reduce risks to network operators of not being able to recover the incurred cost of service.

In principle regulated hydrogen network operators should be able to source funds from the market (through equity, loans or bonds) at lower interest rates than non-regulated network operators, thanks to a lower risk premium. Hence, the regulation of hydrogen networks would lead to a lower tariff level to network users. However, although regulation would likely lead to a lower cost of capital, the important investments needed for the deployment of hydrogen networks could still lead to a higher cost of capital than for electricity and natural gas network operators, due to the perception of increased risk arising from the roll-out of infrastructure in a developing market and/or to higher leverage ratios of hydrogen network operators.

Significant innovation will still be required in the technologies for the roll-out of hydrogen systems (not only regarding production infrastructure, but also transmission/distribution and end-use equipment and appliances). Hence, while efficiency considerations will still remain relevant for hydrogen TSOs/DSOs, the use of efficiency incentives such as an x-factor might be less relevant than the consideration of innovation incentives in the revenue regulatory framework. Otherwise, if network operators are not able to recover the costs of their R&I programs, the feasibility of developing hydrogen networks could be threatened, and lead to delayed implementation and/or higher costs in the long run.

The revenue regulation of hydrogen network operators will also be influenced by the charging methods applied to network users concerning two specific aspects at least: the impact of tariff levels on the connection of new users to hydrogen networks (and the disconnection of users from methane networks), and cost-reflectivity to users in electricity, methane and hydrogen systems.

[187] Trinomics et al. (2020). Energy costs, taxes and the impact of government interventions on investments. Final report – network costs.

First, high tariffs could disincentivise potential hydrogen users from connecting to the network. As indicated in the network charging section, high initial investments should not necessarily translate in high grid tariffs for first movers, as late-comers would also benefit from the investments. Also, new users should not be penalised for shifting to renewable or low-carbon hydrogen and hence contributing to energy and climate policy objectives. On the other hand, methane users might face increasing network tariffs as early adopters migrate to hydrogen and thus leave a smaller pool of remaining methane network users to bear the cost of service, which may still include a significant non-depreciated RAB (unless a large part of the non-depreciated RAB can be repurposed for hydrogen use). The potential decommissioning of non-depreciated methane infrastructure would exacerbate this issue, as network operators may claim a compensation for the residual asset value, possibly leading to a sharp increase in the tariff levels if the compensation is not borne by taxpayers.

Second, due to the pursuit of cost-reflectivity in electricity and gas network tariffs and the avoidance of cross-subsidisation, there is generally no monetary transfer between the two sectors. However, as the roll-out of hydrogen networks will contribute to the flexibility of the electricity system and facilitate the decarbonisation of the gas system, intersectoral monetary transfers enabling hydrogen network operators to (partly) finance the required investments in networks, might in some cases be cost-reflective and thus not constitute (cross-)subsidisation.

Such transfers would only be justified if the positive externalities resulting from hydrogen deployment are not properly internalised through other mechanisms, for example via carbon prices or taxes or prices paid for flexibility and security of electricity supply provided by conversion technologies such as electrolysers or hydrogen-based power generation.

Due to some specific factors, the positive externalities of hydrogen deployment enabled by specific networks may not be fully internalised. First, investment in dedicated hydrogen networks will be lumpy, i.e. the network capacity will be discrete and over-dimensioned, in order to value the economies resulting from the sub-additive cost curves of pipelines and the repurposing of methane pipelines. Second, revenues of technologies coupling the hydrogen to the electricity and methane systems are mainly determined by the short-run marginal costs in the different electricity and methane systems, which may offer an adequate remuneration for flexibility but not for security of supply, as the benefits of hydrogen deployment resulting from reduced dependence of energy imports and enhanced diversification of sources and technologies are not reflected in the market prices. Finally, while electricity generation is part of the ETS, fossil fuels' consumption by non ETS end-users is not subject to a similar carbon tax, which hinders the shift from fossil energy to renewable or low-carbon electricity and hydrogen.

The value of non-internalised externalities such as increased system reliability and security of supply could be paid by electricity system users, while environmental positive externalities could be better borne by taxpayers (potentially recovered by a carbon tax on fossil fuel consumption by non-ETS end-users). One of the biggest challenges is correctly quantifying these non-internalised externalities and achieving a transparent re-allocation of costs with objective criteria.

Stakeholders' opinions

Natural gas network operators and market parties in general support that NRAs should allow to include the efficiently-incurred costs to build dedicated hydrogen infrastructure (by new investments or conversion of methane infrastructure) into the network RAB. While natural gas network operators generally support the creation of combined gas network operators covering both methane and hydrogen, market parties do not have an established opinion on whether the RAB for hydrogen and methane assets should be separated, although specific actors do support the separation of accounts (but not necessarily ownership or legal/functional unbundling).

One national regulator indicated that while a similar approach to revenue regulation as for natural gas could be used, aspects like the applicability of benchmarks and asset depreciation periods might not be the same. In the transition phase, a simplified approach could be desirable, without applying all elements of the natural gas regulatory framework.

Two stakeholders specifically supported the possibility for hydrogen projects to apply for EU investment funding, such as through being eligible for PCI status and hence having access to CEF funding.

Regulators highlighted that a regulated revenue model based on the RAB allows to depreciate investment costs over a long time period, leading to lower annual costs for network users. A network operator highlighted that the roll-out of hydrogen networks will be different across Member States, but that the general principle of favouring conversion of methane networks instead of decommissioning where efficient should be followed in order to reduce overall costs to network users. It noted also that incentives to end-users will be necessary to adapt or change equipment and appliances.

Finally, a stakeholder indicated that it must be ensured that subsidies to the hydrogen sector do not undermine market signals for energy efficiency and electrification of end-uses.

3.4.1 Greenfield hydrogen regulation: Revenue regulation

Network cost re-allocation

The options detailed in the table below addresses the issue of potential re-allocation of the cost of hydrogen, methane and electricity networks. Appropriate revenue regulation should aim to avoid investments by network operators which would lead to a lock-in in unsustainable pathways and/or to stranded assets. Thus, regulation that mandates an objective, transparent and non-discriminatory planning process is critical to minimise these risks and thus the efficient cost of service.

Assuming that the costs incurred by network operators are efficient, cost re-allocation may still be warranted to adequately phase-out or decarbonise natural gas systems, to reflect energy system positive externalities which are not internalised, and to incentivise potential hydrogen network users.

Cost re-allocation may be explicit (through monetary transfers between network operators of different carriers or through government subsidies), or implicit (by joint accounts of combined gas operators). This is reflected in the options for cost allocation:

- **Option A:** Neither cost re-allocation between networks nor subsidies by governments are allowed;
- **Option B:** Cost re-allocation between hydrogen, methane and electricity network operators is allowed;
- **Option C:** The use of combined accounts by combined gas network operators implicitly allows for cost re-allocation, if e.g. tariff revenues from methane network users are used to recover the allowed revenue of hydrogen network operators, especially the capital remuneration and depreciation components.

It is assumed that for any of the options, subsidies (state aid) would be allowed for hydrogen networks, as part of energy infrastructures. Options for state aid to hydrogen networks are not analysed in this study, as they are part of the scope of the Guidelines on State aid for environmental protection and energy rather than related to network regulation.

Table 3-7 Cost re-allocation options

	Option A	Option B	Option C
Re-allocation allowed	Cost re-allocation not allowed	Cross-sectoral cost allocation	Combined gas network operators without accounts unbundling
Explicit/ implicit allocation	None	Explicit	Implicit
Advantages	• Low regulatory costs • Automatically cost reflective in case of no significant externalities	• Reflects provision of non-internalised system benefits • Beneficial for minority consumers (H2 at start, later NG) • Employs methane / electricity tariff revenue	• Reduced administrative burden • Allows sharing of risks and costs • Beneficial for minority consumers (H2 at start, later NG)
Disadvantages / risks	• Not cost reflective in case of significant externalities that are not internalised	• Increases electricity / methane network tariffs • Complex integrated system assessment	• Cost allocation not transparent • May incentivise inefficient decisions if techno-economic parameters are fundamentally different
Mitigation measures	• Subsidies to hydrogen networks	• Require assessment of externalities	• Use accounts unbundling • Use technology-specific techno-economic parameters

The consideration of cost re-allocation either among ratepayers or to taxpayers should follow some guidelines:

- Cross-sectoral cost allocation or subsidies should reflect externalities that are not internalised, and should be recovered from the beneficiaries of the positive externalities;
- Energy network users should pay for the positive system externalities such as system reliability and security of energy supply which benefit them, while environmental externalities can be supported by taxpayers, and possibly recovered via a surcharge from the concerned end-users;
- Cross-subsidisation between different categories of consumers should in principle not occur. For example, residential methane gas consumers should not cross-subsidise hydrogen networks serving mainly industrial consumers;
- Assessment of the externalities should be a pre-condition to any cross-sectoral cost re-allocation or subsidies.

The non-internalised positive externalities of hydrogen networks could be estimated by:

1. Conducting a forward-looking resource adequacy assessment of the energy system;
2. Calculating the system-optimal level of hydrogen infrastructure deployment;
3. Comparing that to the expected level of deployment without cross-subsidisation;
4. Recovering the difference through subsidisation and/or charges to the methane and electricity sectors.

Ideally, well-designed electricity and methane markets should adequately remunerate technologies at the interface with hydrogen systems. Hence, for example, electricity capacity remuneration mechanisms should also allow the participation of electrolysers and hydrogen-based power generation. Only if these technologies would not be adequately remunerated and grid tariffs would not allow to recover hydrogen network costs, subsidies and cost re-allocation can be considered to facilitate hydrogen network investments. Other mechanisms can be employed to recover the hydrogen networks investments in a cost-reflective manner. For instance, long depreciation periods could be used in order not to unduly burden initial hydrogen network users.

To cover the costs arising from the eventual decommissioning of methane assets, the "Potentials of sector coupling for decarbonisation" study indicates that the options of cost reallocation to taxpayers and ratepayers of the electricity and hydrogen systems could be both feasible (with a preference for the reallocation to taxpayers). Front-loading the recovery of costs through accelerated depreciation, shorter depreciation periods or classifying a higher share of costs as OPEX is also proposed as a solution[188]. Recently, CEER also hinted at eventual cost sharing to be possible between energy sectors, although also stating that "potential negative impacts such as unjustified cross-subsidies" should be kept to a minimum.[189]

Another study for Germany indicated that significant special depreciation costs for decommissioned methane assets would arise, in the order of 6 billion € for the 2033-2050 period.[190] The study argued that the special depreciation costs could be avoided through investments in hydrogen networks (through the conversion of the to-be-decommissioned assets), leading to societal benefits and freeing up funds. This would complement available funds already arising from the reduced allowed revenue for methane network operators, which would result from the depreciation of assets and decreased investment levels.

The biomethane and hydrogen study[191] raised a number of potential policy and regulatory measures on network charging relevant for hydrogen networks. These include "joint tariffication of methane and hydrogen networks", which would be compatible with option D above, and application of "super-shallow connection charges and tariff discounts for renewable and/or decarbonised gases when justified by system benefits or policy objectives", which could be applied in any of the options.

[188] Frontier Economics et al. (2019) Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU.

[189] CEER (2020) Paper on Whole System Approaches. C19-DS-58-03.

[190] bbh (2020) Principles of the regulation of German hydrogen networks in the context of an adaptation of the European legal framework and the financing of hydrogen networks by integration into the legal framework of gas network regulation.

[191] Trinomics, LBST and E3-M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure

Additional principles for network revenue regulation

Next to the topic of the allowed network revenue recovery through taxpayers and/or ratepayers, a number of other principles should be followed by Member States when regulating the allowed revenue. EU legislation could set general guidelines to ensure that national regulatory frameworks respect the following principles:[192]

- Require an objective, transparent and non-discriminatory network planning process with strong oversight;
- Encourage a balanced consideration of OPEX- and CAPEX-based solutions;
- Assure stakeholder consultation on network development plans and on a project level (for large projects);
- Require that capitalised costs financed with third-party contributions such as government subsidies or cross-sectoral transfers are not included in the RAB;
- Avoid that the RABs are re-evaluated in case of (further) unbundling of network operators or upon conversion of methane infrastructure. The roll-out of hydrogen networks and changes to the regulatory framework should not constitute a reason for methane grid operators to review (increase) the residual accounting value of their repurposed assets;
- Review the depreciation rules of methane infrastructure so that they better anticipate the expected evolutions of the gas system and properly reflect the economic lifetime of assets, considering current tariff levels and the ability of network users to absorb short-term hikes, especially vulnerable consumers and industrial users exposed to international competition;[193]
- Maintain separated accounts between hydrogen and methane networks, to assure transparency, cost-reflectivity, and avoid information asymmetry between regulators and network operators;
- Ensure that the revenue methodology parameters for hydrogen and methane networks do not constitute a perverse incentive for incumbent methane network operators to repurpose methane pipelines where not socially beneficial. This could be the case if the capital remuneration level for hydrogen network RABs would be significantly higher than for methane networks while the effective capital costs would be similar.

3.4.2 Natural gas as a basis for hydrogen network regulation: Revenue regulation

The recovery of costs is regulated under the Article 13 of the Gas Regulation (Tariffs for access to networks), which states that network usage tariffs should be used to cover the actually incurred network costs, provided the service is run efficiently, and include appropriate return on investment. The revenue regulatory requirements are further elaborated in the Chapter IV of the Commission Regulation establishing Network Code on Harmonised Transmission Tariff Structures for Gas (TAR NC).[194]

The following summary of revenue regulation building blocks is based on the study 'Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators', commissioned by ACER.[195]

Most countries in the EU apply some kind of incentive-based approach to revenue regulation. In 2018, 13 countries applied a revenue cap mechanism, 2 countries a price cap mechanism, and 9 countries deployed a hybrid approach, usually applying a revenue cap on OPEX and a cost-plus approach for CAPEX. Only one country applied solely a cost-plus based approach. 19 out of 27 regulators apply efficiency factors for OPEX, only those using a TOTEX approach apply efficiency factors to capital expenditures.

The allowed revenues are in most EU countries established by assessing all cost components separately, e.g. using the building block approach. Only 3 countries apply a combined OPEX and CAPEX assessment (TOTEX) approach. Most of the regulators use a bottom-up approach for the CAPEX assessment, e.g. assessing individually all cost items claimed by network operators. For the OPEX assessment however, using a top-down cost approach is prevalent as well. The less prevalent method is benchmarking the costs to external factors.

The regulatory periods range from 1 to 8 years in Europe, although a vast majority of countries opts for 4 to 5 years.

[192] Some principles proposed in Ecorys et al. (2019) Do current regulatory frameworks in the EU support innovation and security of supply in electricity and gas infrastructure?
[193] Trinomics, LBST and E3-M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure
[194] EC (2017). Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas
[195] ECA (2018). Consultant report for ACER - Methodologies and parameters used to determine the allowed or target revenue of gas transmission system operators (TSOs)

The mostly used valuation **method for determining the regulatory asset base** is based on the historical costs (11 countries), followed by the actual economic value assessment (8 countries). In most cases, the asset value is not revaluated during the regulatory periods (except for deducting the depreciation), only two NRAs use the replacement cost as a basis for the periodic revaluation.

While there is a wide consensus on using the linear **depreciation method** (as opposed to an accelerated depreciation), the regulated lifetime of assets substantially varies across the EU, as shown in Table 3-12 below.

Table 3-8 Depreciation period (in years) of gas network assets

Type of asset	Min value	Typical value	Max value
Pipelines	30	40-50	90
Compressors	12	20-30	65
Controllers & metering	9	20-30	45
SCADA & telecom	4	5-10	45

The allowed **cost of capital** also substantially differs among the EU countries, especially since there are different calculation methods, the most dominant method being the pre-tax calculation, either in nominal or in real values. The risk-free rate seems to significantly vary between Member States without a clearly established range, whereas the market risk premium seems to be more consistent, with most countries setting a value between 4,5% - 5,05%. There is however a wide-scale consensus on setting the equity beta value below 1, suggesting that investments in regulated network assets bear less risk than in market assets in general.

One national regulator specifically raised the question whether the same asset lives and fixed OPEX rates as used for natural gas could be applied to hydrogen, indicating that this issue requires further study. The question of OPEX rates was specifically investigated in the biomethane and hydrogen study[196], where stakeholders from the gas sector indicated that the OPEX levels for hydrogen distribution networks could be similar to methane networks at around 1%/a of CAPEX, although the study acknowledged that further research is needed to validate these assumptions. The OPEX for natural gas transmission networks are significantly higher, at 1.7%/a to 2.4%/a of CAPEX, based on the 2018 TYNDP data. Similar or higher levels could thus be expected for hydrogen transmission networks. The European Hydrogen Backbone[197] study assumes annual OPEX costs (excluding electricity costs for compression) of 0.8-1.7% of CAPEX of new investments, but scenarios lead to total OPEX costs (also including electricity costs for compression) of 5.4-6%, presumably due to CAPEX savings resulting from the repurposing of methane infrastructure.

Options formulation

In option A, there would be no revenue regulation for hydrogen networks. In option B, the regulatory approach for natural gas and hydrogen networks would be the same for all regulatory elements (e.g. WACC, depreciation period). The revenues from both networks would be cumulated and the resulting deviation from the allowed revenues would be globally assessed – any under-/over-recovery in one network could be balanced out by the other network. In option C, some of the specific regulatory elements would be defined separately for natural gas and hydrogen networks, such as technology-specific lifetimes or specific WACC rules, reflecting different risk levels for investing in methane or hydrogen networks. The overall regulatory principles, i.e. incentive-based or cost+ approach, would remain the same and there would be no differentiation in the regulatory accounts between hydrogen and methane infrastructure. The last option D builds on option C, but both networks would be separated in the regulatory accounts, thus eliminating the possibility of balancing the accounts between networks.

[196] Trinomics, LBST and E3-M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure

[197] Enagás et al. with support of Guidehouse (2020) European Hydrogen Backbone

Table 3-9 Revenue regulation options based on the natural gas regulatory framework

	Option A	Option B	Option C	Option D
Approach between methane and hydrogen	No revenue regulation	Unified approach	Unified approach with technology-specific adaptations	Separation of methane and hydrogen in regulatory accounts
Advantages	• Reduced administrative burden • Increased flexibility for network operators adjusting tariffs	• Reduced administrative burden • Allows sharing of risks and costs • Beneficial for minority of consumers (H2 at start, later NG) • Technology-neutral	• Reduced administrative burden • Allows sharing of risks and costs • Reflects main differences in techno-economic parameters	• Reflecting different value of assets; expected lifetime; level of risk • Reflecting different drivers of sector development (NG: efficient usage of existing assets; H2: development of new networks)
Disadvantages / risks	• Cost allocation not transparent • Potential discrimination of price-insensitive network users •	• Cost allocation not transparent • May incentivise inefficient decisions if techno-economic parameters are fundamentally different • Cross-subsidisation likely	• Increased complexity compared to option A • Cost allocation not transparent	• Harder to distinguish which approach to apply e.g. for hydrogen admixture costs
Mitigation measures	• Regulatory approval of tariffs • Ex-post control mechanisms by NRAs	• Separate sub-accounts • WACC adders for high-risk investments	• Separate sub-accounts	• Cost re-allocation between energy networks to reflect non-internalised externalities

3.5 Network planning

The overall framework for network planning involves the definition of 1) the responsibility for network planning; 2) oversight of the planning process and approval of the plan, and 3) investment in and operation of the assets.[198] Steps 1) and 3) may be conducted by the same or different operators, while generally step 2) is the responsibility of the competent authority or regulator. Hence, the following archetypal network planning models can be defined:[199]

- Centralised network planning by an appointed organisation, and investment and operation of assets conducted by one or more separate companies;
- Combined network planning, investment and operation by the same company;

The regulator may be responsible for authorising expansion plans for any of the possible approaches above. The model of network users-driven expansion planning is rarely applied. Merchant investors may develop transmission projects which were not included in network expansion plans, also with prior authorisation (and provision of necessary exemptions of e.g. third-party access) by regulators.

Commonly used network planning criteria (security of supply, positive net socio-economic welfare, integrating renewable energy sources, minimising negative environmental impacts, and less often innovation) are also relevant for hydrogen networks. Traditionally, network development plans are demand-based, i.e. they must ensure system adequacy based on the forecasted demand, while also integrating the planned decentralised production of electricity, methane (biomethane) and hydrogen.

[198] Pérez-Arriaga (*ed.*, 2013). Regulation of the power sector.
[199] Network users-driven expansion planning is also possible but rarely applied, where network users are responsible for proposing and voting candidate projects, and the network operator or a consortium of network users build the project(s).

Box 3-9 CEER's paper on whole-system approaches[200]

CEER's paper released in June 2020 develops concepts for the whole-system approach for planning and operation of energy systems on three layers: the whole-network (i.e. TSO-DSO), the whole-chain (i.e. within one energy sector) and the cross-systems layer (e.g. between the electricity and gas sectors). It notes the cross-border layer could be added to the typology.

The lack of a whole-system approach could lead to the planning and operation of an energy system which does not properly consider the interactions between the different vectors, with a (strong) potential to lead to sub-optimal results from a societal perspective.

The paper notes 4 types of mechanisms to foster such a whole-system approach:

- **Regulatory incentives**: within-network positive and negative incentives should be inserted in the regulatory framework setting the allowed revenue and tariff structure;
- **Regulatory requirements:** such as requirements for coordination and cooperation between network operators and third-parties;
- **EU and national laws and regulation** not impeding regulators and network operators to cooperating outside of their specific sector and pursuing common pathways, while minimising risks such as unjustified cross-subsidies;
- **Data transparency and interoperability**, which act as an enabler for whole-systems approaches.

Network planning and dedicated hydrogen networks

Adequate planning procedures for hydrogen networks will serve to provide certainty for investments from regulated network operators as well as from network users. Network plans are a central instrument for guaranteeing that efficient investments proposed by network operators are authorised by regulators and hence may be included in their regulatory asset base and recovered via regulated tariffs. For (potential and existing) network users, hydrogen network plans will be useful to have updated information about the planned roll-out of hydrogen networks, when considering using the network versus alternatives such as on-site H_2 production.

The network planning will need to consider, to the extent where relevant, the entire energy system, at least the electricity and methane systems. Several studies about long-term decarbonisation scenarios have shown that an integrated planning approach is the lowest cost solution, in particular due to the fact that conversion of methane infrastructure is cheaper than investing in new hydrogen infrastructure. This is supported by the Energy System Integration Strategy of the European Commission.[201] Moreover, as energy efficiency measures and direct electrification of end-uses are often the most cost-efficient solution, these will need to be considered before investments in methane and hydrogen infrastructure are made. Further interaction between the electricity, methane, hydrogen and heat sectors will take place through conversion technologies and hybrid equipment and appliances, such as hybrid turbines or boilers.

This implies that the planning will also need to include the main potential solutions in each of the sectors for a secure and affordable energy supply that contributes to the energy and climate objectives. While the methane and hydrogen systems can provide important daily and seasonal storage as well as supply flexibility through LH_2 terminals, these capacities may be constrained in size and location. Also, constraints in the electricity and hydrogen network capacity will play a role in determining the location of large-scale electrolysers.

Policymakers will need to provide guidance regarding the planned roll-out of hydrogen networks and the eventual downscaling or decarbonisation of methane networks, so that the (dis)connection of methane network users is aligned with the energy and climate objectives. Policymakers will also need to consider under which conditions network operators can be obliged to connect new users to the hydrogen or methane network (and eventually revise existing obligations).

When hydrogen systems will reach scale and will get integrated across borders, the planning of cross-border infrastructure will gain importance in specific regions. Planning at the EU level will then be necessary for major cross-border / cross-zonal infrastructure and also for addressing potential domestic structural congestion, also since transit flows may become important in some Member States that transport hydrogen from peripheral / coastal regions to central Europe. Hence, cross-border cooperation and consistency between the planning at the EU and national levels will

[200] Available at https://www.ceer.eu/documents/104400/-/-/c52735ff-54db-9d8b-146d-753d7edc141d

[201] European Commission (2020). Powering a climate-neutral economy: An EU Strategy for Energy System Integration. COM(2020) 299 final.

be required depending on the scale of hydrogen deployment. This will also be necessary for the repurposing of cross-border methane interconnections, which will need to consider the cross-border transport capacity demand for hydrogen, which may, notwithstanding its lower energy density, be significantly lower than the capacity of the repurposed pipelines. However, compressors may be dimensioned to the actual forecasted demand, leading to CAPEX economies.[202]

Integration between hydrogen transmission and distribution systems will also be necessary. Hydrogen systems may start being developed in either of the two levels, depending on the supply and demand characteristics, the eventual integration of hydrogen clusters as well as other factors. As the hydrogen infrastructure is expected to gradually develop, some new users may have the option to connect at the transmission or distribution level, which may create the risk for limited visibility of TSOs and DSOs on injection/demand forecasts at each level. Also, small-scale technologies such as electrolysers of up to tens of MWs can lead to significant production of hydrogen at the distribution level in certain clusters.

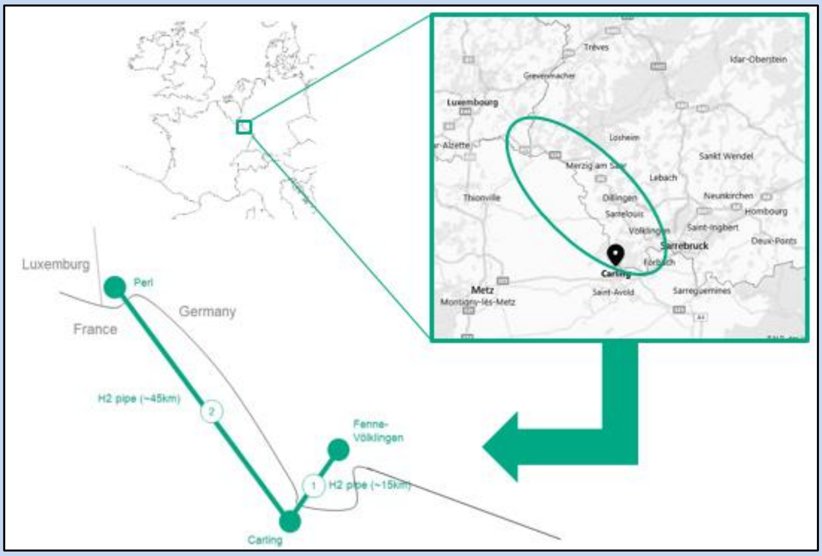
Hence, hydrogen TSO-DSO cooperation will be necessary for systems where such two network levels will exist or would be deployed within the planning horizon. The decision on which level to connect new users should, preferentially, rest with the network operators rather than the users. This would avoid situations such as in Denmark, where biomethane producers could choose the grid connection level and bear the related costs, which meant that late-comers could only be connected to the (more expensive) transmission level, as the distribution network capacity was already taken. The model was changed to assign the planning responsibility to the network operators, which are supposed to realise the necessary efficient network investments allowing to connect biomethane users at the most adequate level.[203]

Moreover, the roll-out of (cross-border) hydrogen networks will require the definition of interoperability guidelines and subsequent agreements, as well as European standards for gas quality and end-user equipment and appliances. For methane grids, similar requirements are necessary, also due to the planned blending of hydrogen in some methane networks.

Box 3-10 The MosaHYc (Mosel Saar HYdrogen Conversion) project[204]

In May 2020 the French natural gas TSO GRTgaz and the Luxembourger TSO Creos have signed a collaboration agreement for the MosaHYc (Mosel Saar HYdrogen Conversion) project.

MosaHYc aims to converting existing natural gas pipelines to develop a 70-km hydrogen network across the France-Germany-Luxembourg border, aiming at supplying the transport sector. It could be further expanded to connect industrial clusters in the region. The gas TSOs will cooperate with the national regulators to develop the technical aspects of the project, but also the required regulatory framework to take a final investment decision in 2022.



[202] Enagás et al. with support of Guidehouse (2020) European Hydrogen Backbone
[203] See for example Energinet (2018) System Plan 2018 – Electricity and gas in Denmark
[204] Source: GRTgaz (2020) Hydrogen: signing of a collaboration agreement between GRTgaz SA and Creos Deutschland GmbH
http://www.grtgaz.com/en/press/press-releases/news-details/article/hydrogene-lancement-du-projet-mosahyc.html

Stakeholders’ opinions

Stakeholders agree that network planning should be holistic and consider investment, operation and decommissioning costs as well as security of supply, climate and environmental impacts along the entire hydrogen, methane and electricity value chains.

Multiple stakeholders, also including regulators, consider the network planning monopoly as a potential source of efficiency. One stakeholder highlighted the need for European guidelines on planning transparency and assessment of competing alternatives in the hydrogen, methane and electricity sectors.

A stakeholder highlighted that the previous TYNDPs tended to analyse in detail network expansion options, while dedicating less attention to alternatives, leading to biased scenarios and the lack of acknowledgment for the alternatives. It stressed the need to define how conflicts of interest of network operators for the conversion of methane networks will be managed, and also whether current gas users could be forced to disconnect from the methane grid and/or switch to hydrogen.

Generally, natural gas network operators do not see a need for the separation of network planning from the investment and operation of network assets, noting that there are synergies between them leading to investment and operational savings, especially in the case of significant conversion of methane pipelines. According to the network operators, the current transparent, non-discriminatory planning processes for methane networks, which include oversight and consultation of stakeholders, would be an appropriate model for the planning of hydrogen networks. Regardless of which organisation has the responsibility for network planning, it is generally recognised that network and storage operators have an important role to play in the siting of assets such as for conversion, as transparency on available infrastructure capacity and constraints is key for efficient decisions.

Gas TSOs support the immediate start of coordinated planning for a hydrogen backbone in Europe, to “diversify supply sources and prevent anti-competitive market structures”. They sustain that planning at the EU level would be carried out best within the existing TYNDP framework (updated as necessary). This would leverage existing and tested processes, and promote transparency.

A market actor suggested that the TYNDP process should also evaluate the impact of decommissioning of energy infrastructure, in consultation with the users of the specific infrastructure.

A natural gas network operator indicated that the discussion about separating the planning from the investment and operation of assets is similar to that taking place in the natural gas sector, and that the answer is not straightforward, as the proportionality of such a measure should be considered. Strict regulatory oversight in the concerned country should ensure that the benefits of network investments outweigh the costs. The transparency and non-discrimination of the planning process would involve multiple other questions such as information requirements, consultations and cooperation mechanisms, and existing measures could be improved.

Stakeholders are unanimous regarding the need for increased coordination between TSOs and DSOs to plan the necessary infrastructure development, system operation and connection of network users. Interestingly, a stakeholder also highlighted the need for coordinating the R&I projects which will still be necessary in order to enable the deployment of a hydrogen system.

A network operator indicated that the consideration of hydrogen infrastructure projects as being of public interest would facilitate the permitting procedures.

3.5.1 Greenfield hydrogen regulation: Network planning

The options developed for hydrogen network planning are organised in three main dimensions:

- Network planning responsibility and oversight;
- Cross-border network planning;
- Cross-carrier network planning.

Extensive stakeholder consultation should be part of the development of the scenarios, methodologies and network development plans for all options discussed below. The network operators should provide an analysis and justification of (non-)actions taken in response to stakeholder inputs.

Box 3-11 A proposal for an EU hydrogen TSO

Some of the options for the regulatory elements considered in chapters 3 and 4 imply the creation of an EU hydrogen TSO. This EU H2 TSO could be responsible for a number of functions, in particular:

- Network planning (section 3.5)- Development of EU-level determinative hydrogen network planning, including methodologies and scenarios (with ACER/EC approval).
- CACM (section 3.7) - Management of capacity management and congestion platform employed for:
  - DA/IDA implicit market coupling (in cooperation with market coupling operator, MCO, and TSOs);
  - Countertrading and re-dispatching actions.
- Network charging (section 3.6) - Management of inter-TSO compensation mechanism;
- Balancing (section 4.2.3) - Management of balancing market coupling platform (with market area manager) – potentially same as CACM platform.

DA/ID implicit market coupling, CACM and inter-TSO compensation would occur in the following manner:

1. Market participants trade
2. TSOs inform capacity availability data to the capacity management platform
3. Market participants submit supply/demand bids to nominated market operators
4. Capacity management platform and nominated market operators' inform capacity and bid data to market coupling operator
5. Market coupling operator clears coupled market with information from capacity management and nominated market operators
6. EU H2 TSO manages intra-day and close to real-time congestion management actions (preferentially countertrading, otherwise redispatching)
7. Ex-post flows, other data are employed to define inter-TSO compensation for used interconnection capacity, congestion management measures

The functioning of the ITC mechanism would be as follows:

- Harmonised principles for XB and national tariffs would be set to address market distortion issues
- NRAs or TSOs with NRA approval set regulated tariff levels
- Tariffs at IPs for clearing markets (ID, DA, BAL) would be set at 0 / limited value reflecting variable costs
- Ex-post flows, other data (e.g. network capacity) employed to define inter-TSO compensation for used/available interconnection capacity, congestion management measures
- TSOs pass through ITC costs/surpluses to network users cost-reflectively

Ideally, the planning of cross-border and trans-European hydrogen, methane and electricity infrastructure should be conducted by a single organisation or with strong cooperation of the sector-specific EU-level (EN)TSOs employing common scenarios and a single energy systems model and CBA methodology. This single EU-level energy TSO entity could be set up by (or formed by the merger of) the electricity and methane ENTSOs with the new EU H_2 TSO. However, in this scenario this single organisation could have different mandated activities for the hydrogen vs the electricity and methane sectors (e.g. regarding capacity allocation). Options to integrate network planning across energy carriers thus comprise:

- The new organisation could be responsible solely for planning, while other responsibilities could be assigned to a hydrogen-specific EU TSO;
- Sector-specific EU-level (EN)TSOs would cooperate in planning while being mandated to jointly develop the scenarios, CBA methodology and energy systems model. If the mandates of ENTSO-E, ENTSOG and the EU H_2 TSO are deemed compatible, they could be merged into a single organisation in order to facilitate sector coupling and reduce overhead costs.

Another important aspect is whether the EU H_2 TSO would be responsible for all above-mentioned functions or whether some of them could better be assigned to regional organisations. Planning of hydrogen backbone infrastructure should take place at the EU-level, due to the importance of integrated planning across regions as well as the fact that planning of electricity and methane infrastructure (which would ideally be integrated with that of hydrogen infrastructure) is already conducted at the EU-level. Capacity allocation and congestion management, balancing and inter-TSO compensation could be managed by regional organisations reflecting interconnected hydrogen systems. However, as hydrogen systems would in the future have to be interconnected at a pan-European level, single EU platforms for such activities would be more efficient.

Regarding the structure of the EU H_2 TSO, two main options can be considered:

1. The EU H_2 TSO is an independent organisation funded via fees from network operators and led by a management board with representatives from hydrogen TSOs and DSOs, regulators, hydrogen market participants, as well as with representatives from electricity and methane network operators and market participants. This representation would assure that the planning process conducted by the EU H_2 TSO is unbiased. To simplify the process, existing EU-level organisations could represent all concerned stakeholders (i.e. with ACER, the EU H_2 TSO, ENTSO-E, ENTSOG and EU-level representatives of market participants on the board);
2. Gas TSOs are shareholders of the EU H_2 TSO, with an advisory board of (possibly EU-level) stakeholders representing NRAs, hydrogen market participants, electricity / methane / combined gas network operators and market participants.

The above-mentioned proposal for market coupling is related to but separate from the question of the definition of wholesale and balancing hydrogen market areas. A regulatory process for defining the most appropriate market areas should be established considering aspects such as hydrogen system interconnection levels, potential congestion and electricity and methane market areas' configuration. Market coupling measures should then be established for major corridors, and ideally EU-wide in the long-term.

Natural gas TSOs are of the general opinion that setting up a EU H_2 TSO would be premature, as it would not be able to take into account the "different speeds of market development in the various regions and the different pipeline topographies".

Responsibility and oversight of hydrogen network planning

The table below presents the main options for hydrogen network planning responsibility and oversight:

- **Option A:** Joint hydrogen network planning, investment and operation, with 'light' oversight in the form of opinions from policy makers and/or regulators;
- **Option B:** Joint hydrogen network planning, investment and operation, with strong oversight in the form of approval and amendments from policy makers and/or regulators;
- **Option C:** Hydrogen network planning conducted by a separate independent body, with strong oversight in the form of approval and amendments from policy makers and/or regulators.

Table 3-10 Network planning responsibility and oversight options

	Option A	Option B	Option C
Oversight	Opinions by authority	Approval and amendment of methodology and outputs by authority	Approval and amendment of methodology and outputs by authority
Planning, investment and operation	Planning by network operator	Planning by network operator	Separate planning by independent body
Advantages	• Low regulatory cost and shorter process	• Non-discrimination of other resources	• Non-discrimination of other resources • Lower regulatory cost and information asymmetry than option B
Disadvantages / risks	• Information asymmetry • Network operator not obliged to consider opinions	• Longer regulatory process • Information asymmetry • Regulatory cost	• Higher coordination necessary • Higher regulatory cost compared to option A • May require unbundling of existing network operators to separate activities
Mitigation measures	• Transparency obligations • Dispute arbitration mechanism for third-parties	• Transparency obligations	• Allow legal/functional unbundling (instead of stricter OU) to separate planning

The main elements of the network planning process where oversight should be exerted by the authority are the scenarios, the CBA methodology and the network development plans. Network planning is a critical regulatory element as it has a direct impact on the cost for achieving climate and energy objectives (including the roll-out of hydrogen networks), on the allowed revenue of network operators, and ultimately on tariffs to hydrogen network users. Moreover, neutral scenarios and an appropriate CBA methodology are necessary to ensure that all options are adequately considered, including storage, demand response, sector coupling as well as network OPEX-oriented solutions.

Combined gas network operators could have a specific interest in favouring the conversion of methane network assets instead of other solutions. In the context of expected decreasing demand for methane gases, the risk for potential over-investment should be properly addressed. Moreover, there will certainly be cases where decommissioning methane infrastructure is from a societal perspective a better solution than repurposing it.

In addition to the moral hazard that network operators may over-invest in hydrogen networks, there is the converse risk of potential under-investment in hydrogen infrastructure. Such mismatches could arise from the uncertainty on the transition pathways, and the fact that regulated network operators may take investment decisions based on policy and regulatory signals rather than on market needs. Network development plans based on realistic and validated scenarios aligned to firm policy goals are hence an important element to avoid over- or under-investments and to ensure that the development of energy networks adequately supports the energy and climate objectives, including the decarbonisation of the energy system at least overall cost.

Hence, non-discriminatory and transparent planning based on policy-aligned scenarios is essential. A scenario with significant investments for development of hydrogen networks across Member States would require strong oversight of the planning process (options B and C) in order to ensure alignment to policy objectives and approval of efficient network investments only, based on an analysis from a cross-border and cross-energy carrier perspective (discussed below).

Separating the planning of hydrogen networks from the asset investment and operation (option C) would guarantee that the planning process is non-discriminatory and transparent, and lead to a lower regulatory cost and less information asymmetry between the network operator and regulator compared to option B. It would furthermore allow to tender the construction of new network sections and/or O&M of network assets to individual companies. However, separate planning would require increased coordination between the planning organisation and network operators. Separate planning would also be more interesting if it could be implemented not only for hydrogen but also for methane and electricity networks: i.e. if an independent organisation could be tasked with the network planning for all energy carriers.

Finally, transparency would benefit from the use of an open model and data (input and output) by the network operators or planning organisation. Any regulated organisation should be required to publish the models and data employed, which would furthermore increase public trust in the network development plans, thus facilitating their implementation.

Cross-energy carrier network planning

An increasing degree of integration of cross-carrier network planning can take place as reflected by the options in the table below:

- **Option A:** No harmonisation at EU level, i.e. network operators for each energy carrier are not obliged to cooperate with each other, and Member States are free to decide on the issue at the national level;
- **Option B:** Network operators in hydrogen, methane and electricity (and possibly heat) are by EU law obliged to employ common scenarios, as well as considering significant interlinkages between the energy systems. However, the use of an integrated energy systems modelling is not required, leading to the development of separate network development plans for each energy system;
- **Option C:** Network operators in hydrogen, methane and electricity are by EU law required to employ common scenarios and an integrated energy systems models linking all energy systems. This leads to an integrated NDP, or at least to separate NDPs based on common modelling outputs.

Table 3-11 Cross-energy carrier network planning options

	Option A	Option B	Option C
Options	No harmonisation at EU level	Common scenarios and consideration of main interactions	Common scenarios, integrated energy systems model and NDP
Advantages	• Low coordination required	• Considers main interactions • Common scenarios enhance neutrality and consistency	• Considers detailed interactions • Common scenarios enhance neutrality and consistency
Disadvantages / risks	• Risk of uncoordinated / biased scenarios	• Medium complexity • Medium coordination required	• High complexity • High coordination required
Mitigation measures	• Foresee minimum information exchange requirements between network operators	• Phase in when hydrogen system reaches scale • Require only when significant interactions with methane/electricity sectors exist	• Phase in when hydrogen system reaches scale • Ensure consistency of CBA methodologies and models prior to option introduction

The adequacy of the options will depend on the expected level of deployment of hydrogen networks and the level of sector integration. Hence, in countries with little or no hydrogen deployment, option A would be most suitable as limited interaction would occur between the hydrogen and other energy systems. Nonetheless, to ensure a minimum level of coordination, option A could foresee minimum information exchange requirements between network operators.

The use of common scenarios and consideration of main interactions suggested in option B is similar to the current interlinked model of the ENTSOs. Common scenarios would enhance the neutrality and consistency of the network development plans, by obliging network operators with different interests and expertise to agree on common scenarios. A methodology would need to be developed for the identification and consideration of main interactions, such as those related to large-scale electrolysers (hundreds of MWs), possibly through exchanging supply and demand curves and checking the compatibility of the plans regarding those large interactions (e.g. to ensure that no structural network constraints would arise at either side of the conversion technology). This option would be coherent with the process for the definition of Projects of Common Interest in the TEN-E regulation, which will be revised to also include hydrogen corridors.

Option C would best consider the system integration through the use of an integrated energy systems model, at the cost of higher complexity and need for coordination between network operators. Hence, such approach could be applied once the hydrogen system will reach a significant scale, and a high level of interactions. Criteria would need to be defined to establish this threshold, and work conducted proactively to develop the planning model.

Moreover, it is difficult to migrate to an integrated energy systems model once network operators are employing their own mature models and separate CBA methodologies. Hence, measures could be taken to facilitate the transition to an integrated energy systems model, as it would require not only hydrogen but also methane and electricity (and in some Member States also heat) network operators to adapt their approach. Measures could ensure the consistency of the CBA methodologies and models as much as possible. Soft linking of the models of the network operators would also allow to represent the relevant features of each energy system while limiting the integrated model complexity.

For all options, unregulated or exempted hydrogen network operators should be obliged to timely provide information on their network development plans and demand and supply forecasts for the organisation responsible for the planning of hydrogen networks to consider in their own planning.

At the national level, there generally exists a framework for notifying and coordinating decommissioning of assets. The Council Regulation (EU, Euratom) No 617/2010[205] establishes notification obligations to the Commission of investment projects in energy infrastructure within the EU, including gas transmission pipelines.[206] A new provision obliging network operators to assess the economic and technical impacts of plans for decommissioning large methane network assets

[205] Council Regulation (EU, Euratom) No 617/2010 of 24 June 2010 concerning the notification to the Commission of investment projects in energy infrastructure within the European Union and repealing Regulation (EC) No 736/96
[206] DNV GL for CEER (2018) Study on the Future Role of Gas from a Regulatory Perspective

could be included in EU legislation. Divestment plans related to networks with cross-border impact should also be included in the network development plans, and the concerned neighbouring Member States should be consulted.[207] If combined with appropriate cross-energy carrier network planning, this would minimise the risks that methane pipelines were decommissioned that could better be repurposed for hydrogen transport.

Cross-border network planning

The options for cross-border network planning obligations reflect an increasing level of obligation on hydrogen network operators to cooperate at supra-national level, from no cross-border planning required (option A) to developing network development plans at the regional (option B) or even EU level (option C).

Table 3-12 Cross-border network planning

	Option A	Option B	Option C
Options	No cross-border planning obligations	Regional planning	EU-level planning
Advantages	• Low planning costs	• Increased integration	• Increased integration
Disadvantages / risks	• Lack of coordination for cross-border planning	• Risk of uncoordinated regional plans • Unnecessary for smaller system scales • Medium planning costs	• High planning costs • Unnecessary for smaller system scales
Mitigation measures	• Incentivise regional cooperation	• Migrate to regional planning when national systems are forecasted to be interconnected	• Migrate to EU-level planning when regional systems are forecasted to be interconnected • Combine and check consistency of regional plans

Cross-border network planning should take place at the foreseen level of network development during the planning horizon. Hence, as regional hydrogen systems are forecasted to be developed in the following e.g. 10 years, the relevant network operators should cooperate in developing regional network development plans. When regional networks are forecasted to be interconnected, plans should be developed at the EU level. These plans could initially be developed by combining and checking the consistency of the regional network development plans.

Cross-border network planning of hydrogen networks will require the definition of the responsibility for and oversight of planning as well as consideration of cross-energy system interactions also at the regional or EU level. The planning process would benefit from maintaining, as far as possible, a similar approach for these aspects between the EU/Member States, especially for oversight and cross-energy system interactions. Ideally, at both the EU and national level, policy makers and regulators should exercise strong oversight for all regulated energy systems, and ensure that common scenarios and consistent CBA methodologies are used, as well as integrated or at least compatible energy systems models. Some countries could have a separate organisation conducting the overall planning, while in others planning could be done by network operators.

3.5.2 Natural gas as a basis for hydrogen network regulation: Network planning

Under the current EU regulatory framework, there is no obligation to develop a single gas NDP in countries where more than one TSO operate. However, current practices in countries with several gas TSOs indicate that national regulatory frameworks require in general the development of consolidated national NDPs. The view that consolidated NDPs are beneficial for consistent gas network development is also supported by ACER[208].

There is also a difference across the Member States in the level of involvement of NRAs in network planning. "In about 40% of the instances, NRAs are formally empowered, albeit in differing ways, to approve, reject or validate the NDP proposals of the TSOs, and in some cases the NRAs also carry out a consultation process on the draft NDP"[209].

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[207] ACER and CEER (2019) The Bridge Beyond 2025 Conclusions Paper
[208] ACER (2016). ACER opinion on gas network developments: Review of national network development plans to assess their consistency with the EU TYNDP. Available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2014-2016.pdf
[209] ACER (2018). ACER opinion on the review of national network development plans to assess their consistency with the EU TYNP. Available at:

Apart from the process of network planning, there are different elements that can be considered when developing the NDPs:

- As noted by ACER[210], the current NDPs often lack coordination on cross-border projects, for example on their planned capacity and timing of their construction. This problem could be avoided by enhancing the involvement of neighbouring Member States in the consultation process;
- There is a difference between Member States in the consideration of innovative solutions in the planning process. One issue is the potential bias towards CAPEX-based solutions, versus efficiency-oriented OPEX-based solutions. CAPEX-based solutions might be favoured by TSOs as they increase their RAB value and hence their remuneration. The risks associated with innovative projects might in some national frameworks not be properly valued and TSOs might be deterred by penalties for not meeting deadlines. The regulatory frameworks also often lack incentives for applying efficiency measures[211];
- The NDPs can differ in their approach relative to other infrastructure, in particular electricity networks. The options include: 1) separate development of scenarios for each sector 2) developing common future scenarios 3) developing interlinked development plans (based on common scenarios) 4) developing common NDPs for all sectors. Currently, the second option is applied on the EU level and work on applying interlinked TYNDPs is in progress. The EU-wide approach however focuses mainly on cross-border capacities, not on network development within Member States. Given the increasing need for coordination of electricity and gas network development and possibly conflicting TSO interests, at least common scenarios aligned to the National Energy and Climate Plans (NECPs)[212] should be required.

Furthermore, there is currently no planning obligation for DSOs in the EU legislation. DSO-related planning aspects are discussed in section 3.8.

Option development

Option A involves having no oversight of network planning (however, authorities still approve investment projects, which are included in RAB), or oversight limited to a consultation role (e.g. NRAs and/or policy makers providing an opinion or organising a consultation process). Option B empowers the authorities to approve the NDP. In option C, next to the approval of the NDP by the authorities, they also have an oversight role regarding the scenario building. In option D, the TSOs would be required to develop scenarios that follow policy goals (for example NECP scenarios). In this option, the authorities would be empowered to approve the scenarios and NDPs, and also mandate changes in the scenarios to ensure coherence with the policy goals.

Next to the sectoral network development, there are also several possibilities for cross-sectoral planning. The NDPs form a basis for creating an EU-wide TYNDP, which is developed by ENTSOs and based on their own development scenarios. As the decision has been taken to agree on common scenarios for future electricity and gas TYNDPs, the implementation of common electricity-methane-hydrogen scenario formulation on EU level is feasible. The regulators are also calling for better alignment of these scenarios with policy goals.

Because of the additional European-level layer of planning, even the options with less oversight (A and B) will be partially based on cross-sectoral impact considerations. In the options C and D, the authorities have the power to approve/amend the scenarios, so they might decide to require cross-sectoral planning if necessary (weighing the potential cost and benefits of such exercise). In the option D, the scenarios should ideally be based on policy scenarios, which would consider to some extent cross-sectoral interactions.

https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2011-2018%20on%20the%20review%20of%20national%20NDPs%20consistency%20with%20EU%20TYNDP.pdf

[210] Ibid

[211] EC (2019). Do current regulatory frameworks in the EU support innovation and security of supply in electricity and gas infrastructure?. Available at: https://op.europa.eu/en/publication-detail/-/publication/6700ba89-713f-11e9-9f05-01aa75ed71a1

[212] ACER (2019). The Bridge beyond 2025 conclusions paper. Available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/SD_The%20Bridge%20beyond%202025/The%20Bridge%20Beyond%202025_Conclusion%20Paper.pdf

Table 3-13 Network planning options based on natural gas regulatory frameworks

Network planning	Option A	Option B	Option C	Option D
Option	Network planning a TSO responsibility	Approval of NDPs	Approval of scenarios and NDPs	Network planning follows policy goals. Approval of scenarios and NDPs.
Advantages	• Enables more flexibility in development of the network plan	• Oversight of efficient investment still possible but enables initiative of industry	• May enable oversight of conversion from NG to H2 infrastructure – ensuring supply to limited groups of consumers • Possible to align network planning with policy goals	• Scenarios reflect policy goals • Network planning aligned with policy goals • Decreases risks of overinvestment/stranded assets as future needs are defined independently
Disadvantages / risks	• Scenarios developed to reflect TSO's interest, lack of transparency • Permitting process may be more difficult • Supply of NG to consumers might be stopped if TSO decides to switch to H_2	• Lack of transparency in scenario development	• Resources invested in the process might outweigh potential benefits (especially when considering cross-sectoral impacts)	• Scenarios possibly less ambitious than network operators' expectations • Resources invested in the process might outweigh potential benefits (especially when considering cross-sectoral impacts)
Mitigation measures	• Checking the results against the EU TYNDP	• Checking the results against the EU TYNDP	•	• Proper consultation process when developing scenarios

3.6 Network charging

Network charges can be separated in connection and access charges, the latter being called use of system charges. Balancing of energy systems and recovery of balancing costs are discussed in more detail in chapter 4. It is not straightforward to determine an adequate network connection and access charging structure, as it must satisfy conflicting tariffication principles, especially cost reflectivity, cost recovery, non-discrimination, transparency, predictability and simplicity.[213]

The challenge lies not only in properly balancing these principles, but also in satisfying them individually. For example, perfectly assuring cost reflectivity is impossible as not all network costs can be directly assigned to a specific network user (group) and thus should partly be socialised. For instance, while a new connection may require the reinforcement or extension of the network, other existing or future network users may also benefit from these investments.

Also, shallow connection cost allocation approaches may be used by policy makers and regulators to reward specific network technologies which provide environmental or system benefits, such as renewable energy or storage projects. Network charges (also for access) should be cost-reflective, and preferentially not used to promote specific policy objectives (which can better be implemented through other instruments). Hence, any network tariff design is not perfectly cost-reflective, both due to the inability to fully define cost causality, and to conflicting tariffication principles such as the need for stability and transparency of the tariffs.

The setting of network access charges is directly linked to the approach on network access, as so-called regulated vs negotiated third-party access will imply a different level of regulatory oversight. Nonetheless, regulated network tariffs should be cost-reflective, transparent and non-discriminatory.

[213] Trinomics et al. (2020). Energy costs, taxes and the impact of government interventions on investments. Final report – network costs.

Cost-reflective network charges also serve to provide appropriate incentives to network users to take investment and operation decisions which minimise total system costs. To this end, charges may contain locational and time-related components aiming at providing such incentives. Further measures can be applied to gas network charges, such as specific discounts to certain network user groups, such as storage and users with specific utilisation profiles, e.g. power plants or industry.

Regulated network access charging in gas systems can employ an entry-exit or point-to-point approach. In an entry-exit system, "network users book capacity at entry points and exit points independently. Gas can be injected at entry point and made available for off take at exit points on a fully independent basis. The gas does not follow a predefined contractual path. The entry-exit system has a virtual trading point where gas can change ownership within the system."[214] Alternatively, point-to-point access charging defines tariffs according to the contractual path of the gas. Entry-exit systems with transparent tariffs facilitate gas trade by providing flexible and non-discriminatory access to network users within a system, as well as across multiple systems using entry-exit tariffs. Both approaches, if well designed, could be suitable for the hydrogen market, and allow market operators to conclude long-term supply and capacity contracts. Risks for potential contractual congestion should be mitigated by adequate regulation (UIOLI) and physical bottlenecks should timely be eliminated by network investments.

Network charging and dedicated hydrogen networks

As network charges serve to recover not only O&M but also depreciation costs, and to remunerate capital, they are directly related to investment levels, especially in a context of strong network development, which is expected to be the case in some countries and regions with large-scale deployment of dedicated hydrogen infrastructure.

The biomethane and hydrogen study[215] estimated a tariff of around 1.6 €/MWh for hydrogen transmission in 2050 in the hydrogen scenario, which is quite similar to the current natural gas transmission tariff. However, the results are dependent especially on the chosen OPEX levels and cost of capital, and will differ for specific Member States. Tariffs for the recovery of hydrogen network investments and related OPEX could be partly compensated by lower costs for methane networks, if the former are developed mainly by repurposing methane networks.

Network tariffs should be cost-reflective, which requires considering the long-term costs of hydrogen systems as well as the flexibility benefits that electrolysers and hydrogen storage can provide. Early users of dedicated hydrogen systems should not be penalised for following national strategies and contributing to decarbonisation. These early users will furthermore enable the system build-up (and consequently technical and regulatory learning leading to cost reductions) from which later users will also benefit. It will be also important that hydrogen network access charges are stable and predictable. Distribution aspects related to the potentially different user groups of methane and hydrogen networks need also to be considered, and are further analysed in section 3.4 above.

Network tariffs should be cost-reflective, which requires considering the long-term costs of hydrogen systems as well as the flexibility benefits that electrolysers and hydrogen storage can provide. Early users of dedicated hydrogen systems should not be penalised for following national strategies and contributing to decarbonisation. These early users will furthermore enable the system build-up (and consequently technical and regulatory learning leading to cost reductions) from which later users will also benefit. It will be also important that hydrogen network access charges are stable and predictable in order to allow the necessary investments by market actors.

In case of strong electrification facilitated by hydrogen deployment and shift of natural gas users to dedicated hydrogen systems, the remaining natural gas users could face an important increase of the grid tariff, as transported volumes and the number of connected users would substantially decrease. The effective impact will depend on the rate of methane network defection compared to the rate of depreciation and capital remuneration costs, as well as the fixed O&M. To reduce this risk, any new investment in natural gas infrastructure should be thoroughly assessed. Possible cost reallocation between the electricity, methane and hydrogen sectors as well as issues concerning tariff levels for early adopters and followers are further discussed in section 3.4.

Stakeholders' opinions

Stakeholders have provided limited comments regarding network charging practices. Generally, stakeholders are in favour of the regulation of tariffs for new hydrogen networks, while many

[214] KEMA et al. (2013) Study on Entry-Exit Regimes in Gas. Part A: Implementation of Entry-Exit Systems
[215] Trinomics, LBST and E3-M (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure

recognise exemptions from regulated access and tariffs could be granted to existing private hydrogen system operators. Some support the provision of these exemptions on a case by case basis, while others indicate that existing private operators should not be legally obliged to e.g. unbundle and offer third-party access.

A stakeholder highlighted a commonly supported view that tariff setting for hydrogen infrastructure should not be seen in isolation, but should also consider the natural gas systems, for example to properly take into account the cost-effectiveness of converting natural gas infrastructure to hydrogen, and the need to address the eventual residual value of decommissioned natural gas infrastructure.

According to this stakeholder, the decisions on incentives are a responsibility of policy makers, but such incentives should foster competitive markets and provide adequate investment signals rather than distort markets, including by avoiding cross-subsidisation between energy systems. A network operator is however of the opinion that subsidies to hydrogen network investments would keep tariffs for early hydrogen adopters at moderate levels, and could be justified by the environmental benefits of dedicated hydrogen systems.

Another stakeholder indicated that it will be necessary to ensure that consumers with limited choice (e.g. who cannot put the upfront capital for efficiency measures and heat pump investments) can still have access to several options.

Some energy exchange operators highlighted the importance of introducing virtual trading points (VTP); the experience in the natural gas market shows that this instrument has a positive impact on market liquidity. They moreover support the definition of a market area manager to manage balancing and the trading notifications from the market operators.

3.6.1 Greenfield hydrogen regulation: Network charging

The main relevant aspect regarding hydrogen network charges is whether such charges will be based on the point of entry and exit, or on the contractual path (and whether this will be defined at the EU level or not). This is reflected in the three options for network charging below. The choice between regulated and negotiated tariffs is discussed in section 3.3.

Table 3-14 Network charging model options

	Option A	Option B	Option C
Options	No harmonisation	Entry-exit	Path-based
Advantages	• Flexibility for Member States	• Lower transaction costs • Provides locational signals for entry and exit congestion of domestic and interconnection points	• Provides locational signals for path congestion • Possible with highly decentralised network operation
Disadvantages / risks	• Lack of harmonisation hampering cross-border trade	• Tariff pancaking • Higher congestion management required	• Higher transaction costs, increasing with system complexity • Ex-post costs in case of migration to an entry-exit system • Not harmonised with current natural gas entry-exit model
Mitigation measures	• Harmonisation once cross-border integration develops	• Appropriate entry-exit area design and review • Monitor tariff levels	• Develop capacity allocation platforms • Use NC-like process to migrate to entry-exit according to market maturity

While an entry-exit model facilitates trade via large networks, it may increase the need and cost of congestion management and require coordination with multiple network operators in case of decentralised networks. In contrast, a path-based model can better reflect physical network constraints in trading and thus reduce congestion, including in a highly decentralised network, at the cost of higher transaction costs for market participants, which would increase with system complexity. However, in the case of significant repurposing of methane networks, there might be some overcapacity (despite the lower energy content of hydrogen), reducing congestion concerns and the need for congestion management. This will depend on the capacity of the compressors, which would most probably be dimensioned based on the foreseen transport demand (with some margin), and thus significant over-dimensioning of hydrogen networks is unlikely.

Path-based charges are currently applied in the US methane sector with adequate contractual and coordination measures in place to facilitate trade, leading to a highly liquid market.[216] Also, while entry-exit areas can facilitate the development of liquid markets, their benefits would be less important if a significant share of hydrogen supply was committed in bilateral long-term contracts, for which the transaction costs to assure transport capacity in a path-based approach would be less significant. Furthermore, as the major share of the EU hydrogen production would be domestic, hydrogen cross-border transit would be less important compared to natural gas, which could also justify the use of path-based charges.

Hence, the most adequate model will depend on the scale of hydrogen networks and markets, their interconnection level, the advantages of having a harmonised approach between hydrogen and methane networks as well as the acceptability of higher congestion costs and their eventual socialisation among network users.[217] The experience with the harmonisation across the EU of the entry-exit model with the third energy package suggests that, when the hydrogen system grows and becomes more interconnected, it would still be possible to migrate to a harmonised solution, albeit with significant costs.

If either the entry-exit or the path-based system were defined by EU legislation, harmonised tariff principles could be defined. In the case of an entry-exit system, these principles could be set for interconnection and/or domestic points. The latter could be justified to avoid cross-subsidisation between intra- and cross-system flows, or at least a cross-subsidisation test could be required, such as in the TAR network code. Cross- and intra-system flows in each market area may differ significantly, according to the area hydrogen demand, production, imports and exports.

Whatever the system used, it will be important to ensure that market parties are incentivised to balance their portfolios as much as possible, by using bilateral transactions and with TSOs employing market-based mechanisms for providing linepacking services to market participants and managing congestions.

Principles in network charging

Access tariff structures for hydrogen network users should, as for other energy infrastructure, reflect the drivers of the cost of service. Hence, if hydrogen networks exhibit similar economic characteristics as natural gas networks, such as high fixed costs, the use of mainly fixed and capacity related tariff components would be sensible. The most appropriate tariff structures could, however, be significantly different for individual Member States, depending on aspects such as the share of domestic vs imported hydrogen, the level of coupling with the electricity and methane systems, and the use of domestic infrastructure for hydrogen transit.

In a context of strong network development and connection of new network users, the use of appropriate signals to consumers to reflect system constraints could improve investment and operational decisions and thus facilitate the roll-out of hydrogen networks. However, while significant experience has been gained in the electricity and natural gas sectors in employing locational and time-related signals in tariffs, the strength of eventual incentives to network users needs to be weighed against the final impact on their decisions (considering also the relative importance of the energy and taxation component in final hydrogen prices) and the added complexity that such signals would bring.

Generally, the principle of not using network charges in order to support policy objectives should be followed also for hydrogen networks. Economic support to hydrogen deployment would best be implemented by support mechanisms to producers and consumers, rather than by reduced network tariffs, as the latter would reduce cost-reflectivity. Eventual re-allocation or subsidisation of the cost of service of hydrogen network operators could nonetheless be envisaged to reflect the positive externalities as indicated above, and serve to (partially) recover investments proportionally to the benefits derived from hydrogen networks.

3.6.2 Natural gas as a basis for hydrogen network regulation: Network charging

The 2009 Gas Directive established entry-exit tariffs as the standard model across the EU. The network charging based on Articles 13 and 14 of the Gas Regulation was further developed in the TAR network code. The Gas Regulation states i. a. that the tariffs shall be transparent, reflect the

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[216] Hallack et al. (2013) European Union regulation of gas transmission services: Challenges in the allocation of network resources through entry/exit schemes
[217] Hallack et al. (2013) European Union regulation of gas transmission services: Challenges in the allocation of network resources through entry/exit schemes

actual cost incurred and be non-discriminatory. The TAR NC sets the requirements (based on the Gas Regulation) for setting the reference tariff methodologies. The methodologies should:

- Take into account the actual costs;
- Ensure non-discrimination and prevent undue cross-subsidisation;
- Ensure that significant volume risk is not shifted from cross-system to intra-system use;
- Ensure that reference prices do not distort cross-border trade.

The only entry or exit points that are allowed to benefit of a grid tariff discount are storage and LNG facilities.

In 2018, 20 (out of 22 analysed) Member States had a majority capacity component in transmission access tariffs, 6 of them having only capacity components in their access charges. Since the NC TAR entered into force, new tariff regulation is being put in place in Member States. The trend is only highlighting the shift to a greater share of capacity-based charges, with 9 countries applying no commodity charges in the new regulatory periods. Most of the Member States currently apply an entry/exit cost allocation split that relies more on withdrawal charges (e.g. over 50% of costs recovered from withdrawal charges)[218].

Most of the Member States apply shallow network connection charges (both on transmission and distribution level), and some use super-shallow connection charging. Only 5 Member States apply deep connection charges.[219]

Option formulation

Application of the natural gas regulatory framework for hydrogen would imply the use of entry-exit charges for hydrogen network tariffs. The advantages and disadvantages of an entry-exit model compared to one based on the contractual path are discussed above.

The application of the TAR NC to hydrogen would further restrain hydrogen transmission tariff methodologies to providing discounts only to storage and LH_2 facilities and to be capacity-based, among others.

Similar to the options for revenue regulation, the options for network charging can be distinguished by determining whether the charging methodologies for both networks would be the same or could be different. A single regulatory account for methane and hydrogen networks would imply that the same charging methodology is employed (although methane and hydrogen network users could be treated as separate user groups in the methodology). If separate regulatory accounts for methane and hydrogen networks are employed, the same charging methodology could still be employed.

Having a single charging methodology might be counter-productive in countries that have different patterns of production/consumption for natural gas and hydrogen. For example, Southern European countries are at present pure importers of natural gas, but could become important hydrogen producers and even exporters. Similarly, some countries that have an important transit role for natural gas might not be in the same position for hydrogen (e.g. countries on important transit routes from Russia). For such countries, having different entry/exit or transit/domestic split might be important to cover accurately the incurred costs and avoid cross-subsidisation.

Given the similar technical and economic characteristics of natural gas and hydrogen networks, employing similar principles for the charging methodologies of both networks could be sensible, such as the use of mainly capacity-based tariffs (electricity costs for compression can represent a significant share of total OPEX costs, this could be counterbalanced by the over-dimensioning of pipelines and the fixed depreciation and capital remuneration costs). However, the use of the same charging methodology for both carriers seems too restrictive and would not allow for tariff structures to reflect important differences in patterns of supply, transport, storage and consumption.

[218] Trinomics et al. (2020). Energy costs, taxes and the impact of government interventions on investments. Final report – network costs.
[219] Trinomics et al. (2020). Energy costs, taxes and the impact of government interventions on investments. Final report – network costs.

Table 3-15 Network charging options based on natural gas regulatory frameworks

Network charging	Option A	Option B
Tariff methodologies	Single tariff methodology	Separate tariff methodologies (with mirroring of principles allowed)
Advantages	• Reduced administrative burden • Allows sharing of risks and costs • Beneficial for minority of consumers (H2 at start, later NG) • Technology-neutral	• Tailored charging approaches for NG and H2, reflecting different role in MS • Transparent tariff methodology, reduces risk of cross-subsidisation
Disadvantages / risks	• Cross-subsidisation likely • Cannot account for different patterns of natural gas and hydrogen supply, transport, storage and consumption	• Divergence between methane and hydrogen tariff methodologies
Mitigation measures	• Allow differences for certain tariff design parameters	• Mirror methodology principles

3.7 Capacity allocation and congestion management

Capacity allocation concerns the procedures for allocating the transport capacity of the network. Specifically, this refers to the transport capacity at interconnection points between different areas in the case of an entry-exit system, while point-to-point (path-based) systems require the allocation of capacity along the contractual path.

Capacity allocation may make use of capacity products standardised by duration (from yearly to quarterly, monthly or less), interruptibility and unit (e.g. MW), traded (or not) via centralised platforms employing e.g. capacity auctions. Capacity may be allocated, however, for longer periods, with long-term contracts established for multiple years ahead. Capacity allocation may also comprise bundled products, where transport capacity at both sides of an interconnection point is jointly offered (i.e. the right to withdraw gas on one side and inject it on the other).

Capacity allocation procedures may foresee mechanisms for incrementing transport capacity, e.g. realising investments in new / upgrading of pipelines or in cross-border reverse flow capacities. Such mechanisms involve calls for interest from market participants for additional capacity, who eventually commit to contracting future incremental capacity arising from investments by the network operator(s).

Congestion management refers to the rules for addressing eventual contractual or physical congestion in the network due to insufficient network capacity. Congestion management procedures may use mechanisms such as long- or short-term use-it-or-loose-it conditions, or the obligation for market actors to return unused capacity to be reallocated to other actors, as currently foreseen in the gas capacity allocation mechanisms network code. These mechanisms should ensure that transport capacities are efficiently employed, allowing shippers to trade capacity rights and re-nominate them.

CACM and dedicated hydrogen networks

Capacity allocation and congestion management rules should aim to improve non-discriminatory access to the network, maximise the efficiency of network utilisation, and reduce contractual and physical congestion while minimising the cost of necessary congestion management measures such as re-dispatching.

CACM rules design will also depend on whether an entry-exit or point-to-point model is employed for each specific system. Nonetheless, regardless of the model, rules will be necessary for both cross-border and domestic congestion management, and allocation rules at least for cross-border capacity.

Long-term capacity bookings may lead to the foreclosing of access to other network users, if they represent a relevant share of total network capacity, and in the absence of measures to ensure actual utilisation of the capacity, such as use-it-or-lose-it (UIOLI) rules. However, as long-term hydrogen supply agreements should play an important role in fostering new hydrogen production capacity, market actors will want to have sufficient secure transport capacity. Hence, CACM rules will need to consider the need to provide non-discriminatory access to the network, optimise its utilisation, enable liquid hydrogen markets as well as provide certainty for long-term investments in hydrogen supply. Ideally, capacity allocation using market-based instruments would be employed facilitating cross-border trade with the use of e.g. bundled products, with a liquid secondary market for market actors to trade capacity.

Coupling of market areas could further facilitate trade, while congestion management could be kept manageable if constraints at interconnection points were adequately represented when clearing the market. Also, initially hydrogen clusters would potentially not be interconnected, although a clear Hydrogen Target Model could provide guidance to Member States regarding the development of regulation once their hydrogen clusters become interconnected (addressed in section 3.9).

Stakeholders' opinions

Network operators and market actors highlighted that, based on the experience from the natural gas sector, there are benefits of cross-border harmonisation of CACM rules and considered that the approach of the relevant gas network codes would be applicable and appropriate for hydrogen networks. One stakeholder noted that uncoordinated actions by Member States and voluntary EU guidelines in the past were not able to efficiently contribute to harmonisation. Stakeholders also highlighted that interoperability agreements for different areas are necessary to foster cross-border trade. One stakeholder noted that while some specific rules cannot be applied to hydrogen yet as there is no existing market, they should be timely foreseen as the development and amendment of network codes is a lengthy process.

3.7.1 Greenfield hydrogen regulation: Capacity allocation and congestion management

The main question regarding capacity allocation and congestion management is whether CACM rules for hydrogen interconnection and/or domestic points should be harmonised at EU level, and whether a hydrogen market coupling mechanism should be employed. The applicable CACM rules will be dependent of the charging system chosen: entry-exit or path-based (discussed in section 3.6).

Thus, the main options considered below comprise:

- **Option A**: No CACM harmonisation at EU level
- **Option B**: Harmonised rules for cross-area CACM
- **Option C**: Harmonised rules for cross-area CACM and for domestic congestion management
- **Option D**: Market coupling (for an entry-exit system)

Table 3-16 CACM options in the EU hydrogen regulatory framework

CACM	Option A	Option B	Option C	Option D
Harmonisation of rules and market coupling	No harmonisation of CACM at EU level	Rules for cross-area CACM	Rules for cross-are CACM and domestic congestion management	Market coupling
Advantages	• Flexibility for MSs	• Improved market integration • Harmonised CACM for different IPs	• Improved market integration • Harmonised CACM for different IPs • No discrimination of domestic/foreign users	• Lower transaction costs for trading • Incentivises cross-border trade by eliminating tariff pancaking
Disadvantages / risks	• Divergence of CACM for different IPs	• Higher complexity	• Higher complexity	• May lead to higher congestion management costs • Administrative costs for market coupling
Mitigation measures	• Development of CACM NC/GL later on	• Provide a menu of options for TSOs to address contractual congestion	• Provide a menu of options for TSOs to address contractual congestion	• Monitor tariff levels • Initially couple market areas with significant IP capacity

While options A-C are mutually exclusive, market coupling considered in option D would necessarily require the harmonisation of CACM rules proposed in options B and C. The market coupling process is further detailed in Box 3-11 above. Harmonisation of domestic congestion management rules could be justified if there was a relevant risk or demonstration that hydrogen network operators were discriminating cross-area flows to relieve internal congestion.

3.7.2 Natural gas as a basis for hydrogen network regulation: Capacity allocation and congestion management

If the EU natural gas regulatory framework would be employed as a basis for hydrogen regulation, the main design questions concerning CACM would be whether to employ the same CAM network code and CMP guideline, and also the same CACM mechanisms (auction platforms, capacity products, congestion mechanisms (UIOLI, etc). The following CACM options can be thus be derived:

- **Option A**: Employing the same CAM NC and CMP GL, as well as the same CACM mechanisms foreseen in these;
- **Option B**: Employ the same CAM NC and CMP GL, but with separate mechanisms for CACM, allowing for some flexibility to account for the hydrogen sector specificities;
- **Option C**: Develop separate CACM network codes/guidelines for hydrogen, while employing a similar development and amendment process as for natural gas.

Table 3-17 CACM options based on natural gas regulatory frameworks

CACM	Option A	Option B	Option C
Network codes	Same CAM NC and CMP GL	Same CAM NC and CMP GL	Same development and amendment process, different NCs/GLs
Separation of auction platforms, capacity products, congestion mechanisms (UIOLI, etc)	Same as for methane	Separate for hydrogen and methane	Separate for hydrogen and methane
Advantages	• Lower administrative costs • Tested & proved CAM NC and CMP GL	• Medium flexibility in products/platforms/ mechanisms for different stages of network development and integration	• Full flexibility for stages of hydrogen network development • Tested & proved NC/GL development & amendment process
Disadvantages / risks	• Lack of flexibility for different stages of network development and integration	• Menu of products/platforms/ mechanisms is the same	• Regulatory cost for NC/GL development • Potential diseconomies of scale
Mitigation measures	• Add new optional capacity products/congestion mechanisms	• Add new optional capacity products/congestion mechanisms	• Coordination in CH_4/H_2 NC/GL development • Use of same CACM platforms for economies of scale

While Option A would allow to employ established regulation and mechanisms for CACM of hydrogen systems and potentially could provide economies of scale in managing the necessary CACM mechanisms, there is a significant risk that the mechanisms would not be sufficiently tailored to the specific characteristics of the hydrogen system (such as different supply and demand profiles, interlinkages with the electricity system, share and length of long-term capacity contracts, market liquidity). Option B could allow e.g. certain congestion management mechanisms to be applied separately for the methane gases and hydrogen systems, or for capacity products to be tailored to the hydrogen system. Finally, option C would employ the tested network code/guideline process to elaborate and amend hydrogen CACM rules. Hence, capacity products, congestion mechanisms and even the platforms for allocating capacity and managing congestion could be tailored to the hydrogen system. While the benefits arising from the design flexibility could be significant, employing the same CACM platforms could be beneficial as it would lead to economies of scale due to sharing of fixed costs, and could thus be considered.

3.8 Regulation of distribution networks

This section discusses specific adaptation and mitigation measures to the regulatory elements analysed above, that should be considered for hydrogen distribution networks. Plans exist for a relatively fast development of a European hydrogen transmission backbone and it is likely that many of the first future hydrogen networks will mainly serve to supply large industrial consumers. Nonetheless, the future EU regulatory framework for hydrogen should consider the regulation of hydrogen distribution networks as well, given that projects already exist to convert methane gases distribution networks to hydrogen, and that hydrogen distribution networks may exhibit significant differences to their present methane counterparts, given e.g. the fact that PtG may lead to significant hydrogen injection at distribution level. The table below indicates the aspects regarding the regulatory elements analysed above, and the possible mitigation measures and adaptions to the regulatory options which could be adopted. Balancing is also included in this table, but is more extensively addressed in the next chapter.

Table 3-18 Common/different aspects for hydrogen distribution networks

Regulatory element	Main differences to transmission / other energy sectors	Possible mitigation measures / adaptations
Overarching	• Transmission and distribution roll-out will differ per MS • Competition with alternative hydrogen transport modes differ • Conversion of distribution pipelines may be easier for many MSs	• Adapt potential exemptions/waivers to distribution, with/without regulatory test: emergent/isolated markets, closed distribution systems, direct lines, major hydrogen distribution infrastructure
Unbundling	• Gas Directive allows exemption/waiver to DSOs serving less than 100 000 customers • Gas Directive exemption to closed distribution systems	• Eliminate or lower the customer threshold for hydrogen DSOs • Require account unbundling for all hydrogen network operators • Enforce unbundling from hydrogen production for all network operators
Network access	• Gas Directive exemption for closed distribution systems	• See overarching category
Network planning	• No TYNDP or national planning obligations • No hydrogen EU DSO entity as in electricity	• Mandate coordination between DSOs and TSOs for planning of infrastructure needs and decision for connection of users • Mandate obligation for DSO planning mirroring new electricity market design • Create hydrogen EU DSO entity / inclusion of hydrogen in mandate of electricity EU DSO entity
Revenue regulation	• Differences by MSs between TSOs and DSOs in approaches / various regulatory parameters	• Promote best practices / benchmarking between NRAs
Network charging	• No TAR NC • Path-based and entry-exit systems not applicable	• Harmonise minimum charging principles
CACM	• Flexibility resources may be necessary to deal with congestion	• Establish principles for DSOs contracting flexibility resources
Balancing	• DSO-connected balancing resources may be significant	• Integrated DSO-connected balancing resources in balancing markets through TSO-DSO cooperation

3.9 Transitional measures and regulatory experimentation

The hydrogen sector will develop with different speeds in the EU Member States, each country or region following one of the pathways developed in chapter 1. Nonetheless, hydrogen networks are incipient in all Member States, despite private networks existing in North-Western Europe. Hence, the hydrogen network and market regulation discussed in this study will need to be gradually implemented, while simultaneously providing guidance to market and regulated actors, and assuring regulatory stability. Additionally, significant technological and business model innovation still needs to occur in the hydrogen (and generally the energy) sector.

To address these needs, the hydrogen sector regulation at the EU and Member State levels need to incorporate two design principles:

- Transitional measures, to pace regulatory requirements to the stages of market development, while at the same time providing clear guidance to all stakeholders on future regulation;
- Regulatory experimentation, to promote regulatory learning and sharing of the most adequate practices, and address cases requiring particular treatment (see Box 3-12 for a typology of regulatory experimentation mechanisms).

At the EU level, a number of main measures could be considered in this regard to introduce stepwise the regulation, promote regulatory learning and accelerate the stages of market development:

- **Define a Hydrogen Target Model** guiding the development of EU network codes and guidelines applicable for Member States with interconnected hydrogen systems, and enabling Member States to develop national regulation which is compatible with the model;

- **Derogate Member States from specific regulatory requirements** until their hydrogen systems become interconnected across borders. This approach is similar to the provisions in Article 49 of the Gas Directive on emergent and isolated markets (mostly derogations from regulation of concessions for infrastructure developers, from unbundling, market opening and from regulation of direct lines).These derogations would apply to relevant hydrogen cross-border aspects, while provisions necessary to avoid distortions to the internal energy market should still be applied even for isolated hydrogen systems, given the coupling of local hydrogen clusters with the electricity and methane systems. Regulatory elements that are eligible for derogation could comprise unbundling, planning, and CACM requirements, while network third party access requirements should be required even for isolated clusters / systems. This mechanism should furthermore be designed in order to stimulate Member States to consider developing cross-border interconnections,[220] and to prepare the necessary national regulatory framework adaptations in anticipation of interconnection, according to the network development plans;
- **Define requirements for waivers and exemption procedures** of hydrogen network operators, covering potentially pre-existing operators, direct pipelines and closed distribution systems;
- **Establish an EU regulatory sandbox model,** which could then be employed by NRAs for regulatory learning in specific initiatives.

The hydrogen regulatory framework needs to provide exemption procedures for isolated hydrogen systems in interconnected markets

An important specific case should be addressed by the transitional measures listed above: that of isolated hydrogen *systems* in Member States which are not considered as isolated hydrogen *markets.* As Belgium, the Netherlands and France have already cross-border private hydrogen pipelines, these countries could in principle not qualify anymore as isolated hydrogen markets (unless the criteria would only consider networks with third party access).

Initiatives to develop isolated hydrogen networks could arise in these countries (e.g. by converting certain distribution networks). These hydrogen networks would not qualify for the derogation of the regulatory requirements granted to isolated markets. They would also not qualify for exemption procedures, if these exemptions were reserved to pre-existing networks, direct pipelines and closed distribution systems.

However, for isolated hydrogen networks to fully comply with the Hydrogen Target Model could be very costly, e.g. if networks users were responsible for their imbalances in the absence of a liquid hydrogen market. Other requirements would simply not apply, e.g. related to cross-area CACM.

Hence, regulatory requirements should be phased in not only according to the hydrogen networks stage of development of each Member State, but also of *each individual network*. To address this issue, in addition to exemption procedures for pre-existing operators, direct lines and closed distribution systems, the EU regulatory framework could allow NRAs to exempt such isolated networks from certain regulatory requirements, according to defined criteria.

Principles for an EU hydrogen regulatory sandbox model

Regulatory sandboxes are not defined in EU energy sector regulation. ACER and CEER (2019) support the definition of a regulatory sandbox model at the EU level.[221] For the financial services industry, the Commission has supported the development of innovation hubs and regulatory sandboxes in its 2018 FinTech Action plan, which was followed by a report on best practices by EU financial services authorities.[222]

The EU hydrogen regulatory framework should address known cases deserving special treatment (such as potentially pre-existing or isolated clusters / systems) through waivers and exemption procedures. The EU regulatory sandbox model would rather serve to promote regulatory learning regarding aspects which are unclear at this moment and thus cannot be adequately addressed yet by specific legislative provisions. Once one or more sandboxes provide sufficient learning, they

[220] A concrete example of such deterrents to cross-border expansion does exist. The Electric Reliability Council of Texas (ERCOT) system is not synchronously connected to the rest of the US power system and its utilities do not sell to interstate customers, and thus ERCOT is not subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). See Fleisher (2008). ERCOT's Jurisdictional Status: A Legal History and Contemporary Appraisal; Slate (2003). Why Texas Has Its Own Power Grid.
[221] ACER and CEER (2019) The Bridge Beyond 2025 Conclusions Paper
[222] EC (2018) FinTech Action plan: For a more competitive and innovative European financial sector.
ESMA, EBA and EIOPA (2019) FinTech: Regulatory sandboxes and innovation hubs.

should end and the necessary regulatory changes (if any) made at the EU and/or Member State level.

ACER and CEER propose the following characteristics for such a sandbox model:

- Having limited duration;
- To specifically produce useful information of public interest on regulation;
- As long as there is no significant risk of harm to the market; and
- With knowledge sharing between NRAs to reduce the need for replication and accelerate the regulatory process.

Regulatory sandboxes should address specific regulatory barriers hampering technological or business model innovation, such as new forms of investments in hydrogen infrastructure or efficient operation of the hydrogen system. The EU sandbox model should clearly delimit the scope of application (e.g. specific legislative articles from which the experiment could be exempted) and define requirements for the transparent, non-discriminatory design, monitoring and evaluation of the sandbox.

Box 3-12 Regulatory experimentation: waivers, exemption procedures and regulatory sandboxes[223]

Regulation can act as an enabler or a barrier to the energy transition, responding and anticipating developments such as strong technological innovation, the need to decarbonise our economies, market and system integration and the appearance of new market actors and applications.

Therefore, regulatory experimentation has been drawing increased attention as a way to allow regulatory innovation and the required process of transparent, dynamic and inclusive trial and error. This without being burdened by the inertia of the regulatory process, nor making far-reaching yet untested regulatory changes in a sector with significant importance to the energy and climate objectives as well as to the economy.

FSR and CSEI (2020) identify three types of regulatory experimentation approaches: waivers, exemption procedures, and regulatory sandboxes. These would be characterised by the targeted activity or actor, the scope of exemption and the granting of exemption, as detailed below.

	Targeted activity or actor	Scope exemption	Granting of exemption
Waiver	Strictly defined	Narrow	More general
Exemption procedure	Strictly defined	Narrow	Case-by-case
Regulatory sandbox	More open	Broader	Case-by-case

While these instruments have been employed already by NRAs in various European countries, the authors further note that EU directives give a larger room for bottom-up experimentation by Member States than regulations.

Regulatory experiments for the development of hydrogen infrastructure are also in place or being planned. For example, in its hydrogen strategy,[224] the German government indicates that it is exploring "new business and cooperation models for operators of electrolysers and for grid and gas network operators in line with the principle of regulatory unbundling". The results should be available in 2020 and include the identification of the necessary regulatory changes enabling one or two model projects to "ease the burden on the grids at an affordable price without distorting the hydrogen market".

Waivers and exemption procedures are already in place in the electricity and gas regulatory frameworks, and their use in an hydrogen regulatory framework could build on the experience in these sectors.

[223] Based on FSR and CSEI (2020) Regulatory Experimentation: Waivers, Exemption Procedures and Regulatory Sandboxes.
[224] Federal Ministry for Economic Affairs and Energy (2020) The National Hydrogen Strategy

4 HYDROGEN MARKET DESIGN AND DEVELOPMENT

4.1 Introduction

The aim of this chapter is to develop regulatory options at the EU level for the design of hydrogen markets. Well-functioning and liquid hydrogen markets will be key for increasing the production and use of renewable and low-carbon hydrogen in the EU. The development of properly functioning hydrogen commodity markets should allow producers, shippers and suppliers to optimally value their products, and for all market participants to manage their price and volume risks. Appropriate market functioning will depend on different aspects, such as:

- The size of hydrogen supply and demand
- The level of market concentration
- The availability of appropriate transport infrastructure to physically trade and supply hydrogen
- The existence of adequate price benchmarks and of market products from the long- to the short-term (forwards, futures or derivatives, spot and balancing products);
- The balancing rules and the availability of storage and other flexibility tools (e.g. virtual or physical conversion to and from methane-based gases and electricity) to balance supply and demand.

The analysis considers the following inter-related objectives of the market design framework:

- Stimulate hydrogen market liquidity by avoiding market fragmentation & foster renewable and low-carbon hydrogen deployment;
- Facilitate hydrogen trading through adequate market instruments, advanced market coupling and effective competition;
- Reduce regulatory uncertainty, avoiding useless complexity and administrative burden.

This chapter identifies and assesses potential measures to develop market liquidity. It is structured into two main sections:

- Section 4.1 summarises the EU legal framework regarding gas markets and its relevance for the design of hydrogen markets, analyses the existing gas market structure and characteristics and identifies and assesses the relevant market design elements for hydrogen markets;
- Section 4.2 develops the market design elements, assesses the potential barriers to the development of hydrogen markets, and proposes regulatory options to enable efficient hydrogen markets.

This chapter focuses on dedicated hydrogen markets; hydrogen blended with natural gas, transported and sold via the natural gas infrastructure and market, is hence not addressed in this chapter. However, blending hydrogen with natural gas into existing methane networks is considered, next to the development of a dedicated hydrogen market and infrastructure, as an enabler to accelerate hydrogen deployment. Blending can in a transitional period represent an adequate solution to commercialise the output of hydrogen production facilities situated in areas where dedicated transport infrastructure is not (yet) available.

4.1.1 Existing EU legal framework for gas markets and its relevance for hydrogen markets

This section summarises the main legal provisions in the Gas Directive (2009/73/EC) and Gas Regulation (715/2009) related to the functioning of the gas market that may be relevant for elaborating an EU regulatory framework for hydrogen markets.

Table 4-1 Legal provisions of the Gas Directive relevant for hydrogen markets

Main elements	Gas Directive	Relevance for hydrogen
Customer protection	Art 3	Limited relevance as these provisions are focusing on end-users in residential buildings, while hydrogen is expected to mainly be deployed in the industrial and transport sectors.
Authorisation procedure	Art 4 – ease granting authorisations	Can be relevant for hydrogen market participants, to avoid administrative burden.
Closed distribution system and direct lines	Art 28 – CDS distribute gas within a geographically confined industrial, commercial or shared services site and does not supply households Art 34 – direct lines	Current hydrogen transport infrastructure could be considered as CDS (industrial clusters) or direct pipelines. In the future, such infrastructure could co-exist in parallel with interconnected networks.
Access to storage	Art 33 – rules for access to storage (and obligation to make rules public)	Hydrogen market operators should have regulated or negotiated access to storage, and/or be allowed to own/operate storage facilities. The current gas storage regime could potentially be mirrored for hydrogen storage
Record keeping	Art 44 – relevant data relating to all transactions in gas supply contracts and gas derivatives with wholesale customers and transmission system operators as well as storage and LNG operators	Similar provisions could be implemented for hydrogen transactions; the scope should be defined, including the potential applicability to existing supply contracts
Retail market	Art 45 – shall ensure that the roles and responsibilities of transmission system operators, distribution system operators, supply undertakings and customers and if necessary other market parties are defined with respect to contractual arrangements, commitment to customers, data exchange and settlement rules, data ownership and metering responsibility.	Similar provisions could be implemented for hydrogen retail markets

Table 4-2 Legal provisions of the Gas Regulation potentially relevant for hydrogen markets

Main elements	Gas regulation	Relevance for hydrogen
Access to storage	Art 15 – Third-party access services concerning storage and LNG facilities	Setting non-discriminatory and market-based rules for access to storage assets
Capacity allocation and congestion management	Art 16 – Capacity allocation, congestion management (Art 17 for storage)	Setting non-discriminatory and market-based rules for connection to and use of network capacity
Transparency	Art 18 – Transparency requirements (Art 19 for storage)	Fair access to information for all market participants
Balancing	Art 21 - Balancing rules and imbalance charges	Setting the framework for H2 networks balancing, by defining the responsibility of market participants and of system operators
Capacity rights trading	Art 22 - Trading of capacity rights	Setting rules for capacity rights trading

4.1.2 Structure and characteristics of electricity, gas and hydrogen markets

The regulatory framework for a dedicated hydrogen market should be designed taking into account the specific characteristics of hydrogen. This section compares the characteristics of the hydrogen market with those of the electricity and natural gas markets, including their liquidity.

The following table illustrates major differences in market size and characteristics. The current hydrogen market is still very limited and concentrated, compared to the electricity and gas markets. Also, in 2030-2050, the overall estimated market volume would be lower than current natural gas market volumes, while the market concentration would depend on the scenarios, and might be different between EU regions. When assessing the options for a hydrogen market regulation, it is essential to consider the existing and expected situation, as well as the similarities and differences with the electricity and gas markets.

Table 4-3 Key markets' characteristics

Characteristics	Natural gas	Electricity	Hydrogen
EU traded volumes	2018: >48 457 TWh[225]	2019: 12 470 TWh[226]	2015: 325 TWh[227]
Total EU-28 import (2018)[228]	4 296 TWh	393 TWh	NA
EU consumption expected in 2030 LTS	Baseline: 1802 TWh	Baseline: 4059 TWh	481 - 665 TWh[229] 43 – 183 TWh of ren. H_2[230]
EU consumption expected in 2050 LTS	H2 scenario: 640 TWh ELEC scenario: 837 TWh	H2 scenario: 3966 TWh ELEC scenario: 4826 TWh	H2 scenario: 1547 TWh ELEC scenario: 116 TWh
Number and type[231] of producers in EU - in 1990 - in 2020 - in 2030-2050	- limited number of large mainly non-EU producers - idem - increasing number of local biogas/biomethane producers in EU	- mainly centralised large scale producers - increasing number of decentralised producers - high number of decentralised producers	- very limited number of producers - idem - increasing nr of decentralised producers
Number of traders/suppliers in EU - in 1990 - in 2020 - in 2030-2050	- high market concentration (mainly OTC transactions) - high nr of traders & suppliers, high/increasing market liquidity - idem	- high market concentration (mainly OTC transactions) - higher nr of traders & suppliers, high liquidity in wholesale markets - idem	- high market concentration (only OTC transactions) - idem - larger nr of suppliers and traders
Number and type of consumers in EU - in 1990 - in 2020 - in 2030-2050	- high nr of residential and tertiary/industrial consumers - increased nr of consumers - decreasing nr of consumers	- high nr of residential and tertiary/industrial consumers - high nr of consumers, increased nr of prosumers - idem	- very limited nr of industrial consumers - idem - increasing nr of consumers, mainly in industrial and transport sectors
Wholesale price convergence and market coupling - in 1990 - in 2020 - in 2030-2050	- inexistent - high price convergence at regional level - idem	- inexistent - high price convergence at regional level - idem	- inexistent - idem - depends on market development and regulation

The definition of the hydrogen market rules and products should properly account for the differences between the natural gas and hydrogen value chain characteristics, as illustrated in Table 4-4 which highlights some important characteristics to be considered when assessing whether the natural gas market rules and instruments would also be suitable for trading and supplying hydrogen.

Table 4-4 Value chain characteristics

	Natural gas value chain	Hydrogen value chain
Production	Natural gas is mainly extracted in non-EU countries (and to a limited extent domestically produced) and transported to the EU by vessels or pipelines, mostly over long distances. Production can fluctuate or be constant over time and delivery has to adapt to demand.	Hydrogen will mainly be produced within the EU and to a more limited extent also be imported and will enter the market via several routes: produced locally near to or at users' sites; produced remotely and transported to users either by vessels, trucks or pipelines. There will be an increasing share of electricity supply-driven hydrogen production, through electrolysers located close to or distant from (renewable) electricity generation plants.

[225] ACER (2019) Traded volumes and CAGR at EU hubs via market platforms – 2012 to 2018. Comprises trades via transparent market platforms with a price reference and some product standardisation.
[226] Yearly (2016 figures) traded volume of electricity on the most liquid European Markets (BE, NL, CEE, ES, IT, UK, FR, Nordic, DE) is approximately 14 130 TWh, from figure 11 on the Monthly traded volume of electricity (incl. exchange executed and OTC) on the most liquid European markets, https://ec.europa.eu/energy/sites/ener/files/documents/quarterly_report_on_european_electricity_markets_q2_2017.pdf
[227] FCH JU Hydrogen Roadmap Europe
[228] Eurostat. Simplified energy balances [nrg_bal_s]
[229] FCH JU Hydrogen Roadmap Europe
[230] Trinomics and LBST (2020) Opportunities from the inclusion of hydrogen in NECPs
[231] Type = centralised or decentralised

	Natural gas value chain	Hydrogen value chain
Buffer & Flexibility	Variable injection in transport pipelines from production facilities and LNG terminals acts as buffer to adapt supply to demand. Furthermore, flexibility is provided by storage, including operational storage at LNG terminals, linepacking, and to a limited extent demand side response.	At the present, supply volumes are adapted to demand on a bilateral basis. In the future, storage (tanks, UGS, linepacking) will provide system flexibility, in combination with flexible production & conversion (renewable and fossil-based hydrogen, methanation) and possibly demand response.
Demand profile	The large volumes of gas consumption and the knowledge of consumption patterns provide to network operators and market participants a good basis to anticipate demand levels and variations in function of some parameters (e.g. degree days, seasonal, weekly and daily profiles, …).	In the first development phase demand profiles will mainly be determined by industrial users and heavy duty transport, with a more stable demand profile. The seasonality will hence be much more limited than for natural gas. In the second development phase, other end-uses (transport, power/heat generation) with more varying demand profiles may develop. Especially in the initial phase, the demand profile for individual clusters will be highly dependent on its specific network users and will hence be difficult to forecast.

4.1.3 Potential market failures or barriers related to the development of a hydrogen commodity market

To ensure a properly functioning and competitive market, the market rules and instruments should be adequately designed in order to avoid or mitigate market failures or barriers. These are presented in Table 4-5; the different measures to address them are discussed in the subsequent sections.

The market design elements discussed in section 4.2 address multiple market failures and barriers simultaneously, to a different extent. Therefore, to facilitate the reading, the most relevant potential failures and barriers are presented in this overview table. The market design elements addressed in this chapter comprise the following:

- Development of liquid hydrogen exchanges and OTC platforms;
- Appropriate hydrogen product types with cross-border standardisation;
- Efficient balancing mechanisms for hydrogen systems;
- Access for market parties to short and long-term hydrogen storage;
- Licensing of hydrogen traders and suppliers.

In addition to these market elements, other factors not discussed in this chapter are required for the development of a liquid, transparent hydrogen market at the EU level. These include:

- Stable and predictable policy signals;
- Further R&I in hydrogen technologies to enhance their maturity and competitiveness with conventional technologies;
- Public support for non-mature promising hydrogen technologies with significant cost-reduction potential, in particular to compensate non-internalised positive externalities;
- Objective, transparent and non-discriminatory planning, investment and operation of hydrogen transport and storage infrastructure;
- Efficient energy systems' integration;
- Development of cross-border hydrogen transport infrastructure;
- Adequate carbon price and taxation signals for all energy products and uses;
- Adequate oversight of energy markets to detect and address potential abuse of market power.

Table 4-5 Potential market failures or barriers

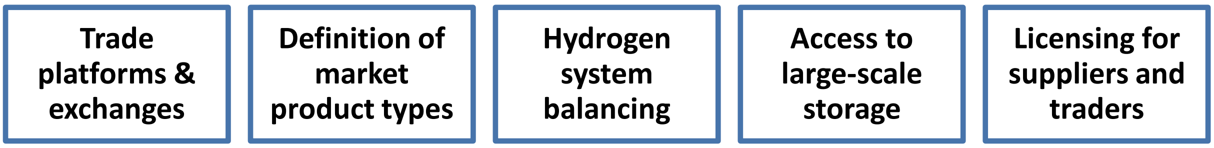
Market failures or barriers
Market concentration / vertical integration of production/import and supply, leading to potential abuse of market power and constituting a barrier to new entrants
Fragmented market structure (e.g. size of market areas) hampering cross-border transactions and therefore not allowing effective trade and competition
Unstandardised and/or inadequate market rules, products and contract types (including short-term standardised products), limiting market liquidity, cross-border participation and/or access for smaller participants
Lack of transparency regarding information (quality, price, type and origin) of hydrogen traded on platforms
Lack of network availability data, especially cross-border, and on system operation, limited harmonisation on transparency requirements
Difficulties to conclude long-term hydrogen supply contracts to finance production, partially as a result of the inexistence of a liquid hydrogen market
Competition between market hubs and concentration of trade in highly liquid hubs impeding the development of regional hubs
Limited sector coupling hampering efficient competition between hydrogen, methane, electricity, and heat, due to e.g. incomplete integrated planning or implicit coupling in operation of each energy system
Inadequate disclosure measures resulting in market participants being unable to value the specific benefits of renewable or low-carbon hydrogen compared to grey hydrogen
Non-harmonised guarantees of origin/certificates for renewable and low-carbon gas, hindering trade across national borders, market deployment, GO liquidity and information provision to consumers
GOs/certificates granted only for renewable hydrogen, reducing interest to invest in low-carbon hydrogen production; also hindering full disclosure of energy supply mix
Strictness of national licensing requirements for suppliers/traders in some markets hampering market entry and hence competition
Lack of mutual recognition of licenses for traders and suppliers hampering market entry and hence efficient competition
Distortive effect of RES support mechanisms

4.2 Market design elements

This section develops the five regulatory elements (see Figure 4-1) that are deemed relevant for the design of hydrogen markets.

For each market design element, a first section introduces the main theoretical and operational underpinnings used for the analysis of the hydrogen market design. A second section assesses the potential barriers to the development of hydrogen markets. A third section proposes regulatory measures to stimulate market liquidity and enable hydrogen deployment. The overall set-up and relationship between these market design elements ultimately determine the effectiveness of a possible regulatory intervention and different market regulation alternatives to facilitate market development.

Figure 4-1 Hydrogen market design elements



4.2.1 Hydrogen trade via OTC platforms and exchanges

Wholesale energy markets

Gas and electricity producers, shippers and traders operate in a liberalised market environment. They compete in the wholesale energy markets to sell to traders, large industrial consumers and retailers. Energy commodities are traded on different types of wholesale markets, as summarised in Table 4-6. This table also assesses whether these types of wholesale energy markets would be suitable for hydrogen trade.

Table 4-6 Types of wholesale energy markets

	Gas & electricity (*)	Hydrogen
Exchange or multilateral trading platform (e.g. EEX)	Market participants submit supply and demand bids. The market is cleared per predefined time period and a single market price (price as cleared) is determined. The clearing prices are published and can serve as a reference for other market participants.	Currently not used for hydrogen trade or supply. The use of exchanges requires participation of several market operators, both at the supply and demand side, in order to have sufficient liquidity allowing markets to clear at a representative price. Furthermore, the offered volumes per relevant market area and time period should reach a minimum level.
Bilateral over-the-counter (OTC) trading	Market parties agree bilaterally on a trade or supply contract by directly interacting with each other. The prices at which OTC contracts are concluded are not disclosed to other market participants.	The current trade and supply of hydrogen is based on bilateral OTC contracts. There is limited transparency regarding offered volumes or negotiated prices, with the first hydrogen price index published only in 2020[232].
Organised over-the-counter (OTC) trading	Market participants submit supply and demand bids via a market platform which is continuously registering new bids; any market player can bilaterally accept the bid of another market player, resulting in different prices for each trade. Prices can be published by a number of services, as is currently done for OTC natural gas trade in the TTF hub.[233]	Currently not used for hydrogen trade or supply. The use of such platforms could be considered even with a limited number of market participants and limited volumes, in order to enhance transparency about actual market volumes and prices. This option could possibly be used before the market is sufficiently mature to use exchanges.

(*) The design of gas and electricity markets is adapted to properly account for their specificities, especially regarding the definition of market products, timeframe, and balancing requirements (instantaneous basis for electricity versus daily or hourly basis for gas).

Box 4-1 illustrates the current situation in the wholesale gas markets. Investments in cross-border transport infrastructure and implementation of regulation (capacity allocation, market rules), have led to highly integrated gas markets and prices that are at regional level converging to a large extent.

Box 4-1 Wholesale gas markets

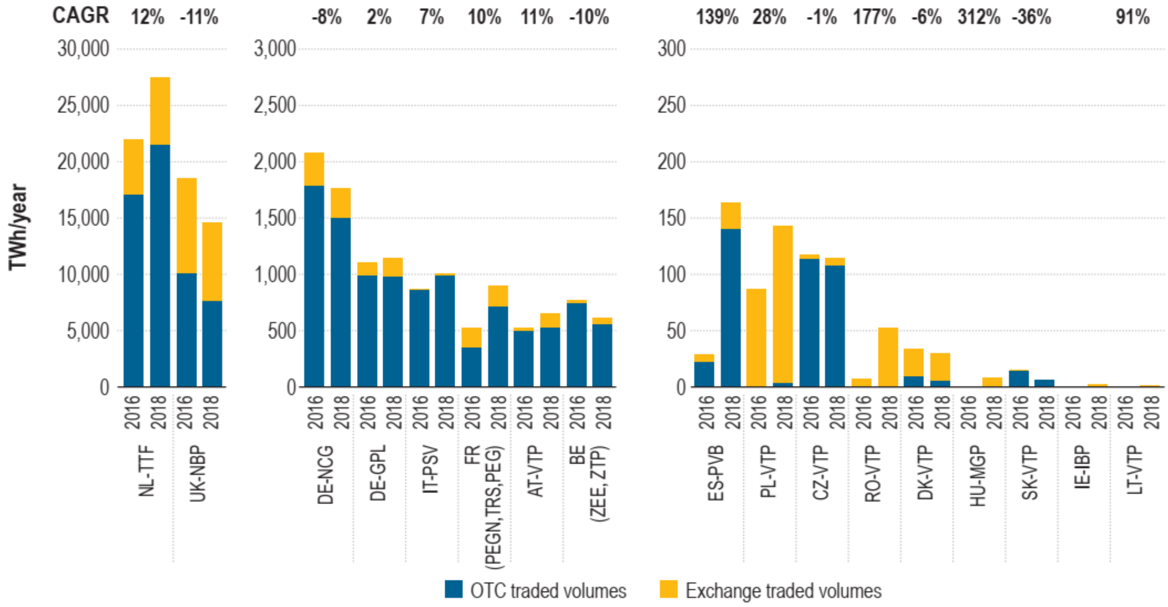
Gas trading on energy exchanges plays a key role in fostering liquid gas markets. Exchanges and trading platforms are important sources of price signals and enable trading of standardised products with minimised counterparty risk, aiming to create a viable and strong gas market that can satisfy the demand of traders, retailers and consumers in the short and long run.

According to the ACER Market Monitoring Report 2018[234], most EU gas wholesale markets have become very liquid and dynamic; market participants conclude future, forward and spot commodity contracts using long-term and short-term capacity products according to their business requirements and the economic fundamentals. Network Codes are contributing to these market improvements and their implementation increases liquidity, competition and price convergence. The concentration of capacity bookings is significantly higher for the longer-term capacity than short-term, due to historical contracts and the fact that naturally more market participants seek to optimise their portfolio in the short-term.[235]

Figure 4-2 illustrates that the large majority of the transaction volumes in the wholesale gas market are still OTC based; the liquidity has however substantially increased at most gas hubs thanks to increased traded volumes and a higher number of market participants. The gas trading platforms have substantially contributed to more effective competition and more representative price formation.

[232] https://www.spglobal.com/platts/en/our-methodology/methodology-specifications/electric-power/hydrogen-methodology
[233] ICIS - Daily prices, analysis and news for the Dutch gas markets and TTF hub. See https://www.icis.com/explore/energy/dutch-ttf/
[234] ACER/CEER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 Gas Wholesale Markets Volume, September 2018
[235] ACER MMR 2018 – Gas wholesale market volumes

Figure 4-2 Gas wholesale market volumes



Source: ACER (2019) Market Monitoring Report 2018 – Gas Wholesale Market Volume

To have liquid and properly functioning hydrogen wholesale markets, larger supply volumes and a higher number of market participants (both at the supply and demand side) are preliminary conditions. Once a minimum threshold in terms of market volumes and participants will have been reached, appropriate instruments will be needed such as OTC platforms and centralised exchanges (covered under section 4.2.1), and adequately designed market products.

Electricity and gas exchanges and OTC platforms[236]

Natural gas and electricity are traded on transparent market platforms ensuring liquidity and efficient market competition. Box 4-2 provides some background regarding the establishment of energy exchanges. CEER indicates that in most cases, the prevalent initial trigger for the establishment of energy exchanges in the EU was commercial interest. In addition, a few European exchanges have been developed with the involvement of their respective energy regulator. [237]

Box 4-2 Involvement of energy regulators in the establishment of exchanges[238]

According to CEER "the Spanish electricity exchange OMEL, the Portuguese exchange OMIP and the Romanian exchange OPCOM were established due to legal enforcement by the government)." The Norwegian energy regulator was involved and granted a license for the foundation of the Statnett Marked electricity spot exchange in 1993 (the predecessor of Nord Pool). CEER also indicates that "the Portuguese regulator was involved through discussions in the MIBEL Council of Regulators, and Romania's energy regulator has granted the license for the power exchange, gradually issued and approved the market rules and established the market monitoring system. The Netherlands Competition Authority (NMa) advised the Ministry on the regulation of APX. Most other NRAs were not involved in the development of energy exchanges."

Most of the energy exchanges are licensed either by the national government or competent Ministry (e.g. Germany, Austria), the competent national financial (e.g. derivatives exchanges in Austria, France) or energy regulatory authority, and are supervised by an exchange supervisory authority, which is often the same authority as the one granting the license.

Hydrogen trading via specific hydrogen platforms or via existing OTC platforms or exchanges for natural gas or electricity

Specific trading platforms could be set up for hydrogen, but using existing platforms for natural gas or electricity to also trade hydrogen could be considered as an efficient alternative. Using existing

[236] An energy exchange is a multilateral system for the trading of wholesale electricity and/or natural gas spot and/or derivatives products operated and/or managed by a market operator, which brings together or facilitates the bringing together of multiple third party buying and selling interests in wholesale natural gas and/or electricity spot and/or derivatives products in a way that results in a contract, in respect of the wholesale energy product admitted to trading under its rules or systems.
[237] CEER (2011) Final advice on the regulatory oversight of energy exchanges.
[238] CEER (2011) Final advice on the regulatory oversight of energy exchanges.

trading platforms would save development time and cost, reduce operational costs, underpin price formation (as arbitrage between natural gas, electricity and hydrogen will, to a certain extent, be relevant) and allow to have representative price formation and price level information per relevant EU market.

The issue whether natural gas and hydrogen could be traded using the same market rules, products and instruments, is influenced by a number of factors:

- The differences in market structure regarding supply and demand, number of market participants and concentration;
- The differences in operators' expectations (including contracts' duration to secure new assets);
- The differences in product characteristics and end-use (for energy and/or feedstock);
- The possibility to separate for both gas types the carbon footprint and the physical product;
- The expected hydrogen market volume that would justify the use of trading platforms.

At the present, publicly available information about hydrogen prices is still very limited; Platts has in April 2020 started to report daily hydrogen prices in the US and Europe (the Netherlands).[239] But this is, up to now, rather limited in scope and product information. The European Commission has indicated in its hydrogen strategy document that it will develop a benchmark for euro-denominated transactions in hydrogen.[240] Such a hydrogen price benchmark is considered key to developing trading in all market horizons.

Rather than being traded via organised platforms, hydrogen is expected to continue to be traded via long-term OTC contracts allowing to underpin investments and hedge risks, at least in a transitional period until a liquid hydrogen market develops and in the absence of further policies for the development of organised markets. OTC contracts for short-term trade and balancing purposes will probably develop progressively – preferably via platforms to enhance transparency - to complement long-term OTC contracts. Electricity supply and electrolysers' costs will play an important role in developing hydrogen markets, as hydrogen producers will take advantage of the variability in short-term electricity prices to improve the competitiveness of (renewable) electrolytic hydrogen. In a later stage, centralised exchanges might develop naturally once the number of market participants and the hydrogen production and import have reached a minimum level. On the basis of the current information, liquid exchanges might at the earliest develop in a few EU regions around 2030; national documents such as the Dutch and German hydrogen strategies do not explicitly provide a more ambitious timeline.

Rules and conditions should favour participation of multiple operators in the trading platforms in order to stimulate liquidity. Services such as price reporting, market making, market broker platforms and exchanges would emerge alongside. Liquidity will be very low in the initial phase, and could be enhanced by incentivising or obliging existing market parties to trade (part of their) supply volumes via an open platform or oblige dominant parties to release part of their long-term commodity contracts. It would be useful to further analyse whether and under which conditions such a legal obligation could be imposed on existing and new market parties.

Could a single commodity market be used for both methane and hydrogen?

Theoretically, a single gas commodity market could be set up for hydrogen and methane gases, in order to have high market liquidity and to avoid fragmentation of the gas market. Trading could be based, separately, on the energy content on the one hand and on the 'sustainable value' of the concerned gases on the other hand. The physical systems could be taken into account by implicitly coupling the markets for the two gas types, with the consideration of the conversion constraints.

Such a single market would require more dynamic metering and exchange of data, given the differences in product characteristics (energy content, volumetric density, production and demand profiles, different hydrogen and methane types and required purity, …). A market area manager would need to clear the market taking into consideration available capacity informed by conversion asset as well as by network operators.

However, the creation of such a single commodity market for natural gas and hydrogen may face several difficulties, like physical conversion constraints (limited capacity, limited conversion technology maturity, high conversion costs), clearing of the single market with implicit

[239] https://www.spglobal.com/platts/en/our-methodology/methodology-specifications/electric-power/hydrogen-methodology

[240] European Commission (2020). A hydrogen strategy for a climate-neutral Europe

consideration of the constraints, and balancing of the methane and hydrogen systems. If markets could be coupled, the limited (and asymmetric) conversion capacity would lead to frequent decoupling of markets and thus to different commodity prices.

A single market does de facto assume that the existing platforms, contract types and products are also suitable for hydrogen (see section 4.2.2 on product types). The single price and market products would not allow to reflect the different daily to seasonal production and load profiles, subjecting hydrogen consumers to price determinants which do not concern them, and conversely methane gases consumers. This while hydrogen supply would be much more strongly coupled to electricity markets development, as electricity prices would directly affect electrolytic hydrogen production. Moreover, clearing at a single commodity price for methane and hydrogen would not allow to reflect their different market value. And an important number of hydrogen consumers, such as the chemical and steel-making industries that use hydrogen as feedstock would not be able to switch consumption to methane gases anyway, regardless of their market value.

Additionally, a single commodity market could lead to a situation where TSOs of natural gas and hydrogen grids would have a dominant role if the operation of conversion assets would be assigned to them. If, in contrast, market participants were to operate conversion assets, they would have to inform the available conversion capacity and prices to the market area manager. Reflecting the climate footprint of the different gases would also be more complex, although trade in guarantees of origin could be separated from trade in the gases themselves.

Taken into account the complexity and potential negative impacts of a single commodity market, it might be preferable to have separate commodity markets for methane and hydrogen, also to properly value the specificities of each gas type. If technical progress reduces the cost and increases the capacity of conversion assets and when hydrogen markets will develop, the markets could eventually be implicitly coupled, but maintaining separate prices for methane gases and hydrogen would still be desirable.

Stakeholders' opinions

The following table summarises the feedback received from stakeholders regarding hydrogen trading platforms and exchanges.

Generally, the current natural gas market framework is considered as a good basis for a future hydrogen market design, but changes might be required to account for the specificities of hydrogen versus natural gas. Stakeholders are divided on the adequacy of a single commodity market for hydrogen and methane gases.

Table 4-7 Stakeholders' opinions on OTC platforms and exchanges topics

Topic	Arguments in favour	Arguments against
One single market for methane and hydrogen	• Some TSOs suggest to set up a single commodity market for methane and hydrogen, to avoid market fragmentation. • The integration of H2 and NG markets could be done by trading the energy content of the commodity separately from other features such as the carbon footprint - certificates or GOs could be used to value the different footprints on the basis of a "book & claim" system. If two commodity markets (methane and hydrogen) co-exist, the liquidity of the hydrogen market will be very limited. • While acknowledging that a common market is unlikely in the short- to medium-term, they consider it as feasible option in the long-term.	• Market operators consider that a single energy market for natural gas and hydrogen (via e.g.TTF) would be very difficult to implement.
Using natural gas market platforms (using similar contract types and conditions)	• The large majority of stakeholders (network operators, gas traders/suppliers, hydrogen industry) consider that natural gas market platforms can be used to trade hydrogen. • As the gas sector in NL and UK has a very keen interest in H_2 development, it is expected that the TTF and NBP will be the first platforms to develop products for hydrogen. • Operators of gas exchanges indicate they can support the development of a hydrogen market already now, highlighting the importance of price benchmarks.	• For some gas infrastructure operators, it is too early to start trading hydrogen on gas platforms. Once more hydrogen production capacity is available to increase liquidity, it would be feasible to include hydrogen in the NG platforms so that shippers/traders can leverage the available tools.

Options for a single gas market vs two separate commodity (hydrogen and methane) markets

Hydrogen could be traded via one single gas market for both methane and hydrogen, as a separate commodity while using the same trading platforms and exchanges, or through separate platforms and exchanges. In the second case using separate platforms and exchanges, the current regulation for natural gas could also apply to hydrogen, or specific regulation could be considered.

The first option (option A) is thus to have one single commodity market for methane and hydrogen, allowing to trade both gases in the same portfolio, similar to how H-gas, L-gas or biomethane are jointly traded based on their energy content.

The second option (option B) is using the existing gas platforms and applying the same regulation, but the products' definition and contract types could be specific for hydrogen, and the markets would de facto be organised separately. The trade of gases across networks would imply the need to prove that there is sufficient transport and conversion capacity.

The third option (option C) is to leave the hydrogen market unregulated, at least for the time being, to leave time to the market to develop.

Options formulation

The three options are

- A: One single gas market;
- B: Two separate markets, with common platforms;
- C: Two separate markets, with no regulation for the hydrogen market;

Table 4-8 Regulatory intervention in the establishment of hydrogen markets

	Option A	Option B	Option C
Single or separate gas markets	One single commodity market for methane and hydrogen	Separate hydrogen and methane markets, with common platforms	Not regulated
Advantages	• Increases liquidity for hydrogen trade • Addresses natural gas consumption decrease and its impact on market liquidity • Maximises use of conversion capacity across markets	• Coherence with electricity and methane regulatory framework regarding freedom of exchange operation • Separate hydrogen and methane trade based on product characteristics and uses • Facilitates market coupling while allowing for separate prices • Monitoring can be set up according to risks and market dynamics • Adapted to the progressive market uptake (OTC only in a first phase)	• Low administrative costs • Flexibility for product innovation • Separate hydrogen and methane trade based on product characteristics and uses • Adapted to the progressive market uptake (OTC only in a first phase)
Disadvantages / risks	• Potentially high implementation and operational costs • Limited conversion capacity may require frequent decoupling of markets • Conversion capacity may be asymmetric between markets • Does not reflect different product characteristics and uses and market values • Less flexibility for hydrogen market participants and possible exchange operators	• Requires a new regulatory framework dedicated to hydrogen • Potentially lower welfare due to more limited coupling compared to option A	• Lack of standardisation can become an important barrier (to cross-border trade) • Potentially lower welfare due to limited market coupling • Higher monitoring costs and eventually need to react (and regulate) when needed • Low security to investments due to slower market development
Mitigation measures		• Monitoring existing exchanges regarding their expansion to hydrogen and adapt licensing accordingly	• Monitoring existing exchanges regarding their expansion to hydrogen and adapt licensing accordingly • Incentivise harmonisation and exchange of best practices • Incentivise exchange mergers/expansion once liquid markets develop

Options regarding the setting up of organised platforms or exchanges for hydrogen

This section deals with the options for setting up (or not) organised market platforms or exchanges for hydrogen. The central question concerns the regulatory intervention in the establishment of hydrogen exchanges, obliging their use by market participants or leaving it open to new and existing market platform operators to develop profitable business cases.

The establishment and use of organised energy trading platforms and exchanges is not regulated at EU level, and is addressed differently by Member States. However, in most Member States, energy exchanges were established without any legal obligations and set up on a voluntary and commercial basis by market operators, albeit with oversight from energy and/or financial authorities and regulators.

Oversight of the trading platforms and exchanges would be conducted by the energy and/or financial authorities and regulators in all options presented below, which differ on the role of the policy makers and regulators in their establishment.

The three options are therefore:

- Option A: No mandatory rules for the establishment of hydrogen trading platforms and exchanges;
- Option B: Mandatory rules for the establishment of hydrogen trading platforms and exchanges;
- Option C: Involvement of energy regulator in establishing hydrogen trading platforms and exchanges;

The first option (option A) is to follow the general rule and leave it open to market participants to progressively offer hydrogen trading options via organised platforms or exchanges once the hydrogen market reaches maturity (in terms of market volume and number of participants) to justify a profitable business case.

The second option (option B) is to impose the establishment of organised platforms or exchanges for hydrogen through legal enforcement by national governments.

A third option (option C) is to ensure the involvement of the energy regulator (which would be responsible also for the regulatory oversight of the hydrogen sector), e.g. by granting licenses for hydrogen trading platforms or exchanges, by establishing a market monitoring system, and by issuing specific market rules or by advising other involved authorities on market related issues.

Table 4-9 Options for the establishment of hydrogen trading platforms and exchanges

	Option A	Option B	Option C
Options	No mandatory rules for the establishment of organised platforms and exchanges	Mandatory rules for the establishment of organised platforms and exchanges	Regulator involvement in organised platforms and exchanges establishment
Advantages	• Leave freedom to use existing organised platforms or exchanges or to develop new ones • Market driven, stimulating innovative developments & based on profitability • Let time to develop the market (volume and number of participants)	• May possibly accelerate the accessibility of trading platforms and exchanges to all market participants • Ensure coherence with other energy regulatory framework regarding trading platforms & exchanges operation • Mainstream monitoring needs	• Ensure coherence with other energy regulatory framework regarding trading platforms & exchanges operation • Monitoring can be set up according to risks and market dynamics • More flexible than mandatory rules for the establishment
Disadvantag es / risks	• Incumbent market platform operators have possible competitive advantage	• Difficult to reflect the real costs as it would not be market driven • Not flexible to adapt market products • May not be cost-efficient	• Non-harmonised establishment of rules and regulatory intervention across Member States
Mitigation measures	• Monitor existing trading platforms and exchanges and, if required, adapt licensing, or foresee setting up a legal framework	• Extract lessons from gas trading platforms and exchanges costs to adapt and apply to hydrogen • Remain legal framework flexible and open to changes	• Monitoring trading platforms and exchanges and ensure NRAs coordination

4.2.2 Definition of market product types for hydrogen

Different product types are used in the gas market to maximise market value and hedge risks

The liberalisation of the gas sector has introduced competitive access to markets, implying new risks for market participants. To reduce these risks, ad-hoc instruments have been implemented to manage and hedge portfolios of assets and customers, to protect market values or to take benefit from trade opportunities. Energy trading covers more than just proprietary commodity trading. The use of complex structured products in energy markets is related to the intrinsic complexity of the business, which requires the trader to virtually replicate assets and their portfolio constraints.

Such structured products could also be developed and used by hydrogen market participants. Similar to the natural gas market, their development should be left to the initiative of market operators, and should in principle not require regulatory intervention. For the purpose of this assessment, the focus will be on market product types directly interacting with market operations. Table 4-10 gives an overview of the main products traded at the gas wholesale market and assesses whether similar products would be suitable for hydrogen trade.

As the properties of hydrogen are more similar to those of natural gas than of electricity, especially regarding the timeframe and balancing requirements, the current gas market structure and products are considered as the most relevant basis for hydrogen. Balancing products are addressed in the next section.

Table 4-10 Gas market product types and their suitability for hydrogen trade

	Gas market	Suitability for hydrogen trade	Need for adaptation
Futures	Futures are standardised contracts that can be further traded on energy exchanges	• Could progressively complement Forwards • Futures can underpin both domestic and cross-border trade. Development of cross-border trade will depend on availability of interconnected corridors throughout Europe • Standardisation at EU level may be appropriate • Futures are useful to ensure long term investment security (on demand and supply sides)	• Market uptake (minimum market volume and number of participants) will be needed before platforms will develop hydrogen futures • Market integrity and transparency monitoring and surveillance rules (REMIT) could be extended to the hydrogen sector
Forwards	A forward contract is a customised contract between two parties to buy and sell energy at a specified price to be delivered in a future time period (e.g. year n +1). It provides higher price certainty to the involved parties compared to short-term transactions	• This type of contracts is currently used in the hydrogen market	• Forward contracts for hydrogen should in the future progressively comply with the "energy" related market rules (they now seem to be based on industry and feedstock-related rules) • Market integrity, transparency monitoring and surveillance rules (REMIT)could be extended to the hydrogen sector
Day-ahead market	In DA markets, gas trade are concluded one day before actual delivery[241] via OTC or platforms. At the end of the day-ahead market, each BRP submits a balanced portfolio to the TSO	• DA markets (or equivalent) allow participants to adjust their long-term position or act as the central platform for supply and trade • Can provide additional revenues to flexible technologies (storage, hydrogen production, demand response) •	• Need for rules regarding settlement, balancing and nomination (similar to the gas market rules or specific) • Market integrity and transparency monitoring and surveillance rules (REMIT) could be extended to the hydrogen sector
Intraday and balancing markets (ID)[242]	After clearing of the day-ahead market, BRPs can intraday still trade and submit revised nominations to TSOs. Portfolio imbalances are dealt with via the balancing market	• Current functioning of ID and balancing markets for natural gas seems suitable for hydrogen • Would allow to provide additional revenues for flexibility offered by hydrogen production, storage and demand	Id.

Long term contracts are needed to secure investors in hydrogen infrastructure and production capacity

In the gas sector, long-term capacity contracts are traditionally needed to ensure financing for new, large-scale infrastructure investments and to ensure long-term capacity bookings for TSOs and LNG terminal operators. In addition, LTC holders require them to mitigate the risk of lack of

[241] The day-ahead market is of major importance to balance individual portfolios and the market zone
[242] The intra-day market enables market participants to still adapt their positions, also in view of minimising their residual imbalance cost

capacity and high costs of transmission or other services.[243] Next to long-term capacity contracts, 20/30 years long-term gas supply contracts have played a key role in supporting the development of the gas infrastructure and supply.

In the hydrogen sector, it is likely that capacity and supply agreements will also be concluded on a long-term basis, to underpin the development of the required hydrogen supply assets. However, this practice may compromise hydrogen market liquidity. Moreover, electrolytic hydrogen producers may want some flexibility through e.g. interruptible transport capacity contracts that allow to take benefit from the volatility of electricity prices. Hence, adequate market platforms and instruments (e.g. forward and future contracts and adequate price benchmarks) need to be developed in order to attract market participants to use these platforms to hedge their risks while providing long-term security of investments and flexible market products.

Considered options on the hydrogen market product types

The central question will be to identify whether the existing gas market products are suitable for hydrogen trade, to contribute to hydrogen market deployment and market liquidity. While development of hydrogen market products should be left to the initiative of market operators, and hence would in principle not require regulatory intervention, policy makers and regulators could play a role in incentivising the harmonisation of product types across the EU and sharing of best practices.

Furthermore, setting minimum product characteristics could be necessary in order to ensure that there are no entry barriers for new or smaller market actors, such as small-scale electrolytic hydrogen producers. As hydrogen markets will develop and ultimately would have a large number of participants (as illustrated in Table 4-3), minimum product obligations could be warranted. This would approximate the approach of the new electricity market design, where minimum bid sizes of 500 kW and a settlement period of 15 min (with derogations) are required by 2021 for day-ahead and intraday markets.[244]

The first option (option A) is to establish the same minimum product requirements for hydrogen and methane markets, assuming that there are strong similarities between them regarding the required timeframe of delivery, the product definition and the adequate contractual arrangements. The second option (option B) is not to regulate hydrogen markets, at least for the first development phase (e.g. until 2030). The third option (option C) is to mirror minimum product requirements for hydrogen and methane markets, with some adaptations to better fit with the hydrogen system characteristics.

As illustrated in Table 4-4, the three most important differences between gas and hydrogen , which are directly influencing market features, are

- The more domestic and dispatchable character of hydrogen production compared to natural gas production;
- The expected lower coverage and interconnection of hydrogen networks compared to the natural gas networks;
- The interaction of hydrogen deployment with the electricity and methane systems.

Options formulation

The three options are

- Option A: Mirror all gas market products;
- Option B: Mirror gas market products but adapt some product requirements to properly account for specific features of hydrogen.
- Option C: No mandated standardisation;

[243] EY & REKK (2018) - Quo Vadis EU gas market regulatory framework – Study on a Gas Market Design for Europe
[244] Regulation 2019/943 on the internal market for electricity.

Table 4-11 Wholesale hydrogen market product types standardisation

	Option A	Option B	Option C
Options	Mirror all gas market products minimum requirements	Mirror and adapt some product requirements	No standardisation
Advantages	• Lower administrative costs compared to option B • Fits to all market participants needs as long as characteristics are similar / minimum requirements are of sufficient resolution	• Fits to all market participants needs as long as minimum requirements / adaptations are of sufficient resolution • Accounts for differences between methane and hydrogen systems	• Low administrative costs • Adapted to the current situation with industrial market participants only • Allows for innovation in products
Disadvantages / risks	• May not properly reflect the specific characteristics of hydrogen supply and demand	• Higher administrative costs • May compromise hydrogen and methane market integration (into one single market), unless adaptations are harmonised	• Lack of standardisation can become important market barrier, e.g. to cross-border trade
Mitigation measures	• Set minimum product requirements to maximum common denominator (i.e. most strict requirements) • Monitor the success and adapt when required • Incentivise development of regional exchanges and initiatives	• Extract lessons from gas and electricity exchanges' products harmonisation • Incentivise development of regional exchanges and initiatives	• Extract lessons from gas and electricity exchanges' products harmonisation • Set ex-ante target product requirements (initially no standardisation and gradually increase requirements according to an established roadmap) • Incentivise development of regional exchanges and initiatives

4.2.3 Balancing rules and tools to balance hydrogen portfolios

Balancing rules and tools used in the gas system[245]

The experience in the natural gas sector regarding portfolio and system balancing, provides relevant input to determine the possible balancing approach for the future hydrogen system. To ensure that a gas system operates safely and efficiently, balancing injection in and withdrawal from the system is required, taken into account the flexibility offered by linepack. Previously, natural gas TSOs were responsible for balancing supply and demand within their network, holding options for injection or withdrawal of gas via long-term contracts (e.g. using large storages). The Balancing Network Code was introduced to stimulate liquidity in the short-term market and to enable and incentivise network users (NU) to balance their own portfolios, through adapting their injection (from production, import or storage) and/or offtake (for consumption or storage). This resulted in the development of the Balancing Target Model.

Natural Gas Balancing Target Model (BTM) features and tools

The balancing position of a network user is the difference between its inputs (e.g. local gas production or gas shipped into the balancing zone from adjacent balancing zones, LNG terminal or storage, or bought on the market) and its off-takes (e. g. gas consumed by its end-customers or sold on the market). The actual differences at the end of the Gas Day are cleared between the TSO and the network users at the marginal price.

Network-related rules on information provision, imbalance charges, settlement processes associated with daily imbalance charges and provisions on operational balancing underpin the operation of balancing markets. To meet the aims of the Balancing Network Code (BAL NC), the following tools or features are relevant:

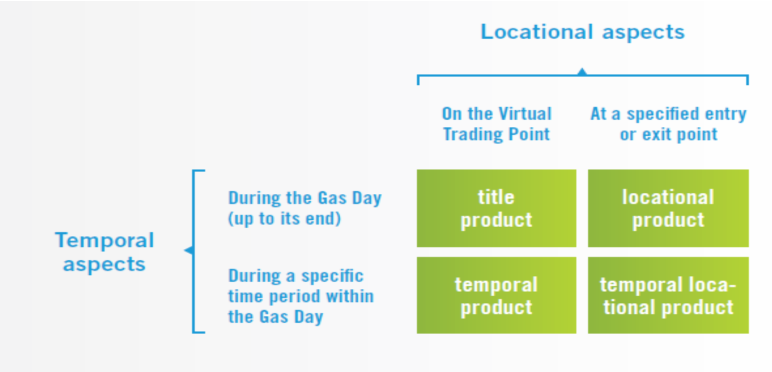
1. **Trading Platform and Short Term Standardised Products**

   TSOs should trade gas for residual balancing purposes on the same trading platforms as network users using Short Term Standardised Products (STSPs) with the aim of increasing competition and liquidity of the short-term wholesale gas market.

[245] This section is based on ENTSOG (2018) Balancing Network Code – an Overview. Available at https://entsog.eu/sites/default/files/2019-11/BAL%20leaflet.pdf

The STSPs have to be traded for delivery on a within day (ID) or day ahead (DAM) basis seven days a week, in accordance with the applicable rules. The STSPs are defined in the BAL NC as represented in the next figure.

Figure 4-3 Short Term Standardised Products definition[246]



The ultimate aim is that TSOs will use only Within-Day title products.

For the procurement of STSPs, TSOs use a trading platform that meets all of the following criteria:

- provides sufficient support to both NUs and TSOs to undertake balancing actions using relevant STSPs;
- provides transparent and non-discriminatory access;
- provides services on an equal treatment basis;
- ensures anonymous trading at least until a transaction is concluded;
- provides a detailed overview of the current bids and offers to all trading participants;
- ensures that all trades are duly notified to the TSO.

2. **Virtual Trading Point & Trade Notifications**

   It allows for the tracking of the market party that is financial responsible for gas supplies within the entry/exit system. The Balancing NC describes the underlying features of trading at the VTP, such as the lead time and the information to be provided in the trade notification process.

3. **Operational Balancing (merit order)**

   When deciding upon the appropriate balancing actions, the TSO shall prioritise the use of title products where and to the extent appropriate over any other available short term standardised products or balancing services.

4. **Nominations**

   The NU provides nomination information to the TSO. This section of the code harmonises the information the NU has to provide to the TSO to have or to change the gas flow (i.e. nomination or re-nomination) at Interconnection Points (IPs). It also sets common rules about this process: re-nomination should be possible every hour of the Gas Day, with the general rule that the lead time for re-nomination is two hours ahead.

5. **Daily Imbalance Charges**

   NUs have to be bound to pay or be entitled to receive (as appropriate) daily imbalance charges in relation to their daily imbalance quantity. These charges shall be cost reflective.

6. **Within Day Obligations**

   In a daily balancing regime, NUs must be balanced at the end of the day. WDOs are additional within day constraints. The Code provides for three types of WDOs: System-wide WDOs[247]; Balancing portfolio WDOs[248]; Entry-exit WDOs[249].

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[246] ENTSOG (2018) Balancing Network Code – an Overview. Available at https://entsog.eu/sites/default/files/2019-11/BAL%20leaflet.pdf
[247] Designed to provide incentives for NUs to keep the transmission system within its operational limits
[248] Designed to incentivise NUs to keep their individual position during the Gas Day within a pre-defined range
[249] Designed to provide incentives for NUs to limit the gas flow or the gas flow variation under specific conditions at specific entry-exit points

7. **Neutrality arrangements**

   A balancing neutrality mechanism will be used to enable the TSO to recover and appropriately apportion charges and revenues related to its balancing activities.

8. **Information Provision**

   To allow shippers to balance their portfolios, information is provided to them regarding their inputs and off-takes from the TSO. The information provided to NU by the TSO should refer to the overall status of the transmission network, the TSO balancing actions and the network user's inputs and off-takes for the Gas Day.

9. **Line-pack Flexibility Service (LFS)**

   The LFS service is an additional tool to allow NU to be balanced at the end of the day. A TSO may offer the provision of LFS to NU after the approval of the related terms and conditions by the NRA.

10. **Interim Measures**

    In the absence of sufficient liquidity of the short-term wholesale gas market, suitable interim measures shall be implemented by the TSO. Balancing actions undertaken by the TSO in case of interim measures have to foster the liquidity of the short-term wholesale gas market to the extent possible.

Options to balance hydrogen portfolios and the overall hydrogen system

To balance hydrogen portfolios and the system, market and network operators can use various tools such as:

- Hydrogen storage (underground storage, tanks, …);
- Demand side flexibility via interruptible contracts and injection of hydrogen into the gas system (blending);
- Supply side flexibility: next to flexible import, domestic hydrogen production via electrolysers will offer opportunities for balancing the hydrogen system by taking benefits from the price variability in the electricity market.

Hydrogen prices on the intra-day and balancing markets will hence to a large extent be determined by the short-term electricity prices. Having a liquid market for short-term hydrogen market products, will hence be key to balance both the electricity and hydrogen system while optimally value the price differences and variations on both markets via arbitrage. As long as there is no liquid short-term market for hydrogen, TSOs could be held responsible to cover residual imbalances by concluding direct contracts with storage operators and other flexibility providers (local producers, industrial users) and possibly by own conversion activities (blending, separation,…).

Hydrogen producers, traders, storage operators and suppliers should be stimulated to participate in the short-term/balancing market. In order to enhance the system flexibility and reduce the overall balancing costs, it would be appropriate to opt for large balancing areas, which would require a high interconnection level of the future hydrogen networks. Connecting the existing and possibly new 'closed' pipelines (exempted from TPA) also to the future 'open' hydrogen networks, would allow to enhance short-term market liquidity and reduce balancing costs. Potential contractual or physical congestion should be addressed by adequate rules (e.g. UIOLI) or investments. Large balancing zones would be enabled by properly interconnecting the future hydrogen backbones in the different EU Member States.

Stakeholders' opinions

Table 4-12 summarises the feedback received from stakeholders regarding rules and tools to balance hydrogen portfolios and the system.

Table 4-12 Stakeholders' opinions on balancing rules and options

Topic	Comments provided by stakeholders
Homogenous EU approach to regulating balancing	A homogenous EU approach to regulating balancing has been proved to be more effective and suitable than a fragmented approach. A gas exchange operator supports EU harmonised requirements for balancing agreements and balancing periods.
Arrangements for hydrogen balancing could be similar to gas balancing in zones comprising both H-gas and L-gas	For several stakeholders (TSOs and other gas infrastructure operators, gas suppliers and traders, hydrogen industry), coupling between natural gas and hydrogen balancing would avoid fragmentation and could take place in the following way: - TSO determines imbalance of the hydrogen network and balancing position of each network user - TSO provides conversion capacity from and to the methane network - Balancing markets allow to trade standardised short-term balancing products (according to one stakeholder complemented with locational and capacity-based longer-term products)
Need for additional tools in early phase	A trading association suggests that, in the early phases, some additional tools may be necessary to enable TSOs to ensure the system remains safe.
Balancing tools	All possible sources should be eligible to provide balancing services: flexible hydrogen production and import; underground and other storage, line-pack of TSOs and DSOs; conversion services and sufficient physical means for conversion in both directions should be in place.
Clusters	Local or regional clusters might need to respect strict balancing requirements considering their lower flexibility potential (e.g. 1 or more storage tanks), whereas larger interconnected hydrogen systems can leverage more flexibility as they will be directly or indirectly connected to several facilities, that can provide balancing services.

Considered options on balancing rules and tools

Stakeholders globally agreed that the Balancing Target Model currently used in the gas sector could be applied for the hydrogen market as well. Table 4-13 analyses some features and tools of the BTM, and assesses their suitability for the hydrogen market. Taking into account the limited market maturity, some approaches may not be feasible in the initial phase, but could become relevant when the market reaches maturity and liquidity.

Options formulation for the hydrogen balancing design

The first option (option A) is, at least for the time being, not to regulate balancing at the EU level, meaning that each Member State is free to decide on the regulation of balancing its hydrogen systems.

The second option (option B) for a hydrogen balancing design is to fully mirror the existing NG Balancing Target Model and BAL NC. In this option, the neutrality arrangements should be very clear, and in the case of a methane TSO also endorsing the role of hydrogen TSO, there should be a clear separated balancing of methane and hydrogen systems. Virtual and physical conversion for balancing purposes would be contracted by the TSO from market parties.

The third option (option C) is to mirror the existing NG Balancing Target Model as in option B, but to lighten some features that may not be essential, at least in a first phase (e.g. shorten the nomination requirements, and adopt interim measures more widely such as balancing instead of trading platforms).

Table 4-13 Features and tools of the BTM for gas and suitability for hydrogen balancing

	Gas market	Hydrogen market
Main balancing responsibility	NUs are financially responsible for daily imbalance charges (which should be cost reflective) to stimulate liquidity	Mirror the natural gas approach, to incentivise shippers or NUs to reduce imbalances.
Residual balancing responsibility	TSOs or balancing operator providing physical daily / intra-daily correction	Similar principle seems feasible and appropriate.
Trading platform and Short-Term Standardised Products	TSOs should trade gas for residual balancing purposes on the same trading platforms as NU using STSPs. All participants are eligible as balancing service provider (storage, demand response, production, import, conversion)	Most appropriate option seems to mirror natural gas approach; as the market will be rather illiquid in the initial phase, the role of the TSO will be crucial. All market participants should be allowed to provide balancing services
Virtual Trading Point	Use of VTP for each balancing area.	Depends on choice of entry-exit model (discussed in chapter 3).
Operational Balancing (merit order)	Deciding upon the appropriate balancing actions, the TSO shall prioritise the use of title products	Use of title products should be prioritised. For small clusters, locational and/or temporal products may be more frequently necessary.
Nominations	NU provides nomination to the TSO. Information is harmonised, incl. changes to gas flow at IPs. It also sets some common rules about this process: re-nomination should be possible every hour of the Gas Day, with the general rule that the lead time of the re-nomination is two hours ahead.	Appropriate rules are key to facilitate balancing and to incentivise participants to address own imbalances. Frequent re-nomination (i.e. in intra-hourly intervals) may be necessary to optimise use of dispatchable production/conversion technologies (e.g. electrolysers).
Within-Day Obligations	WDOs address additional within day constraints	WDOs could be important given intermittency of renewable hydrogen production.
Neutrality arrangements	A balancing neutrality mechanism will be used to enable the TSO to recover and appropriately apportion charges and revenues related to its balancing activities	Combined methane-hydrogen TSOs without separation of balancing systems could lead to cross-subsidisation of balancing costs across systems.
Information Provision	Information is provided to shippers, to balance their portfolios (overall status of the transmission network, the TSO balancing actions and the NU's inputs and off-takes for the Gas Day)	Information provision to all market participants is critical for all market stages, including balancing.
Linepack Flexibility Service (LFS)	The LFS service is an additional tool to allow NU to be balanced at the end of the Gas Day	LFS could play important role in all hydrogen system sizes. Provision of LFS should be regulated given the need to provide non-discriminatory and transparent access to network users, and the inverse relationship of network transport and LFS capacity arising from different network pressures.
Interim Measures	In the absence of sufficient liquidity of the short-term wholesale gas market, suitable interim measures shall be implemented by the TSO	Will be relevant as long as the hydrogen balancing markets are not liquid and TSOs are responsible for a large share or all of the network balancing.

The fourth option D is for the TSO to be fully responsible for balancing the injection and withdrawal within their network, holding options for significant amounts of flexible hydrogen via long-term contracts (e. g. with operators of hydrogen storage or production facilities) and contracting further necessary balancing services in the short-term (e.g. via interruptible offtake contracts).

The four options are thus:

- Option A: Full mirroring;
- Option B: Third party to endorse residual balancing responsibility;
- Option C: Charging balancing costs through tariffs;
- Option D: Mirroring and lightening some features

Table 4-14 Balancing rules and tools for the hydrogen system

	Option A	Option B	Option C	Option D
Options	No regulation	Mirror approach for hydrogen and methane networks	Mirror approach for hydrogen and methane networks, with adaptations	No individual balancing responsibility
Main balancing responsibility	Defined by MS / cluster	Network users	Initially TSO, ultimately network users	TSO
Residual balancing responsibility	Defined by MS / cluster	TSO	TSO	Not applicable.
Advantages	• Low initial regulatory costs • Flexibility to develop balancing solutions according to market maturity and later harmonisation	• Straightforward to implement given developed natural gas balancing regulation • Would fit well if H_2 balancing requirements and user profiles are similar to NG • Increases balancing cost-reflectivity	• Straightforward to implement given developed natural gas balancing regulation • Can simplify balancing rules for new market participants • More adapted for an infancy phase • Allows to adapt balancing rules to hydrogen clusters characteristics • Increases balancing cost-reflectivity in the long-term	• Simpler to implement as TSOs have experience in balancing • Can simplify balancing rules for new market participants • Allows to share balancing costs with gas NU in the case of common charging • Possibly more space for flexibility and innovation • Allows to adapt balancing rules to hydrogen clusters characteristics
Disadvantages / risks	• May hamper market integration at a later stage • Specific solutions may not incentivise network users to reduce imbalances, increased balancing costs	• May be too heavy in developing hydrogen markets • May miss the opportunity to adapt for sector coupling specific aspects (*)	• Higher administrative costs • Increased balancing costs initially • Does not stimulate NU to reduce imbalances initially	• Increased balancing costs • Higher regulatory costs • Does not stimulate NU to reduce imbalances • May incentivise market operators active in electricity and methane markets to offload balancing responsibility to hydrogen TSO
Mitigation measures	• Providing guidelines for contractual arrangements and for "public interest" investment in storage and conversion assets (guide to set up a viable business case for all market parties)	• When mirroring, screen with sector coupling criteria (move to option D-like) • Exempt/waiver isolated hydrogen systems from BTM requirements	• Condition interim measures phase-out to market development • Exempt/waiver isolated hydrogen systems from BTM requirements	• Regulator should follow up very closely and strictly • Cost-reflective allocation of balancing costs in charges per user group

(*) This concern is shared by the 4 options

Each option would allocate balancing costs to network users differently. If the main balancing responsibility were allocated to network users (i.e. they would be balancing responsible parties), a significant share of the balancing costs could be allocated to users causing the imbalances (except for eventual balancing reserve costs, if those were due to non-availability of sufficient gas volumes in the short-term market). In contrast, if the TSO was responsible for the main imbalances, balancing costs would be recovered through network tariffs, thus reducing the balancing cost-reflectivity.

Many of the features of the gas Balancing Target Model seem appropriate for balancing hydrogen systems, as indicated in Table 4-13, for example on the main balancing responsibility. Generally, as a minimum, Member States should not be impeded of allocating the main balancing responsibility to network users, as this incentivises them to reduce their imbalances and thus the overall system balancing costs. Suppliers should take on the responsibility for balancing the aggregate imbalances of their customers. Ideally, hydrogen network users would have the main balancing responsibility across the EU.

However, especially smaller network users might have a difficulty in managing their imbalances, particularly in case there is not a liquid spot market. Balancing costs for isolated hydrogen clusters will be higher, relying specially on smaller-scale underground storage (if suitable geological locations exist), power-to-gas and potentially pressurised containers, given the limited linepacking capacity of hydrogen systems (as hydrogen has a lower specific energy content compared to natural gas) and that using large-scale underground storages for daily balancing is not economical (due to higher energy needs for compression).[250]

Therefore, a number of adaptations to the gas Balancing Target Model as well as transitional measures would be appropriate. The first measure consists of foreseeing an increased role for network operators contracting directly balancing capacity and energy (through market-based, non-discriminatory and transparent mechanisms) until a liquid market is developed and isolated hydrogen clusters are interconnected. Also, given the strong coupling of the electricity and hydrogen sectors through power-to-gas and hydrogen-based power generation, tailored market products (with e.g. a higher temporal resolution) might be appropriate.

In case an entry-exit system for hydrogen is adopted, this would enable virtual trading points which could facilitate the development of spot hydrogen markets employed also for balancing. Another aspect for consideration is the unbundling of combined (methane and hydrogen) network operators. Here, at least accounts unbundling of hydrogen and methane systems balancing costs would be beneficial to increase transparency and avoid cross-subsidisation between the two sectors.

The survey of potential barriers and measures adopted in the EU regulation and market design for the electricity and natural gas sectors in section 3.1 highlights the importance of sufficiently large balancing zones, transparency, a liquid market, appropriate balancing rules and cross-border harmonisation. It furthermore suggests regional initiatives as a channel to promote the integration of balancing markets and share best practices.

Given these considerations, the option C seems the most appropriate. The definition of a hydrogen Balancing Target Model reflecting the methane one, but with a stronger initial role for TSOs and mechanisms for the integration of front-running hydrogen regions would provide sufficient flexibility but also guidance for the eventual development of EU-wide balancing markets. Eventually, managing residual imbalances could be assigned to the EU hydrogen TSO (described in Box 3-11) or another EU-level organisation focusing on balancing.

Moreover, the EU hydrogen TSO (see Box 3-11) or another organisation could be responsible for managing the residual balancing of network users across the EU or groups of hydrogen market areas in the long-term. This could further reduce the hydrogen balancing costs, but would require a high-level of integration of the involved market areas.

4.2.4 Access for market parties to large-scale hydrogen storage

Regulation of energy storage and its role in the energy market

Electricity storage is according to the EU legislation a competitive activity; electricity storage assets can only be owned and operated by grid operators for well-defined purposes. Third-party access to electricity storage is not foreseen by legislation, but can be negotiated on a commercial basis.

For natural gas underground storage, legal provisions apply to ensure transparent and non-discriminatory tariffs for third party access. Those regulated tariffs are applicable to all users on a non-discriminatory basis. Where a storage facility operates in a sufficiently competitive market (no natural monopoly), access can be allowed on the basis of negotiated tariffs, following a decision taken by the Member State.

Natural gas underground storage facilities are a major flexibility resource in the gas sector, in particular to cover peak demand in winter periods. Even with factors such as the cold spell of the 2018 winter, the closure of the Rough gas storage site in the UK and the imposed cap on the Dutch Groningen field production, a situation of overcapacity in natural gas underground storage can be observed across the EU.[251] This situation, coupled with stabilising or even decreasing demand peaks (due to energy efficiency measures and global temperature rise) and increasing gas interconnectivity of Member States, has led to lower market demand and prices for storage capacity, and to changes of the access regime from nTPA to rTPA of some storage assets (e.g. in France) to maintain the capacity available to the market and avoid closure due to limited profitability. Therefore, converting some of the existing natural gas storage capacities (e.g. salt cavern sites) to hydrogen storage could be an adequate option from a societal perspective to minimise the overall energy system costs and also the risk of stranded gas storage assets.

[250] See for example Northern Gas Networks et al. (2016) H21 Leeds City Gate.
[251] ACER MMR 2018 – Gas wholesale market volumes

In some national markets, gas suppliers are legally obliged to book underground gas storage capacity in order to secure their supply to retail end-users. This obligation, combined with possible restrictions to its utilisation, has an impact on the competition in the concerned Member States and on the gas wholesale and retail prices. For example, "the legal provisions established by the government in Poland, obliging any supplier importing gas to keep 30 days of the yearly volumes in the country's storage facilities starting from 2017, has worsened the price convergence of the Polish market with the NWE region."[252]

Implementing such a legal obligation on hydrogen suppliers would not be an appropriate option, not even if there would be accessible hydrogen storage capacity available. Such obligations are mainly introduced to limit the risks related to the import dependence from non-EU countries and to cope with the high winter demand levels related to the use of natural gas for heating. As the future hydrogen demand in the EU would to a large extent be covered by production within the EU, and is expected to be much less seasonal than the current natural gas demand, the drivers for hydrogen storage would be different. Hydrogen storage is indeed expected to improve the business case of hydrogen production facilities and will to be certain extent also compete with them by also providing daily and seasonal flexibility to other market operators.

Mulder et al. (2019) note, however, that the types of underground gas storage for hydrogen may play a role in determining the need to regulate (or not) storage, as, if hydrogen could be stored in depleted gas fields instead of salt caverns, the number of storage facilities needed in the Netherlands would decrease from 50 to 3. Hence, the different capacities of the reservoir types could lead to a concentration in the Dutch storage market which could warrant regulation of storage.[253]

Next to underground storage facilities, mainly used for seasonal flexibility, LNG terminal operators provide third-party access to operational storage capacity (tanks), mainly used for short-term flexibility purposes. Access to these facilities is in general provided on the basis of regulated terms and tariffs, while some Member States have authorised or determined terminal operators to apply negotiated tariffs.

Similar to natural gas, hydrogen storage is expected to play an important role in providing flexibility to the energy market, both by using storage tanks and underground facilities for short-term or operational flexibility, and by using underground sites for seasonal flexibility. This role could be amplified with the expected development of production of hydrogen using (variable renewable) electricity, thereby increasing the need for hydrogen storage and other flexibility tools.

The following table summarises the storage technology options per market type.

Table 4-15 Storage technology options per market type

Storage type / characteristic	Gas market	Electricity market	Hydrogen market
Short term – balancing and ID/DA market	Tank LNG UGS	Pumped hydro Batteries Flywheels	Tank LH_2 terminals[254] UGS
Long – term (seasonal) – all markets	UGS	/	UGS

The interaction between the electricity, gas and hydrogen systems and markets will be important, as methane and hydrogen storage assets can be used to also provide flexibility to the electricity system, and some natural gas storage facilities can be converted for the purpose of storing hydrogen (tanks, LNG terminals, UGS, …).

Stakeholders' opinions

Stakeholders (TSOs and other infrastructure operators, gas suppliers, hydrogen industry, gas traders) agreed that the current regulatory regime for natural gas storage could be applied to

[252] ACER MMR 2018 – Gas wholesale market volumes

[253] Mulder et al. (2019) Outlook for a Dutch hydrogen market - Economic conditions and scenarios

[254] LNG import terminals can be combined with entry points for (liquid) hydrogen produced in other regions of the world where wind and solar energy are available at larger scale and lower cost than in Europe. Existing gas pipelines connected to LNG terminals could be used to distribute hydrogen locally. RWE is exploring such possibility, with the Brunsbüttel terminal in Germany. RWE (2020) German LNG Terminal and RWE to explore Hydrogen opportunities via Brunsbüttel.

hydrogen storage as well, and that flexibility should be offered to Member States to regulate or not this activity.

One stakeholder highlighted the important role of hydrogen storage in facilitating integration of surplus renewable electricity from electricity markets; to facilitate this, regulated third party access would be necessary to allow proper competition and market functioning.

Considered options

The central question is whether large-scale underground hydrogen storage should be a regulated activity, depending on the situation of the Member States and acknowledging that small-scale hydrogen storage in tanks should anyhow be a commercial activity, without any legal obligation for TPA.

The first option (option A) is to impose regulated TPA access to hydrogen underground storage, assuming that the available capacity will be limited in most Member States and will hence in general be characterised by a natural monopoly.

The second option (option B) is the mirroring of the 3rd Energy Package, with a more flexible regime, allowing Member States to decide whether access to storage is regulated or negotiated. This would assume that adequate regulation and rules for TPA would be necessary to avoid that the concerned owners/operators would abuse their natural monopoly position. This should consider the geographical distribution of potential hydrogen storage sites across Europe and the need to create a well-balanced storage infrastructure, with capacity mainly coming from the conversion of natural gas underground storage.

The third option (option C) consists of not to implement regulated access to storage.

Options A & B are mainly justified by the similar economic and technical characteristics of natural gas and hydrogen storage. Adequate regulation should facilitate the conversion of underground methane storage to hydrogen use.

Options formulation

The considered options are

- A: Regulated TPA;
- B: Regulated or negotiated regime, mirroring the current natural gas regime;
- C: No regulation.

Table 4-16 Options for access to underground hydrogen storage

	Option A	Option B	Option C
Options	Regulated TPA	Regulated / negotiated TPA choice	No regulation
Advantages	• May lower cost of capital • Consistent with the conversion of NG storage assets • EU harmonisation and possibly coordination • Addresses potential abuse of storage market power	• May lower cost of capital • Allows differentiation depending on market situation and technical potential • Allows to match regulatory approach to methane storage • Allows to spur innovation	• Low regulatory implementation costs • Open to all market participants • Market driven • No discrimination between storage in underground facilities and tanks
Disadvantages / risks	• Could limit national action effectiveness • Methane storage operators under nTPA could not be interested in repurposing facilities under an rTPA regime	• Risk of non-harmonised approaches between MS & non-coordinated use of underground storage capacities • Potential distortions between rTPA and nTPA assets	• Potential discrimination of storage users
Mitigation measures	• Strong oversight by NRAs	• Strong oversight by NRAs	• Investment support mechanisms, such as guarantees

4.2.5 Licensing of hydrogen traders and suppliers

Current practices in the natural gas markets

Article 3(5) of the gas Directive 2009/73/EC stipulates that "Member States shall ensure that all customers are entitled to have their gas provided by a supplier, subject to the supplier's agreement, regardless of the Member State in which the supplier is registered, as long as the supplier follows the applicable trading and balancing rules. In this regard, Member States shall take all measures necessary to ensure that administrative procedures do not discriminate against supply undertakings already registered in another Member State."

In the definition of the Gas Directive, 'supply' means the sale, including resale, of natural gas, including LNG, to customers.

Usually, gas traders/suppliers must obtain a licence from their NRA or, less commonly, another national authority or the TSO, [255] when carrying out the following gas related activities:

- Supply gas by pipes to any premises, industrial or household;
- Operate as a gas shipper.

Currently, integrated licenses for trade and supply can be obtained in France, Poland and Romania at least. Licensing requirements for traders are very diverse in the EU and can be rather strict, acting as a barrier to entry. Moreover, market operators that are active in different national markets have to dispose of licenses for each considered market and even establish a local presence, which can also act as a barrier.[256]

Considered options for licensing of hydrogen suppliers and traders

Licensing requirements for suppliers are usually based on national retail market regulation and characteristics and aim to protect retail market consumers, in particular (vulnerable) households. As a large scale use of hydrogen in the household market segment is not expected to develop in the short or medium term, it seems premature to assess within the framework of this study further concrete options for a regulation at EU level regarding licensing of hydrogen suppliers. The current provision in the Gas Directive seems a sufficient basis, and could also be implemented for hydrogen supply to consumers.

As hydrogen trade is expected to become a supranational activity, it would be appropriate to define at EU level harmonised minimum requirements for trading licenses as well as a mechanism of mutual recognition. The licensing conditions should not be too strict in order not to create a barrier to market entry, while however being sufficiently strict to ensure trust in market operators. Introducing a system of mutual recognition for wholesale market authorisations/licences for trading activities across the EU would be an appropriate option to enhance competition and to facilitate cross-border trade. "Once a wholesale trader is authorised or licensed in one Member State, based on well-defined standardised minimum requirements, including in relation to the reliability and financial solvency of the entity, this should automatically be recognised in any other Member States [that] requires a licence or authorisation for wholesale trading." This should also be "accompanied by a mechanism for enforcement action, such as revoking the licence without undue delay if needed. In addition, further steps are needed to mitigate the risk of fraud, including the right to exclude parties that have breached requirements in another Member State".[257]

[255] Schönherr Rechtsanwälte et al. for DG ENER (2020) Upgrading the gas market - Regulatory and administrative requirements to entry and trade on gas wholesale markets in the EU
[256] Schönherr Rechtsanwälte et al. for DG ENER (2020) Upgrading the gas market - Regulatory and administrative requirements to entry and trade on gas wholesale markets in the EU
[257] ACER and CEER (2019) The Bridge Beyond 2025 Conclusions Paper.

Box 4-3 REMIT and hydrogen markets

The scope of the REMIT regulation could be extended to also comprise hydrogen. This would contribute to the harmonisation of the reporting requirements related to hydrogen trading across Member States, improve the level playing field with electricity and methane gas markets, and enable the detection and investigation of suspicious market behaviour by ACER and the NRAs by employing an established mechanism. It would also minimise the need to impose additional reporting requirements to market participants, which in the case of wholesale gas markets has been indicated as one of the most frequent barriers to enter and trade on the market.[258]

In case REMIT is extended to include hydrogen, the reporting obligations would also cover pre-existing operators of private hydrogen infrastructure. This could provide ACER and the NRAs with relevant information to assess market conditions, the potential abuse of market power by such pre-existing operators, especially if they are unregulated or exempt from TPA requirements. This measure would also allow authorities, market parties and stakeholders to dispose of relevant aggregated market information regarding the hydrogen sector.

Employing the existing ACER REMIT information system (ARIS) would provide cost savings in the monitoring of hydrogen markets, thanks to economies of scope. The current cooperation model between ACER and NRAs for the identification and investigation of suspect market activity, could also be the main mechanism for the hydrogen market surveillance. If it is deemed that reporting requirements and market monitoring activities at the national level would be more adequate in an initial phase, the REMIT reporting requirements could be phased in according to the level of market development in each Member State (and according to the required update of ARIS). However, there are benefits of including hydrogen within the scope of REMIT rather early.

The operation of ARIS requires a number of other reporting parties besides market participants – especially the sectoral TSOs, ENTSOs and organised market operators. Therefore, the inclusion of hydrogen in the scope of REMIT and the use of ARIS would imply a certain level of regulation of the sector. In case of no immediate regulation of the hydrogen sector at the EU level, market monitoring activities could be left for EU and national competition and financial services authorities.

[258] Schönherr Rechtsanwälte et al. for DG ENER (2020) Upgrading the gas market - Regulatory and administrative requirements to entry and trade on gas wholesale markets in the EU

5 DEVELOPMENT AND ASSESSMENT OF OPTIONS FOR A REGULATORY FRAMEWORK

This chapter develops and assesses four selected policy options for a regulatory framework for hydrogen infrastructure and markets. These regulatory framework 'packages' are developed by combining the options for each of the regulatory elements developed in chapters 3 and 4.

The assessment considers the criteria required by the Better Regulation Guidelines. Specific criteria focusing on aspects particularly important to a hydrogen regulatory framework are comprised within these main criteria. As a result, the chapter provides a clear picture of the most relevant impacts per option for a hydrogen infrastructure and market regulatory framework, considering the hydrogen pathways developed in chapter 1 and the natural monopoly characteristics' analysis of chapter 2.

This chapter is structured as follows:

- **Context definition**, presenting the context which could justify a regulatory intervention for hydrogen networks and markets, the underlying drivers, and the necessity and value added of action at the EU level;
- **Objective setting,** shortly presenting the objectives of the assessment;
- **Assessment methodology,** presenting especially the indicators employed for each of the main and specific criteria;
- **Regulatory framework options,** briefly describing each of the four options as well as their specific combination of the regulatory elements developed in chapters 3 and 4;
- **Assessment of the options** according to the criteria and indicators developed.

5.1 Context definition

Definition & scale

Currently, the investment, ownership and operation of dedicated hydrogen networks is not regulated in the EU, except for technical legislation addressing environmental and safety aspects. A limited number of hydrogen networks for industrial purposes have been developed in the past in areas with large chemical industry clusters; this development was solely market-driven by hydrogen end-use and hydrogen production economics. Today, these pipelines, limited in size and capacity compared to the methane grids, are operated by industrial gases companies, with no third party access rules and carrying hydrogen qualities governed by industry-specific rules. These vertically integrated hydrogen producers negotiate prices with large industrial users and currently the hydrogen market is limited in size and focused exclusively on fossil-based hydrogen.

The hydrogen strategy of the European Commission[259] indicates that "Renewable and low-carbon hydrogen can contribute to reduce greenhouse gas emissions ahead of 2030, to the recovery of the EU economy, and is a key building block towards a climate-neutral and zero pollution economy in 2050". As part of a number of key actions, it proposes to design an enabling and supportive framework for hydrogen, addressing the topics of support schemes, market rules and infrastructure.

Given the importance of hydrogen for the energy transition, the limited development of hydrogen infrastructure and markets, and the absence of sector-specific regulation, the main issues can be defined as:

1. Enabling the development of the hydrogen sector: Hydrogen uptake in the EU economy should support meeting energy & climate goals, which will require the development of hydrogen infrastructure and markets;
2. Need to update the infrastructure regulatory framework: The current energy infrastructure regulatory framework does not address hydrogen networks, potential interactions with natural gas and electricity infrastructure regulation and systems integration in general - the development of hydrogen networks and markets should consider the whole energy systems in planning (including for efficient repurposing of methane infrastructure) and operation;
3. Lack of liquid and well-functioning hydrogen markets: Market failures could lead to insufficient development of hydrogen markets, unfair competition between hydrogen and electricity, methane and other energy vectors, or other distortions in the internal energy market.

It should be noted that there is still significant uncertainty regarding the energy transition pathways and the role that hydrogen will play, although its relevance is increasingly recognised by scenarios developed by public and private actors. Nonetheless, regulatory frameworks for hydrogen

[259] European Commission (2020). A hydrogen strategy for a climate-neutral Europe. COM(2020) 301 final.

at the EU and national levels will need to be robust in order to address the multiple possible pathways as well as the diversity of national strategies.

Main drivers

Enabling the development of the hydrogen sector

In all scenarios of the Long-term Strategy and the impact assessment of the 2030 Climate Target Plan[260] achieving net decarbonisation by 2050, hydrogen is expected to play a role. Hydrogen (and its derived products like methane or ammonia) will be important especially in hard-to-decarbonise market segments such as specific industrial applications and transport (heavy duty road, rail, aviation, maritime). The impact assessment of the 2030 Climate Target Plan indicates that "more broadly, moderate and uneven efforts in terms of energy system integration, uptake of electricity and other low-carbon energy carriers such as advanced biofuels, hydrogen or e-fuels, carbon capture and storage (CCS) and CCU technologies, especially if compounded with lack of dedicated energy infrastructure and markets, negatively affect the pathway to climate neutrality, especially the decarbonisation of industry or the transport sector".[261]

Renewable or low-carbon hydrogen production is expected to grow significantly, starting with some Member States. This development will first take place in industry and to a lesser extent transport given the challenges in decarbonising these sectors as mentioned, and will mainly be driven by supportive regulation and specific incentives, energy & climate targets as well as a number of national and EU policy ambitions and strategies (such as the increased ambition for the Climate Target Plan and the hydrogen strategy). Chapter 1 analyses the national strategies in detail, while the hydrogen strategy pathway is detailed in Box 5-1.

Blending of limited hydrogen volumes in methane gases networks can support the initial deployment of hydrogen production, but in order to efficiently value larger hydrogen volumes, dedicated hydrogen networks will be required in specific clusters and eventually for the interconnection of hydrogen systems. A majority share of this dedicated hydrogen network could arise from the repurposing of methane networks.

Even though assessments expect renewable and low-carbon hydrogen technology costs to become increasingly competitive, it is widely recognised that public intervention is needed to speed up the development. The expected cost reductions and the need to kick-start renewable and low-carbon hydrogen production for hard-to-decarbonise end-uses justify the need for public intervention. This includes not only public support, but also regulation addressing market failures which could negatively affect the development of the necessary hydrogen infrastructure and markets, described next.

Need to update the gas infrastructure regulatory framework

There is currently a lack of certainty concerning the future hydrogen regulatory framework, stemming among others from the diversity of national strategies, the lack of sector-specific regulation at the moment, the inherent uncertainty of future development pathways, and the lack of clarity regarding the role of incumbent methane network operators in dedicated hydrogen infrastructure. The expectation of future regulatory intervention at the EU and national levels may delay potential investment decisions and the development of hydrogen infrastructure and markets.

The lack of regulatory certainty and subsequent delays in hydrogen assets investment create a risk that the required cross-border backbone infrastructure for hydrogen-intensive pathways will not develop in time, limiting the integration of hydrogen clusters and the development of an internal hydrogen market. Without adequate regulatory provisions at the EU level, there is an additional risk of divergence of national regulatory frameworks, making posterior cross-border harmonisation of regulation and integration of hydrogen systems more difficult and costly. Lack of properly interconnected pipelines and harmonised rules regarding cross-border capacity allocation, congestion management and balancing would limit the market development and integration, and increase system costs.

Even if sufficient investments do occur, the lack of adequate regulatory provisions to ensure non-discriminatory third party access to hydrogen networks could negatively impact the entry of new hydrogen producers or suppliers, and hinder the development of a liquid market. In the absence of adequate third-party access regulation, operators of hydrogen networks would have to negotiate access with every new user, potentially affecting the speed of development of the network. Lower

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[260] European Commission (2020). Impact Assessment for "Stepping up Europe's 2030 climate ambition - Investing in a climate-neutral future for the benefit of our people". SWD(2020) 176 final.
[261] European Commission (2020). Impact Assessment for "Stepping up Europe's 2030 climate ambition - Investing in a climate-neutral future for the benefit of our people". SWD(2020) 176 final.

investment will also result in more limited reductions in technology costs (e.g. because of reduced economies of scale).

There is furthermore the risk that the development of hydrogen infrastructure does not sufficiently consider the benefits of an optimal configuration and dimensioning of the networks (taken into account the sub-additive cost curve) and of a system integration as well as the interactions with other energy sectors (electricity, methane and heat). A number of issues can be identified in this regard:

- The planning of electricity and methane infrastructure is being increasingly integrated, but hydrogen networks are not yet properly taken into account. This concerns planning for national, cross-border and trans-European infrastructure;
- A substantial part of the hydrogen network is expected to develop by converting existing methane infrastructure, which is largely owned by regulated network operators. There is no regulatory framework to guide the efficient repurposing of methane infrastructure assets and avoid their decommissioning where beneficial from an overall energy system's perspective;
- Hydrogen can compete with regulated energy vectors (electricity, methane and heat) for certain end-uses, potentially distorting the internal energy market in the absence of a minimal set of EU hydrogen regulatory provisions.

Private hydrogen infrastructure and operators exist in some Member States, including a few cross-border pipelines. While their right to conduct business should be safeguarded, from the societal perspective it could be beneficial to mandate third-party access to (some of) their networks. These private operators could themselves be inclined to provide third-party access for a number of reasons, including to remain competitive with new producers and transporters and to focus on their core business which is hydrogen production rather than transport.

Lack of liquid and well-functioning hydrogen markets

The assessment of current hydrogen markets in this study revealed no evidence of abuse of market power by the large industrial hydrogen producers. However, if the hydrogen sector will develop as envisaged in the hydrogen-intensive pathways depicted in this study, market failures might arise. The four main factors leading to potential market failures that should be addressed by regulation are:

1. Due to certain technical properties of hydrogen networks, the infrastructure is characterised by a sub-additive cost curve;
2. Hydrogen is expected to become a traded commodity with a high number of producers/sellers and buyers;
3. Leaving the responsibility for hydrogen network planning to investors/operators without adequate oversight, might create a monopoly situation in infrastructure development and lead to a sub-optimal outcome from a global energy system perspective;
4. Refurbished methane pipelines will offer a competitive advantage to the concerned owners/operators over operators planning to build new hydrogen pipelines.

Another potential risk of market failure stems from inefficient hydrogen price formation, as a result of the absence of a liquid EU-wide hydrogen market. The lack of hydrogen price benchmarks will interact with the limited scale of local hydrogen markets, leading to insufficiently liquid markets and preference of market operators for long-term contracts, as they will not be able to hedge their risks with forwards, futures or shorter-term market products. The lack of a liquid market with appropriate short-term products and an efficient price benchmark will also increase balancing costs, and make the role of hydrogen as flexibility provider less efficient.

Inadequate infrastructure regulation and the prevalence of long-term contracts could lead to significant barriers for new market entrants, with possible discrimination for connection to and use of the networks for both small-scale hydrogen producers and consumers. The positive externalities of renewable or low-carbon hydrogen usage, namely its contribution to climate change mitigation, may not be adequately priced in the market in the absence of a liquid market with representative price formation and a harmonised system of guarantees of origin.

Necessity and added value of action at the EU level

Legal basis for EU action

The legal basis for regulatory interventions at the EU level regarding hydrogen networks and markets is the Article 194 of the TFEU (as established in electricity and natural gas sector regulation). In line with Paragraph 1, the considered measures aim to improve the functioning of the energy market; promote the interconnection of energy markets; promote energy savings and development of new forms of renewable energy, and ensure the security of energy supply in the Union. At the same time, the regulatory interventions have to be designed in such a way that enables the Member States to determine their own energy production and supply mix, including by opting for pathways that do not heavily rely on hydrogen.

Added value of EU intervention

The main added value of EU regulatory intervention is ensuring the efficient functioning of energy markets and the development of hydrogen infrastructure supporting the attainment of the energy and climate objectives of Member States at least cost. A set of EU rules for hydrogen can contribute to better governance of the overall energy sector's contribution to the EU energy and climate targets.

Although it is expected that some Member States will develop functioning hydrogen markets, it is widely recognised that interconnecting national markets further improves their liquidity and efficient functioning (as proved by the integration of electricity and methane markets). Timely-introduced EU level hydrogen market and infrastructure regulation will additionally reduce the potential ex-post costs of regulatory harmonisation.

EU intervention can also foster the integration of hydrogen with electricity and methane infrastructure and coupling of markets, which are most efficient if investments and operations are planned from a holistic system perspective. It is expected that hydrogen networks will eventually form interconnected EU-wide networks; to accelerate and facilitate this process, integrated planning for cross-border and trans-European networks on the EU level can bring benefits not achievable with national planning alone. Similarly, EU level planning could support the efficient repurposing of existing cross-border methane infrastructure to hydrogen. The repurposing or decommissioning of methane infrastructure will have potential cross-border effects on the hydrogen, methane and also electricity sectors.

Some level of EU regulation in the hydrogen sector could help to increase the investment certainty, also by reducing the risk of inadequate regulatory intervention at the national level and by defining the principles and mechanisms for harmonised national regulation in the future.

5.2 Objective setting

There are a number of policy objectives that should be taken into account when designing a regulatory framework for hydrogen networks and markets. At the highest level are the EU climate and energy goals (decarbonisation, security of energy supply, effective and fair competition, development of renewable energy and energy efficiency). These are complemented by generic environmental and industrial policy goals, and also the post-covid economic recovery. These policy drivers may necessitate a faster development of dedicated hydrogen infrastructure and markets than it would happen without policy intervention at the EU level.

The EU Hydrogen Strategy explicitly considers these policy objectives and lists a number of key actions. The Strategy indicates that hydrogen is 'essential to meet the carbon neutrality by 2050', contributing to the global efforts to implement the Paris Agreement, and eliminating pollution. Moreover, an EU hydrogen value chain could employ 1 million people and support the post-COVID-19 economic recovery. The key actions proposed by the Strategy cover the design of an adequate regulatory framework for hydrogen markets and infrastructure. But many others are included, comprising the regulatory framework for support, schemes, EU financing, fostering demand and scaling up production, promoting R&I, and addressing the international dimension (strengthening collaboration and the EU stand in international activities).

Hence, the Strategy takes a broader approach on the hydrogen sector than this study, and also refers to several other instruments and actions. A regulatory framework for dedicated hydrogen networks and commodity markets should have clearly established primary objectives for supporting the development of the hydrogen sector:

- Increasing investment certainty by providing predictability on the regulatory framework, also clearly distinguishing between regulated and competitive activities;
- Guiding the repurposing of existing methane infrastructure to hydrogen infrastructure, if and only when efficient from a societal perspective;
- Enabling the development of local hydrogen clusters;
- Developing an efficient energy system capable of integrating high volumes of variable renewable energy and of decarbonising the energy supply at least cost through cross-sectoral network planning and coupling of the electricity, methane, hydrogen and heat systems;
- Ensuring fair competition, preventing abuse of market power and removing barriers for market entry;
- Creating the basis for efficient cross-border trade that ensures proper valuation of hydrogen;

- Fostering innovation in hydrogen technologies and infrastructures.

Nonetheless, an EU regulatory framework for hydrogen networks and markets can contribute to some of the policy objectives not directly related to its main objectives. The main secondary objectives are thus:

- Promoting environmental policy objectives, for example by considering pollution impacts in the planning of hydrogen networks;
- Fostering R&I in all components of the hydrogen supply chain, including production and end-use;
- Promoting the EU hydrogen industry, e.g. through transparent and non-discriminatory long-term planning processes considering all available solutions, and providing long-term visibility on demand for hydrogen infrastructure products and services;
- Supporting the up-scaling of investments in hydrogen production and end-use, e.g. by enabling long-term hydrogen purchase contracts, providing price signals to market participants, and also information on the network status and future development.

5.3 Assessment methodology

The assessment of the regulatory options follows the Better Regulation Guidelines, considering the following additional criteria specified in the Terms of Reference:

- The ability to accommodate the different hydrogen pathways depicted in chapter 1;
- The need to regulate hydrogen transmission/distribution (and storage) infrastructure, according to the analysis of chapter 2;
- Coherence of the chosen regulatory elements within each option, including between network regulation and market design elements;
- The incentives to regulated and market actors, including to the efficient conversion of methane infrastructure;
- Diversity between options.

The hydrogen sector development pathway presented in the strategy should be considered as a major reference for the envisaged sector regulation, and is described in the box below. Coherence with the principles elaborated in the recent Hydrogen Strategy are assessed, and differences duly justified. In addition, to account for the diversity of national strategies and the fact that the hydrogen sector will develop with different speeds across Member States, the different pathways developed in chapter 1 will be considered to assess the adequacy of the proposed regulatory interventions to multiple scenarios, as mentioned.

In September 2020, the European Commission has released its 2030 Climate Target Plan, accompanied by an impact assessment analysing a number of scenarios for achieving GHG emission reductions in the range of 50-55% by 2030 compared to 1990 levels. While this significantly higher ambition will also impact the deployment of hydrogen technologies, the Hydrogen Strategy and the Long-term Strategy already depicted hydrogen-intensive pathways. Hence, although the final decarbonisation target will impact the hydrogen sector, it constitutes but one of the many highly uncertain variables influencing it. Therefore, it is considered that the pathways developed in chapter 1 and in the Hydrogen Strategy already cover a wide range of possible future outcomes, including the pathways of the 2030 Climate Target Plan Impact Assessment. The expected increase of the climate target to 55% might even increase the relevance of the present analysis.

Transitional measures are proposed for each option to facilitate the gradual roll-out and integration of hydrogen systems and markets, as well as potential exemptions for existing and new infrastructure (except when pre-defined by the application of the current natural gas regulatory framework). A roadmap is also developed to indicate when regulatory framework provisions are expected to be phased in and transitional measures are phased out.

The indicators for the impact assessment are presented in Table 5-1. It must be noted that several indicators contribute to the assessment of multiple categories. For example, energy system costs savings or tariff levels affect the socio-economic impacts of the regulatory option as well as its efficiency. This is properly accounted for in the assessment of the options in section 5.5.

Ideally, the analysis of coherence of the options would consider the final proposals or even agreed versions of other EU legislation and instruments under development (such as the revised TEN-E regulation and Energy and Environmental Protection State Aid Guidelines). As this is not possible, the coherence analysis is based on the information available in November 2020, and assumes the TEN-E regulation will be revised to include hydrogen infrastructure in its scope.

Box 5-1 Sector development pathway according to EU hydrogen strategy[262]

- **From now to 2024**, the installation of at least 6 GW of renewable hydrogen electrolysers in the EU and an annual production of up to 1 million tonnes of renewable hydrogen.
  - **Infrastructure needs for transporting hydrogen will remain limited** as **demand will be met initially by production close or on site** and in certain areas **blending with methane gases might occur** but planning of medium range and backbone transmission infrastructure should begin.
  - The policy focus will be on laying down the regulatory framework for a liquid and well-functioning hydrogen market and on incentivising both supply and demand in lead markets, including through bridging the cost gap between conventional solutions and renewable and low-carbon hydrogen and through appropriate State aid rules. Enabling framework conditions will push concrete plans for large wind and solar plants dedicated to gigawatt-scale renewable hydrogen production before 2030.
  - Investments will be supported also through the development of a strong portfolio by the European Clean Hydrogen Alliance and the Strategic Forum for IPCEIs[263], and the use of EU funding mechanisms, some part of the Commission's recovery plan.
  - In the first phase and later, the EU will support R&I in hydrogen production, infrastructure and end-use. Infrastructure R&I will cover hydrogen distribution, storage and dispensing, as well as the repurposing of methane infrastructure.
- **From 2025 to 2030**, hydrogen needs to become an intrinsic part of our integrated energy system, with at least 40 GW of renewable hydrogen electrolysers and an annual production of up to 10 million tonnes of renewable hydrogen in the EU. Electrolyser investments in 2020-2030 could range from 24 to 24 billion €, and investments in hydrogen transport, distribution, storage and refuelling stations could reach 65 billion €.
  - Dedicated demand side policies will be needed for industrial and transport demand to gradually include **new applications, including steel-making, trucks, rail and some maritime transport applications**, and other transport modes. Renewable hydrogen will start playing a role in **balancing a renewables-based electricity system** by transforming electricity into hydrogen when renewable electricity is abundant and cheap and by providing flexibility. Hydrogen will also be used for **daily or seasonal storage**, as a backup and provide buffering functions, enhancing security of supply in the medium term.
  - **Local hydrogen clusters**, such as remote areas or islands, or regional ecosystems – so-called "Hydrogen Valleys" – will develop, relying on local production of hydrogen based on decentralised renewable energy production and local demand, transported over short distances. In such cases, a dedicated hydrogen infrastructure can serve hydrogen use not only for industrial and transport applications, and electricity system balancing, but also for residential and commercial buildings.
  - The **need for an EU-wide logistical infrastructure** will emerge, and steps will be taken to **transport hydrogen from areas with large renewable potential to demand centres** located possibly in other Member States. The **backbone of a pan-European grid will need to be planned** and a network of hydrogen refuelling stations to be established. The existing gas grid could be partially repurposed for the transport of renewable hydrogen over longer distances and the development of larger-scale hydrogen storage facilities would become necessary. **International trade can also develop**, in particular with the EU's neighbouring countries in Eastern Europe and in the Southern and Eastern Mediterranean countries.
  - EU financing instruments in the first phase will be scaled up to support the significant investment levels. A pilot support mechanism (preferably at the EU level) will be set-up to support hydrogen production (in phase I or II)
- **From 2030 onwards**, renewable hydrogen will be **deployed at a large scale across all hard-to-decarbonise end-use sectors**. EU investments in hydrogen production from 2020 to 2050 would amount to 180-470 billion €.

[262] European Commission (2020). A hydrogen strategy for a climate-neutral Europe. COM(2020) 301 final.
[263] Important Projects of Common European Interest

Table 5-1 Indicators for impact assessment

	Indicator
Socio-economic impacts	1. Energy system costs savings compared to a system without regulation 2. Security of hydrogen supply 3. Network tariffs level 4. End-user adaptation costs
Technical impacts	5. Allows interoperability of interconnected hydrogen systems / deployment of hydrogen end-use equipment/appliances 6. Supports system flexibility / renewable electricity 7. Allows repurposing of methane infrastructure when efficient
Effectiveness	8. Accommodation of chapter 1 pathways 9. Planning and use of hydrogen cross-border infrastructure 10. Ability to satisfy transport and large-scale industry demand 11. Providing large-scale storage 12. Development of local hydrogen clusters
Efficiency	13. Delivering a level playing field and competitive market, addressing potential abuse of market power 14. Lowers the overall regulatory costs 15. Enables efficient planning across energy carriers, levels and areas 16. Efficient consideration of existing H_2 infrastructure 17. Investment efficiency, use of currently existing hydrogen and methane infrastructure, and reduced risk of investment in stranded assets 18. Incentives for regulated / market operators to deploy innovative technologies and market products
Coherence	19. With electricity, methane (and heat) sectors regulatory framework 20. With Hydrogen Strategy 21. With TEN-E 22. With Energy and Environmental Protection State Aid Guidelines 23. Internal coherence
Proportionality and subsidiarity	24. EU has competency to act to: ○ Contribute to proper functioning of energy markets ○ Ensure security of energy supply ○ Promote energy efficiency ○ Promote interconnection of energy networks … which could not be ensured with national regulation alone 25. MSs maintain right to determine own energy supply mix
Affected parties	- Hydrogen/methane/electricity network/storage operators (regulated/exempted/new/pre-existing) - Methane / hydrogen producers / traders / suppliers - Methane / hydrogen consumers (industry, buildings, transport, power generation)

5.4 Regulatory framework options

Each regulatory framework option that will be assessed is an internally coherent combination of the options for each of the individual network regulation and market design elements addressed in chapters 3 and 4. These framework options were designed considering the objectives set in the chapter 5.2 (except for the 'no immediate action' option that describes the status quo).

Seven options were considered for assessment. After a preliminary assessment of these options according to the main and specific criteria, the following four options have been selected in concertation with DG ENER:

- No immediate action
- Light EU regulation
- Full EU regulation
- Full+ EU regulation

The options are briefly described next. An overview of the regulatory framework option assessed is presented in Table 5-2, and these are further detailed in Table 5-3.

Description of the regulatory framework options

No immediate action

The assessment of a "business as usual" scenario is mandated by the Better Regulation Guidelines, to establish the magnitude of impacts of the policy options in comparison to the baseline option. In this option, no changes are brought to the EU regulatory framework regarding hydrogen networks and markets, and Member States are hence free to regulate on the matter.

Light EU regulation

This package sets mainly the rules that define the ownership relations (unbundling) between hydrogen and methane network (and storage) infrastructure and production and supply assets and activities. This package would thus define the rules for main interactions with the regulated methane sector, but leaves the decision on other areas to the Member States, except when there is a risk of distortion to the internal energy market due to coupling of the hydrogen with the other energy sectors.

Therefore, the 'light EU regulation' option defines the following regulatory elements at the EU level:

- **Role of gas TSOs and horizontal unbundling from methane networks:** Common operation of hydrogen and methane networks is authorised by EU legislation, with at least accounts unbundling required;
- **Role of private hydrogen operators:** NRAs may exempt specific hydrogen pipelines owned by merchant operators and closed distribution systems from unbundling, TPA or tariffication regulation;
- **Third-party access rules:** Member States may choose between negotiated or regulated third-party access rules for networks and large-scale storage

No specific EU regulation exists in this option for the following regulatory elements: network tariffication and planning, CACM, balancing and regarding organised markets platforms or exchanges. A Hydrogen Target Model (HTM) could provide clear guidance to the preferred approach for these elements, enabling Member States to develop national legislation and regulation aligned to the HTM.

The package is built around the premise that the growth of the hydrogen sector will be natural and market driven. Member States thus would have the opportunity to adjust the level of regulation to the specific national situation. Front-running countries have the freedom to set up a supportive regulatory framework, which might provide higher better certainty for hydrogen revenue streams and encourage large-scale investment in infrastructure. This national framework should in any case be compliant with EU competition and state aid rules.

It is also expected that most advanced countries would cooperate to create rules on cross-border interaction on regional level. Experience from early regulatory frameworks can then be drawn upon when designing regulation in other Member States, or potentially on EU level, when the cross-border infrastructure reaches sufficient maturity. By defining a minimum set of rules for the most important regulatory elements, the option aims to limit the regulatory divergence. It is possible for national regulatory frameworks to converge when the hydrogen sector matures, becomes more interconnected and regional cooperation leads to regulatory harmonisation.

Full EU regulation

The Full EU regulatory framework is to a large extent coherent with the EU framework for natural gas regarding the extent of EU regulatory intervention and chosen approach for the different elements, while allowing for a tailored approach to hydrogen where necessary to properly account for its specificities compared to natural gas. The Full EU regulation thus draws on lessons learned not only from the EU gas regulatory framework but also from the new EU electricity market design. The approach of extending the Gas Market Design to hydrogen is not adopted in this or the other options, but is briefly analysed in Box 5-3.

Hence, the approach to elements such as unbundling, TPA, network tariffication, planning, CACM and balancing is similar to the EU natural gas regulatory framework. Specifically, the 'Full EU regulation' option defines the following regulatory elements at the EU level:

- **Role of gas TSOs and horizontal unbundling from methane networks:** Common operation of hydrogen and methane networks is authorised by EU legislation, with at least accounts unbundling required;
- **Role of private hydrogen operators:** NRAs may exempt specific hydrogen pipelines or isolated systems owned by merchant operators and closed distribution systems from unbundling, TPA or tariffication regulation;

- **Third-party access rules:** Third-party access rules is required for all non-exempted hydrogen networks. Member States may choose between negotiated or regulated third-party access rules for large-scale storage;
- **Network tariffication:** harmonised principles and tariff structures are in place;
- **Planning:** A ENTSO-H_2 is set-up with similar responsibilities as the existing ENTSOs, and national planning requirements are also defined;
- **CACM:** rules for cross-market area CACM are established;
- **Balancing:** Market players have the primary balancing responsibility, with TSOs realising the residual balancing. Balancing zones are national/regional depending on the voluntary cooperation between Member States and network operators;
- **Organised markets**: Harmonised market rules exist, and hydrogen markets are included in the REMIT scope.

Given the different development stages of the methane and hydrogen sectors, a number of transitional measures are foreseen (detailed in section 3.9), including a Hydrogen Target Model (see Table 1-1). Moreover, a provision similar to Article 49 of the Gas Directive on emergent and isolated markets would derogate from several provisions Member States whose hydrogen systems are not directly connected to any other Member State. These derogations would apply to relevant hydrogen cross-border aspects, while provisions necessary to avoid distortions to the internal energy market should still be applied even for isolated hydrogen systems, given the coupling of local hydrogen clusters with the electricity and methane systems.

Box 5-2 The Hydrogen Target Model

A Hydrogen Target Model (HTM) provides the vision of how an integrated hydrogen system and market should function in the medium to long term. It defines an end-point of the regulatory process of dedicated hydrogen infrastructure and markets, and also suggests how this end-point might be achieved (e.g. with major provisions to be laid down in network codes). It also defines the basic principles related to market design and rules. It thus gives clear guidance to the regulation, implementation and revision of specific EU regulatory elements, as well as for Member States to develop complementary national legislation and regulation aligned to the HTM. Determining a Hydrogen Target Model is as such not a regulatory measure, but it is considered an adequate preliminary EU action, to guide future initiatives both at EU and national level.

Full+ EU regulation

As its name indicates, the Full+ EU regulation builds on the Full EU regulatory option, but is more ambitious for a number of aspects. It takes a ‘greenfield’ approach to some regulatory elements departing from the methane and electricity EU regulatory frameworks, which were constrained by what was feasible at the time of their introduction.

The ‘Full+ EU regulation’ options consists of the following additional specific measures:

- **Role of private hydrogen operators**: Strengthens access to all networks by restricting exemptions to existing hydrogen network operators;
- **Organised markets**: Establishes nominated hydrogen market operators;
- **Planning**: Establishes an EU H_2 TSO and conducts determinative network planning of trans-European or EU-relevant hydrogen networks
    - With EU approval of methodology, scenarios and EU network development plans;
    - With harmonised requirements for national planning and NRA approval of methodology, scenarios and NDPs;
    - With the requirement for inclusion of EU network projects in NDPs (to the extent that this is compliant with the future TEN-E Regulation).
- **CACM**: Establishes an EU capacity allocation and congestion management platform, integrates day-ahead and intraday hydrogen markets by market coupling and an inter-TSO compensation mechanism for cross-border flows;
- **Balancing:** Integrates balancing zones through a balancing market coupling platform.

Furthermore, exemptions to existing hydrogen network operators could be granted only upon authorisation from NRAs:

- For a limited duration (i.e. sunset clause); and/or
- With a market test demonstrating there are no existing market participants with firm interest in accessing the network.

The Full+ option is thus the most ambitious option in providing an EU regulatory framework advancing integrated planning across market areas, regulated energy carriers and network levels, market integration including market coupling measures, and generally providing a level playing field for all internal energy market participants. Nonetheless, it maintains many of the transitional measures and exemptions foreseen in the Full EU option.

Box 5-3 Extension of the Gas Market Design to hydrogen

A potential approach to develop a regulatory framework for hydrogen is updating the definition of gas and other articles of the Gas Directive and Regulation to include hydrogen. In this option there would be only one gas sector and one gas definition, encompassing methane and hydrogen gases.

This option has been proposed by some gas sector stakeholders. They argue that with some modifications of the Gas Directive and Regulation as well as the consideration of transitional measures as necessary, this would be a feasible and beneficial approach, building on the mature regulatory framework for natural gas.

While it would be possible to apply the principles of the EU regulatory framework for natural gas to hydrogen networks (and storage) without further modifications, in legal terms it is not possible to apply the concerned legislation as is. The EU Gas Directive and Regulation were developed for natural gas, addressing hydrogen only in so far as it "can technically and safely be injected into, and transported through, the natural gas system". Hence, there are ambiguities and unaddressed aspects in the EU regulatory framework which need to be clarified or modified, regardless of whether they are to be applicable to hydrogen,[264] to provide further demarcation between methane and hydrogen legislation, or to enable a single regulatory framework for both gases.

Taking into account its complexity and drawbacks, this approach was not considered for assessment. The design of a regulatory framework for hydrogen can draw on multiple best practices of the methane one, and there are advantages of mirroring some regulatory aspects. The importance of repurposing methane networks highlights the advantages of allowing combined gas network operators and adequately considering the interlinkages between the hydrogen and methane sectors. However, there are a number of reasons for not applying a single regulatory framework to both gases:

- While natural gas is mainly imported into the EU based on demand, hydrogen is expected to be produced to a large extent within the EU, mainly driven by demand but also partly driven by supply (flexibility needs in the electricity system). The network configuration and the role of transit will hence be different.
- While methane and hydrogen networks share many common economic and technical characteristics, supply technologies and sources for hydrogen (such as power-to-gas) may differ significantly. This may require differences in elements such as market product characteristics, network revenue regulation and tariff structures;
- Electrolytic hydrogen is expected to play a central role in the hydrogen sector in the long run. Coupling of the hydrogen with the electricity sector implies that coherence with the electricity market design will be as important as with the methane market design;
- Addressing the differences in technical & economic characteristics and developmental stages between hydrogen and methane would require a large number of specific provisions for either sector, unduly complexifying the regulatory framework;
- To some extent, the 'greenfield' nature of the hydrogen sector allows for increased ambition of the EU regulatory framework to more quickly promote an internal hydrogen market, while a single regulatory framework for both natural gas and hydrogen would not easily enable increased ambitions (or reduced EU regulatory intervention when beneficial);
- Separate regulatory frameworks lead to increased transparency in cost allocation to methane and hydrogen network users, reducing the potential for undue cross-subsidisation.

[264] See for example GEODE (2020). Towards the New Age of Gas Networks: Proposal on the Regulation of a European Hydrogen Infrastructure; Benrath (2019). Applicable law to hydrogen pipelines for energy purposes in Germany. Journal of Energy & Natural Resources Law; FNBGas et al. (2020) Auf dem Weg zu einem wettbewerblichen Wasserstoffmarkt Gemeinsamer Verbändevorschlag zur Anpassung des Rechtsrahmens für Wasserstoffnetze

Table 5-2 Overview of regulatory framework options assessed[265]

<table>
<tr><th></th><th>No immediate EU action</th><th>Light EU regulation</th><th>Full EU regulation</th><th>Full+ EU regulation</th></tr>
<tr><td>Role of gas TSOs</td><td rowspan="10">Not regulated at EU level</td><td colspan="2">Common operation authorised by EU law</td><td>+ EU-level H_2 TSO</td></tr>
<tr><td>Horizontal unbundling from regulated CH_4 infra</td><td colspan="2">Accounts</td><td>Accounts
Variant: legal + functional</td></tr>
<tr><td>Role of private hydrogen networks</td><td>Exemption from unbundling, rTPA, rTariffs for specific cases</td><td colspan="2">Legal unbundling, rTPA and rTariffs
Exemptions requires a market test / sunset clause</td></tr>
<tr><td>TSO network TPA rules</td><td>rTPA / nTPA choice</td><td colspan="2">Regulated TPA</td></tr>
<tr><td>Network tariffication</td><td rowspan="4">No H_2 specific EU regulation</td><td>Harmonised principles and tariff structures</td><td>Market coupling + Harmonised principles and tariff structures</td></tr>
<tr><td>Planning</td><td>ENTSO-H_2
Requirements for national planning</td><td>With EU TSO organisation
Requirements for national planning</td></tr>
<tr><td>CACM</td><td>Rules for cross-market area CACM</td><td>Market coupling
Rules for cross-border and domestic CACM</td></tr>
<tr><td>Balancing</td><td>Individual balancing responsibility for market players
Residual balancing by TSOs
National/multinational balancing zones</td><td>Individual balancing responsibility for market players
Residual balancing by EU TSO
EU balancing zone</td></tr>
<tr><td>Access to storage</td><td colspan="2">rTPA / nTPA choice</td><td>Regulated TPA</td></tr>
<tr><td>Organised market platforms or exchanges</td><td>No H_2 specific EU regulation</td><td>Harmonised market rules
REMIT scope includes hydrogen</td><td>+ market area managers</td></tr>
</table>

[265] Transitional measures are not indicated. All network codes (e.g. for congestion) should not be developed in the short term, but the principles ("Target regulatory model") should be defined, and all transitional measures and (national) regulatory initiatives would need to be compliant with the target model.

Table 5-3 Detailed parameters of the regulatory framework options selected

Note: - denotes no regulation at the EU level. MSs are free to regulate / market operators to cooperate regarding parameters when applicable.

Category	Parameter	No immediate action	Light EU regulation	Full EU regulation	Full+ EU regulation
Network activity regulation	Owning/operating hydrogen networks is a competitive/regulated activity	-	Defined by MS with harmonised market test principles	Regulated	
	Hydrogen and methane gases definition	Separate gases			
	Common ownership/operation of CH_4 and H_2 networks?	-	Allowed		
Unbundling	Vertical unbundling	-	Accounts Legal+functional for combined gas operators	Legal+functional	
	Horizontal unbundling from regulated CH_4 infra	-	Accounts		Accounts Variant: legal
Role of private hydrogen networks	Exemptions to existing private hydrogen networks?	-	Upon NRA authorisation[266]		
	Exemptions to new private hydrogen networks?[267]	-			
TPA	TSO network third-party access	-	rTPA / nTPA choice	rTPA	
Network tariffication	Entry-exit / path-based system	-	-	Entry-exit	
	Harmonised cross-market area tariff principles?	-	-	Yes	
	Harmonised intra-market area tariff principles?	-	-	No	Yes
	Same tariff rules as NG?	Separate, but mirroring possible			
	Market coupling mechanism?	-	-	-	Implicit with ITC-like mechanism

[266] NRA authorisation requirements established in EU legislation for all parameters
[267] Exemptions from unbundling, rTPA and rTariffs for hydrogen clusters, isolated markets, merchant operators, closed distribution systems.

Category	Parameter	No immediate action	Light EU regulation	Full EU regulation	Full+ EU regulation
	Re-allocation of non-remunerated system benefits between hydrogen/methane/electricity[268]	-		Allowed, harmonised principles Variant: single RAB allowed	
Planning	EU planning process	-	-	TYNDP-like process by ENTSO-H_2	Determinative planning by EU H_2 TSO
	Cross-carrier planning[269]	-	-	Common scenarios and consideration of main interactions	Common scenarios, modelling and TYNDP
	Cross-border planning	-	-	EU-level planning	EU-level planning
	National planning	-	-	Harmonised requirements	Harmonised requirements
	EU oversight	-	-	Methodologies and scenarios: EC approval, ACER opinion. TYNDP: ACER opinion[270]	Methodologies and scenarios: EC approval, ACER opinion. TYNDP: ACER approval
	National oversight	-	-	Required approval	Required approval
CACM	Rules for cross-market area CACM?	-	-	Yes	Yes
	Harmonised rules for domestic CACM?	-	-	-	Yes
Balancing	Balancing responsibility	-	-	With BRP	With BRP
	Cost recovery	-	-	Residual through tariffs	Residual through tariffs
	Balancing market coupling / merger	-	-	-	Coupling
Access to storage	TPA to large-scale storage[271]	-	rTPA / nTPA choice	rTPA / nTPA choice	rTPA
Organised market platforms or exchanges	Single gas commodity market?	-	-	No	No
	Harmonised hydrogen markets rules?	-	-	Yes	Yes
	Mutual recognition of licenses?	-	-	Yes	Yes
	REMIT reporting obligations?	No	No	Yes	Yes
	Market area managers?	-	-	Yes	Yes

[268] While subsidisation is not within the scope of hydrogen infrastructure and market regulation, it is addressed in the discussion of the regulatory elements (Chapter 3). Subsidisation of hydrogen related activities would be possible under the current EEAG and GBER.
[269] Also with electricity.
[270] At present, the European Commission approves the methodology, while ACER provides opinions on the methodology, scenarios and gas TYNDPs.
[271] Owning/operating hydrogen storage < threshold (TBD) would be a competitive activity. New or refurbished underground storage sites are expected to have a capacity > threshold.

5.5 Assessment of hydrogen regulatory framework options

The following tables present the assessment of the four hydrogen regulatory framework options, according to the indicators listed in Table 5-1 for the following main criteria:

- Economic impacts
- Technical impacts
- Effectiveness
- Efficiency
- Coherence
- Proportionality and subsidiarity
- Affected parties

These main criteria take into account the specific criteria required by the Terms of Reference:

- Accommodation of various pathways;
- Delivering a level playing field and competitive market, addressing potential abuse of market power;
- Investment efficiency;
- Reducing ex-post costs, uncertainty and risks for technologies and business models;
- Accounting for pre-existing infrastructure and operators.

Table 5-4 provides a summary of the assessment for the criteria. The affected parties are only indicated in the detailed assessment tables, available in Annex A.

Table 5-4 Summary of impact of regulatory packages according to assessment criteria

Criteria		No immediate action	Light EU regulation	Full EU regulation	Full+ EU regulation
Economic impacts	1. Energy system costs savings	--	0	+	++
	2. Security of hydrogen supply	-	-	+	+
	3. Network tariffs level	--	-	+	++
	4. End-user adaptation costs	0	0	+	+
Technical impacts	5. Interoperability/equipment/appliances	0	0	+	+
	6. Supports flexibility / renewable electricity	-	-	+	++
	7. Efficient repurposing of CH_4 infrastructure	-	0	+	++
Effectiveness	8. Pathways accommodation	+	+	++	+
	9. Planning and use of cross-border H2 infra	--	--	+	++
	10. Ability to satisfy transport/industry demand	+/++	+/++	0	0
	11. Providing large-scale storage	0	+	+	++
	12. Development of local hydrogen clusters	+	++	0	0
Efficiency	13. Level playing field and competitive market	-	-	+	++
	14. Overall regulatory costs	+	++	-	--
	15. Investment efficiency / Asset stranding	-/0	-/0	+	++
	16. Efficient planning (carriers/levels/areas)	--	--	+	++
	17. Accounting for existing H2 infrastructure	+	0	0	-
	18. Innovative techs/market products incentives	0	0	++	+
Coherence	19. With energy sectors regulatory framework	--	0	+	++
	20. With TEN-E	-/+	-/+	+	+
	21. With EEAG	+	-	-	-
	22. With hydrogen strategy	--	-	+	+
	23. Internal coherence	++	++	++	++
Proportionality & subsidiarity	24. Regulation at EU level is justified	Not applicable	Yes	Yes	Yes
	25. Right for MS to determine energy supply	No restrictions	No restrictions	No restrictions	No restrictions

Legend:
++ / + : measures explicitly support the objective
0 : neutral/no clear relation / impact on the objective
- / -- : measures pose barriers for achieving the objective

Transitional measures

The measures below aim to providing flexibility for an early development of hydrogen clusters, increase the robustness of the regulatory options (i.e. the capacity of each regulatory framework option to accommodate the different hydrogen development pathways) and reduce the regulatory burden to Member States, network operators and market actors. They would be phased out when the (internal) hydrogen market becomes mature. However, some measures may remain in place even in a mature hydrogen market, especially potential waivers and exemptions to new investments and CDSs – given that even in a mature market these may be necessary in specific cases to foster investments.

The table below indicates which transitional measures are foreseen for each regulatory framework option. Based on the analysis of section 3.9, the different possible transitional measures are:

- **Hydrogen Target Model**: the HTM should determine all relevant regulatory framework elements, including those that are not foreseen to be phased in immediately at the entry into force of the EU legislation. The legislation should establish a process for developing EU network codes and guidelines for these elements at a later point of time. The target model for hydrogen systems and markets should be developed in an early phase at EU level and should specify the vision for the final market organisation, in particular with regards to cross-border interactions, harmonisation of relevant regulatory elements and coupling of market zones. This vision should guide national authorities in designing their regulatory framework and prevent regulatory divergence. The experience from more advanced Member States and regional cooperation initiatives together with the HTM (that could be periodically updated, when necessary) could then also support the development of the network codes and guidelines.
- **Exemption procedures for developing isolated hydrogen clusters:** These waivers should in principle serve to enable the regulatory flexibility of isolated hydrogen clusters, even in MSs that might have other interconnected network system (and thus would not qualify for the general MS derogation). This could, for example, happen in a country that will develop a hydrogen transit pipeline, but where hydrogen clusters might be developed in parallel. A transit pipeline requires generally a more detailed network planning analysing demand on EU-level to justify the investment, which is irrelevant for the local hydrogen cluster. This instrument does not have to be necessary phased out with time to incentivise interconnections, but could be limited in duration – a waiver for a particular isolated network could be for example limited to 10 years after it was granted. This waiver could be granted by respective NRAs, with approval from or a notification procedure to the Commission, based on an application from the network operators.
- **MS derogations for isolated systems:** These derogations could apply to MSs whose networks are not connected to the European hydrogen network, similarly to Article 49 of the Gas Directive on emergent and isolated markets. As this instrument should not disincentivise MSs from developing interconnections, derogations should be temporary and phased out by a certain date, for example 2030 (to reflect the Hydrogen strategy). In cases where the exemption procedures for isolated hydrogen clusters are sufficient to enable their initial development, an MS derogation should not be granted in order to incentivise interconnection.
- **Exemption procedures/waivers for pre-existing network operators:** Exemptions to unbundling, TPA and other requirements for pre-existing operators should be allowed only when it is demonstrated that the social benefits of the considered rules would not outweigh its social costs. A market test could be conducted to identify the interest of third-parties in accessing a pre-existing network. Incentives could be granted to pre-existing operators to unbundle and provide third-party access. Such requirements could also be phased in gradually, entering into force only once existing supply contracts expire.
- **Network planning processes:** As an EU-level planning process for regulated hydrogen infrastructure will need to be developed from scratch, it will need to be improved throughout various iterations. In the 'Full+ EU' option, requirements such as the use of a fully-integrated energy systems model can be phased in when the EU H2 TSO develops its planning model. Network operators which are exempted from TPA requirements could be also exempted from participating in EU-level planning processes for a limited duration. They should nonetheless provide information on e.g. forecasted demand so that it can be taken into account in the hydrogen, methane and electricity planning processes.
- **Others:** Regulatory sandboxes should address specific regulatory barriers hampering technological or business model innovation, such as new forms of investments in hydrogen infrastructure or efficient operation of the hydrogen system. The EU sandbox model should clearly delimit the scope of application (e.g. specific legislative articles from which the experiment could be exempted) and define requirements for the transparent, non-discriminatory design, monitoring and evaluation of the sandbox.

Table 5-5 Transitional measures applicable per regulatory framework option

<table>
<tr><th>Transitional measure</th><th>No immediate action</th><th>Light EU regulation</th><th>Full EU regulation</th><th>Full+ EU regulation</th></tr>
<tr><td>Hydrogen Target Model</td><td>• No Hydrogen Target Model specified</td><td>• Potential Hydrogen Target Model (HTM) on aspects not regulated initially such as planning, tariffication and CACM</td><td>• HTM focuses on CACM, harmonisation of market rules</td><td>• HTM focuses on CACM, harmonisation of market rules and eventual market coupling.</td></tr>
<tr><td>MS derogations to isolated clusters / systems</td><td rowspan="4">• No EU level provisions requiring derogation</td><td>• From vertical unbundling and relevant cross-border aspects</td><td>• Previous option+
• From CACM rules
• From entry-exit system and balancing responsibility
• From market harmonisation regulation</td><td>• Previous option+
• Harmonisation of intra-market area tariff principles
• Implicit market coupling</td></tr>
<tr><td>Waivers / exemption procedures for pre-existing network operators</td><td>• NRAs can exempt operators based on defined procedure.</td><td>• NRAs can exempt operators based on defined procedure. A market test can be required and sunset clauses foreseen.
• Exempted networks should still be included in the network planning process</td><td>• NRAs can exempt operators based on defined procedure. A market test can be required and sunset clauses foreseen.
• Exempted networks should still be included in the network planning process</td></tr>
<tr><td>Network planning processes</td><td rowspan="2">• Not defined at EU level</td><td>• Networks exempted from TPA requirements could just provide information on e.g. forecasted demand to the ENTSO-H2</td><td>• Planning requirements to the EU H2 TSO could initially focus on cross-border infrastructure and employ less developed integrated energy systems models</td></tr>
<tr><td>Others</td><td>• Regulatory sandboxes that are in line with the Hydrogen Target Model could be allowed to gain experience for later design of missing regulatory elements</td><td>• Regulatory sandboxes that are in line with the Hydrogen Target Model could be allowed to gain experience for later design of missing regulatory elements</td></tr>
</table>

Robustness of regulatory framework options to the hydrogen gas infrastructure development pathways

To further evaluate the impacts and appropriateness of the considered regulatory options, an additional analysis of their adequacy for the different development pathways (defined in Chapter 1) has been undertaken. In those pathways, different regulatory elements will become important for the concerned MSs as their network may vary in role, density, size and interconnectedness or type of connected consumers. The main factors for every pathway are summarised below.

Pathway 1: Full H_2 grid integration

- Characterised by strong coupling of hydrogen with other sectors, further extension of the grid and/or cross-border integration.
- It is supposed that adequate regulatory frameworks for the development of domestic networks and liquid domestic markets can be adopted on a national level. However, supra-national harmonised rules on cross-border aspects are necessary to fully capture the potential benefits of markets and systems integration, and to avoid internal market distortions.
- Since hydrogen imports might be needed in some MSs, and others will exploit their renewable energy potential for hydrogen exports, the establishment of an interconnected network and EU-wide market is needed to enable cross-border trade.
- The pathway requires regulatory flexibility for the initial development of hydrogen clusters, which will later be connected at the national and cross-border levels.
- Cross-sectoral planning is relevant as hydrogen is supposed to provide flexibility to the electricity system, to promote the refurbishment of some of the methane networks when efficient (and to avoid over-investment in potentially stranded assets), to avoid inefficient decommissioning of methane infrastructure, and to develop cross-border infrastructure.
- Due to expected significant development of hydrogen networks (not only through repurposing existing methane networks, but also by constructing new pipelines), the investment might appear attractive not only to incumbent natural gas network operators but also to other actors who might compete for the development of hydrogen networks.

Pathway 2: H_2 grid upscaling

- Characterised by strong development of the grid and some coupling of hydrogen and other sectors, while cross-border integration is less relevant for concerned MSs than in Pathway 1.
- There is an important role of planning to determine the future extent of demand and required grid, to assure timely development given the fast network growth, to promote the refurbishment of some of the methane networks when efficient, and avoid inefficient decommissioning of methane infrastructure. The vision also requires firm policy signals on target development levels.
- Cross-sectoral planning is also very important as hydrogen is supposed to provide flexibility and balancing services to electricity network,
- When new hydrogen networks will be constructed, there is more potential to adopt competition "for the market". Organising competition may have a positive impact on the system costs, provided that the configuration (route, capacity) is properly determined from an overall energy system perspective.
- Balancing & storage rules will be the focus of national regulation, given more limited cross-border integration.
- The pathway requires regulatory flexibility for the initial development of hydrogen clusters, which will later be connected at the national and sometimes cross-border level.
- Cross-border aspects will be less important (initially) as the focus will be on solving national challenges. But strong coupling with the electricity sector will require cross-border harmonisation in order not to distort competition also in other energy sectors.

Pathway 3: H_2 grid downsizing

- Existing methane infrastructure will be downgraded in size and sometimes repurposed to hydrogen. Significant decommissioning and possibly devaluation of existing assets may occur.
- Operators will face declining revenues from the operation of methane networks, financing hydrogen infrastructure might be problematic without public support.
- Protection of methane consumers might be an issue due to grid defection and incentives for the network operator to realise inefficient investments in hydrogen ('gold plating').
- The pathway requires regulatory flexibility for hydrogen clusters which may remain isolated.
- Strong planning oversight required to avoid over-investments in H_2 networks.

Pathway 4: Transit-focused H_2 grid

- The focus of countries following this pathway will be on developing transit pipelines, rather than on developing domestic systems/markets (or if so, they would focus on large industrial actors, which reduces the potential of network operators to abuse their natural monopoly)
- Long-term contracts are needed to build new transit pipelines (in case of developing new transit routes, e.g. from North Africa)
- The pathway requires regulatory flexibility for hydrogen clusters which may remain isolated from transit backbones.
- EU level system planning beneficial to analyse if existing transit pipelines can be converted, without hampering EU security of supply (e.g. pipelines from Ukraine that might face low or no utilisation rates when new natural gas import routes will be constructed).

Based on the factors affecting the main pathways, the adequacy of the regulatory options to each pathway is summarised in Table 5-6 and further detailed in Table 5-7.

Table 5-6 Summary of the pathway assessment

Pathway	No immediate action	Light EU regulation	Full EU regulation	Full+ EU regulation
PW1: Full H_2 grid integration	Provides regulatory flexibility to develop local hydrogen clusters. Does not allow sufficient network development, cross-border integration and sector coupling.	Provides basic rules for competition and non-discriminatory access, but cross-border integration and sector coupling still not sufficiently addressed.	Provides investment certainty for network development, facilitates cross-border market integration. Exemptions provide regulatory flexibility.	Provides investment certainty for network development, maximises cross-border and sector coupling synergies. Exemptions provide regulatory flexibility.
PW2: H_2 grid upscaling	Provides regulatory flexibility to develop local hydrogen clusters. Lack of network planning and cross-border integration reduces the potential benefits of cross-sectoral integration. No regulation to ensure fair competition across sectors.	Provides basic rules for competition and non-discriminatory access. Lack of network planning and cross-border integration reduces the potential benefits of cross-sectoral integration. No regulation to ensure fair competition across sectors.	Network planning and cross-border rules sufficient to realise benefits of integrating energy sectors (also increasing investment certainty). Rules for fair competition across sectors established.	Provides regulatory & investment certainty for timely network development. Focus on EU level benefits might be detrimental to the initial goal of fulfilling national needs (integration of RES).
PW3: H_2 grid downsizing	Provides regulatory flexibility to develop local hydrogen clusters. Risk of overinvestment in hydrogen infrastructure by incumbent methane TSO (and also increased tariffs for remaining NG grid users).	Provides basic rules for competition and non-discriminatory access. Allows regulatory flexibility to develop local hydrogen clusters. Risk of overinvestment and unfair tariffs for NG grid customers only partially addressed by horizontal accounts unbundling.	Provides regulatory framework to ensure fair transition of the methane grid. Exemption procedures foreseen for local hydrogen clusters development if not addressed by exemptions.	EU-level planning guides the efficient transformation of methane infrastructure. EU regulation would be too restrictive for local hydrogen clusters development if not addressed by exemptions.
PW4: Transit-focused H_2 grid	Does not provide EU-level planning framework to justify development of transit pipelines. EU-level security of supply is not considered if major methane transit pipelines are converted. Lack of investment certainty for the large projects.	Provides basic rules for competition and non-discriminatory access. Lacks EU-level planning framework for development of transit pipelines. EU-level security of supply is not considered if major methane transit pipelines are converted. Lack of investment certainty for large projects.	Provides more substantial justification for development of transit pipelines and harmonisation of rules for cross-border trading. EU regulation would be too restrictive for local hydrogen clusters development if not addressed by exemptions.	EU-level TSO might be in better position to develop transit pipelines than national players. EU regulation would be too restrictive for local hydrogen clusters development if not addressed by exemptions.

Table 5-7 Regulatory framework options robustness

Pathway	No immediate action	Light EU regulation	Full EU regulation	Full+ EU regulation
PW1: Full H_2 grid integration	• Regulatory flexibility for MSs to design tailored regulation, enabling liquid domestic markets • Reduces investment certainty and increases transaction costs for network expansion, delaying investments and market integration, creating risk of underinvestment. • EU regulation at later stage will probably lead to ex-post costs • Lack of cross-border cost and capacity allocation mechanism and EU-level planning will make it harder to develop cross-border capacities and integrate markets • Lack of TPA enforcement would limit the access of small actors to the network if not addressed on national level.	• MSs can adopt early regulation complementing the EU framework • EU regulation will have to be adjusted at later stage (due to Hydrogen Strategy ambitions). This poses a risk of ex-post cost of regulatory adjustment; reduces investment certainty and may delay the necessary investment to develop hydrogen markets • Lack of cross-border harmonisation and EU-level planning will make it harder to establish import routes for developed markets with large demand • Horizontal accounts unbundling for CH4 TSOs will reduce their competitive advantage over new network operators	• Unbundling, TPA rules and measures for market integration provide regulatory certainty, facilitating investments in the long-term. • Exemption procedures for certain networks and staged applicability of cross-border-related rules provides flexibility for initial roll-out of networks • Harmonisation of tariffs, cross-border capacity allocation regulation and EU level planning harmonisation fosters cross-border integration of networks and markets and potentially enables creation of import routes to developed hydrogen markets	• Unbundling, TPA rules and measures for market integration provide regulatory certainty, facilitating investments in the long-term. • Exemption procedures for certain networks and staged applicability of cross-border-related rules provides flexibility for initial roll-out of networks • Creation of EU TSO and EU-level network planning facilitates creation of import routes for developed hydrogen markets
PW2: H_2 grid upscaling	• Hydrogen network build-up can be coordinated with electricity sector on national level, but without EU-level planning & coordination the benefits of large-scale system integration will be lost • Regulation of balancing and storage will have to be designed on national level • No need for designing cross-border rules early on if they are not needed • Market oversight to guarantee fair competition across sectors (e.g. electricity and H2 markets) not guaranteed	• Hydrogen network build-up can be coordinated with electricity sector on national level, but without EU-level planning & coordination the benefits of large-scale system integration will be lost • Regulation of balancing will have to be designed on national level • EU-level regulation of storage provides more certainty for the business • No need for designing cross-border rules early on if they are not needed • Basic EU rules regulating "competition for the market" ensure market power abuse will be checked, horizontal accounts unbundling for CH4 TSOs will reduce their competitive advantage • Market oversight to guarantee fair competition across sectors (e.g. electricity and H2 markets) not guaranteed	• Unbundling, TPA rules and measures for market integration provide regulatory certainty, facilitating investments in the long-term. These rules also provide better link to external markets, improving the EU-level system efficiency • Exemption procedures for certain networks and staged applicability of cross-border-related rules provides flexibility for initial focus on domestic system integration • Competition for the market sufficiently regulated on the EU level • EU-level market regulation provides better guarantees for fair competition across sectors	• Unbundling, TPA rules and measures for market integration provide regulatory certainty, facilitating investments in the long-term. These rules also provide better link to external markets, improving the EU-level system efficiency • Focus on EU level (EU TSO) might be detrimental to addressing national needs (integration of renewable electricity) • Competition for market problem solved by creating EU TSO
PW3: H_2 grid downsizing	• Effective planning and revenue regulation not ensured on EU level, thus it might lead to inefficient investment in hydrogen infrastructure	• Efficient network planning not guaranteed at EU level, potentially risking inefficient infrastructure transformation in hydrogen infrastructure (gold plating),	• EU requirements on national planning can ensure the transformation of infrastructure will	• Harmonised EU-level network planning will guide the efficient transformation of infrastructure

Pathway	No immediate action	Light EU regulation	Full EU regulation	Full+ EU regulation
	(gold plating), NG users paying for investments in hydrogen infrastructure in MSs with now incentives to develop proper regulatory framework • Risk of increasing tariffs for remaining CH4 users due to lack of tariff and revenue regulation • Allows flexibility for development of local hydrogen clusters	• Horizontal accounts unbundling (from CH4 infrastructure) ensures better transparency in revenue regulation, thus reduces risk of revenue reallocation from CH4 to H2 infrastructure construction • Risk of increasing tariffs for remaining CH4 users due to lack or tariff and revenue regulation • Allows flexibility for development of local hydrogen clusters	be efficient and will take into account remaining CH4 consumers • EU-level guidelines on reallocation of revenues across sectors and tariffication rules ensure fair prices for CH4 and H2 users • Rules on balancing, organised market platform or establishing entry-exit system might be too restrictive for local hydrogen clusters	and will take into account remaining CH4 consumers • EU-level guidelines on reallocation of revenues across sectors and tariffication rules ensure fair prices for CH4 and H2 users • Rules on balancing, organised market platform or establishing entry-exit system might be too restrictive for local hydrogen clusters
PW4: Transit-focused H_2 grid	• Due to absence of EU level planning and scenarios predicting future demand, sound justification for building the transit pipelines will be missing • (EU-level) security of supply is not considered • Allows long-term contracts to secure revenues for transit pipeline development • Lack of rules on cross-border interactions will be a barrier to development of cross-border transit pipelines • Uncertainty regarding regulatory frameworks and market developments in other MSs can raise the costs of project financing and deter (or delay) necessary investment • Minimal market regulation allows more flexibility for market that is expected to be focused on large consumers, allows flexibility for potential development of hydrogen clusters separately from transit routes	• Due to absence of EU level planning and scenarios predicting future demand, sound justification for building the transit pipelines will be missing • (EU-level) security of supply is not considered • Allows policy support for transit projects • Lack of rules on cross-border interactions will be a barrier to development of inter-state pipelines • Uncertainty regarding regulatory frameworks and market developments in foreign countries can raise the costs of project financing and deter (or delay) necessary investment • Minimal market regulation allows more flexibility for market that is expected to be focused on large consumers, allows flexibility for potential development of hydrogen clusters separately from transit routes	• EU-level demand scenarios will provide justification for transit pipeline development, although lack of common network models for all sectors does not assure efficient investment • Security of supply issues are partly considered • Rules on cross-border capacity allocation might be too strict for the national actors to develop international projects with long-term returns • Rules on balancing, organised market platform or establishing entry-exit system might be too restrictive for local hydrogen clusters developing separately from transit routes	• EU level scenarios and network planning will enable development of transit pipelines and will take into account security of supply considerations • EU-level TSO would be in good position to develop costly transit projects due to its size

Roadmap for implementing the regulatory framework options

To avoid unnecessary regulatory costs where the hydrogen sector is not fully developed yet, and to enable sufficient regulatory flexibility, some elements of the proposed regulatory frameworks can be implemented at a later time, when the market reaches sufficient maturity.

As already elaborated in the section on transitory measures, this would mean that some of the regulatory elements would be defined only in general terms in the adopted legislation, but elaborated further with the help of Hydrogen Target Model. At a later stage, more detailed rules would be formalised with help of Commission implementing regulations or a similar legal instrument. Additionally, some of the exemptions designed to reduce the regulatory burden on developing isolated markets should be phased out with time in order not to incentivise the fragmentation of the networks. An appropriate moment to phase out these MSs derogations could be 2030, in line with the goals of the Hydrogen Strategy (with the possibility for extension depending on the actual development of the hydrogen sector). Similarly, exemptions or waivers for private network operators should be phased by a certain date. The timing of this phase-out is less clear, but it could be dependent on the duration of existing long-term hydrogen purchase agreements.

No immediate action

No immediate action would be taken in the short term up to 2025. However, if the hydrogen sector actually develops enough to play a relevant role in the overall EU energy sector, there will be an increasing need to address at least the interactions between hydrogen and other regulated energy sector activities. An evaluation of the market conditions and the need for a regulatory framework proposal might be needed in the medium-term up to 2030.

Light EU regulation

The main logic behind this option is to set the basic regulation that reduce the risks of discriminatory access to hydrogen networks and of distortion of the internal energy market, but otherwise sector regulation is left to Member States. For this reason, the basic rules on e.g. unbundling or TPA should be defined in the short term. For a similar reason to the "No immediate action" option, an assessment of the market conditions should be carried out e.g. around 2030 to evaluate if a further revision of EU regulatory framework is necessary.

Full EU regulation

Although the main regulatory elements should be defined in EU law as soon as possible to provide the regulatory certainty facilitating the necessary investments in the hydrogen sector, the entry into force of some elements could be delayed. Furthermore, some elements can be defined in more detail through the network codes and guidelines. The final vision for the hydrogen market should be nonetheless defined in the Hydrogen Target Model (HTM). The HTM will help frontrunner MSs to align their regulation with the expected future EU framework, reducing ex-post regulatory costs. In an iterative process, the HTM should be periodically reviewed (setting the adoption of a first HTM in 2025 with an update every five years would be in line with the Hydrogen Strategy milestones).

The main elements applicable immediately should concern unbundling and the role of gas network operators, setting regulated network TPA rules and an entry-exit based system together with rules for grid balancing. The process of creation of the hydrogen ENTSO should also start right away, to finalise a first hydrogen TYNDP by 2025. Based on the gained experience, common cross-sectoral scenarios for network planning could be developed in the 2025-2030 period.

Since it is expected that the hydrogen markets will initially develop in smaller clusters which will be interconnected only gradually, the rules setting up a framework for EU-wide internal market for hydrogen do not have to be introduced in the short term. However, the rules for cross-border capacity allocation should be defined by 2030, when more substantial interconnection can be expected for the MSs following more ambitious pathways (and also to adhere to the Hydrogen Strategy). Further harmonisation of market rules and regulation of organised markets will be necessary by 2030 or only in the long term, when the cross-border trade will reach a more significant volume.

Full+ EU regulation

The implementation timeline of Full+ EU regulation option is in many cases similar to Full EU option. The major challenge for this option is however setting up the EU hydrogen TSO.

On the one hand, it would be beneficial to postpone the creation of such entity to a later phase (towards 2030), in order to give the sector enough time to adjust to this model and to leave enough time to clarify the future role of the EU H2 TSO. However, one of the key competencies of an EU-level TSO would be determinative network planning, leading the planning of the European backbone infrastructure. Postponing (EU-level) network planning process would significantly reduce the potential benefits and probably also delay the necessary investment.

For this reason, the EU TSO should be set up from the start and assume its role in network planning. Due to the expected duration of the legislative process, a first EU-level hydrogen network development plan would anyway be published only around 2025. At a later stage (by 2030 or later, depending on the actual development of the networks) the EU TSO would work on establishing implicit market coupling and establishing an EU-level balancing platform.

Table 5-8 Roadmap for implementation of the regulatory framework options

Pathway	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
Short-term (to 2025)	• No action	• Defining the role of gas TSOs, horizontal unbundling • Defining possible exemptions for private hydrogen networks • Defining the TPA regime possibilities for networks and large-scale storage	• Setting up the Hydrogen Target Model • Defining the role of gas TSOs, horizontal unbundling • Setting up ENTSO-H2, TYNP for hydrogen • Defining the rules for re-allocation of non-remunerated system benefits between sectors • Setting up entry-exit system, rules for balancing, cross-border capacity allocation	• Setting up the Hydrogen Target Model • Defining the role of gas TSOs, horizontal unbundling • Setting up EU H2 TSO, TYNP for hydrogen • Defining the rules for re-allocation of non-remunerated system benefits between sectors • Setting up entry-exit system, rules for balancing, cross-border capacity allocation
Medium-term (to 2030)	• Evaluation of market conditions and potential proposal for regulation of hydrogen networks and markets	• Evaluation of existing market conditions and potential proposal for revision of regulation • End of derogations to isolated markets • End of exemptions for private hydrogen networks	• Defining common cross-carrier scenarios with hydrogen • Cross-border CACM rules • End of derogations to isolated markets • End of exemptions for private hydrogen networks	• Harmonised intra-market area market principles • Harmonised cross-market rules • Cross-border CACM rules • End of derogations to isolated markets • End of exemptions for private hydrogen networks
Long-term (after 2030)			• Harmonised cross-border market rules, mutual recognition of licenses, market area managers	• Setting up spot market coupling and market area managers • Setting up balancing market coupling

Design variants on the horizontal unbundling option for gas network operators

In Table 5-2 and Table 5-3, two variants regarding the horizontal unbundling of hydrogen network operators are presented:

- In the Full+ EU regulatory framework, legal & functional unbundling could be employed as a variant to the main option of accounts unbundling;
- An opposite variant is that any EU regulatory framework option (Light/Full/Full+) does not impose unbundling requirements between the regulatory asset bases for hydrogen and methane gases.

As the impacts of legal & functional or no unbundling requirements are similar in all regulatory framework options, their impact compared to the default option of 'accounts unbundling' according to the relevant criteria is presented in the following table.

Table 5-9 Assessment of variants on the horizontal unbundling option for gas network operators

	Legal+functional	No EU unbundling requirement
Economic impacts	- Could reduce economies of scope, increasing total fixed costs.	- May lead to cross-subsidisation between hydrogen and methane network users. - Revenue regulation and tariff structures may not account for differences in economic and technical characteristics.
Effectiveness	- No change compared to accounts unbundling	- Facilitates repurposing of methane networks by combined gas operators.
Efficiency	- Increases administrative costs due to required transfer of repurposed methane assets. Undue re-evaluation of the residual regulated value of refurbished assets can be avoided by specific provisions in EU (or national) legislation. - Increases oversight costs and transparency of network operator costs.	- Reduces administrative costs for repurposing methane networks. - Increases regulatory costs due to need for closer oversight by regulators and competition authorities to avoid discriminatory practices and abuse of natural monopoly by network operators.
Coherence	- Not coherent with unbundling requirements for electricity and methane network operators.	- Not coherent with unbundling requirements for electricity and methane network operators.
Affected parties	- Increases total fixed costs of combined gas network operators. - Further impacts pre-existing operators if they are not exempted from unbundling requirement by NRA, in Full+ EU option.	- Could negatively affect hydrogen or methane network users in case of cross-subsidisation.

6 KEY FINDINGS AND RECOMMENDATIONS

Prototype pathways for hydrogen gas infrastructure

In view of the development of four generic or prototype pathways for the deployment of renewable and/or low-carbon hydrogen in the EU energy system, the most relevant hydrogen related plans and strategies published by European countries or industries have first been identified and analysed. On the basis of this analysis, it was found that both the Member State specific frameworks as well as strategic goals of relevant actors in industry and politics are multi-facetted. Analysis of potential factors having an impact on the emergence of a dedicated hydrogen infrastructure across Europe covering the full value chain of gas provision, infrastructure and end-use, made clear that the potential development paths will be quite different across EU Member States, depending on their ambitions and their potential for renewable energy, their existing methane gas infrastructure, and the specific characteristics of their energy system and end-uses.

The four generic pathways suggested therefore comprise (in parenthesis: starting from):

- **Pathway 1. Full hydrogen grid integration**
  (Large RES potential, well-established gas grid)
- **Pathway 2: Hydrogen grid upscaling**
  (Large RES potential, modestly-established gas grid)
- **Pathway 3: Hydrogen grid downsizing**
  (Small RES potential, modestly-established gas grid)
- **Pathway 4: Transit-focused hydrogen grid**
  (Small RES potential, modestly-established gas grid)

The exercise to identify and analyse potential generic development pathways clearly results in the learning that an EU-wide harmonised regulatory approach would enable EU Member States to benefit from higher techno-economic benefits (economies of scale) and infrastructural synergies (cross-border hydrogen exchange) and hence from improved efficiencies and significant cost reductions, compared to a scenario with uncoordinated and hence possibly diverging national regulatory approaches.

Non-exhaustive arguments for an EU hydrogen regulatory framework are:

- **Hydrogen production base:** Member States with significant renewable electricity generation potential could aim to substitute their natural gas use by renewable electricity-based hydrogen and even become net exporters, and consequently have an interest in repurposing their methane networks which would otherwise be decommissioned. This could help to efficiently facilitate the upscaling of hydrogen as an energy carrier in Member States with hydrogen-intensive energy strategies, which would in turn contribute to fulfil some of EC's most important energy and climate policy goals (climate change mitigation, reducing energy import dependency and improve energy efficiency).
- **Hydrogen quality definition:** An EU-wide hydrogen quality harmonisation may facilitate the development of hydrogen end-use equipment and appliances at larger production scales as well as foster the integration of the EU hydrogen market, helping to align national hydrogen pathways.
- **Hydrogen-blending level:** Shared learning as well as an exchange on and testing of concepts will foster a rapid EU-wide implementation of blending hydrogen into the natural gas grid, which is an adequate option to facilitate the deployment of hydrogen. Several EU Member States are already taking initiatives to this end. As far as observed, all concerned grid operators have indicated their willingness for cooperation and EU-wide harmonisation.
- **Conversion of existing methane networks to hydrogen or new-build:** Early analysis has shown that the conversion of existing methane infrastructure to hydrogen operation is significantly cheaper than new-build hydrogen pipelines. Common material standards and operating routines will support conversion activities across the EU. If deemed necessary, this will also help to develop well-defined interfaces to import renewable or low-carbon hydrogen through pipelines from outside of Europe.
- **Today's hydrogen gas pipeline business:** An early European regulatory framework could consider the long-term supply contracts and network assets of existing private hydrogen operators and, at the same time, build on the existing infrastructure to develop the wider energy system use of hydrogen in a stepwise manner.

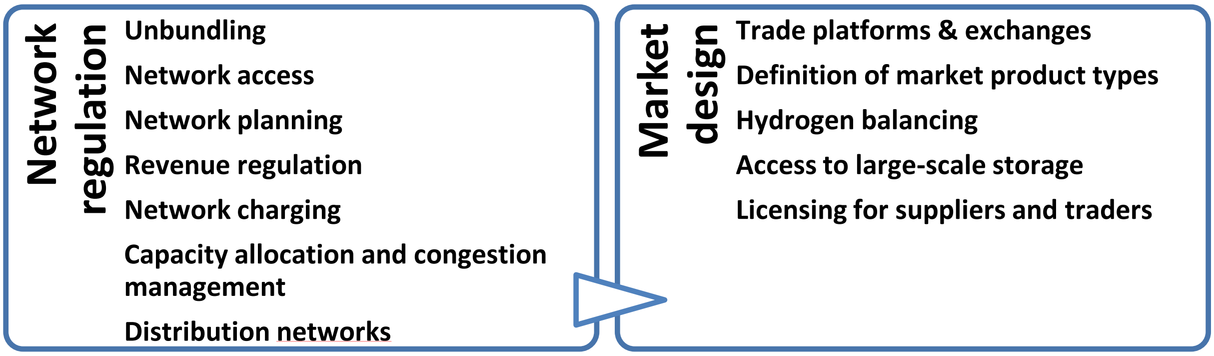
Pipelines as a natural monopoly?

Chapter 2 analyses whether and to what extent dedicated hydrogen networks give rise to a natural monopoly justifying regulatory intervention. Although the hydrogen market development is in very early stages, there are strong indications that hydrogen transmission and distribution networks may constitute a natural monopoly in mature hydrogen markets, where hydrogen becomes or is close to becoming a traded commodity. This would coincide with phase 2 (2025-2030), and more broadly phase 3 (2030 towards 2050) defined in the European Commission's Hydrogen Strategy. Also, in emerging markets, there is a relevant probability of natural monopolies to occur due to the sub-additive investment cost curves of pipelines, and the fact that repurposing methane pipelines to hydrogen will be less expensive than new-build and will hence provide a competitive advantage to the concerned owners/operators.

The views of stakeholders diverge on the exact circumstances and the adequate timing for regulatory intervention with some stakeholders supporting rather early regulatory intervention, while others prefer late actions. A view voiced rather widely is to apply market tests, and to actively develop regulatory approaches step by step. Starting early with thorough tests and validations accompanied by scientific evaluation support is a robust no-regret approach before implementing any regulation.

Regulatory elements for dedicated hydrogen networks and markets

Chapters 3 and 4 develop a number of options for the different network regulation and market design elements shown in the figure below. The options developed for each regulatory element are either based on the EU natural gas regulatory framework or are developed as a 'greenfield' approach. While an analysis per regulatory element facilitates the development of the options, any EU regulatory framework for hydrogen must be developed and assessed holistically, given the interdependencies between the different regulatory elements. This global analysis is extensively presented in chapter 5 of this study.



Development and assessment of EU hydrogen regulatory framework options

Hydrogen is poised to play an important role in the EU energy transition, as indicated by the EU Hydrogen Strategy, the impact assessment for the 2030 Climate Target Plan, and the Long-term Strategy.

To facilitate the large-scale development of the hydrogen sector according to the pathways identified in chapter 1, adequate policies will be necessary to enable the deployment of hydrogen production, trade, supply, transmission/distribution, storage, as well as of end-use equipment and appliances at the pace required for the energy transition. Given the current absence of economic regulation of the hydrogen sector at the EU and Member State level, this study contributes to determining the appropriate level of EU regulation to facilitate the optimal development of hydrogen infrastructure and markets.

The analysis of chapter 2 indicates that several factors may justify some level of hydrogen sector regulation, including the sub-additive investment costs of hydrogen network assets leading to the need to ensure non-discriminatory third party access to networks (and to large-scale storage), the societal benefits of integrated network planning, and the potential cost savings resulting from repurposing methane infrastructure to hydrogen compared to new-build.

Both regulated and market actors of the EU energy sector highlighted the need for regulatory certainty at both the EU and national levels. EU regulatory action for hydrogen can be based on article 194 of the Treaty on the Functioning of the EU (TFEU), which is also the basis for the EU regulatory framework for electricity and natural gas.

By providing a level playing field for all market participants and technologies across the EU, adequate EU action can provide regulatory certainty, promote integrated network planning and operation of the energy system, facilitate the integration of the future hydrogen market, and minimise the risks of distortion to the overall EU internal energy market. EU action should employ the best practices and lessons learned from the experience in the natural gas and electricity sectors, and also leverage existing EU-level organisations and institutions where appropriate.

The design of a new EU regulatory framework for hydrogen needs to be robust (i.e. perform adequately in any foreseeable transition pathway) and properly take into account the high uncertainty level at this stage, the overall incipient stage of development of hydrogen infrastructure and markets, and the different development speeds across end-use sectors and Member States. Moreover, any hydrogen regulation should be aligned with other developments in energy regulation, particularly regarding the promotion of electricity and gas systems integration, the use of incentive-based network regulation, and the simultaneous provision of regulatory stability and flexibility.

The EU regulatory framework for natural gas has been introduced when the EU gas sector had already developed for several decades, which constrained regulatory options. The future hydrogen sector regulation is comparatively less constrained and must take a number of specific points into account. Repurposing methane infrastructure to hydrogen will facilitate the development of large segments of the future hydrogen networks, which will in particular support hydrogen-intensive scenarios. Hence, there is a significant potential role for methane network operators, but also for existing private hydrogen operators given their relevant assets and expertise. Moreover, trading hydrogen via organised market platforms and exchanges for methane gases can accelerate the development of a well-functioning, liquid hydrogen market. Finally, existing long-term supply contracts and network assets of private hydrogen network operators should properly be considered when implementing a regulatory framework.

The EU regulatory framework options assessed in this study and summarised in the table below range from a *de minimis* intervention to avoid distortions of the internal energy market (the 'EU light' option), to a regulatory framework similar to that for natural gas (the 'Full EU' option), and finally an ambitious regulatory framework further advancing the integration of the internal energy market (the 'Full+ EU' option). Competition *for-the-market* (i.e. tendering hydrogen network concessions) could be used to introduce a competitive element and complement the regulation of hydrogen networks.

There is still strong uncertainty regarding the energy transition pathways, but given the ambitious EU climate and energy targets, competition and energy sector-specific regulation at EU level should accommodate pathways where renewable and low-carbon hydrogen play an increasing role, while also respecting the right of Member States to pursue other decarbonisation pathways.

The Full/Full+ EU options provide, from the start, an adequate regulatory framework for the timely development of an internal hydrogen market, supported by dedicated infrastructure accessible to all network users and coordinated with the electricity, methane, and heat sectors. These options also provide sufficient flexibility through transitional rules and a Hydrogen Target Model for the development of local hydrogen clusters or valleys and allow Member States to develop economies of scale and of scope with the methane sector, while also ensuring a level-playing field and respecting existing long-term hydrogen supply contracts and network assets. By being compatible with the long-term policy targets and providing flexibility to Member States, they minimise the ex-post regulatory costs and provide regulatory certainty.

By fostering integrated network planning and market coupling especially, the Full+ EU regulation would provide an improved level playing field for hydrogen market participants across Europe. However, harnessing the full benefits of the option implies addressing existing differences in the regulatory provisions and structure of the electricity and methane sectors.

Chapter 5 provides a detailed assessment of the options, including the robustness to the pathways and a roadmap for implementation. Whichever regulatory approach is ultimately opted for, a number of key principles should be respected to enable the hydrogen sector to efficiently contribute to reaching the major EU and national energy and climate objectives:

- Non-discriminatory third-party access to hydrogen networks (and large-scale storage) should be guaranteed for all market operators, with only limited and duly justified exemptions;
- Network planning should be integrated across market areas, energy carriers, and network levels, with strong EU and national regulatory oversight and public consultation. It should also be aligned to policy objectives. The risk for stranded assets should be minimised, not only when considering conversion of existing methane infrastructure to hydrogen, but also when considering new investment in fossil gas or fossil-based hydrogen infrastructure. Given the EU decarbonisation targets and the pathways uncertainty, it is necessary to carefully assess the needs for fossil gas-based infrastructure and to apply adequate sustainability requirements to new energy infrastructure investments;
- Member States should be allowed to realise efficiency gains and economies of scope through combined natural gas and hydrogen network operators. But this should not compromise transparency and cost-reflectiveness of grid tariffs;

- The regulatory framework should provide flexibility through transitional measures such as exemption procedures to isolated hydrogen clusters. A Hydrogen Target Model could be defined in order to guide Member States in developing regulation which is aligned with the EU framework and does not hamper the later interconnection of their hydrogen system.

ANNEX A DETAILED ASSESSMENT OF REGULATORY FRAMEWORK OPTIONS

Economic impacts	No immediate EU action (BAU)	Light EU regulation	Full EU regulation	Full+ EU regulation
1. Energy system costs savings compared to a system without EU regulation	• System cost savings of PW1/PW2 (related to economies of scale, sector coupling and hydrogen market integration) difficult to achieve without any EU regulatory framework. Hydrogen development restricted to certain MSs / slowed due to increased reliance on MSs for regulatory certainty, lack of EU measures for cross-border interconnection and hydrogen market integration. • Cost savings resulting from sub-additivity might not be fully realised / occur later, as planning will be predominantly national and cross-border hydrogen network interconnection is hence expected to be very limited. • Limited cross-border market integration leads to less efficient use of hydrogen system and renewable energy resources.	• Cost savings resulting from systems integration potentially not fully realised as there is no EU obligation for integrated planning. However, savings may be achieved at national level for (frontrunner) MSs with combined gas network operators. • Cost savings resulting from sub-additivity might not be fully realised / occur later, as EU hydrogen network development is expected to be mainly national, without strong interconnection. • Limited cross-border market integration leads to less efficient use of hydrogen system and renewable energy resources.	• Cost savings resulting from systems integration realised to a large extent (but less than in the Full+ option), thanks to EU-wide planning coordination with other carriers, coherent regulated approach to energy infrastructures. • Cost savings realised on national level, resulting from common planning scenarios and CBA methodology but in the absence of integrated energy systems modelling investments might not be realised in the most efficient way possible. • Harmonised market rules enable better competition in markets. Common network scenarios and CBA methodology indicate the future demand for energy carriers and flexibility, guiding investment in flexibility resources and renewables.	• Cost savings resulting from systems integration realised to a large extent thanks to integrated planning, coherent regulated approach to energy infrastructures. • Cost savings related to infrastructure investment realised to a large extent, as EU hydrogen network develops according to policy objectives and with integrated EU-wide planning. • Efficient use of hydrogen system and renewable energy resources, and decreased risks for distortion of the internal energy market thanks to integrated EU-wide planning, market integration (including coupling of wholesale and balancing markets) and establishment of organised trading platforms with appropriate market products.
2. Security of hydrogen supply	• SoS guaranteed for existing networks with long-term contracts. For other actors, the potential lack of organised trading platforms to hedge their short and long term risks, and the lack of negotiated and/or regulated TPA to network (and storage) infrastructure might lead to low security of hydrogen supply at affordable prices. • As TPA is not imposed by EU law, converted methane infrastructure could, in the absence of adequate national law, become 'closed' hydrogen pipelines, potentially excluding new network users and reducing security of hydrogen supply.	• SoS guaranteed for existing networks with long-term contracts. For other actors, the potential lack of organised trading platforms to hedge their short and long term risks, and the lack of negotiated and/or regulated TPA to network (and storage) infrastructure might lead to low security of hydrogen supply at affordable prices. • As rTPA is not imposed by EU Law, converted methane infrastructure under rTPA could, in the absence of adequate national law, become hydrogen pipelines under nTPA, potentially excluding new network users and reducing security of hydrogen supply.	• Market integration, liquidity measures and networks rTPA increases H_2 SoS, including to small network users, by reducing dependence on single or limited number of supply sources. • rTPA for hydrogen networks assures non-discriminatory access for all network users.	• Market integration, liquidity measures, integrated EU-wide planning and networks rTPA increases H_2 SoS, including to small network users, by reducing dependence on single or limited number of supply sources. • rTPA for hydrogen networks assures non-discriminatory access for all network users.

Economic impacts	No immediate EU action (BAU)	Light EU regulation	Full EU regulation	Full+ EU regulation
3. Network tariffs level	• Does not ensure that network tariffs are cost-reflective and non-discriminatory, and set with transparent and objective criteria. Inefficient investments may increase tariff levels. • Without EU wide harmonised network revenue regulation and tariff structure principles, national approaches regarding connection cost allocation or volume/capacity tariff components might unduly burden certain network users, such as first movers or users with a low network utilisation. • Lack of EU-wide horizontal unbundling requirements for new hydrogen / combined gas network operators may in some MSs lead to cross-subsidisation between hydrogen and methane network users.	• Does not ensure that network tariffs are cost-reflective and non-discriminatory, and set with transparent and objective criteria. • Without EU wide harmonised network revenue regulation and tariff structure principles, elements like connection cost allocation or inadequate volume/capacity tariff components might unduly burden certain network users, such as first movers or users with a low network utilisation. • Lack of integrated EU-wide planning processes can lead to inefficient investments and higher tariff levels.	• Energy system cost savings lead to lower overall tariff levels to energy consumers. • Requirements ensure that network tariffs are cost-reflective and non-discriminatory, and set with transparent and objective criteria. • Harmonised revenue regulation and tariff structure principles addressing elements such as connection cost allocation increase tariff cost-reflectivity and decrease cross-border distortions.	• Energy system cost savings lead to lower overall tariff levels to energy consumers. • Requirements ensure that network tariffs are cost-reflective and non-discriminatory, and set with transparent and objective criteria • Wholesale and balancing markets coupling eliminate effects of tariff pancaking and foster cross-border trade, with inter-TSO compensation allocating costs first to areas and subsequently to network users in each area. • Harmonised revenue regulation and tariff structure principles addressing elements such as connection cost allocation increase tariff cost-reflectivity and decrease cross-border distortions
4. End-user adaptation costs	• Some network users might be forced to convert equipment and appliances for hydrogen, but the lack of harmonised rules for markets' integration and XB trade negatively affects competitiveness of hydrogen supply. • The potentially slower uptake of hydrogen markets enables more time for converting/replacing equipment and appliances, but might be outweighed by lack of economies of scale and EU-wide standardisation, and lower competition in hydrogen supply.	• Some network users might be forced to convert equipment and appliances for hydrogen, but the lack of harmonised rules for markets' integration and XB trade negatively affects competitiveness of hydrogen supply. • The potentially slower uptake of hydrogen markets enables more time for converting/replacing equipment and appliances, but might be outweighed by lack of economies of scale and EU-wide standardisation, and lower competition in hydrogen supply.	• Some end-users might be enforced to convert equipment / appliances. Coordination of hydrogen networks roll-out with policy objectives should allow for staged conversion of equipment and appliances with assistance from the regulated network operators.	• Some network users might be enforced to convert equipment / appliances. Coordination of hydrogen networks roll-out with policy objectives should allow for staged conversion of equipment and appliances with assistance from the regulated network operators.

Technical impacts	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
5. Allows interoperability of interconnected hydrogen systems / deployment of hydrogen end-use equipment/appliances	• Lack of EU harmonised gas quality standards and interoperability network code at EU level may hamper interconnection of hydrogen networks and the conversion of end-user equipment/appliances.	• Lack of EU harmonised gas quality standards and interoperability network code at EU level may hamper interconnection of hydrogen networks and the conversion of end-user equipment/appliances.	• Gas quality standards and interoperability network code enable interconnection of hydrogen networks and the conversion of end-user equipment/appliances. Common scenarios indicate where future interactions with electricity and methane systems will be needed. However, this is arguably already done by common electricity & methane scenarios which indicate the potential future infrastructure bottlenecks.	• Gas quality standards and interoperability network code (out of scope of this assessment) enable interconnection of hydrogen networks and the conversion of end-user equipment/appliances. Common scenarios and modelling provide clear signals on capacity and bottlenecks of electricity, methane and hydrogen systems.
6. Supports system flexibility / renewable electricity	• May limit the efficient use of renewable energy sources for electricity and supply of flexibility to the energy system, due to the lack of requirements on integrated EU-wide planning (both cross-border and cross-energy carriers), slower establishment of organised trading platforms with appropriate market products, and low level of internal hydrogen market integration.	• May limit the efficient use of renewable energy sources for electricity and supply of flexibility to the energy system, due to the lack of requirements on integrated EU-wide planning (both cross-border and cross-energy carriers) and slower establishment of organised trading platforms with appropriate market products.	• Efficient use of hydrogen system and renewable energy resources (though lower than in Full+), and decreased risks for distortion of the internal energy market due to coordinated EU-wide planning, market integration and establishment of organised trading platforms with appropriate market products.	• Efficient use of hydrogen system and renewable energy resources, and decreased risks for distortion of the internal energy market due to integrated EU-wide planning, market integration (including coupling of wholesale and balancing markets) and establishment of organised trading platforms with appropriate market products.
7. Allows repurposing of methane infrastructure when efficient: See 17.				

Effectiveness	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
8. Accommodation of various pathways	*** A full assessment of the suitability of regulatory options to accommodate national pathways is presented in the Table 5-7.**			
	• Regulatory flexibility to MSs early on. Frontrunners MSs (PW1) can adopt early regulatory framework, laggards (PW4) can delay / not implement sector-specific regulation. • Integrated hydrogen market by 2030 of Hydrogen Strategy / PW1 MSs unlikely, given missing measures, and risk perception due to lack of regulatory certainty. Significant entry barriers for new (smaller) market participants due to potential absence of TPA requirements, non-transparent price formation. • Lack of integrated planning may lead to inefficient decommissioning of methane infrastructure in PW3. • Long-term supply/transport contracts may assure demand for (some) hydrogen networks. But does not guarantee investments are aligned to national and EU energy plans, due to lack of EU regulation on integrated planning.	• Limited EU regulation gives regulatory flexibility to MSs early on. Frontrunners MSs (PW1) can adopt early regulation complementing the EU framework, laggards (PW4) can delay / not implement sector-specific regulation • Integrated H_2 market by 2030 of Hydrogen Strategy / for PW1 MSs unlikely given missing measures, and risk perception due to potential necessity to update the framework later on to match EU policy objectives in hydrogen-intensive pathways (PW1/PW2). • Lack of integrated planning may lead to inefficient decommissioning of methane infrastructure in PW3. • National flexibility to choose for nTPA may facilitate long-term hydrogen purchase and transport contracts, thus enabling development of transit pipelines in PW 4.	• Unbundling, TPA rules and measures for market integration provide regulatory certainty for hydrogen-intensive pathways (PW1 / PW2 / Hydrogen Strategy), facilitating investments in the long-term. • Cooperative EU-wide planning facilitates efficient decommissioning of methane infrastructure in PW3. • Exemption procedures for certain networks and staged applicability of cross-border-related rules provides flexibility for initial roll-out in PW1/PW2 • rTPA and CACM rules offer better investment certainty for transit countries (PW4), but measures are needed to facilitate long-term hydrogen purchase / transport capacity contracts, otherwise can have negative impact on investments. • Increased market liquidity and rTPA may increase market size, potentially lowering H_2 prices and facilitating pathways.	• Integrated EU-wide planning, unbundling, TPA rules and measures for market integration (including market coupling) provide regulatory certainty for hydrogen-intensive pathways (PW1 / PW2 / Hydrogen Strategy), facilitating investments in the long-term. • Integrated planning facilitates efficient decommissioning of methane infrastructure in PW3. • Integrated planning provides additional investment certainty for transit pipelines construction (PW4). • Exemption procedures for certain new networks and staged applicability of cross-border-related rules provides flexibility for initial roll-out in PW1/PW2 • rTPA and CACM rules offer better investment certainty for transit countries (PW4), but measures needed to facilitate long-term hydrogen purchase / transport capacity contracts, can otherwise have negative impact on investments • Increased market liquidity and rTPA may increase market size, potentially lowering H_2 prices and facilitating pathways.
9. Planning and use of hydrogen cross-border infrastructure	• Absence of an EU-wide framework for integrated network planning and differences in TPA requirements may lead to a suboptimal outcome, as voluntary cooperation of Member States may be less efficient. • Higher risk perception by investors due to lack of certainty regarding national	• Absence of an EU-wide framework for integrated network planning and differences in TPA requirements may lead to a suboptimal outcome, as voluntary cooperation of Member States may be less efficient. • Higher risk perception by investors due to lack of certainty regarding	• Establishes hydrogen networks as a regulated activity, defines EU-wide planning process for developing networks and repurposing methane networks.	• Establishes hydrogen networks as a regulated activity, defines EU-wide planning process for developing networks and repurposing methane networks. • Establishment of wholesale and balancing markets coupling, cross-border CACM and organised exchanges

Effectiveness	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
	regulatory framework and differences in strong hydrogen growth pathways (PW1) result in higher investment costs and potentially under-development of the hydrogen backbone.	national regulatory framework and differences in strong hydrogen growth pathways (PW1) result in higher investment costs and potentially under-development of the hydrogen backbone.	• Lack of common EU-wide planning models risks sub-optimal planning from systems integration perspective. • Establishment of harmonised market rules, cross-border CACM and organised exchanges accelerates the development of well-functioning liquid markets and facilitates cross-border investments.	accelerates the development of well-functioning liquid markets and facilitates cross-border investments.
10. Consumption by transport and large-scale industry	• Allows MSs to tailor framework for early hydrogen applications in industry and transport. Access of producers/suppliers to smaller transport users (especially FCEV refuelling stations) will depend on national regulation. • MSs could allow vertically integrated hydrogen producers to supply directly industrial users and hydrogen refuelling stations without the need for exemption procedures. • Private H_2 networks can stay under current regulatory framework.	• Allows MSs to tailor framework for early hydrogen applications in industry and transport, while TPA requirements can facilitate access to smaller transport users. • MSs could allow vertically integrated hydrogen producers to supply directly industrial users and hydrogen refuelling stations without the need for exemption procedures. • Private hydrogen networks can stay under current regulatory framework.	• Unbundling, rTPA should facilitate cross-border network development, access to smaller transport users. New large and small hydrogen consumers would have to rely especially on regulated network operators. • Private hydrogen networks can stay under current regulatory framework if exempted by NRA, suitable for long-term hydrogen supply contracts.	• Unbundling, rTPA should facilitate cross-border network development, access to smaller transport users. New large and small hydrogen consumers would have to rely especially on regulated network operators. • Private hydrogen networks can stay under current regulatory framework if exempted by NRA, suitable for long-term hydrogen supply contracts.

Effectiveness	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
11. Providing large-scale storage	• Lack of EU provisions may delay investments until MS define adequate regulatory framework, including particular incentives for development of storage. • Allows different national regulatory framework (e.g. ownership of storage facilities), depending on national specificities, including market situation and technical potential. • Risk of non-harmonised approaches between MS, possibly leading to less efficient use of the capacities, and also uneven possibilities of market participants across MSs to access storage services. • Potential distortions between rTPA and nTPA storage assets, and abuse of market power by large-scale storage under an nTPA regime or in the absence of TPA requirements.	• Sets a basic rTPA/nTPA framework for large-scale storage, although it does not offers particular incentives for development of storage. • Allows differentiation depending on market situation and technical potential. • Risk of non-harmonised approaches between MS and of non-coordinated use of underground storage capacities. • Potential distortions between rTPA and nTPA storage assets, and abuse of market power by large-scale storage under an nTPA regime.	• Sets a basic rTPA/nTPA framework for large-scale storage, although it does not offers particular incentives for development of storage. • Allows differentiation depending on market situation and technical potential. • Risk of non-harmonised approaches between MS and of non-coordinated use of underground storage capacities. • Potential distortions between rTPA and nTPA storage assets, and abuse of market power by large-scale storage under an nTPA regime.	• rTPA for large-scale storage guarantees non-discriminatory access to large-scale storage, important especially if there is a limited number of suitable sites. • Reduces competition distortion between large-scale storages. • Operators of methane storage under a nTPA regime may be interested or not to repurpose facilities with a rTPA regime, depending on hydrogen and methane market conditions for storage. • rTPA regime can lower cost of capital for repurposing methane storage sites.
12. Development of local hydrogen clusters	• Allows MSs to tailor framework for early hydrogen clusters, but access of smaller transport network users will depend on national regulation.	• Sufficient regulatory space for development of isolated local hydrogen clusters is provided, due to limited / no rules on unbundling, network planning, and wholesale and balancing markets.	• Requirement for rTPA facilitates development of clusters serving not only industry and transport but also small-scale hydrogen producers and consumers. • Exemption procedures for certain new networks and staged applicability of cross-border-related rules provides flexibility for hydrogen clusters as well as long-term visibility on HTM.	• Requirement for rTPA facilitates development of clusters serving not only industry and transport but also small-scale hydrogen producers and consumers. • Exemption procedures for certain new networks and staged applicability of cross-border-related rules provides flexibility for hydrogen clusters as well as long-term visibility on HTM.

Efficiency	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
13. Delivering a level playing field and competitive market, addressing potential abuse of market power (see also 18.)	• Lack of integrated planning and measures such as harmonised market rules and products, CACM and network charging may lead to barriers to market entry and integration. • Does not preclude development of national markets, and voluntary harmonisation and market integration is still possible. Liquid hubs for hydrogen likely to remain restricted to a few regions/countries and with limited coupling of markets. • The lack of harmonised market rules can lead to opaque price formation / barriers to foreign participants. Information asymmetry can lead to competitive advantages against market participants on methane and electricity markets. • Significant entry barriers for new (smaller) market participants due to potential lack of TPA or hydrogen sector planning requirements, non-transparent price formation, unless national regulatory framework addresses these aspects. • New network operators may be disadvantaged vis-a-vis incumbent methane network operators as planning is a function of the latter • Competition regulation could address eventual market power abuses, but at significant delay and with burden of proof to regulators.	• Lack of integrated planning and measures such as harmonised market rules and products may lead to barriers to market entry and integration. • Does not preclude development of national markets, and voluntary harmonisation and market integration is still possible. But liquid hubs for hydrogen may develop only in a few regions/countries and with limited coupling of markets. • The lack of harmonised market rules can lead to opaque price formation in the hydrogen market / barriers to foreign participants. Information asymmetry can lead to competitive advantages against market players on the natural gas and electricity markets. • Significant entry barriers for new (smaller) market participants due to potential absence of rTPA or hydrogen sector planning requirements, non-transparent price formation unless national regulatory framework addresses these aspects. • New network operators may be disadvantaged vis-a-vis incumbent methane network operators as planning is a function of the latter. • Competition regulation could address eventual market power abuses, but at significant delay and with burden of proof to regulators.	• Provides non-discriminatory access to all hydrogen network users. Measures for market integration, coordinated EU-wide planning aligned to policy objectives and fostering cross-border infrastructure, and non-discriminatory access for users support the development of hydrogen infrastructure and markets in MSs and regions with hydrogen-intensive pathways. • Due to lack of market coupling, more significant price differentials might occur initially. • Harmonised market rules reduce the information disparity between actors. • Competition regulation can still be applied to complement and reinforce sector-specific regulation.	• Provides non-discriminatory access to all hydrogen network users. Measures for market integration (including market coupling), integrated EU-wide planning aligned to policy objectives and fostering cross-border infrastructure, and non-discriminatory access for users support the development of hydrogen infrastructure and markets in MSs and regions with hydrogen-intensive pathways. • Competition regulation can still be applied to complement and reinforce sector-specific regulation. • Increasingly integrated EU hydrogen markets with separate prices for hydrogen and methane gases allows hydrogen to be employed where most valued. • Harmonised market rules reduce the information disparity between actors.

Efficiency	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
14. Lowers the overall regulatory costs	• Regulatory costs depend on national legislation (no EU legislation which needs to be implemented/ transposed). • Uncertainty about potential future regulation of the sector can lead to posterior regulatory costs after 2030 (also to harmonise national frameworks). • Low initial cost for MSs with limited interest in hydrogen, but when an EU-wide market will develop, these MSs may need to develop adequate national regulation and/or adapt their initial regulation to properly address cross-border issues (and then incur ex-post regulatory costs).	• Low regulatory costs for transposing/implementing EU legislation. Further design of regulatory frameworks on national level leads to additional regulatory costs. If liquid European market for hydrogen is to materialise as envisaged in hydrogen strategy, additional rules will have to be developed, leading to further regulatory costs. • Low initial cost for MSs with low interest in hydrogen but as EU-wide market develops under PW1 these MSs may also need to develop regulation.	• Additional costs for planning, setting-up and operating the ENTSO-H_2 and platforms for balancing, CACM. • Regulatory authorities have more tasks, requiring resources. • Stricter oversight might pose disproportionately higher burden on smaller market participants. • Low initial cost for MSs without interest if EU provisions with a cross-border impact are waivered until their hydrogen systems are interconnected. • Network planning process requires additional costs that will be transferred to network users, but can be counterbalanced by the systemic benefits. • Harmonising market rules/licenses might be a potentially unnecessary burden for markets/clusters that are not interconnected (this could be covered by derogations or other transitional measures).	• Clear definition of competitive and regulated activities, Hydrogen Target Model and harmonisation of regulatory elements minimises ex-post regulatory costs. • Additional costs for planning, setting up the EU H_2 TSO, wholesale and balancing market coupling, CACM platforms. • Regulatory authorities have more tasks, requiring resources. • • Stricter oversight might pose disproportionately higher burden on smaller market participants. • Low initial cost for MSs without interest if EU provisions with a cross-border impact are waivered until their hydrogen systems are interconnected.
15. Enables efficient planning across energy carriers, levels and areas	• Limited integrated planning due to lack of EU-level processes and harmonised requirements for MS. Cross-sectoral planning can take place on national level or voluntarily in certain regions, but this is more efficiently done on a wider scale given electricity and methane sectors are already highly integrated. • There is no required assessment on costs and benefits of using private infrastructure to integrate regulated hydrogen networks.	• Limited integrated planning due to lack of EU-level processes and harmonised requirements for MS. Cross-sectoral planning can take place on national level or voluntarily in certain regions, but this is more efficiently done on a wider scale given electricity and methane sectors are already highly integrated. • There is no required assessment on costs and benefits of using private infrastructure to integrate regulated hydrogen networks.	• Efficient EU-wide planning of cross-border network. Possible interactions between energy systems not explored to a full extent. • Planning process assesses benefits of integrating private networks in hydrogen system	• Integrated EU-wide planning takes place with EU H2 TSO and harmonised requirements for MS planning are in place. • Planning process assesses benefits of integrating private networks in hydrogen system

Efficiency	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
16. Efficient consideration of existing infrastructure	• Pre-existing infrastructure operators can maintain business model.	• Possible exemption procedures allow pre-existing infrastructure operators to maintain business model, if authorised.	• Possible exemption procedures allow pre-existing infrastructure operators to maintain business model, if authorised.	• Possible exemption procedures allow pre-existing infrastructure operators to maintain business model, if authorised.
17. Investment efficiency, use of currently existing hydrogen and methane infrastructure, and reduced risk of investment in stranded assets	• Inefficient repurposing from EU perspective likely, as decision may not optimise the planning from a multinational and multi-vector perspective. Regulatory regimes for methane and hydrogen may differ, complicating the repurposing. • Long-term supply/transport contracts under nTPA or from vertically integrated undertakings may assure sufficient interest exists in transport capacity for the entire lifetime of (some) hydrogen infrastructure assets. However, it does not guarantee investments are aligned to national and EU energy plans, due to lack of EU regulation on integrated planning and oversight.	• Potentially leads to inefficient repurposing from EU perspective, as the decision on infrastructure repurposing depends on national regulation only and there are no EU requirements for integrated or coordinated planning. • Long-term contracts under nTPA may assure sufficient interest exists in transport capacity. However, it does not guarantee investments are aligned to national and EU energy plans. • Possibility for re-allocation of non-internalised system benefits might enable to hedge some of the risks related to early hydrogen network development and decommissioning/ repurposing of methane networks.	• Efficient repurposing from EU perspective, given coordinated but not fully integrated planning aligned with policy objectives, oversight by policy makers and regulators, possibility of combined network operators, and accounts unbundling of methane and hydrogen network operators. • Alternatives to network expansion may be overlooked if not assessed in the coordinated planning. • Possibility for re-allocation of non-internalised system benefits might enable to hedge some of the risks related to early stage of hydrogen network development and decommissioning/ repurposing of methane networks.	• Efficient repurposing from EU perspective, given integrated planning aligned with policy objectives, oversight by policy makers and regulators, possibility of combined network operators and accounts unbundling of methane and hydrogen network operators. • Possibility for re-allocation of non-internalised system benefits might enable to hedge some of the risks related to early stage of hydrogen network development and decommissioning/ repurposing of methane networks.

Efficiency	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
18. Incentives for regulated / market operators to deploy innovative technologies and market products	• Can lead to innovative network regulation or business models. However, in the short-term, offering clarity and certainty regarding network capacity availability and access rules is more likely to kick-start innovation in H2 production and end-use. • Incentives to employ innovative solutions for hydrogen infrastructure and for planning process to consider alternatives to network expansion depend on national regulation. • Market operators may set up organised market platforms and exchanges, developing innovative market products. • Market participants may develop hydrogen networks without need for authorisation/exemption from NRAs if hydrogen networks operation is deemed a competitive activity by MSs. However, investments are likely delayed until MSs define this.	• Can lead to innovative regulation or business models. However, in the short-term, investment certainty is more likely to kick-start the hydrogen sector than innovative market products. • Incentives to employ innovative solutions for hydrogen infrastructure and for planning process to consider alternatives to network expansion depend on national regulation. • Market operators may set up organised market platforms and exchanges, developing innovative market products. • NRAs may exempt hydrogen networks from unbundling, regulated TPA and tariffs, incentivising innovative business models. Non-regulated network operators may face increased capital cost due to higher risks.	• Less room for innovative regulation or business models, but Member States are still free to provide incentives for innovation to regulated network operators. • Entry/exit system is more flexible, enabling shorter-term trading (especially for smaller market participants) and exploring possibilities in interactions with other energy markets. • Harmonising market rules/licenses might be a potentially unnecessary burden for markets/clusters that are not interconnected (this could be covered by derogations for non-interconnected systems or other transitional measures).	• Less room for innovative regulation or business models, but Member States are still free to provide incentives for innovation to regulated network operators. • Market area managers and harmonised markets rules limit the space for products innovation. Regulatory sandboxes and the network code development and amendment process can potentially provide room for innovation in market design. • Entry/exit system is more flexible, enabling shorter-term trading (especially for smaller market participants) and exploring possibilities in interactions with other energy markets. • NRAs may exempt hydrogen networks from unbundling, regulated TPA and tariffs, incentivising innovative business models. Non-regulated network operators may face increased capital cost.

Coherence	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
19. With electricity, methane (and heat) sectors regulatory framework	• Not coherent with EU regulatory framework for electricity and methane. • Lack of harmonised hydrogen market rules and alignment with other energy sectors regulation can lead to competition distortion and to inefficient arbitrage between energy markets (i.e. not allowing to optimally exploit price differentials for the different energy vectors in the respective markets). • Lack of network tariffs regulation in some MSs could lead non-regulated hydrogen system operators cross-subsidising against specific price-insensitive users such as households, distorting competition in end-uses where hydrogen is substitute to electricity or natural gas. Combined gas operators could cross-subsidise fixed costs between regulated and non-regulated network users.	• Coherent definition of network transport as a regulated activity. • Lack of harmonised hydrogen market rules and alignment with other energy sectors regulation can lead to uneven competition and inefficient arbitrage between market participants in different MSs or energy sectors. • May incentivise market operators active in electricity and methane markets to offload balancing responsibility to hydrogen TSO. • Lack of network tariffs regulation in some MSs could lead non-regulated hydrogen system operators cross-subsidising against specific price-insensitive users such as households.	• Coherent definition of network transport as a regulated activity, requirement of TPA, balancing market, use of an entry-exit system. • H2 ENTSO would have coherent structure and tasks to electricity and methane counterparts. • Due to lack of market coupling, significant price differentials on national hydrogen markets might initially occur. This can also lead to uneven competition and inefficient arbitrage between market participants in different MSs or energy sectors.	• Coherent definition of network transport as a regulated activity, requirement of TPA, balancing market, use of an entry-exit system • Market coupling coherent with electricity regulatory framework approach, not with methane. Market area manager coherent with approach for methane. • Harmonised hydrogen market rules and mutual recognition of licenses not coherent with (current) methane regulatory framework. • EU H_2 TSO has no correspondent organisation for methane or electricity. • Coherent approach to multiple regulatory elements reduces potential for distortions in the internal energy market.
20. With TEN-E	• This regulatory package can be considered as coherent with TEN-E regulation in its current form, as the common understanding is that it does not cover hydrogen (unless blended). • Would be incompatible with TEN-E regulation should it be amended to cover hydrogen as well.	• This regulatory package can be considered as coherent with TEN-E regulation in its current form, as the common understanding is that it does not cover hydrogen (unless blended). • Would be incompatible with TEN-E regulation should it be amended to cover hydrogen as well.	• EU-wide network planning process aligned with current TEN-E regulation, it would be possible to incorporate hydrogen networks in the PCI process if the TEN-E regulation would be amended to include hydrogen.	• EU-wide network planning process aligned with current TEN-E regulation, it would be possible to incorporate hydrogen networks in the PCI process if the TEN-E regulation would be amended to include hydrogen.
21. With EEAG	• Coherent as hydrogen infrastructure would not need to be included in definition of energy infrastructure.	• Requires EEAG adaptation to include hydrogen infrastructure.	• Requires EEAG adaptation to include hydrogen infrastructure.	• Requires EEAG adaptation to include hydrogen infrastructure.
22. With Hydrogen Strategy: See 8.				

Coherence	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
23. Internal coherence	• Coherent as there are no EU-level provisions for all regulatory elements	• Coherent as it contains only provisions on unbundling (accounts), TPA and role of private network operators exist at EU level. Defines the minimum requirements for ensuring non-discriminatory access while MSs are free to regulate (or not) other aspects.	• Coherent as provisions at EU level for all regulatory elements guarantee non-discriminatory access, foster market integration and minimise distortions of the internal energy market. Nonetheless, national authorities and network operators retain significant room for further defining the regulatory framework and developing the hydrogen system.	• Coherent as regulatory elements (especially on network regulation) are further defined at EU level (compared to 'Full EU', with integrated planning, market coupling (spot and balancing) and CACM.

Proportionality & subsidiarity	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
24. Regulation at EU level is justified to: **· Contribute to proper functioning of energy markets** **· Ensure SoS** **· Promote energy efficiency** **· Promote interconnection of energy networks**	• Not applicable	• EU regulation justified to provide minimum requirements on the regulation of hydrogen infrastructures and markets to ensure non-discriminatory third-party access, with MSs being allowed to determine hydrogen network investment and operation are competitive activities only based on a market test assessing the potential for distortions of the internal energy market.	• EU regulation justified to provide minimum requirements on the regulation of hydrogen infrastructures and markets to ensure non-discriminatory third-party access, promote interconnection of hydrogen networks under the expectation of strong development in certain MSs and contribute to a well-functional internal hydrogen market without undue distortions to the internal electricity and methane markets. • The shift of decision-making powers to EU level is justified as it concerns areas with cross-border impacts (e.g. network planning, harmonised market rules). • Package proportional due to waivers and exemption procedures allowing MSs to not adopt cross-border regulatory elements until their hydrogen systems are interconnected, with minimum requirements to avoid distortions to the internal electricity and methane markets.	• EU regulation justified to provide minimum requirements on the regulation of hydrogen infrastructures and markets to ensure non-discriminatory third-party access, promote interconnection of hydrogen networks under the expectation of strong development in certain MSs and contribute to a well-functional internal hydrogen market without undue distortions to the internal electricity and methane markets. • Package proportional due to waivers and exemption procedures allowing MSs to not adopt cross-border regulatory elements until their hydrogen systems are interconnected, with minimum requirements to avoid distortions to the internal electricity and methane markets. Setting up an EU H2 TSO seems a priori proportional given the importance and economic benefits of integrated planning and of cross-border systems and markets coupling. Based on lessons learned from the (lengthy and complex) integration process of the electricity and methane markets and networks, this regulatory package might be adequate to efficiently reach the objective of a pan-European interconnected hydrogen backbone and an integrated and liquid market.
25. MS maintain right to determine own energy supply mix	• No restrictions on hydrogen/methane usage or production pathways are imposed, the right of MSs is maintained.	• No restrictions on hydrogen/methane usage or production pathways are imposed, the right of MSs is maintained.	• No restrictions on hydrogen/methane usage or production pathways are imposed, the right of MSs is maintained.	• No restrictions on hydrogen/methane usage or production pathways are imposed, the right of MSs is maintained.

Affected parties	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
26. Most affected parties	• In markets with fast-developing demand, the network growth might not be quick enough due to difficulties in planning, negotiating with new users and acquiring right of way. Also, if no regulation of third party access is assured, this might lead to discriminatory access. • Smaller scale market participants are not guaranteed the same level of market access even if hydrogen networks develop, if only negotiated TPA exists and there are no transparent price signals from organised markets. • Methane network operators may develop hydrogen networks if NRAs provide adequate regulation; repurposing methane infrastructure could be easier (less administrative constraints) but efficiency might be lower due to lack of integrated planning. • New network operators may be disadvantaged vis-a-vis incumbent methane network operators due to higher costs of new hydrogen infrastructure (in comparison to repurposing). • Pre-existing infrastructure operators can maintain business model.	• More suitable if it is expected that mainly the actors that have access to information / scale (e.g. large industrial consumers; networks operators, large-scale producers) will be the main actors in hydrogen sector. • Smaller scale market participants are not guaranteed the same level of market access, if only negotiated TPA exists and there are no transparent price signals from organised markets. • Methane network operators may develop hydrogen networks, but repurposing of methane infrastructure more difficult due to lack of integrated planning. • New network operators may be disadvantaged vis-a-vis incumbent methane network operators as planning is a function of the latter. • Exemptions assure pre-existing infrastructure operators can maintain business model.	• Provides non-discriminatory access to all hydrogen network users. • Balancing responsibility with market participants requires additional costs that can be disproportionately higher on smaller market players, but transitional measures can address this. • Infrastructure operators/owners have less risky business due to regulated revenues, but face more administrative burdens & need technical expertise for systemic network planning. • Increased oversight and other tasks for policy-makers, NRAs and ACER.	• Provides non-discriminatory access to all hydrogen network users. Balancing responsibility with market participants requires additional costs that can be disproportionately higher on smaller market players, but transitional measures can address this. • Methane network operators may develop hydrogen networks, with efficient repurposing of methane infrastructure facilitated through integrated planning. • Existing private hydrogen network operators will need to comply with unbundling, regulated TPA and other provisions or be granted an exemption by NRAs. • Increased oversight and other tasks for policy-makers, NRAs and ACER.

Transitional measures	No immediate EU action	Light EU regulation	Full EU regulation	Full+ EU regulation
27. Ability to ensure flexibility to network/market development according to pathways and national differences	• Not applicable	• Member States may be derogated from unbundling and cross-border requirements following regulatory requirements until their hydrogen systems become interconnected.	• Member States may be derogated from the following regulatory requirements until their hydrogen systems become interconnected: unbundling, network tariffication, planning, CACM, storage TPA requirements	• Member States may be derogated from the following regulatory requirements until their hydrogen systems become interconnected: unbundling, network tariffication, planning, CACM, storage TPA requirements
		• Sets an indicative Hydrogen Target Model, promote voluntary regional harmonisation and define a deadline (e.g. 2030) for an impact assessment for revision of the EU hydrogen regulatory framework.	• Sets a Hydrogen Target Model and legal framework to enable the gradual development and implementation of necessary network codes and guidelines, on initiative of ACER or the Commission, for the following regulatory requirements: harmonised tariff principles, market coupling, CACM, balancing, harmonised market rules	• Sets a Hydrogen Target Model and legal framework to enable the gradual development and implementation of necessary network codes and guidelines, on initiative of ACER or the Commission, for the following regulatory requirements: harmonised tariff principles, market coupling, CACM, balancing, harmonised market rules
		• For interconnected systems[272], clearly define requirements for waivers and exemption procedures of hydrogen network operators, covering pre-existing operators, direct lines and closed distribution systems.	• For interconnected systems, clearly define requirements for waivers and exemption procedures of hydrogen network operators, covering pre-existing operators, direct lines and closed distribution systems.	• For interconnected systems, clearly define requirements for waivers and exemption procedures of hydrogen network operators, covering pre-existing operators, direct lines and closed distribution systems.
		• Sets clear exemption procedures to new and pre-existing hydrogen network operators.	• Sets clear exemption procedures to new and pre-existing hydrogen network operators.	• Sets clear exemption procedures to new and pre-existing hydrogen network operators.
		• Include guidelines on tests for further regulatory intervention, to increase investment certainty.	• Develop EU network planning CBA methodologies, scenarios and models gradually, through each plan.	• Develop EU network planning CBA methodologies, scenarios and models gradually, through each plan

[272] These requirements could be defined at national level for isolated clusters that are not interconnected. For interconnected systems, harmonised rules would be required to avoid market and competition distortions.

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