EUROPEAN
COMMISSION

Brussels, 15.12.2021
SWD(2021) 455 final

PART 1/2

COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT REPORT

Accompanying the

Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast)

Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast)

{COM(2021) 803 final} - {COM(2021) 804 final} - {SEC(2021) 431 final} - {SWD(2021) 456 final} - {SWD(2021) 457 final} - {SWD(2021) 458 final}

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1 POLITICAL AND LEGAL CONTEXT

1.1 Context of initiative

The European Green Deal (EGD) and the Climate law set the target for the EU to become climate neutral by 2050 in a manner that contributes to European competitiveness, growth and jobs. This, together with a 55% greenhouse gas emissions reduction target by 2030, requires an energy transition and significantly higher shares of renewable energy sources in an integrated energy system and acceptance and active participation of consumers in competitive markets, to benefit from affordable prices, good standards of service, and effective choice of offers mirroring technological developments.

On 14 July, the European Commission adopted[1] a first set of proposals to make the EU's climate, energy, transport and taxation policies fit for reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels. The present initiative is equally part of the Fit for 55 package.[2] It covers market design for gases. Whilst it will not deliver decarbonisation by itself, it will remove barriers for this to happen and create the conditions for this to take place in a more cost effective manner.

Electrification of demand sectors[3] will further increase as it is generally the most cost-effective and energy-efficient way to decarbonise final energy demand. Coupled with an increased contribution from renewables, energy efficiency and a circular economy, electrification delivers a substantial part of the emission reductions across the energy system.

Gaseous fuels (natural gas[4], biogas[5] and biomethane[6], synthetic methane[7] and hydrogen) will however continue playing an important role in the energy system. Their ability to store energy allows matching seasonal demand patterns and complements fluctuating supply of renewable electricity. For processes, which cannot easily be electrified for technical or economic reasons, gaseous fuels are likely to remain present in the EU's energy system. It is however clear, that these gases must be decarbonised on the way to 2050.

This document analyses how to adapt the current legal framework for the internal gas market (mainly the Gas Directive[8] and the Gas Regulation[9]) to facilitate the decarbonisation of

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1 https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en

2 https://eur-lex.europa.eu/resource.html?uri=cellar%3A91ce5c0f-12b6-11eb-9a54-01aa75ed71a1.0001.02/DOC_2&format=PDF

3 Commission policy scenarios expect the share of electricity in final energy consumption to increase from currently 20% to about 32% in 2030 and 56% in 2050.

4 In this document references to natural gas shall be understood as references to methane of fossil origin. Fossil gases include natural gas, hydrogen of fossil origin and synthetic methane produced from hydrogen of fossil origin.

5 Biogas is a mixture of methane, CO2 and small quantities of other gases produced by anaerobic digestion; its precise composition depends on the type of feedstock and the production pathway. Biogas cannot be directly injected into the gas grid.

6 Biomethane is a near-pure source of methane produced either by 'upgrading' biogas (a process that removes any CO2 and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation. Biomethane, subject to fulfilling specific gas quality standards, can be directly injected into the gas grid.

7 Methane produced from hydrogen and CO2, such as CO2 captured from air

8 Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC, OJ L 211, 14.8.2009, p. 94–136; EUR-Lex - 32009L0073 - EN - EUR-Lex (europa.eu)

gaseous fuels in a competitive manner at least economic costs whilst ensuring energy security and placing consumers at the heart of the energy markets. Two main pathways, are likely to emerge in parallel and expected to develop at different pace across the EU:

- A hydrogen-based infrastructure will progressively complement the network for methane gases;
- A methane-based infrastructure in which natural gas will progressively be replaced by other sources of methane (i.e. biomethane and synthetic methane, possibly occasionally blended with hydrogen).

Currently, some 300 Mtoe[10] (350-400 bcm) of gaseous fuels are consumed in the EU per year, of which 95% is natural gas. They account for roughly 25% of total EU energy consumption, used for 20% of EU electricity production, and 39% of heat production. In line with the policy scenarios that underpin the Fit for 55 initiative, biogas and biomethane[11], renewable and low-carbon hydrogen and synthetic fuels (E-gas) will gradually replace fossil gases and represent very significant shares of the gaseous fuels in the energy mix towards 2050. Conversely, the share of natural gas is projected to be significantly reduced and coupled with Carbon Capture Usage and Storage (CCUS) technologies.

Figure 1 shows the latest projections for consumption of gaseous fuels produced by the Commission with the PRIMES energy model[12]. The projections also show that the energy carried by gaseous fuels would, after slightly decreasing between 2020 and 2030, stay in 2050 at about 85% of the current level.

Two scenarios are shown in the Business as Usual (BAU) case (the Reference 2020 – REF) and in the Green Deal scenario (MIX).

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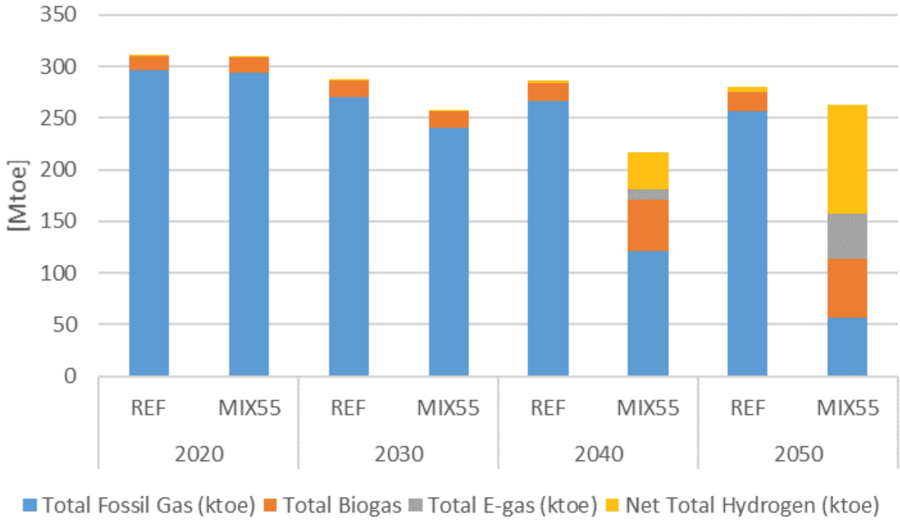
9 Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005, OJ L 211, 14.8.2009, p. 36–54; EUR-Lex - 32009R0715 - EN - EUR-Lex (europa.eu)

10 Million tonnes of oil equivalent.

11 Methane produced from hydrogen and CO2, such as CO2 captured from air

12 Price-Induced Market Equilibrium System: an energy system model for the European Union.

Figure 1: Total consumption of gaseous fuels (Mtoe)[13]



Source: PRIMES

Under current framework conditions, biomethane, synthetic methane and hydrogen have significantly higher levelised costs of energy compared to natural gas[14]. This cost gap can be addressed by a much higher carbon price[15], by direct financial incentives in particular for renewable gases and by reducing the cost for access to the system for the gaseous fuels other than natural gas.

However, the renewable and low-carbon gases today face regulatory barriers for market and grid access that represent a comparative disadvantage versus natural gas. The differences in costs of production and potential of biomethane and hydrogen production between EU Member States are significant and are a strong argument to enable cross-border trade. Abolishing the regulatory barriers will enable renewable and low carbon sources of gases to compete in the EU gas market, bringing down costs of production, increasing cost efficiency and leading to less support measures and state aid. It will also enable supply of those gases to Member States, and end-consumers, that otherwise would not satisfy their demand[16].

1.2 Scope of initiative

The initiative aims to adapt the rules for the transmission, distribution, supply and storage of methane and hydrogen based gases. It lays down the rules relating to the organisation and functioning of these gas sectors, access to the market and the operation of systems as well as rights of consumers of gases[17]. Where necessary, the rules for hydrogen and methane gases

13 Net total hydrogen consumption excludes hydrogen that is further processed to renewable fuels or liquids.

14 Direct use of biogas for electricity/heat production may in several cases be less costly than converting it into biomethane.

15 For instance, filling the gap between biomethane costs and natural gas prices by 2030 would require a carbon price of about EUR 350/tCO2 (for a biomethane LCOE of EUR 88/MWh).

16 See in this regard also Annex 5.

17 See also Sector Integration Strategy, which, alongside with the Hydrogen Strategy, sets out how the energy markets could contribute to achieving the goals of the European Green Deal: [EU strategy on energy system integration | Energy (europa.eu)]

are differentiated to make them fit for purpose. Maintaining overall energy security is an underpinning factor.

1.3 Organisation and timing

The Commission has conducted a number of wide and targeted public consultations between 2019 and 2021[18] on the different problem areas covered by the present Impact Assessment. Given the cross-cutting nature of the planned Impact Assessment work, the Commission set up an inter-service steering group, which held regular meetings to discuss the policy options of the proposed initiatives and the preparation of the Impact Assessment. In parallel, the Commission has also conducted a number of studies for this Impact Assessment[19].

1.4 Links with other initiatives

The proposed initiative is focussing on enabling the markets to decarbonise gas consumption. It is strongly linked and complementary to the legislative proposals brought forward in the context of the Fit for 55 package to implement the European Green Deal, including:

- The **revised Renewable Energy Directive** (RED II)[20], which is the main EU instrument dealing with the promotion of energy from renewable sources. It aims to incentivise the penetration of renewable energy, including renewable gases. Its proposed amendment[21] to increase the target for renewable sources in the EU's energy mix to 40% and promote the uptake of renewable fuels, such as hydrogen in industry and transport, with additional targets. However, other low-carbon fuels (including low-carbon gases, such as low-carbon hydrogen) are not in the scope of RED and its revision. Such fuels can however also play a role in the transition, particularly in the short and medium term to rapidly reduce emissions of existing fuels, and support the uptake of renewable fuels such as renewable hydrogen. In order to fill in this gap and enable low-carbon fuels to be a viable solution for Member States in a transitional period, this Impact Assessment explores options for deploying a system of terminology and certification of non-renewable low-carbon fuels;
- The **Energy Efficiency Directive (EED)[22]** and the related **Energy Performance of Buildings Directive (EPBD)** including the proposals for their amendment interact with the present initiative as they affect the level and structure of gas demand. Energy efficiency measures can alleviate energy poverty and reduce consumer vulnerability. As gaseous fuels are currently dominating in European heating and cooling supply and in the cogeneration plants, their efficient use stays at the core of the energy efficiency measures. The present initiative is coherent with the energy efficiency first principle: an open and competitive EU market with prices that reflect energy carriers' production costs, carbon costs, and external costs and benefits would efficiently provide clean and safe hydrogen to end users who value it most.

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18 For more information on the consultation and inter-service process, please refer to Annex 2.

19 For the list of studies and a summary description, please refer to Annex 1.

20 Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources EUR-Lex - 32018L2001 - EN - EUR-Lex (europa.eu)

21 For an overview of the Commission's proposals: https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/delivering-european-green-deal_en#cleaning-our-energy-system

22 Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency EUR-Lex - 32018L2002 - EN - EUR-Lex (europa.eu)

- The **TEN-E Regulation**[23], as proposed by the Commission in December 2020, aims to better support the modernisation of Europe's cross-border energy infrastructure for the EGD. It introduced hydrogen infrastructure as a new infrastructure category for European Network Development. The present initiative is complementary as it focuses on alignment of the national plans with the requirements of the European Network Development plan;
- As announced in the EU **strategy to reduce methane emissions**[24], the Commission will propose legislation to reduce methane emissions in the energy sector. The initiative will seek to improve information for all energy-related methane emissions. The present initiative seeks to facilitate the penetration of renewable and low-carbon gases, enabling a shift from natural gas;
- The **Emission Trading Scheme (ETS)**[25] increases the price of using fossil fuels relative to renewable and low-carbon gases and, thus, fosters the demand of such gases and investments in related production technology. The Commission has proposed strengthening, including reinforcements in and extensions to the aviation sector, maritime and road transport, and buildings.
- The revised **Alternative Fuels Infrastructure Regulation**[26], which will repeal Directive 2014/94/EU on deployment of alternative fuels infrastructure (AFID)[27], as proposed by the Commission in July 2021, aims to tackle rising emissions in road transport to support the transition to a nearly zero-emission car fleet by 2050. The Regulation requires Member States to expand their network of recharging and refuelling infrastructure in line with zero emissions car sales, and to install charging and fuelling points at regular intervals on major highways.

The present initiative is coherent and has clear synergies with these instruments and others[28].

1.5 Alignment with the FIT for 55 Impact Assessment

The quantitative assessments shown in this report build on the analysis performed for the Fit for 55 policy package. Consequently, all model-based analysis related to hydrogen and renewable and low carbon gases is aligned to the MIX-H2 PRIMES scenario[29], which underpins the Impact Assessment supporting the proposal for a revised Renewable Energy Directive. While the Impact Assessment for a revised Renewable Energy Directive, is looking at policy measures to promote the demand and production of hydrogen as well as renewable and low carbon gases, the present assessment explores the policy measures required for optimum infrastructure and efficient markets. By using the MIX-H2 PRIMES scenario, the overall relationships between energy supply and demand are preserved. This ensures consistency with the underlying policies driving the transition to Greenhouse Gas (GHG)

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23 Proposal for a Regulation of the European Parliament and of the Council on guidelines for trans-European energy infrastructure and repealing Regulation (EU) No 347/2013 EUR-Lex - 52020PC0824 - EN - EUR-Lex (europa.eu)

24 eu_methane_strategy.pdf (europa.eu)

25 https://ec.europa.eu/clima/eu-action/eu-emissions-trading-system-eu-ets_en

26 https://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX:52021PC0559

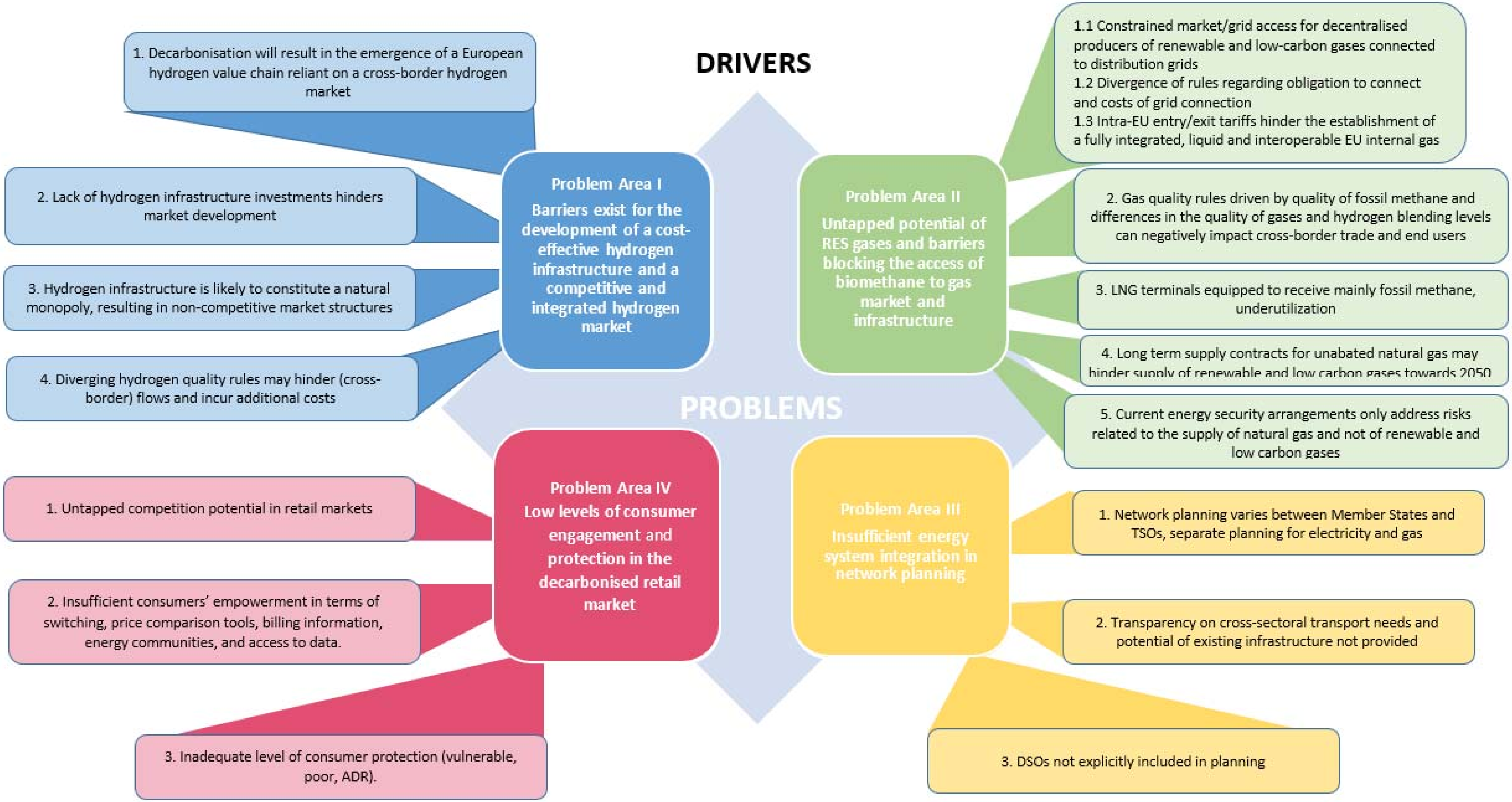
27 Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure EUR-Lex - 32014L0094 - EN - EUR-Lex (europa.eu)

28 See also Annex 12.

29 The MIX-H2 scenario achieves the objectives of the EU hydrogen strategy. It is described in detail in the Impact Assessment accompanying the proposal for a revised Renewable Energy Directive.

neutrality as proposed in by the Fit for 55 initiative. The relationship between the MIX-H2 PRIMES scenario and the policy measures that are assessed in this report is further explained in Section 6 and Annex 4.

Figure 2: Problems and drivers



2 PROBLEM DEFINITION

2.1 Problem Area I: Hydrogen infrastructure[30] and markets

2.1.1 Problem: Barriers exist for the deployment of a cost-effective hydrogen infrastructure and a competitive and integrated hydrogen market

Today, hydrogen represents a modest fraction of the European Union's energy mix. It is mainly used as industrial feedstock and is largely produced from fossil fuels[31] emitting CO2. Hydrogen is not yet a traded commodity and a hydrogen network is not yet an essential facility, as producers and consumers are not competing for access to a cross-border network for hydrogen transport[32]. Existing networks are privately owned and tailored for the point-to-point transport of hydrogen to industrial customers.

The Communication on a hydrogen strategy for a climate-neutral Europe[33] (the EU Hydrogen Strategy) published in 2020 as well as the hydrogen strategies of a number of Member States, define ambitions towards 2030 to prepare for the expected steep increase of hydrogen consumption between 2030 and 2050 (in particular hydrogen produced from water using renewable electricity through a process of electrolysis)[34]. Next to renewable hydrogen, other forms of low-carbon hydrogen can play a role, primarily to rapidly reduce emissions from existing hydrogen production and to support the parallel and future uptake of renewable hydrogen. The Communication describes a roadmap for the development of a hydrogen value chain that would progressively require EU logistical infrastructure and would reach a more mature phase by 2030.

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30 The term 'hydrogen infrastructure' refers to hydrogen pipelines, large-scale hydrogen storage and hydrogen terminals.

31 According to FCH JU (2019) Hydrogen Roadmap Europe today's share is 2%. This includes the use of hydrogen as feedstock.

32 Merchant hydrogen (hydrogen that is not captive/dedicated to specific clients) represented less than 15% of total hydrogen production capacity in 2018. Energy Transition Expertise Centre (ENTEC, forthcoming), The role of renewable hydrogen import and storage to scale up the EU deployment of hydrogen.

33 https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1594897267722&uri=CELEX:52020DC0301

34 See *Table 1*.

Table 1: EU Hydrogen Strategy and national hydrogen strategies: envisaged developments towards 2030 and PRIMES projections towards 2050

	Today - 2024	**2025 - 2030**	**2050**
Electrolyser installed capacity	6 GW	40 GW	500-550 GW[35]
Production RES H2[36]	Up to 1 Mt	Up to 10 Mt	70-80 Mt
Infrastructure[37]	Infrastructure needs for transporting hydrogen over longer distance will remain limited.	Need for an EU-wide logistical infrastructure will emerge.	Fully developed EU hydrogen network in place (with connections to non-EU countries)
Electrolyser targets national hydrogen strategies (until November 2021)	-	32.5-33.5 GW	-

Source: EU Hydrogen strategy and national hydrogen strategies, PRIMES

The current regulatory framework for gaseous energy carriers does not address the second pathway identified above by which gaseous fuels will be decarbonised, namely the deployment of hydrogen and the development of a dedicated hydrogen infrastructure next to the already existing methane-based infrastructure. There are no rules on the operation of new hydrogen infrastructure or the repurposing of existing natural gas networks for the future transport of hydrogen. The security challenges of hydrogen deployment are also not addressed in the SoS Regulation[38,39].

The problem resides in the fact that barriers exist for the development of a cost-effective hydrogen infrastructure and integrated, competitive hydrogen market.

2.1.1.1 Driver 1: Decarbonisation will result in the emergence of a European hydrogen value chain reliant on a cross-border hydrogen market

With renewable energy resources being key but unevenly distributed over Member States[40] the availability of well-integrated, cross-border hydrogen markets will be key to support the EU's climate neutrality objectives and ensure its cost-effectiveness.

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35 See the supplementary data published for SWD(2020) 176 final https://ec.europa.eu/clima/document/download/ec1acac9-10fe-4eeb-915f-cad388990e0f_en

36 Renewable Hydrogen

37 Whilst not really comparable as not based on the MIX-H2 PRIMES scenario, Guidehouse (July 2021) foresees the emergence by 2030 of an initial 11,600 km hydrogen pipeline network, connecting emerging hydrogen valleys. This compares with approximately 1600 km today. The hydrogen infrastructure can subsequently grow to become a pan-European network, with a length of 39,700 km by 2040. Further network development can be expected after 2040. (https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/).

38 Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010, OJ L 280, p.1.

39 See Driver 5 under Problem Area II.

40 JRC (2018), Wind potentials for EU and neighbouring countries; http://publications.jrc.ec.europa.eu/repository/bitstream/JRC109698/kjna29083enn_1.pdf.Similarly, see also EHB June 2021 'Analysing future demand, supply, and transport of hydrogen' https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf.

Hydrogen networks will allow the transport of hydrogen from regions with excess capacity of renewable energy to supply demand centres in (cross-border) regions with lower hydrogen production capacity. Any trade barriers for hydrogen and a lack of transport capacity could hamper the development of the hydrogen value chain and, consequently, decarbonisation.

In view of the variability of renewable hydrogen production on the one hand and the need to provide stable supply to users on the other hand, storage infrastructure will be an important asset on such a hydrogen market. It allows hydrogen producers to optimise their economic activities by utilizing electrolysers on the basis of (favourable) price variations for renewable electricity instead of adapting the operation of electrolysers to consumption patterns. Currently, salt caverns are the only proven large-scale hydrogen storage option but, due to geological conditions this storage option is only available in certain Member States[41]. Accordingly, large-scale storage might be scarce (especially at the ramp-up stages) thereby underlining the need for (cross-border) markets.

EU hydrogen demand might be partially covered by imports from third countries depending on the competitiveness of renewable and low carbon gases produced in these countries relative to domestic EU production and the possibilities and costs to import them into the EU. In terms of volumes, the potential for hydrogen imports and exports remains uncertain, especially by 2030[42]. Moreover, alongside pipelines that interconnect the EU with third countries, hydrogen can be imported from (more distant) third countries by ships that can use a range of different modes to transport hydrogen such as in liquid form or as ammonia. As the optimal import means will also depend on the envisaged end use of hydrogen, it is not yet fully clear what means of hydrogen import will become predominant[43]. In any event, investments in and the operation of import facilities will equally be dependent on functioning commodity markets (and on the available transportation infrastructure to reach demand centres).

Low-carbon hydrogen (LCH) and low carbon fuels (LCFs) have decarbonisation potential. However, they lack a definition. Yet, it can be expected, at least in the short term, that Member States will use LCF and LCHs to initiate the development of transport infrastructure as well as adaptations by end-users for the eventual uptake of renewable hydrogen. Not certifying LCF and LCHs in a comprehensive and harmonised manner risks to jeopardise the integrity of the EU market and hamper cross-border trade, inside the EU as well as trade with

41 Only 9 MSs have any significant salt cavern storage potential (Germany, the Netherlands, Denmark, Poland, Portugal, Spain, Romania, France, and Greece), complemented by several non-EU countries (UK, Norway, Bosnia & Herzegovina, Albania). Guidehouse/Frontier Economics assistance to the Impact Assessment for designing a regulatory framework hydrogen, p. 76.

42 Under the scenarios used for the present Impact Assessment they remain limited by 2030, but in 2050 the global market for hydrogen is expected to be between 8 000 and 20 000 TWh (IEA Net Zero Report (2021) & IRENA World Energy Transition Outlook (2021)). The global 'Power-to-X Atlas' compiled by Fraunhofer IEE made a first assessment that, in the long term (by 2050) the technical potential to produce liquid hydrogen outside Europe is 5x larger than the expected global demand (Energy Transition Expertise Centre (ENTEC, forthcoming, The role of renewable hydrogen import and storage to scale up the EU deployment of hydrogen).

43 Hydrogen Council (2021) Hydrogen insights, a perspective on hydrogen investment, market development and cost competitiveness.

third countries, since it would create uncertainty about the real GHG footprint of such solutions[44].

An efficient hydrogen market can increase welfare by exploiting comparative advantages whilst the price signals it produces will steer investment decisions and the operation of hydrogen assets. Whilst the development of a hydrogen market has clear benefits, no such integrated hydrogen market exists today.

2.1.1.2 Driver 2: Lack of hydrogen infrastructure investments hinders market development

The development of a hydrogen market requires infrastructure.

Pipeline transportation is highly likely to be the most cost-effective means of transporting hydrogen for distances compatible with the European territory[45], compared to other means such as road-based or marine transport or transportation through the electricity grid of electricity before its transformation into hydrogen. A lack of hydrogen networks may increase the carbon footprint of production and render hydrogen more expensive for consumers, as they have to divert to less cost-effective (and sustainable) transportation means[46]. As production and consumption of hydrogen ramp-up across the EU, cross-border hydrogen networks will be required to meet transport needs from favourable production locations to demand centres. The construction of a pan-European grid would require considerable capital investments[47]. Existing natural gas networks can be partially repurposed for the transport of hydrogen, with significant cost savings compared to new-build infrastructure[48]. The same applies to large scale storage and, likely to lesser extent, import terminals.

However, there is no clarity on the context in which infrastructure investments can take place and barriers to exploit repurposing opportunities exist. There is no transparency on what parts of the gas grid may become available for repurposing, no clear rules exist on how

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44 The conditions that apply to imports in terms of e.g. sustainability are not analysed in this document as they are the subject of other policy initiatives.

45 JRC (2021), Assessment of Hydrogen Delivery Options, jrc124206_assessment_of_hydrogen_delivery_options.pdf Similarly, see also EHB June 2021 'Analysing future demand, supply, and transport of hydrogen' https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf.

46 See also Artelys, Trinomics, Frauenhofer, JRC Artelys, Trinomics, Frauenhofer, JRC, Trinomics, Frauenhofer, JRC modelling results and Annex 5.

47 Whist not comparable as not based on the MIX-H2 PRIMES scenario, Guidehouse (April 2021) estimates total investment costs of the envisaged 2040 European Hydrogen Backbone to be in the range of EUR 43 to 81 bn, covering the full capital cost of building new hydrogen pipelines and repurposing pipelines. Repurposed pipelines represent 69% of the total length. https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf.

48 The share of repurposed pipelines in a future hydrogen network is currently estimated to be about 69% overall with the share varying between Member States in accordance with e.g. the current availability of gas networks and network typology. The median estimate for the CAPEX of repurposed pipelines is on average 19% of newly build pipelines with minimum and maximum estimates varying from 10% to 28%. https://gasforclimate2050.eu/wp-content/uploads/2021/04/European-Hydrogen-Backbone_April-2021_V2.pdf.

repurposing could be organised, how (new or repurposed) hydrogen infrastructure is financed and whether current arrangements applicable to gas pipes (e.g. permitting and land use rights) continue to be applicable once these pipes are used for hydrogen transportation.

2.1.1.3 Driver 3: Hydrogen infrastructure is likely to constitute a natural monopoly, resulting in non-competitive market structures

As hydrogen markets develop, dedicated hydrogen networks and possible other types of infrastructure are likely to constitute natural monopolies or essential facilities on which hydrogen producers and consumers depend in order to transport, store and receive hydrogen. While existing hydrogen pipeline infrastructure is currently unlikely to constitute a natural monopoly as current hydrogen producers and sellers/buyers are not competing for access to hydrogen infrastructure, it is expected to happen in the future, based on the following elements:

- Pipelines have a sub-additive investment cost curve. This means that the total cost of transport services are expected to be lower for one pipeline operated by a single firm than for two pipelines with an equal transport capacity that are operated by two firms;
- Other transportation means (such as transportation by trucks) would not provide suitable or competitive alternatives for most uses[49];
- Refurbishing natural gas pipelines to hydrogen operations will be less expensive than new-build pipelines, and will hence offer a competitive advantage to the owners/operators of existing natural gas networks[50]. As a result, the hydrogen pipeline/network 'inherits' the natural monopoly character from the natural gas pipeline/network;
- Hydrogen is expected to become a traded commodity with a high number of producers/sellers and buyers competing for access to transport infrastructure. This would coincide with phase 2 (2025-2030), and more broadly phase 3 (2030 towards 2050) defined in the EU hydrogen Strategy.

Natural monopolies could lead to the foreclosure of upstream (hydrogen production) and downstream (supply of hydrogen to end-users) activities within the hydrogen value chain, which may in turn lead to hydrogen consumers being deprived from supply or being confronted with higher prices in the end also affecting the ability for hydrogen to decarbonise the EU economy.

However, no rules exist to ensure market access addressing the risk of market foreclosure and non-competitive market structures, while taking into account the specificities of a nascent market.

2.1.1.4 Driver 4: Diverging hydrogen quality rules may hinder cross-border flows and incur additional costs

Gas quality for pure hydrogen networks has so far received little attention as current hydrogen supply is predominantly organised on a point-to-point basis. Once hydrogen is injected into the network from different production processes and transported through a meshed network, including across-borders, issues around hydrogen quality (i.e. purity) may arise.

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49 See for instance: JRC 124206_assessment_of_hydrogen_delivery_options.pdf (europa.eu)

50 Trinomics (2020), Sector integration – Regulatory framework for hydrogen Final Report, pp. 37 f.

Different applications require different hydrogen purity levels and can have different tolerances for the composition of the impurities. Industrial grade purity is required at a minimum 99.9%[51] (e.g. in ammonia and steel production and in refineries), fuel cell uses require a purity above 99.97%[52] (e.g. in road and rail transport), while used for its thermal value hydrogen purity is a less important parameter e.g. in power plant turbines.

Different sources and production methodologies lead to different hydrogen purity levels[53] and the transport via pipeline also has an effect on the purity: Existing gas pipelines converted for hydrogen transport can respect a 98% purity[54], which can represent a significant issue with reusing existing gas infrastructure for hydrogen transport. To ensure that the level of hydrogen purity matches end-use requirements, purification might be necessary as an additional step at added cost in the production process or at a later stage, e.g. at end-use points.

Currently, only a few national level standards are applicable or under development, while the European Committee for Standardization (CEN) is investigating the tolerance of infrastructure elements and end-use applications to hydrogen[55]. As of today, there is limited availability of data on and experience with hydrogen purity and its implication on the operation of infrastructure and appliances.

The lack of harmonised rules on a minimum purity level for hydrogen transportation can pose a risk to the unhindered flow and use of hydrogen in the near future. Such issues are expected to become particularly pertinent when dedicated hydrogen networks connect Member States and divergent technical rules, including quality specifications, constitute a barrier to the cross-border flow of hydrogen.

Thus a need exists to assure that diverging hydrogen quality (hydrogen purity and contaminants) rules hinder cross-border flows.

2.1.2 How will the problem evolve?

Today, the share of hydrogen represents a negligible share of all gaseous fuels, predominantly produced and used within chemical production sites and refineries[56]. In the MIX-H2 scenario, the production of renewable hydrogen will increase to more than 17 Mtoe (or 6 Mt of hydrogen) in 2030 and can be 230 Mtoe (80 Mt) in 2050. The share of hydrogen in the total consumption of gases increases to 4% in 2030 and up to 40% in 2050[57.]

If the above issues remain unresolved, market integration will be hampered, infrastructure roll-out slowed down and non-competitive markets outcomes can be expected. Higher hydrogen prices and lower uptake of hydrogen and lower decarbonisation will be the result.

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51 Hydrogen Europe: common industrial grade is generally set at 99.95%.

52 With a list of impurities with specific thresholds set out in existing standards: ISO-14687, SAE-2719 and CEN-17124.

53 E.g. for renewable hydrogen produced via electrolyses from renewable electricity for hydrogen produced from different qualities of fossil fuels, e.g. natural gas.

54 Trinomics:: Sector integration – Regulatory framework for hydrogen, forthcoming.

55 TC 234, TC 109.

56 Fuel Cells and Hydrogen Observatory (2020), https://fchobservatory.eu/observatory/technology-and-market/hydrogen-demand.

57 See also *Table 1*.

Member States may take national initiatives based on national strategies, but these efforts are likely to be dispersed, resulting in uncoordinated and weaker cross-border integration and network development. As geographical and geological circumstances vary among Member States, some will have no or limited access to hydrogen storages and terminals.

These problems will not only pose risks to the objectives as set out by the EU Hydrogen Strategy by 2030, but even more so beyond 2030 in view of the steep increase in hydrogen consumption and production envisaged beyond 2030 towards 2050.

2.2 Problem Area II: Renewable and low carbon gases in the existing gas infrastructure and markets, and energy security

2.2.1 Problem: Untapped potential of RES gases and barriers blocking the access of biomethane to gas market and infrastructure

Today, renewable and low-carbon gases represent a minor role in the EU energy mix. Biogas is primarily used on-site to generate heat and electricity. Biomethane totalled around 20 TWh in 2019, which, was less than 1% of the EU's natural gas consumption of about 3850 TWh. Blending hydrogen[58] into natural gas grids and the production and injection of synthetic methane only exist at the scale of demonstration or pilot projects.

The global biomethane export potential is estimated by the IEA at 8084 TWh in 2018, rising to 9731 TWh in 2040. The costs of imports to the EU ranged in 2018 between EUR 12/MWh and EUR 98/MWh. In 2040, import costs are estimated in the range of EUR 13/MWh and EUR 70/MWh (including shipping costs), depending on the region[59]. Import of biomethane can take place using Liquified Natural Gas (LNG) terminals or transmission pipelines (high pressure pipelines transporting gas on long distances).

In the EU, currently, the production costs of biomethane vary from EUR 36/MWh to EUR 116/MWh[60]. The differences in production costs show an opportunity for trade across the EU. However, unlike natural gas, which is normally injected at the transmission level, about half of the biomethane production capacity is connected to the distribution grid (low pressure pipelines which distribute gas in local areas). Injecting biomethane into distribution grids may, on the one hand be realised at lower operational costs, but on the other hand it deprives the biomethane producers access to the wholesale market which is organised around the transmission grid and the market dominated by natural gas.

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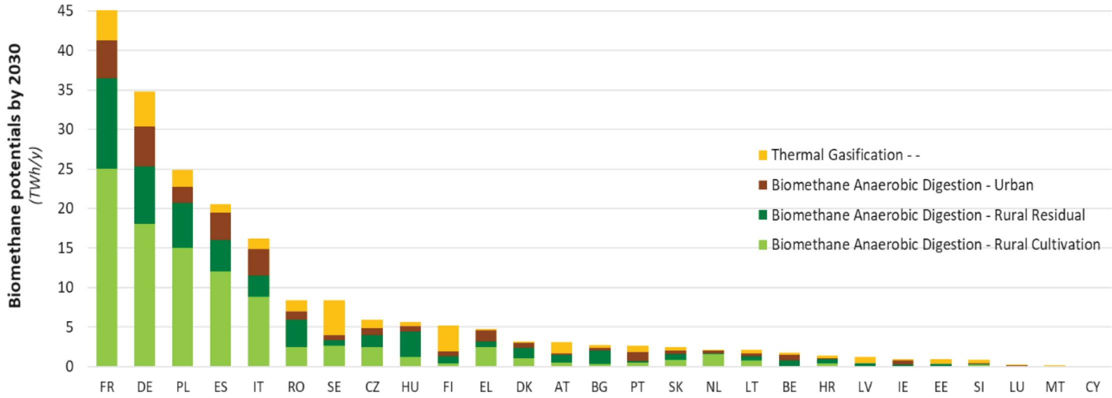
58 Blending means adding small quantities of hydrogen into the methane network. See for further details Section 2.2.1.4

59 IEA (2020).

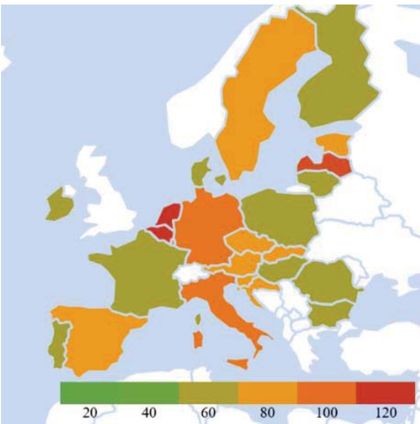
60 Artelys, Trinomics, Frauenhofer, JRC (2021).

Figure 3: Estimation of biomethane potentials in 2030 – by MS[61]



Source: Fraunhofer

Figure 4: LCOE[62] of biomethane in 2030 (EUR/MWh)



Source: Fraunhofer

This results in a problem that the potential to produce **biomethane remains untapped**. At the same time rules applicable to biomethane vary between Member States which **results in lack of level playing field between the producers of biomethane across the EU**[63]. Leaving biogas potentials from agricultural residues and waste (from sewage, municipal waste or landfills) unused represents a missed opportunity to make an additional step towards a circular economy as outlined under the Circular Economy Action Plan (CEAP)[64]. Furthermore, the potential contribution of biomethane to the energy security is not considered in the current framework on energy security.

2.2.1.1 Driver 1.1: Constrained market and grid access for local producers of biomethane connected to the distribution grids

For efficient marketing of renewable and low carbon gases, **access to the gas wholesale market**, i.e. the Virtual Trading Points (VTP), represents a key prerequisite. Yet, current market organisation and legislation in Member States does not necessarily foresee, in terms of market access, the integration of distribution systems in entry-exit zones[65] of Transmission System Operators (TSOs) and the participation of the distribution level injected gases in the wholesale market. Consequently, the tradability of locally produced gases at the VTPs is limited, blocking, in particular smaller facilities, from becoming active components of the

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61 Technical potential depend on time horizon as technology evolution can unlock additional potential.
62 Levelised cost of energy.
63 Similar situation may arise in the future as regards other renewable and low carbon gases when injected into the existing methane network.
64 COM/2020/98 final, 11.3.2020 EUR-Lex - 52020DC0098 - EN - EUR-Lex (europa.eu); new_circular_economy_action_plan.pdf (europa.eu)
65 Please see for more details on entry/exit zones Section 2.2.1.3.

energy system. Currently, entry-exit zones include, under various conditions, distribution grids injected gas in 10 countries (AT, BE, ES, DE, FR, CZ, PL, FI, IT, PT).

Biomethane plants connected to distribution grids may face another barrier in addition to the potentially restricted access to the VTP: Physical injection at the distribution grid level may be capped by the minimum demand levels in the local network as **gas flows are typically mono-directional** (from the transmission to the distribution level). Gas demand in distribution grids typically features a strong seasonal variation, notably where gas is used for space heating. Biomethane production on the other hand does not show a large seasonal variance[66]. Thus, the minimum demand typically occurring during summer represents the limiting factor for biomethane injection. Surplus gas injection may hence not be accommodated in the grid if no remedial action is undertaken. This may even lead to connection request denial. Besides connection to other distribution systems or local storage solutions (which may not always be available), reverse flow compressors from Distribution System Operator (DSO) to TSO level are the most effective infrastructure option. Only Austria, Spain and France appear to have such policies in place. In Italy, a pilot project is under way.

2.2.1.2 Driver 1.2: Divergence of rules regarding obligation to connect and costs of grid connection for renewable and low carbon gases

Biomethane plants may be connected to the transmission or the distribution grid, upon request to the TSO or DSO. Currently, a **connection obligation** exists in 16 Member States, while at least five countries do not have such a national obligation.

Table 2: Connection obligation for network operators across EU MS

Connection obligation exists	No connection obligation	No information available
AT, HR, CZ, DK, EE, FR, DE, HU, IE, IT, LV, LT, LU, NL, SI, ES	BE, PL, PT, SK, SE	BG, CY, FI, GR, MT, RO

Source: (ACER, 2020)

The allocation of **grid connection costs** between the network operator and the biomethane producer is handled quite heterogeneously across the EU:

- **Deep cost allocation** where producers pay all costs associated with the connection. This allocation is applied in Ireland, Italy and Spain;
- **Shallow cost allocation** where producers pay the cost for the physical grid connection and the system operator pays the necessary network reinforcement beyond the connection point. This allocation is applied in Austria, Belgium, Czechia, Denmark, Estonia, Finland and Sweden;
- **Super shallow cost allocation** where producers pay only partially or not at all for the physical grid connection, and system operators bear the majority of costs for the network reinforcement beyond the connection point and all/part of the physical connection. This allocation is applied in France, Germany and Lithuania.

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66 It is economically beneficial to maximise the utilisation of a biomethane plant (notably the fermenter) by opting for a minimal dimensioning of the plant.

When it comes to **grid injection tariffs**, in several Member States injection tariffs are lower for biomethane and hydrogen compared to tariffs for the injection of natural gas in transmission grids. This leads to a distorted level playing field between biomethane and hydrogen producers in various Member States.

2.2.1.3 Driver 1.3: Intra-EU entry/exit tariffs hinder the establishment of a fully integrated, liquid and interoperable EU internal gas market

The current gas market model is organised around entry/exit zones in which TSOs transport two kinds of flows:

- **National flows** from an entry point (TSO, LNG terminal, storage, production) to an national exit point (DSOs, industrial consumers, gas-fired power plants);
- **Transit flows** from an entry point (TSO, LNG terminal, storage, domestic production) to one cross-border exit point.

The costs of transporting these flows are borne by the TSOs. They are recovered via grid tariffs taking into account the **allowed revenues** to remunerate their assets that are determined by the National Regulatory Authorities (NRAs). The methodology to define how allowed revenues are determined is not homogeneous among the Member States and it is not harmonised at EU level. Tariffs can be distinguished by three categories:

- The **exit tariffs at internal exit points**, which are paid only by the national consumers;
- The **exit tariffs at cross-border points**, which are paid by grid users other than national consumers;
- The **entry tariffs** paid by either national or non-national grid users (depending on where the flow crossing this point is destined).

The revenue repartition between these three kinds of tariffs is a complex matter[67].

The Network Code on tariff structures (NC TAR)[68] creates rules on which basis the allowed revenues can be collected, enhancing transparency of tariff setting, providing a framework based on cost-drivers and the principle of cost reflectivity. However, although being transparent and cost reflective, tariffs effectively render cross-border flows uneconomic in case the tariff of the needed capacity is higher than the price difference between markets, to the detriment of overall efficiency. The more borders are crossed, the higher the effect of adding tariff layer on tariff layer, which is called the 'pancaking' effect.

In the context of biomethane, pancaking may lead to a situation where the differences of production costs between Member States are not exploited. This may lower physical cross-border trade with renewable gases that might be compensated by higher natural gas imports.

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67 Transit countries may have an interest in increasing their external entry and exit tariffs and decrease their internal exit tariffs to transfer the costs of transportation to other countries instead of their national consumers, but increasing too much these tariffs may result in shippers/traders choosing a different route. On the other hand, a country that would rely too much on internal exit tariffs may apply an unfair weight on its consumers, while the national services brought by the TSO also benefit other consumers.

68 Commission Regulation (EU) 2017/460.

2.2.1.4 Driver 2: Differences in gas quality and hydrogen blending levels can negatively impact cross-border flows and end-users, current gas quality rules not fit to deal with future developments

Today, gas quality is defined by European Committee for Standardization (CEN)-standards and at national level[69]. The EN 16726 standard on gas quality developed by the CEN is not mandatory. Member States are setting the mandatory gas quality specifications, which can deviate from the CEN standard. In practice, the national specifications vary significantly between Member States[70] to take into account national specificities. Gas producers and suppliers are obliged to deliver the gas within quality ranges specified in commercial agreements between the network user and the system operator. In most Member States, system operators have either the obligation or the right to reject the injection of gases, which do not comply with the applicable gas quality specifications. In the cross-border context this means that TSOs at a cross-border point can reject gases of a quality not corresponding with the applicable (national) gas quality specification.

Beyond the quality standards, a cross-border coordination and dispute settlement framework for interconnection points (IPs) exists. The Interoperability and Data Exchange Network Code[71] obliges neighbouring TSOs to address gas quality aspects in their Interconnection Agreement for a given IP. Should the concerned TSOs fail to agree on a solution, the competent NRAs must adopt a coordinated decision. In the absence of such coordinated decisions, ACER can adopt an individual decision.

In practice, the injection of growing volumes of renewable and low-carbon gases, including biomethane and hydrogen, into the existing gas network is changing the parameters of gas consumed and transported in the EU, both at transmission and distribution levels. These changes in the quality of gases can have negative impacts on their cross-border flow and can cause problems and additional costs for system operators and end-users.

Biogas and biomethane have specific quality aspects to consider. In order to transport biogas in the existing gas network and use it in connected appliances it has to be upgraded to biomethane before injection[72]. Biomethane producing Member States developed their (differing) quality standards, and also CEN developed a biomethane quality standard for injection in the natural gas grid and for use in transport[73]. While biomethane can be used without the need for any changes in transport infrastructure and end-user equipment, quality related issues (e.g. due to differences in oxygen content) might still arise, including at cross-border IPs. Further, the lower and varying calorific value of the gas at high biomethane

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69 EN 16726 'Gas infrastructure – quality of gas – group H', published in OJEU in December 2015 provides a harmonised H-gas (natural gas) quality standard covering a number of relevant specifications.

70 Study Potentials of sector coupling for decarbonisation: Assessing regulatory barriers in linking the gas and electricity sectors in the EU | Energy (europa.eu).

71 Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules (Text with EEA relevance) EUR-Lex - 32015R0703 - EN - EUR-Lex (europa.eu).

72 Biomethane can vary in characteristics such as Wobbe index; ENTSOG 2018.

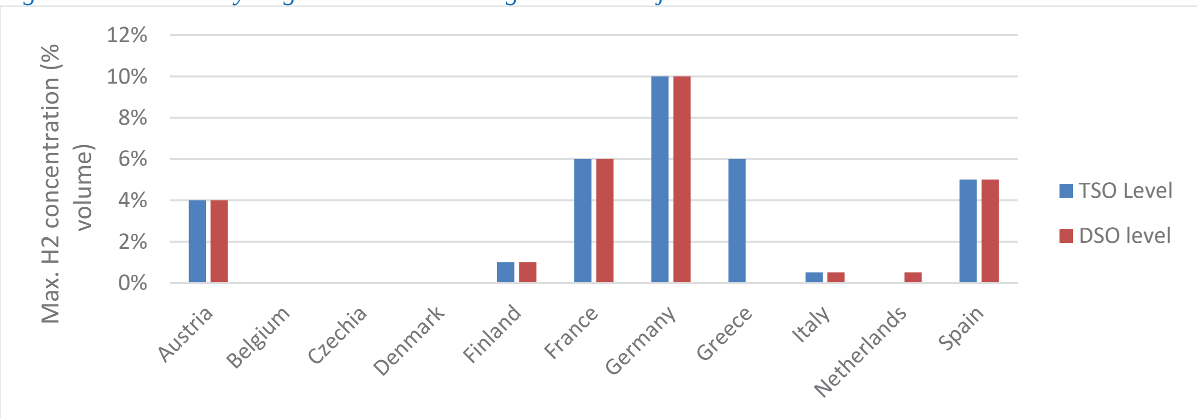
73 EN 16723-1: 2016 for the injection of biomethane in the natural gas grid and EN 16723-2: 2017 on natural gas and biomethane for use in transport.

injection rates could lead to issues related to metering and billing to end-users, as flow meters could incorrectly measure the user's energy consumption.

Blending of hydrogen affects the operation of gas infrastructure, end-user applications, and interoperability of cross-border systems. Hydrogen has a lower specific energy content which reduces the combustion properties of the gas mix, in particular the calorific value. This affects gas engines. Not all gas infrastructure components and gas consumers are able to cope with blended gases.

Currently, allowed hydrogen blending rates are determined in some Member State and vary significantly (see *Figure 5*. The interconnection agreements may not provide specifications regarding hydrogen concentrations. In addition, the future gas mix will lead to changes and more frequent fluctuations of the gas quality, making gas quality management in the existing gas network more complex and costly. . The interconnection agreements may not provide specifications regarding hydrogen concentrations. In addition, the future gas mix will lead to changes and more frequent fluctuations of the gas quality, making gas quality management in the existing gas network more complex and costly.

Figure 5: Maximum hydrogen concentration regulation or objective



Source: (ACER, 2020), (FCHJU, 2021)

2.2.1.5 Driver 3: LNG terminals equipped to receive mainly natural gas, limited access for new gases to LNG terminals

The LNG market has significantly changed since the adoption of the Third Energy Package[74] and rules applicable to LNG terminals in the EU. Efforts were made to utilise the LNG terminals to bigger extend, to move towards shorter-term capacity reservations and to enable small scale LNG and smaller players to develop. Some **barriers to access** LNG terminals persist, such as lack of transparency in tariff setting, capacity availability and allocation procedures.

Even if today's LNG facilities are primarily used for the import of natural gas from third countries, they could act in the future as facilitators for the import of renewable and low-carbon gases into EU. Biomethane, hydrogen and methanol can be liquefied and transported using LNG facilities provided some adaptations:

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74 Third energy package | Energy (europa.eu)

- In case the biomethane or synthetic methane meets the gas quality specifications, no changes are needed in LNG terminals;
- Regarding hydrogen, the physical and chemical differences between methane and hydrogen do not allow using existing LNG infrastructure as such and require its adaptation. Moreover, due to lower energy density of hydrogen the transport costs are likely to be higher;
- Hydrogen can be transformed to ammonia and methanol and LNG ships and terminals can be used to transport these energies. The associated costs for liquefaction, transport, storage and regasification stages are smaller.

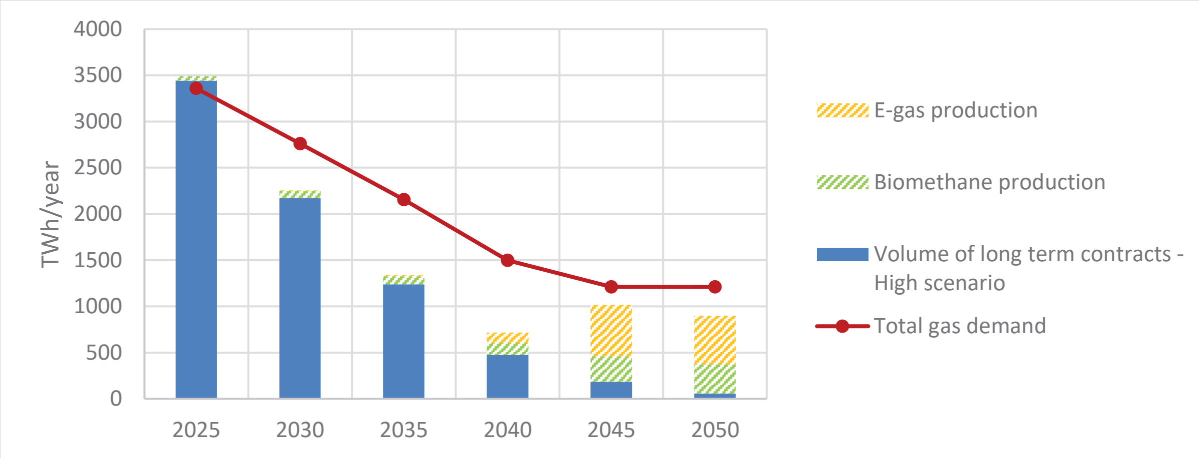
Addressing the residual barriers regarding access to LNG terminals could open the way to importing renewable and low carbon gases from abroad supporting the decarbonisation of the EU gas market.

2.2.1.6 Driver 4: Long term supply contracts for unabated natural gas may lock-in natural gas and hinder supply of renewable gases towards 2050

Long term contracts (LTC) for natural gas amount today to some 80% of the total supplies in the EU gas market. Some LTCs run as far as 2049. Long-term contracted volumes decrease over time (Cedigaz). While many of the current pipeline contracts date back to the 1990's, LNG contracts were in majority concluded after year 2000. As public information indicates, new LTCs could be signed, or the existing contracts could be prolonged, which may have a duration until 2050 and beyond. This will depend on the perception of market participants about EU achieving full net decarbonisation by 2050 and available technologies to reach this.

Natural gas supply contracts reduce the space left for biomethane and low-carbon synthetic methane. This may hinder the penetration of renewable and low-carbon gases as the market could be driven by imports of natural gas combined with contracts on the demand side, even in a situation where biomethane would be cost competitive (e.g., due to a significantly higher carbon price). Overall, the continued unconstrained existence of LTC's up to 2050, risks to lead to carbon lock-in. Consistency with the transition from today towards climate neutrality by 2050 could then only be ensured through large scale deployment of CCS technology.

Figure 6: Natural gas long term contracts overview



Source: Cedigaz database, calculations Artelys

2.2.1.7 Driver 5: Current energy security arrangements only address risks related to the supply of natural gas and not of renewable and low carbon gases.

The current framework on energy security to prevent and manage possible disruptions are laid down in the SoS Regulation, which scope is limited to the risks related to the supply of natural gas only. Effects of repurposing or decommissioning of existing gas infrastructures are not explicitly addressed nor the positive impact or the specific risks of biomethane. Climate change induces risks impacting both infrastructure and production of renewable gas. Moreover the uses of smart grids, big data, artificial intelligence and automation enables a more efficient, resilient and lower-carbon operating model for the energy sector but increase the exposure to cyber threats. The current framework for ensuring energy security is not prepared for this change.

2.2.2 How will the problem evolve?

By 2030, a regulatory patchwork would still exist regarding access to wholesale markets, connection obligations and TSO-DSO coordination measures. Likewise, renewable and low-carbon gas producers will be facing different connection and injection costs across the EU, thereby resulting in an unequal playing field. Existing gas quality standards would remain non-binding and their application cross-border would not be aligned. Regarding biomethane, gas quality specifications would continue to be mainly defined by the quality parameters of natural gas. All these aspects are likely to lower cross-border trade of renewable gases that might be compensated by higher natural gas imports or higher support schemes. The utilisation of the terminals and imports could remain mainly for natural gas. With the increasing share of domestic production of gases and diversified suppliers, the current framework for ensuring energy security based on natural gas corridors, will become less effective. New cyber risks would become much more present, in a changing topology of the network.

2.3 Problem Area III: Network planning

2.3.1 Problem: Insufficient energy system integration in network planning

As outlined in the European Commission’s Energy System Integration Strategy, coordinated planning and operation of the entire EU energy system, across multiple energy carriers, infrastructures, and consumption sectors is a requisite to achieve the 2050 climate objectives.

However, consideration of energy system integration in current network planning schemes and practices is deficient. Additionally, there are discrepancies between the EU-wide ten-year network development plan (TYNDP) and national network development plans (ETS NDP) in relation to the requirement of e.g. joint scenario building between electricity and gas infrastructures, which is all not required for NDPs. As a consequence, this may result in overestimating infrastructure needs in national plans, but also in the TYNDP as the TYNDP is based upon NDPs, and may hence negatively affect more efficient and coordinated infrastructure investments enabling a faster and better transition. On the contrary, a better linkage between the TYNDP and NDPs would allow transnational exchange of information on expected transmission systems usage and developments based on joint scenarios. This aspect in particular is linked with Problem Area I and II because a harmonised system development strategy would also provide the possibility to valorise stranded assets to transport decarbonised gas or hydrogen.

2.3.1.1 Driver 1: Network planning varies between Member States and TSOs, separate planning for electricity and gas

Member States are not required by EU law to develop a national network development plan, if the TSO is certified as ownership unbundled. Therefore, network plans do not exist in all Member States. The TYNDP covers in principle only cross-border infrastructure and is of lower granularity.

Additionally, in about 74% of Member States there is either a methane NDP or no NDP at all, while only in two cases a cross-sectoral approach is taken[75]. Planning on national level is hence based on sectoral needs, and, in contrast to the requirement of joint scenario building between gas and electricity at EU level, can be even based on different scenarios used for different energy sectors. Uncoordinated planning risks that synergies between different sectors are not exploited leading to inefficient investments.

2.3.1.2 Driver 2: No transparency on potential of existing infrastructure for repurposing or decommissioning.

While it is expected that demand for natural gas will decrease significantly, infrastructure of one sector, e.g. gas, may provide services for transporting energy to the benefit of another sector (e.g. electricity) and hence reduce overall infrastructure investments. Current development plans focus on the identification of additional investments, while neglecting information on which infrastructure may not be required anymore in the future. Additionally, without providing this information, the impact on energy security of Member States downstream of the Member State where infrastructure is planned to be used for another purpose or would be decommissioned could be negatively affected.

2.3.1.3 Driver 3: DSOs not explicitly included in TSO planning

Current planning practices and obligations on gas TSOs and DSOs to cooperate on network planning vary significantly across Member States leading to suboptimal information provision for planning purposes. Some Member States have obligations for the TSO(s) and

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[75] ACER OPINION No 09/2020, Annex I.

DSO(s) to cooperate e.g. in order to define the most appropriate level for connection of new biomethane plants[76].

ACER and CEER (Council of European Energy Regulators) note that while TSOs generally provide or publish information on the network and DSOs on connections, the level of information sharing varies per country and usually there is no obligation for the TSO to take the information from DSOs into consideration. In some countries combined transmission and distribution system operators exist, such as in Denmark (Energinet) and Luxembourg (Creos)[77]. However, most EU Member States have separate operators for gas transmission and distribution networks.

2.3.2 How will the problem evolve?

Electricity and gas are already interlinked mainly by gas-to-power assets[78]. However, with power-togas assets, such as electrolysers, the interlinkages between electricity and gases including hydrogen is expected to become more integrated. The TEN-E proposal already includes the requirement of joint scenario building as well as hydrogen as new infrastructure category. Although hydrogen infrastructure is part of the TYNDP, the TEN-E proposal does not require the inclusion in the national plans. Moreover, the implementation of a joint scenario, as described in Section 2.3.1, requires minor changes to the Electricity Directive, e.g. in respect of joint scenario building and involvement of all transmission system operators irrespective of the unbundling model that will equally need to apply to electricity to implement a more sector integrated approach on national level. Without aligning national electricity network planning with gas, the problem of inconsistencies between both, the national and European level planning and between the sectors could evolve into even more inconsistencies as a result of joint scenario building on EU level. Without reflecting a higher degree of integration and coordination, the problem of different approaches to network planning and little information on planned decommissioning or repurposing entails the risk of leading to more inefficiencies, both in terms of sector integration, but also for the integration of renewables gases in the methane-based infrastructure.

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76 This includes France, where the French NRA deliberation N° 2019-242 defines the procedures for assuring the ‘right to connect’ established by law 2018-938. The deliberation 242 requires French gas TSOs and DSOs to cooperate in order to establish a zoning program for the connection of biomethane projects. Candidate biomethane producers must register in a capacity management register, which triggers the development of detailed (for the distribution level) or feasibility (for the transmission level) studies. Based on the estimated costs and the cost allocation rules defined in deliberation 242, the preliminary connection agreement can be signed (with the producer eventually paying for part of the connection and reinforcement costs).

77 Luxembourg is exempted based on Art. 49 (6) of Directive 2009/73/EC from applying Art. 9 (ownership unbundling) of the same Directive.

78 Power-to-gas installations use electrical power to produce a gaseous fuel, usually hydrogen

2.4 Problem Area IV: Low level of customer engagement and protection in the green gas retail market

2.4.1 Problem: Insufficient customer protection, lack of participation and rigid competition make the green methane gases difficult to access the retail market

For new gases to play a full role in the energy transition, the retail market rules should empower customers to make low carbon choices. This is not currently the case. Retail gas markets exhibit market concentration and low levels of new entry and innovation. This prevents customers[79] from benefiting from competition by making low carbon choices. Moreover, as the increase in natural gas prices occurring in autumn 2021 shows, a sharp increase in the price of natural gas can have a significant impact on consumers.[80] The possibility of a resurgence of such a price increase cannot be excluded over time. It is therefore important to take into account the extent to which the contemplated measures can help to prevent and mitigate this price volatility in the future and ensure access to energy as an essential service, in line with the European Pillar of Social Rights.

2.4.1.1 Driver 1: Untapped competition potential in retail markets

Limited competition in many Member States explains poor customer satisfaction and engagement in the gas market as well as slow uptake of new gases. In spite of falling prices in wholesale markets, gas prices for household customers rose between 2010 and 2019[81]. Industrial customers pay, in general, two to three times less for their gas than household consumers[82].

Non-targeted **price regulation** still exists in at least 14 out of 27 gas household markets[83] and in the non-household market in at least Portugal, Slovakia, Hungary and Bulgaria[84]. Price regulation – particularly with low or negative mark-ups – hinders entry by suppliers of new products, notably green gases, and can result in consumer disengagement. Low mark-ups may even lead to market foreclosure in Latvia, Hungary, Romania, Croatia, Bulgaria, Slovakia and Poland[85].

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79 This section uses the term customer to denote both household and/or non-household customer that purchases electricity. The term ‘consumer’, as defined in Article 2 (a) of Unfair Commercial Practices Directive, is used interchangeably with ‘household customer’.

80 After reaching peak prices in October (close or above 200 €/MWh in some countries), wholesale electricity prices have been responding to gas prices falling at the beginning of the November before rising back to around October’s peak levels. Prices are expected to remain volatile, reacting to gas prices and weather changes.

81 Energy Prices and Costs SWD, 2020, p. 65.

82 Energy Prices and Costs SWD, 2020, p. 65.

83 ACER Market Monitoring Report 2020, Energy Retail and Consumer Protection Volume, p. 30. Note that in the context of **supplier of last resort schemes**, all but seven out of 23 screened member states intervene in the price setting in some fashion. See in this regard, ACER Market Monitoring Report 2018, Consumer Empowerment Volume, p. 12.

84 Retail market barrier study, final report, p. 50; ACER market monitoring report 2020, Energy Retail and Consumer Protection Volume, p. 50.

85 Retail market barrier study, final report, p. 50. See also ***Error! Reference source not found.*** on Average annual mark-up in retail gas markets for household consumers.

Household gas markets continue to be more concentrated than industrial and commercial markets[86] indicating high entry barriers for new suppliers particularly of renewable and low carbon gases[87]. While consumer choice has widened in recent years, a closer inspection reveals that variety of offers in Member States are mainly fixed offers. The offer and uptake of other, more innovative products, remains limited[88]. In 2019, **'green' gas offers were available in only seven out of 25 screened Member States**[89]. Countries with a more liberalised retail market tend to have a higher percentage of 'green' offers[90].

2.4.1.2 Driver 2: Insufficient customer empowerment in terms of switching, price comparison tools, billing information, energy communities, and access to data.

To be able to make sustainable energy choices, customers need sufficient **information on their energy consumption and origin**, as well **efficient tools to participat**e in the market. Today customers are not sufficiently engaged in the gas market, which still lags behind on consumer protection compared to the electricity sector, especially with regards to **bills and billing information**, **switching** and **price comparison tools.** Consumers face particular issues in understanding the basic information in their energy bill[91]. There is a high divergence in particular in the internal market regarding information on sources of energy and historical consumption[92].

Switching is an important indicator. Without this pressure, there is no incentive for suppliers to compete for customers, notably by offering renewable or low carbon options. Switching rates **in some countries are still below 1%**, which may be attributed to consumer inertia and aggravated by further price increases due to decarbonisation[93,94]. Consumers often encounter difficulties to understand the terms and conditions of their **energy contracts**, especially with regard to termination[95], **as exit and termination fees** discourage consumers switching[96].

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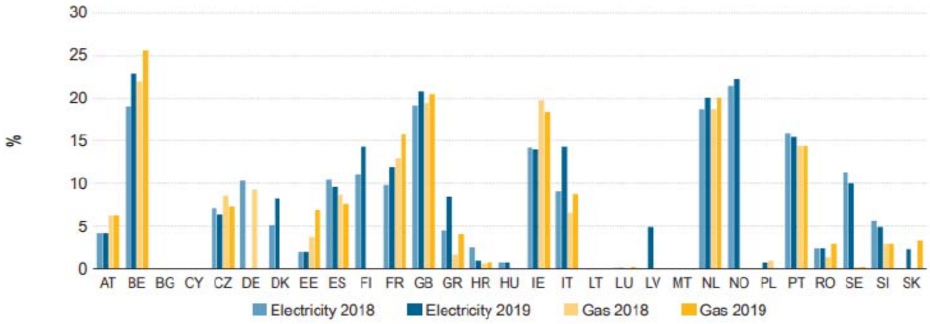
86 See ACER Market Monitoring Report 2020, Energy Retail and Consumer Protection Volume, pp. 27-29. See also Annex 10 for more information.
87 ACER Market Monitoring Report 2019 – Energy Retail and Consumer Protection Volume, p. 42.
88 ACER Market Monitoring Report 2019, Energy Retail and Consumer Protection Volume, p. 55.
89 ACER market monitoring report 2019, Energy Retail and Consumer Protection Volume, p. 55.
90 ACER Market Monitoring Report 2015, Electricity and Gas Retail Markets, p. 18.
91 Investigating the benefits of aligning EU consumer protection and information rules in the gas and electricity sectors, VVA study p. 51-52.
92 See Evaluation Report Section 7.1.2.
93 European Barriers in Retail Energy Markets Project: Final Report; European Commission, 2021, p.59.
94 Consumer study on precontractual information and billing in the energy market, final report, p. 91 https://ec.europa.eu/info/sites/default/files/final_report_2_july_2018.pdf.
95 BEUC, 2017, Stalling the switch, 5 barriers when consumers change energy suppliers.
96 See Evaluation Report Section 7.1.2.

Figure 7: Percentage of external switching rate of household consumers (by number of eligible meter points)



Source: (CEER, 2018)[97]

Price comparison tools (PCTs) facilitating consumer engagement are inconsistently developed among Member States and customers[98]. Even where available, comparison may only be possible based on price rather than renewable credentials. Malpractices (e.g. default offers, misleading language) prevent consumers from access to clear, independent, and free of charge information about their gas supply.

The creation of **energy communities**[99] can be a solution to enhance public acceptance of renewable gas (projects)[100]. However, today, the number of energy communities operational on the green gas market is still limited[101] despite their potential to contribute to the uptake of renewable energy[102]. This may be attributed to a variety of general and renewable gas-specific barriers[103,104]. The enabling framework for 'renewable energy communities' (REC)

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97 CEER Monitoring Report on the Performance of European Retail Markets 2018, p.31.

98 Consumer study on precontractual information and billing in the energy market, final report, p. 91 https://ec.europa.eu/info/sites/default/files/final_report_2_july_2018.pdf. See Evaluation Report, Section 7.1.2.

99 As defined in Glossary.

100 Public resistance is derived from increased vehicle traffic in the area (linked to biogas or biomethane transport), odour associated with biogas production, concerns over impact of biogas production on local air quality and pollution as well as safety concerns around local biogas and biomethane production. See Frontier study (2021), 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 5; T. Bauwens and P. Devine-Wright, 'Positive energies? An empirical study of community energy participation and attitudes to renewable energy' (2018) Energy policy 118. https ://www.biogaschannel.com/en/video/biomethane/7/acceptance-biogas-how-biomethane/1378/ ; and GRDF, 'Méthanisation Agricole Retour d'expérience sur l'appropriation locale des sites en injection', 2016.

101 Out of the 642 members of REScoop in 2021, only an estimated 3% are active in the gas sector. See Frontier study, 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 10. See also Joint Research Centre (2020), 'Energy communities: an overview of energy and social innovation', p. 26.

102 By 2050, 37% of the renewable energy produced by citizens could stem from collective projects, such as energy communities. See Joint Research Centre (2020), 'Energy communities: an overview of energy and social innovation', p. 27.

103 Stakeholder interview with Cormac Walsh from Energy Cooperatives Ireland, 12th of June 2021; Frontier et al's report (2019), 'Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU – Final report', p. 49; Benjamin Huybrechts and Sybille Mertens, 'The relevance of the cooperative model in the field of renewable energy [2014]

in the Renewable Energy Directive 2018/2001/EU does not facilitate a majority of shareholders/members distant from production sites (e.g. in cities) buying renewable and low-carbon gases, and does not fully tap into community potential for bringing more volume or less costly[105] renewable and low-carbon gas to the system[106,107].

Limited access to smart metering and **to data** can also contribute to low engagement by consumers. Smart metering help customers manage energy consumption and supports energy efficiency. It also improves billing accuracy - one of the largest sources of consumer complaints[108]. Currently, the business case for gas smart metering[109] remains more challenging than that for electricity, and as a result, its deployment is limited and is progressing at a slow pace across the EU[110]. Existing legislation lacks rules[111] on data management to govern processes by which data is sourced, validated, stored, protected and processed and by which data can be accessed by suppliers or customers[112]. This is market entry barrier for new entrants. The necessity to adapt to **different data management models** for each national market has an impact on the resources of potential market newcomers. The fact that not all countries have rolled out smart meters yet also creates **significant differences in the availability and accessibility of data**.

2.4.1.3 Driver 3: Inadequate consumer protection in particular for vulnerable and energy poor

The EU's increased climate ambition will result in low income households across the EU bearing a relatively higher burden in terms of heating fuel expenses compared to wealthier

Annals of Public and Cooperative Economics, pp. 199-201; Binod Prasad Koirala, 'integrated community energy systems' (Dphilthesis, Delft University of Technology 2017, p.1.

104 One of the drivers for the heterogeneous picture of energy communities across Member States has been the varying national legislative frameworks in place for energy communities. See Frontiers, 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', pp. 8-9; Ronne, A., and F.G. Nielsen, 'Consumer (Co-)Ownership in Denmark', Energy Transition – Financing Consumer Co-Ownership in Renewables, Palgrave Macmillan, Cham, 2019.

105 Due to the value over profit mentality of energy communities, lower profitability is needed for projects. Financing the projects with citizen results in lower rate of return requirements and lower overall costs. See Artelys, Trinomics, Frauenhofer, JRC (2021).

106 Frontier study (2021), 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 11.

107 For more information on energy communities see Annex 10.

108 The 9th ACER/CEER Market Monitoring Report – Energy Retail and Consumer Protection Volume (2020), shows (in its Figure 55) that the biggest average share of complaints regarding gas suppliers concerns invoicing/billing and debt collection (40%).

109 For more information on smart metering see Annex 10.

110 See also Evaluation Report, Section 7.1.2.

111 Current provisions regarding smart metering: Articles 3(8) and Annex I.2 of the Gas Directive 2009/73/EC; also complementing provisions can be found in Articles 9(2); 10(2); 12(2b) of the Energy Efficiency Directive (EED) 2012/27/EU; provisions regarding access to data: Article 41(1)(q), Article 45(first paragraph), and Annex I (1h) of the Gas Directive 2009/73/EC.

112 Adapted from: CEER Report 'Benchmarking report on removing barriers to entry for energy suppliers in EU retail energy markets' (2016) p. 19; See also VaasaETT, 'Market Entrant Processes, Hurdles and Ideas for Change in the Nordic Energy Market', p.22, (2014).

households[113]. In 2019, natural gas accounted for 32% of the EU final energy consumption in households, the highest energy source[114]. 64% of energy use by households was for home heating where demand is prices inelastic. Gas decarbonisation is likely to result in further price increases.

There is currently a mismatch of energy poverty and vulnerable customers coverage across internal energy market legislation. This results in a lack of coherence with other EU interventions in the wider energy and climate domain.

Protection of gas consumers also relies on the availability of effective means of dispute settlement. All Member States, except Cyprus, have implemented an Alternative Dispute Resolution (ADR) mechanism for both electricity and gas, in most cases free of charge for final household customers. However, there are still varying levels of available mechanisms and information on how to access such mechanisms – for example legal maximum processing times vary substantially across MSs and can reach up to six months[115].

2.4.2 How will the problem evolve?

The identified gaps in all customer empowerment and protection areas, including switching fees, market-based prices, basic contractual rights, vulnerable consumers, and energy communities are likely to worsen if not properly addressed. Both the legal framework and energy policies should, thus, be improved where needed to constantly protect and empower customers, namely households. This should be pursued still in a flexible way to adapt to the changing energy landscape and technologies, while respecting national features, where suitable.

2.5 Interdependencies between problem areas

All problem areas are connected in that they concern the rules affecting (wholesale and retail) markets and infrastructure for gases that are necessary for enabling the energy transition. By readying these rules for the changes that replacing fossil gas with decarbonised alternatives will bring, a system is created whereby renewable and low carbon gas producers can use networks and wholesale markets and challenge incumbents for access to consumers across the internal market and consumers can benefit from functioning (retail) markets across the EU and renewable and low carbon gases. At a more granular level:

- Problem Areas I and II are connected in some sub-areas, notably terms of infrastructure and infrastructure operators and tariffs and governance structure;
- Problem Areas II and IV are connected as both concern methane wholesale and retail markets. Such connections are less pertinent for Problem Areas I and IV as hydrogen retail customers are few and likely larger and more sophisticated[116];

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113 The introduction of a carbon price would increase end-consumer prices for fossil fuels (household heating and cooling expenditure and gasoline for vehicles) to a different degree depending on the carbon price levels and on the underlying relative level of existing other taxes on fossil fuels.

114 Electricity for 25%, renewables for 20% and petroleum products for 12% (Eurostat).

115 ACER Market Monitoring Report 2018 –Consumer Empowerment Volume.

116 In fact, consumer rights to the extent pertinent are dealt with in this Impact Assessment as an integral part of Problem Area I, and not separately.

– Problem Area III is linked to Problem Areas I and II as it adapts the network planning at national level to the integrated approach introduced in the TEN-E Regulation at the EU level.

2.6 Evaluation

Conclusions from the Evaluation and treatment in this Impact Assessment.

2.6.1 Problem Area I

The entry into force of the Third Energy package has positively contributed to competition and performance of the internal energy markets. However, the current regulatory framework for gas focuses on fossil-based natural gas and does not anticipate the emergence of gases and infrastructure for alternatives to methane, in particular hydrogen and hydrogen infrastructure.

The Evaluation thus concluded that a re-examination of the current gas market regulatory framework is therefore needed. Given the different potential in EU Member States for the production of renewable and low carbon hydrogen, a suitable market framework could facilitate hydrogen to play its role as an energy carrier and as an enabler of energy system integration in the EU. On these basis, four main drivers have been identified under Problem Area I of the Impact Assessment.

2.6.2 Problem Area II

The existing gas rules, focusing on natural gas mainly imported from outside the EU, do not address the specific characteristics of decentralised renewable and low-carbon gases production within the EU. Accommodating higher shares of renewable and low-carbon gases in the system poses also new challenges that were not originally foreseen by the Third Energy Package. The growing volumes of biomethane, hydrogen but also LNG affect gas quality and thereby the design of gas infrastructure and end-user appliances. In particular, this Impact Assessment recognizes five main drivers related to renewables and low carbon gases emerging role in the existing infrastructure and markets.

2.6.3 Problem Area III

Concerning network planning, the Evaluation states that under the Third Energy Package cooperation between TSOs and the national regulatory authorities has improved, but needs to evolve further. The increasing penetration of intermittent energy sources, on the contrary, requires the whole energy system, both markets and infrastructure planning, to be better integrated. The progressive integration and emergence of new energy markets characteristics, means that infrastructure becomes more interconnected. A more holistic and inclusive approach to infrastructure network planning may therefore be required for system operators, as opposed to the largely silo-based current practices.

The Impact Assessment outlines three main drivers regarding this Problem Area. Furthermore, a more harmonised system development strategy would further increment interlinkages between electricity and gases systems including hydrogen.

2.6.4 Problem Area IV

The evaluation showed that competition still needs to significantly improve to ensure that the full benefits of market integration are passed on to EU consumers. Furthermore, consumers are still deprived from the necessary tools to get actively involved in the market, including fast switching procedures, independent comparison tools, transparent gas bills, and gas smart metering. Consumer protection provisions in the analysed legislation prove to only be partially fit for purpose. In particular, protection for vulnerable customers is still uneven between Member States and energy poverty continues to be significant across the EU and the years leading to climate neutrality will require solid safeguards to ensure the energy transition leaves no one behind, meaning that energy poverty alleviation measures will need to be strengthened.

Concordantly, Problem Area IV identified three problem drivers.

For a more detailed analyses of the manner in which the conclusions of the Evaluation have been taken into account, reference is made to Annex 11.

3 WHY SHOULD THE EU ACT?

3.1 Legal basis

The planned measures of the present initiative seek to advance the four objectives set out in Article 194 TFEU, while at the same time contributing to the decarbonisation of the EU's economy. The planned measures are to be adopted on the basis of Article 194 (2) TFEU together with Article 114 (1) TFEU. In the field of energy, the EU has a shared competence pursuant to Article 4 (2) (i) TFEU.

3.2 Subsidiarity: Necessity of EU action

To achieve EU decarbonisation goals it will be necessary to gradually replace natural gas by decarbonised energy carriers including electricity, renewable heat and decarbonised gases. The speed and scope of this transition, including how much of which gaseous fuels will be part of the energy mix, will depend on the chosen decarbonisation pathway and the deployment of other policy instruments. However, the current regulatory framework for gas focuses on natural gas and does not anticipate the emergence of alternative methane gases, such as bio-methane, or other gaseous fuels, such as hydrogen.

Currently, there are no rules at EU-level regulating dedicated hydrogen networks or markets and LCH and LCFs. In view of the current efforts at EU and national level to promote use of renewable hydrogen as a replacement for fossil fuels, Member States would be incentivised to adopt rules on the transport of hydrogen dedicated infrastructure at national level. This creates the risk of a fragmented regulatory landscape across the EU, which could hamper the integration of national hydrogen networks and markets, thereby preventing or deterring cross-border trade in hydrogen. Harmonising rules for hydrogen infrastructure at a later stage (i.e. after national legislation is in place) would lead to increased administrative burden for Member States and higher regulatory costs and uncertainty for companies, especially where long-term investments in hydrogen production and transport infrastructure are concerned.

When it comes to biomethane, without an initiative at EU level, it is likely that by 2030 a regulatory patchwork would still exist regarding access to wholesale markets, connection obligations and TSO-DSO coordination measures. Likewise, without some harmonisation at the EU level, renewable and low-carbon gas producers will be facing vastly different connection and injection costs across the EU, resulting in an unequal playing field.

Without further legislation at the EU level Member States would continue to define gas quality specifications based on the quality parameters of natural gas. Therefore, biomethane producers would also in the future need to adapt to this quality at additional cost. The rules on hydrogen blending would be left to the Member States without the definition of allowed hydrogen blending levels at cross-border interconnection points.

All these aspects are likely to lower cross-border trade with renewable gases that might be compensated by higher natural gas imports. The utilisation of the LNG terminals and imports could remain restricted to natural gas, despite that no adaptation of LNG terminals would be necessary in case competitive biomethane or synthetic methane from non-EU sources were available.

Without adjusting the national planning provisions, there is a risk that NDPs and the TYNDP (which builds on NDPs) become inconsistent. Member States may decide to adapt their national plans, but without EU's action it cannot be ensured that all NDPs follow the same basic framework. Ensuring consistency between EU and national network development planning is of Union relevance as it cannot be achieved in an efficient way only on the basis of the European plan due to a lack of more detailed information on network level. Close interaction and informed decisions based on local circumstances are required. It is therefore necessary that the methodology and overall framework for the European planning process and the national planning is consistent with each other.

Moreover, an EU-wide framework for introducing competition on methane retail markets and enabling consumers' choice is beneficial for providing level playing field for energy producers and suppliers as well as to benefit the consumers. Harmonised approach to metering and billing as well as consumer protection provisions safeguard the level playing field for suppliers and provide equal rights for energy consumers. It also facilitates providing cross-border services.

The current framework for ensuring gas supply security will not be adequate for the needs and threats of the future decarbonised gas system. Uncoordinated national emergency preparedness for the new gases risks undermining their effectiveness in case of disruptions. The EUCJ ruling of 15 July 2021 (Case C-848/19) confirmed the need to consider security of supply and energy solidarity in Commission's initiatives.

3.3 Subsidiarity: Added value of EU action

The initiative aims at modifying existing EU legislation and creating a new framework for an internal hydrogen market, which is key to achieve a cost efficient clean hydrogen economy.

The challenges cannot be addressed as efficiently by individual Member States as fostering more efficient and integrated EU markets for gases requires harmonised and coordinated approaches by all Member States; which can only be achieved by EU action. The initiative is also aimed at avoiding the distortive effects of uncoordinated, fragmented policy initiatives as many Member States develop national approaches e.g. with regard to hydrogen deployment. EU action has significant added-value by ensuring a coherent approach across all Member States and towards third countries, as achieving the decarbonisation objectives of the EU may require imports of renewable and low carbon gases from third countries.

The initiative on decarbonised gases also contributes to achieving binding EU-level objectives. The EU has already committed to achieving a share of at least 32% of renewable energy sources in total energy consumption by 2030 and has issued an ambitious strategy for the deployment of hydrogen to reach 40GW of installed electrolyser capacity by 2030. The

European Commission has recently proposed to cut net greenhouse gas emissions even further by at least 55% compared to 1990 levels by 2030, up from the current target for 2030 of at least 40%. The greenhouse gas emissions reduction target of 55% is assessed to lead to a share of renewables of between 38% and 40%. Gaseous fuels will continue to provide an important share of the energy mix also by 2050, requiring the decarbonisation of the gas sector via a forward-looking design for competitive decarbonised gas markets.

Consequently, the objectives of this initiative cannot be achieved only by Member States themselves and this is where action at EU-level provides an added value.

As regards hydrogen, the creation of regulatory framework at EU-level for dedicated hydrogen networks and markets would foster the integration and interconnection of national hydrogen markets and networks. EU-level rules on the planning, financing and operation of such dedicated hydrogen networks would create long-term predictability for potential investors in this type of long-term infrastructure, in particular for cross-border interconnections (which might otherwise be subject to different and potentially divergent national laws).

EU coordinated emergency preparedness for the current gas sector has proven to be more efficient than action only at national level.

4 OBJECTIVES: WHAT IS TO BE ACHIEVED?

4.1 General objectives

Table 3: General policy objective

General policy objective
Contribute to the EU's decarbonisation within the framework of the Fit-for-55 package to implement the European Green Deal in a cost-effective manner by facilitating the creation of a European hydrogen market and the gradual decarbonisation of gaseous fuels markets

4.2 Specific objectives

Table 4: Specific objectives

Problem Area	Objective	Sub-objectives
I	Facilitate the emergence of an open and competitive EU hydrogen value market	- Enable the emergence of an efficient, integrated EU hydrogen market - Remove barriers and ensure incentives to invest in hydrogen infrastructure - Address risk that the natural monopoly character of hydrogen infrastructure gives rise to non-competitive market structures. - Ensure cross-border integration (including on borders with third countries), unhindered hydrogen (cross-border) flows and required hydrogen quality for end-users
II	Ensure access of renewable and low carbon gases to the existing methane networks and markets and their security of supply	- Facilitating access of local production of biomethane to the gas markets across EU - Facilitating connection rules and injection - Ensuring access to LNG terminals for RES&LC gases - Ensure unhindered cross-border flows for RES&LC gases - Tackle risk of negative impact on end-users in terms of gas quality - Avoid lock-in into LTCs for natural unabated gas - Improve the resilience to relevant threats of the future gas system integrating renewable and low carbon gases

III	Ensure transparent and inclusive infrastructure planning	- Provide transparency for repurposing existing gas networks - Enable cost efficient planning on the basis of scenarios that are in line with the climate target objectives
IV	Give consumers tools to choose the cheapest decarbonisation options	- Increase competition in retail renewable and low carbon gas markets by also addressing price regulation - Strengthening consumer engagement in such market - Ensure an adequate level of consumer protection

5 AVAILABLE POLICY OPTIONS

The policy options investigated in this Impact Assessment are packages structured around more detailed sets of measures that reflect different depths of the regulatory intervention for creating markets for gases that enable the energy transition. The policy options hence represent political choices going from a lighter to a more detailed/stringent regulatory framework. Each of these packages reflect different sets of more detailed policy measures (summarised within this chapter for each Problem Area but also described in more detail in the Annexes) that seek to address the problem and its underlying drivers.

5.1 Options in the Problem Area I: Hydrogen infrastructure and markets

5.1.1 Baseline

Today, about 1600 km of hydrogen transportation infrastructure exists. It is fragmented with few cross-border connections. The conditions under which these networks have been built, sized and are used are negotiated between hydrogen producers and, mostly, industrial consumers. Other infrastructure, such as large scale storage and import terminals for liquefied hydrogen[117] do currently not exist within the EU.

The baseline represents the unregulated status of the EU hydrogen infrastructure and market. It assumes adopted and planned policy initiatives under the Fit for 55 package to contribute to the development of renewable hydrogen production and demand. Accordingly, the projections of hydrogen supply and demand under the baseline are derived from the MIX-H2 scenario[118]. In addition, the proposed funding of cross-border hydrogen infrastructure as well as its integration in infrastructure planning under the TEN-E regulation will promote cross-border hydrogen infrastructure development under the baseline. However, there are no (additional) rules on the ownership, operation and financing of hydrogen infrastructure under the baseline. Moreover, there is no common EU terminology and certification system for LCFs/LCH. These rules are however deemed necessary to enable cross-border hydrogen trade[119]. Cross-border trade is needed as locations for a cost effective and high volume production of (renewable) hydrogen production are unlikely to be located next to existing demand centres.

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117 Imported liquefied hydrogen could be reconverted to gaseous hydrogen for subsequent injection in a EU (cross-border) hydrogen pipeline network.

118 These projections have been obtained using the PRIMES energy system model and are documented in detail in the Impact Assessment accompanying the proposal for a revised Renewable Energy Directive.

119 It is important to note that the MIX-H2 scenario assumes the existence of cross-border infrastructure and trade of hydrogen. The RED-II Impact Assessment assumes that (at least some) measures assessed in the present Impact Assessment are already implemented, in allowing for a cross-border exchange of hydrogen.

Whilst Member States will likely take initiatives based on national strategies and approaches to enable hydrogen trade, these efforts are expected to be dispersed under the baseline scenario, resulting in uncoordinated and weak cross-border integration and transportation infrastructure development. As geological and geographical circumstances vary among Member States, some will have no or limited access to large-scale hydrogen storage and import facilitates under the baseline scenario.

5.1.2 Description of policy options

In order to address the problem and its drivers as set out in Chapter 2 and in order to realise the objectives as defined in Chapter 4, different packages of policy options are considered. The detailed measures considered to be part (or not) of a given policy option are summarised in *Table 5*. In Annex 6, more detailed descriptions of each of these measures and their specific advantages and disadvantages are provided. Please note that certain hydrogen related issues are also dealt with under Problem Area II and III, in particular on cross-cutting issues as SoS and network planning.

5.1.2.1 Option 0: Business as Usual (BAU)

In BAU, there are no rules or restrictions at EU level on the ownership or operation of hydrogen infrastructure, or its financing. Infrastructure is operated by unregulated companies that can combine hydrogen production and supply activities with the operation of infrastructure without rules on potential market foreclosure. They can set conditions (if any) for the operation of and access to infrastructure freely and guided solely by the business interests as perceived by the companies concerned. LCH and LCFs are not defined or certified.

Stakeholders' opinions[120]: In the public consultation a large majority of respondents, mainly companies/business organisations, business associations and half of the public authorities that responded, support the introduction of regulation to foster a well-functioning and competitive hydrogen market and hydrogen infrastructure. None of the respondents stated that there is no need for regulation at all. A majority of stakeholders takes the view that LCH and LCFs should be defined and that the claims about their contribution towards decarbonisation should be verified. However, stakeholders had diverging views on how this should be done.

5.1.2.2 Option 1: Rights for network operation tendered

As under BAU, there are no rules or restrictions at EU level on the ownership or operation of infrastructure, or its financing. However, under this option Member States would tender the rights for investments in and the operation and ownership of future hydrogen networks to market participants (including existing gas TSOs). The successful bidder would be granted a regional monopoly position, e.g. on national level or for a local network within Member States or, possibly even, for a specific pipeline or other type of infrastructure, under which the bidder could build and operate it and supply hydrogen customers or, if it chooses to do so, offer infrastructure usage to third parties. The tendering may include conditions or principles

120 https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12911-Revision-of-EU-rules-on-Gas/public-consultation_en. See also Annex 2.

set *at national level* to reflect certain public interests. However, these will not be harmonised by EU rules.

This option thus represents a form of ‘competition for the market’. Concession holders may or may not have interests to foster within the EU or with third countries cross-border interconnection and interoperability, including e.g. ensuring that acceptable and required hydrogen purity levels are addressed[121], to the extent this is compatible with their business interests, which can include upstream and downstream business.

Stakeholders' opinions: In the public consultation, only a minority of respondents, composed by three business associations, one public administration and one company/business organisation, supported this option. Respondents who supported the introduction of regulation for hydrogen markets and networks, stated that a suitable regulatory model should be developed at EU level rather than at national level.

5.1.2.3 Option 2: Main regulatory principles

This option entails the introduction of main regulatory principles that are inspired by those that are applicable to the natural gas (and electricity) markets. Option 2 in essence represents a choice for a ‘competition in the market’ approach (as opposed to a ‘competition for the market’ under BAU and Option 1), but regulation does not have the same depth and scope of the market design of the mature natural gas market. Instead, option 2 reflects a more modest, first step approach. Setting main principles would provide guidance as to investors and operators in what regulatory framework they would act and thus provides investor certainty. However, main regulatory principles would still leave ample scope to investors and operators to develop and test a variety of business models therein. In this manner, it seeks to take account of the uncertainties that still exist at this stage as to the precise pathway the development of the hydrogen value chain will take. If and when required when it fall short of expectation, a regulatory system based on main regulatory principles can be fine-tuned later ‘merely’ by rendering it more specific in certain areas.

Under this option, the natural monopoly character of hydrogen networks is countered through rules that impose constraints on its owners. These include the unbundling of transportation from supply and production activities (vertical unbundling) and rules that govern access for third parties (TPA) to networks. Cross-border integration, including with third countries, is fostered by communality of main regulatory principles but also specific ones, such as rules on the quality of hydrogen at cross-border points or a rules on common EU terminology and certification system for LCFs/LCHs. Similarly, repurposing infrastructure is facilitated to a degree by EU rules. Hydrogen infrastructure can be developed by both private investors and regulated entities, like todays TSOs.

The main regulatory principles would necessitate corresponding powers and competences of national regulatory authorities (and, where appropriate, of ACER) to ensure adequate implementation and monitoring at national level.

Stakeholders' opinions: A large majority of respondents, including companies/business organisations, business associations and half of the public authorities that responded, supports

[121] E.g. in agreements for the cross-border hydrogen transport.

the 'competition in the market' approach and believe that a common approach is needed to define key regulatory principles (such as neutrality of network operation, third party access, cost reflective and market compatible network tariffs, treatment of private networks) as networks can represent a natural monopoly, even if stakeholders have different views on the depth and scope of the rules needed. A step-wise approach is largely supported.

Under Option 2: two sub options are distinguished that both share the characteristics set out above but are different with regards to the requirement they impose on market participants and the degree in which they provide guidance or define a longer term perspective on the regulatory framework for hydrogen infrastructure and markets. I.e. Option 2a and 2b they represent different manifestations of a step-wise approach based on main regulatory principles.

5.1.2.3.1 Option 2a: Main regulatory principles only

Whilst inspired by the rules for the natural gas sector, under Option 2a the main regulatory principles are adapted to the specificities of a developing hydrogen value chain. Options 2a defines the main regulatory principles that would apply during the ramp-up phase of a hydrogen value chain until 2030, it does not look what rules may be required once it reaches a more mature development stage.

Under sub-Option 2a, **existing natural gas TSOs** are relatively unconstrained in being involved in and build out a hydrogen network, including through repurposing the natural gas assets they currently manage.

In order to ensure the emergence of a competitive market structure, **negotiated TPA to hydrogen networks and large scale hydrogen storage** is introduced**.** Negotiated TPA provides flexibility in infrastructure financing options (relative to regulated TPA). **No TPA at all is required for hydrogen terminals** to reflect the fact that, as the means by which hydrogen and its derivatives can be imported are wider in scope than for today's natural gas terminals, it is more likely that hydrogen terminal operators will be subjected to effective competition and less need for regulation exists. Large volumes of imports do not exist yet by 2030 under the scenarios used. Gas TSOs can operate hydrogen networks under the same rules for **vertical unbundling** as in the natural gas sector.

Some measures are taken to **facilitate investments in *existing* infrastructure** by stimulating the grandfathering of existing rights and permits of methane infrastructure when repurposed to hydrogen infrastructure. Gas TSOs can finance and de-risk hydrogen infrastructure investments by using (regulated) revenues from the natural gas side of their business (including revenues collected through cross-border tariffs from network users in other Member States) without constraints (**joint-RAB**). **Private parties** can invest and operate hydrogen infrastructure under exemptions. Such investments can take place without specific measures that ensure a future convergence on a single regulated regime within a progressively inter-connected hydrogen network.

Cross-border operation, in particular **hydrogen quality**, is assured by the same rules as those that exist today for natural gas, including a dispute settlement procedure with the involvement of the concerned regulatory bodies. For **LCH and LCF**s, a common EU terminology and a light GOs-based certification system for LCFs/ LCH) would be introduced. Main regulatory principles apply to interconnections with third countries on the EU territory.

There are **no specific consumer protection rules** beyond the main regulatory principles (such as TPA) reflecting that early users of hydrogen are larger, more sophisticated consumers, unlike the more varied customer base for natural gas (that also includes SMEs and households).

Stakeholders' opinions: A significant majority of stakeholders that gather companies/business organisations, business associations, NGOs and half of the public authorities, academia and citizens that responded consider it very important that **TPA** to dedicated **hydrogen network** is set at an early stage (but their preference is for regulated TPA). Most stakeholders (including companies/business organisations, business associations, public authorities, academia and half of the NGOs that responded) consider that, appropriate measures are now required on imports and a significant majority supports **rules for access to hydrogen terminals**. A large majority of respondents composed by companies/business organisations, business associations, NGOs, academia and public authorities consider it important or very important to define market **rules for access to storage for (pure) hydrogen** at an early stage and it should entail a choice between negotiated and regulated access. The vast majority of stakeholders, including companies/business organisations, public authorities, some NGOs and half of the business associations that responded consider it important or very important to set rules at an early stage to ensure the neutrality of hydrogen network operations (i.e. **vertical unbundling**) and that network operations should be in a distinct legal entity (coherent with the current Independent Transmission Operator (ITO) unbundling model) or ownership unbundled. With regard to **repurposing**, a majority of respondents (companies/business organisations, business associations, and half of public authorities that responded) consider it necessary to clarify whether rights of land use, private easements as well as the validity of public permits that have been granted for the construction and operation of methane gas pipelines continue to be valid when these are used for hydrogen.

Respondents are divided on whether cross-subsidies between hydrogen and natural gas transport activities should be allowed (**separate versus joint RAB**). Half of the respondents (mainly incumbent natural gas TSOs, DSOs and industrial energy consumers) are in favour of (partial) cross-subsidisation to ensure the development of dedicated hydrogen networks.

Most respondents, gathering the majority of companies/business organisations, business associations, NGOs, public authorities and half of the academia that responded, considered it important or very important to define early the role **of private parties** in developing hydrogen infrastructure. However, few supported that this should be done unconditionally and without ensuring regulatory convergence. A quarter of respondents (composed by companies/business organisations, business associations, public authorities and academia) specifically support establishing **hydrogen quality (purity)** standards at Member State level with EU-level cross-border coordination rules. There is strong support for establishing rules on roles, responsibilities and cost-allocation for the management of hydrogen quality at EU-level.

With regard to **LCHs and LCFs**, answering to a poll during the first stakeholder workshop, 38% of the respondents took the view that the RED II certification scheme should be extended to LCH and LCFs. 23% of the respondents think that GOs should become the only verification of a compliance system.

Very few stakeholders (mainly represented by companies/business organisations, business associations and some NGOs) support the view that the main regulatory principles by themselves provide sufficient **consumer protection**.

5.1.2.3.2 Option 2b: Main regulatory principles with a vision

Option 2b is similar to 2a in that it is built on the main regulatory principles governing the current natural gas market. However, it seeks to provide more guidance as to the direction into which the regulatory framework will develop in the future whilst retaining flexibility in the transition in order to take account of the emergent nature of the hydrogen value chain today and the uncertainties surrounding its development. It also takes better account of some of the lessons learnt from the liberalisation of the gas and electricity sectors and takes advantage of the fact that it is possible to take a ‘greenfield’ approach to regulation, in which choices aimed at creating a competitive market can still be made unconstrained by an entrenched factual or regulatory situation (unlike when liberalising the than already mature gas and electricity markets).

Thus, while still representing a light regulatory regime based on the main regulatory principles as the natural gas market, Option 2b takes the adaption to the characteristics of the hydrogen value chain a step further and provides more guidance as to its future. In comparison with Option 2a, Option 2b represents a real step-wise approach that both provides a regulatory framework for the ramp-up of a hydrogen value chain until 2030 as well as a perspective on the main regulatory principles that will govern a more mature hydrogen value chain beyond 2030. Like Option 2a, it remains limited to setting the main principles that provide guidance as to investors and operators in what regulatory setting they would act whilst leaving ample space to develop suitable business models within this context. It thus provides more regulatory certainly without however sacrificing degrees of freedom to investors and operators to develop new business models.

Like under Option 2a, under Option 2b the natural monopoly character of hydrogen transportation infrastructure is countered through rules that impose constraints on infrastructure owners. With regard to **TPA** to hydrogen networks (including cross-border interconnectors and interconnections with third countries) a stepwise approach is envisaged where negotiated TPA remains possible during a transition phase to provide flexibility (like under Option 2a) but where regulated TPA and tariffs would be phased-in later. Learning from the past, it seeks to avoid the ‘pancaking effect’ that currently characterises the natural gas system by prohibiting cross-border tariffs, thereby setting the stage for an EU hydrogen market with a true level playing field later. For **large-scale storage**, Option 2b entails a relatively strict regime of regulated TPA from the start, in accordance with stakeholder views. In view of the intermittency of renewable hydrogen production but the need to provide stable supply to (industrial) users, access to storage will be commercially crucial for hydrogen producers. However, large-scale storage will be scarce (especially at the ramp-up stages) and available only in certain Member States, due to geological conditions. **Import terminals** will under Option 2b not be left fully unregulated (like under Option 2a) but subject to a relatively light regime of negotiated TPA. To benefit from the ‘greenfield’ nature of hydrogen infrastructure regulation and the fact that vertical integration today is rare, a stepwise but relatively strict approach is taken under Option 2b with regard to **vertical unbundling** of networks. In the transition phase, the ITO model can still be used by the current natural gas TSOs that want to repurpose their assets for hydrogen transport. However, after this transition phase, hydrogen network operators are either ownership unbundled or the networks of vertically integrated operators are governed by an independent system operator (ISO)[122], which can already be made available in the transition phase but is than not yet obligatory.

Like under Option 2a, **private investors** can invest and operate infrastructure. However, guarantees are built in to foster convergence and avoid the persistence of divergent regulatory regimes within the later inter-connected network. Existing private networks can also opt-in into the regulated system.

Facilitating networks development will not only be done by facilitating the **repurposing of *existing* infrastructure** (like under Option 2a), but also by ensuring that permitting and land-use rights for ***new* infrastructure** at national level are at least equivalent to those applicable for natural gas infrastructure. This to avoid bias in the feasibility of infrastructure projects and lock-in. With regard to the asset base of regulated entities, the default rule is a separation of hydrogen and gas network asset bases **(separate RABs)** and cost-reflective tariff setting**.** However, flexibility is provided by an option of (temporary) financial transfers between the natural gas and hydrogen asset base (financed by domestic natural gas network users only and subject to conditions). This allows cost-reflective tariffs setting but also hydrogen network operators to stabilise tariffs for hydrogen network users in the ramp-up phases of a hydrogen network whilst avoiding that this is paid for by network users in other Member states. This approach implies the need for (at least) **horizontal accounts unbundling** between natural gas and hydrogen network activities.

Using the green field nature of hydrogen infrastructure regulation and the fact that technical standards already exist for hydrogen end-applications, Option 2b establishes an **EU-wide acceptable purity level** for cross-border points in order to foster cross-border interoperability. Further, this option would include cross-border dispute settlement tools and increased transparency as under Option 2a. With regard to **LCH and LCFs**, this option also provide a common terminology but (unlike Option 2a) certification will be based on life-cycle analyses and a mass-balance approach through voluntary schemes. The application of main regulatory principles to the entire **interconnectors with third counties** is assured through the need to conclude an Intergovernmental Agreement (IGA).

A **light regime of consumer protection** rules will exist, reflecting the fact that early users of hydrogen are likely more sophisticated and need less protection. It will be aligned with those valid for the natural gas system in order to make sure that switching decisions are made on the basis of economic opportunity as opposed to regulatory bias.

Stakeholder's opinions: A large majority of respondents, that gather companies/business organisations, business associations, NGOs and half of the public authorities, academia and citizens that responded, supports the principle of regulated **TPA** to networks. EU legislation ensure non-discriminatory access to network users on the basis of published terms and conditions, including approved or set tariffs by the national regulator. A significant majority of respondents considers the current structure of cross-border gas transmission tariff system

[122] The ISO model could be available already for vertically integrated companies in the transition phase, but will than not yet be obligatory in the transition.

suitable for the hydrogen market. A large majority of respondents, including that gather companies/business organisations, business associations, public authorities, academia and half of the NGOs, consider that rules for dedicated **hydrogen storage** are necessary to the same degree as for methane storage. A significant majority of stakeholder (composed by companies/business organisations, half of the private authorities and academia that responded) supports rules for access to **hydrogen terminals**. About half of the respondents (including companies/business organisations, public authorities, some NGOs and half of the business associations that responded) in favour of requiring **vertical unbundling** think that ownership unbundling should be applied at EU level from the start. A large majority of respondents takes the view that network operators should never own or operate power to gas installations or only under very strict conditions[123].

Few respondents, which gather companies/business organisations, and half of the public administrations, business associations and citizens that responded, consider that existing **private network operators** should remain fully unregulated. A large majority of respondents consider that they may be exempted from certain regulatory requirements, but only temporary. Some take the view that private operators should be given a unilateral possibility to 'opt-in' into an existing regulated system. Few (companies/business organisations, and half of the public administrations, and citizens that responded) consider that future private networks should be left unregulated. A large share of respondents considers that the default rule should be that they are regulated but that exemptions can be considered under conditions.

The vast majority of respondents (companies, business organisation, business association, academia and half of EU citizens and public authorities that responded) considers that **rights and permitting requirements for new hydrogen infrastructure** should be similar to those applicable to methane gas pipelines today. Respondents are divided on the allowance of cross-subsidies between hydrogen and natural gas transport activities (**separate versus joint RAB**). Half of the respondents, mainly representing NRAs, some consumer organisations, NGOs and some industrial energy consumer and stakeholder associations want rules ensuring that hydrogen pipelines are being financed by network users only.

Half of the respondents, composed by companies/business organisations, business associations, academia and a minority of NGOs and public authorities that responded, support establishing an EU-level binding **hydrogen quality standard**.

With regard to **LCHs and LCF,** 38% of the respondents took the view that the RED II certification scheme should be extended to LCH and LCFs. The panellists acknowledged the necessity to have a certification system, including for LCH and LCFs, across the life cycle and indicated the importance of the REDII certification system to cover all fuels, including LCH and LCFs.

Half of respondents, including companies/business organisations, business associations, and some public authorities and NGOs, consider it important that typical first users of a hydrogen

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123 For example, only if this is necessary to guarantee network operations and if no other market party is willing to carry out the investment. Clear and limited conditions should be defined (e.g. limitations in scope, scale and time), after it has been proven that the market is not willing to invest in such installations and foreseeing a procedure to transfer such installations back to a market-based regime once the derogation expires) or that this choice should be left to Member States.

network (from the industrial and transport sector) have the same **consumer protection rights** as if they would be connected to the methane gas grid in order to ensure a level playing field[124].

5.1.2.4 Option 3: Big Bang

Option 3 is designed to reflect a situation where a separate regulatory regime for hydrogen would exist and which would be similar (including the role of NRAs and ACER) to the one currently applicable to the natural gas sector, based on 'competition in the market'. Adaptations to the characteristics of the hydrogen value chain are made. Lessons learned from the liberalisation of the gas and electricity markets and a 'greenfield' approach opportunities are exploited . However, Option 3 does not really foresee a need to distinguish between rules applicable to a ramp-up and more mature development phase. It also is comparable with the current regulatory framework for natural gas in terms of the density and detail. It does provides more clarity but also less degrees of freedom for market actors and operators to develop business models. This option reflects a preference for immediate clarity or 'big bang'. In view of the density of rules, should it perform below expectations, a real reform (as opposed to more precision) will be required.

Stakeholder opinions: Whilst a large majority of respondents want a regulatory framework that reflects 'competition in the market' approach, most of them prefer a stepwise approach (as embodied in Options 2 and 2b). Only a minority composed by 3 business associations, one public administration and one company/business organisation, favours regulation with detailed EU rules (implementing regulatory principles and technical rules) from the very start.

5.1.2.4.1 Sub-option 3a: Hydrogen rules by Big Bang

Sub-option 3a reflects a roll-out of a regulatory framework closest to the current gas-market regulatory framework for gas, but largely separately. Gas TSOs would be able to operate as hydrogen TSOs but these would need to be operated as businesses that are both financially (separate **RABs**) and organisationally (legal and functional **horizontal unbundling**) fully separate. Activities in downstream and upstream hydrogen (and other) activities would be excluded by **ownership unbundling**.

Existing **private** hydrogen network operators would not be able to continue their current business model but would need to be ownership unbundled. Only *new* **private** infrastructure may be exempted (like under the current Gas Directive) and thus not be possible for already *existing* networks.

Importantly, to foster market integration, Option 3a would immediately include (**detailed, technical) rules** on capacity allocation and congestion management at cross-border interconnection points in hydrogen networks and balancing and cross-border operability and tariff setting currently at least partially contained in the technical rules (so-called network codes) for the natural gas market.

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124 According to a large majority of respondents, such rights should include consumption data, billing information, supplied hydrogen quality, CO2 content of hydrogen supply, switching rights and dispute settlement.

Repurposing and the building of existing new infrastructure would be facilitated but through more decisive steps i.e. by harmonising at EU level permitting and land-use rights.

Consumer rights for hydrogen will be fully aligned with this in the gas and electricity sectors, including for SMEs and households.

Like under Option 2b, cross-border tariffs are rendered impossible to avoid pancaking, an EU-wide acceptable **hydrogen quality** for cross-border points is set. **Access rules for large-scale storage and import terminals and terminology** and **certification of LCH and LCF** are also the same as under Option 2b. The application of main regulatory principles to interconnectors with third countries would be assured by an IGA.

Stakeholders' opinions: Half of the respondents, including companies/business organisations, public authorities, some NGOs and half of the business associations that responded, supports the requirement of vertical **unbundling** and state that ownership unbundling should be applied from the start. Whilst only a minority (companies/business organisations and business associations) favour **detailed technical** EU rules from the very start, a large majority[125] of stakeholders consider important to have these at an early stage. Only a small minority (companies/business organisations, public authorities and half of business associations, citizens and academia that responded) thinks that existing **private infrastructure** should *not* have a special treatment and that main regulatory principles should apply to all networks immediately. About half of the respondents, including companies/business organisations, business associations, and some public authorities and NGOs, prefer **consumer rights** fully aligned with those for natural gas consumers, regardless their size (i.e. households) and use of hydrogen.

5.1.2.4.2 Sub-option 3b: Hydrogen rules by Big Bang plus

Option 3a and 3b are rather similar but Option 3b introduces also the creation of an EU hydrogen TSO tasked with operating and developing an EU hydrogen network whilst the actual ownership of the pipelines remains with the national TSOs (**EU ISO model**). In this regard it takes a yet more extreme option by replacing, in operational terms at least, national TSOs and create an EU network operator. It would addresses conflicts of interests resulting from vertical and horizontal integration. On the other hand, it offers an opportunity to avoid full ownership unbundling (like under Option 3a) for vertically integrated companies. It can also have synergies with some options for other main regulatory principles.

Stakeholders' opinions: A majority of the respondents, comprising mainly companies/business organisations, business associations, and half of NGO(s), academia and public authorities that responded, are against the introduction of an **EU TSO (ISO model)** for hydrogen because the coordination of infrastructure can be managed by integrated network planning and the model would be disproportionate to establish a well-functioning hydrogen market.

125 With the exception of technical rules on tariff setting, which was only supported by approximately half the respondents.

5.2 Options discarded at an early stage

The **option of stronger enforcement and voluntary collaboration** was not further assessed as it would not provide appropriate levels of harmonisation or certainty to the market[126]. Stronger enforcement is impossible as currently no rules exist, let alone rules that can be enforced stronger.

It was initially considered to develop options to amend the **electricity market rules** to ensure that electrolysers, which are present at the demand side of the electricity markets, can fully participate therein. However, no clear needs to modify the Electricity Directive and Regulation in this regard were identified.

Certain stakeholders have suggested a form of '**dynamic regulation'**. National Regulatory Authorities (NRAs) should decide when possible regulation of hydrogen networks should kick-in based on periodic market monitoring focused on an assessment of the market circumstances that increase the risk of abuse of dominant position by hydrogen network owners. Intervention, if and when required, should be based on pre-defined EU-wide regulatory principles. This option was assessed but eventually discarded due to the expected disadvantages of the proposed approach of *ex post* regulation, in particular the lack of legal certainty for the required investments in hydrogen facilities and infrastructures with long life cycles and depreciation periods. Moreover, the resulting risk of regulatory fragmentation across different Member States may have a detrimental effect on network interconnectivity and the integration of national hydrogen markets and, thereby, on cross-border trade and market development.

Stakeholders' opinions: The option of 'dynamic regulation' as supported by a small and diverse minority of respondents, mainly composed of companies/business organisations and business associations, and half academia that responded. The large majority of respondents preferred clear ex-ante rules (even if they had different opinions on the depth of such ex-ante rules).

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126 During the earlier stages of natural gas market liberalisation, ACER, in collaboration with NRAs and stakeholders developed a 'Gas Target Model' that represented a shared vision on gas market design and that provided a 'certain' guidance to foster regulatory convergence where discretion existed in EU rules in the absence of more prescriptive ones. It played a complementary role next to legislation. However, such voluntary cooperation is not conducive to remove barriers, to provide for appropriate levels of harmonisation or certainty to the market and legislation is needed to address the identified problems in a consistent way

5.2.1 *Summary of policy options*

Table 5: Summary table of policy options in Problem Area I: Ensuring emergence of cost-effective hydrogen infrastructure and contestable hydrogen markets

Measures	BAU No additional measures	Option 1 Rights for network operation tendered	Option 2 Main regulatory principles		Option 3 Big bang	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big bang*	*3b: Hydrogen rules by Big-bang plus*
Vertical unbundling	No rules	NA	OU/ITO/ISO	Ownership unbundling & ISO model (ITO possible until 2030)	Ownership unbundling	EU TSO (ISO model)
RAB	Seperate RAB	Seperate RAB	Joint RAB allowed	Separate RAB Sub-option: Separate RAB with targeted transfers	Separate RAB	Separate RAB
Horizontal unbundling	No rules	NA	Combined hydrogen & natural gas TSO	Legal and accounts unbundling	Legal and functional unbundling	Legal and functional unbundling
TPA for hydrogen networks	No rules	NA	nTPA	rTPA + no cross-border tariffs + nTPA possible until 2030	rTPA + no cross-border tariffs	rTPA + no cross-border tariffs
TPA for hydrogen storage	No rules	NA	nTPA	rTPA	rTPA	rTPA
TPA for hydrogen terminals	No rules	NA	No rules	nTPA	rTPA	rTPA
Hydrogen quality	No rules	MS responsibility	Cross-border coordination framework and dispute settlement	EU-wide acceptable purity level for cross-border points	EU-wide acceptable purity level for cross-border points	EU-wide acceptable purity level for cross-border points
Hydrogen Network development (cf. also measures described under Problem Area III)	TYNDP on EU level No rules national level	NA	Transparency on infrastructure available for repurposing	Transparency on infrastructure available for repurposing + market test	European Planning	European planning
Facilitating repurposing	No rules	NA	Grandfathering permits and	Option 2a + Equivalence natural	Harmonisation of	Like 3a

			land-use rights existing natural gas infrastructure to hydrogen	gas and hydrogen permitting and land-use rights for new infra	permitting and land-use rights	
Transition: exemptions	No rules	NA	Individual exemptions for new and/or existing infrastructure	Individual exemptions for new and/or existing infrastructure + convergence criteria + voluntary opt-in	Only new infrastructure can be exempted	Only new infrastructure can be exempted
Transition: derogations	No rules	NA	Derogations for geographically confined networks	Derogations for geographically confined networks + convergence criteria	Like Option 2b	Like Option 2b
Consumer rights	No rules	NA	No rules beyond defined elsewhere (e.g. TPA, hydrogen quality)	Consumer protection rules equivalent to those for larger consumers in Gas Directive	Consumer protection rules are those valid for all natural gas users (including e.g. SMEs, households)	Like Option 3a
Technical rules ('network codes')	No rules	NA	No mandate	(Mandate)[127]	Mandate	Mandate
Terminology and certification of LCH/LCFs	No rules	NA	Terminology and light GOs-based certification	Terminology and certification based on life-cycle analyses and mass-balance approach through voluntary schemes	Like Option 2b	Like Option 2b
H2 interconnectors with third countries	No rules	No rules	Alignment with current rules in Gas Directive	Option 2a + Mandatory EU-level IGA	Like Option 2b	Like Option 2b

127 Bracketed as the implication of Section 8.1, not of Option 2b directly.

5.3 Options in the Problem Area II: Renewable and low carbon gases in the existing gas infrastructure and markets, and energy security

The options in this section address the drivers in Problem Area II, namely the untapped potential of renewable gases and barriers in the existing framework. Each of the options addressees all the drivers described in Section 2.2 of this Impact Assessment with increasing depth of the intervention.

5.3.1 Baseline

In the baseline, no further legislative measures would be adopted at the EU level. Any new developments would arise from the measures foreseen in the 3rd energy package, from the process for developing or amending network codes and guidelines, legislative initiatives by Member States, and voluntary cooperation at the regional and national levels. It assumes adopted and planned policy initiatives under the Fit for 55 package to contribute to the development of renewable and low carbon gas production and demand. Accordingly, the projections of biomethane and hydrogen supply and demand under the baseline are derived from the MIX-H2 scenario[128].

In the baseline, **access of renewable and low carbon gases** to the markets and infrastructure might remain hindered and a patchwork of various provisions will persist among the Member States. TSO-DSO coordination rules on connection requests are absent in around half of the Member States at least. Access to wholesale markets for biomethane producers may remain restricted in some Member States. Moreover, even in countries where entry-exit or balancing zones include the DSO level, the lack of reverse flow capacity will most likely constrain production and trade of biomethane. Tariffs at intra-EU interconnection points would still be applied to the transport of biomethane, in the current range of 0.15 - 2 EUR/MWh (commodity-based equivalent tariffs)[129], except in integrated balancing zones. Such zones exist currently at regional level (FI-EE-LV, DK-SE and BE-LU markets). By 2030, additional mergers could occur, but tariffs would still be in place for most intra-EU interconnection points.

Cross-border management of **gas quality** and information sharing would rely on existing procedures defined in the interoperability and data exchange network code. The CEN standard for H-gas (*natural gas*), EN 16726, would be revised to include the Wobbe Index[130]. Other EN standards for hydrogen and hydrogen blends in the network and in end-use would

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128 These projections have been obtained using the PRIMES energy system model and are documented in detail in the Impact Assessment accompanying the proposal for a revised Renewable Energy Directive.

129 The tariffs are based on the data from the 2020 TYNDP, which assumes a 100% utilisation of the Ips for converting any capacity-based tariffs into commodity-equivalents. Therefore, actual equivalent tariffs may be higher, as e.g. a 50% utilisation would mean the actual commodity-equivalent of a purely capacity-based tariff is twice as high. Moreover, for shippers with booked capacity, the tariffs are actually sunk costs. Therefore, capacity already booked should not influence shipper's decisions.

130 The Wobbe Index is an indicator of the interchangeability of natural gas and is frequently defined in the gas quality specifications for e.g. injection or transportation of natural gas. It is used to compare the combustion energy output of different composition gases used in an appliance (e.g. turbine, boiler).

be developed[131]. However, these standards would remain non-binding and their application cross-border would not be aligned. In addition, gas quality specifications would continue to be mainly defined by the quality parameters of natural gas. Rules on **hydrogen blending** levels would remain national, without any cross-border alignment. The presence of non-harmonised hydrogen blending thresholds in neighbouring countries, where important gas trade takes place, could induce significant trade barriers or hydrogen injection constraints to the upstream grid[132]. However, voluntary cooperation between adjacent TSOs across Member State borders could take place on blending thresholds.

LNG terminals operations would depend on the decisions of the national authorities and the development of the LNG market. It can be expected that voluntary initiatives by the LNG sector would address some of the identified problems. The possibility to provide network entry tariffs discounts to LNG terminals would remain, and thus existing discounts to terminals would in principle also remain. In the baseline however, LNG imports could remain restricted to natural gas.

Long-term contracts may continue to be prolonged or signed for periods exceeding 20 years. The climate policies, in particular the increase of the price of ETS certificates may diminish the incentives for importers to sign such contracts. However it is not excluded that a situation of stranded long-term contracts may occur. Companies holding such contracts may engage in practices to lower the price of natural gas, increasing the need for higher support of renewable alternatives.

The current framework on energy security results from the Regulation on security of gas supply, which aims at guaranteeing the secure supply of natural gas. There would be no Union emergency mechanism to deal with the specific needs and threats of the decarbonised gas sector.

5.3.2 Description of the policy options

This section describes four policy options, each composed of a combination of individual policy measures and addressing the problems identified in Chapter 2 to different extents.

The options and its measures are structured based on the depth of the regulatory intervention in order to create gas markets that can enable the energy transition. The packages hence represent the political choices going from a lighter to a more detailed and stringent regulatory framework. Elements contained in Policy Option 1 are included in Policy Option 2 while the latter adds new policy measures which further advance the potential of renewable gases and barriers in the existing framework, and so on up to Option 4. Further, Annexes 6 to 9 include the details of each of the options in terms of more granular measures and present pros and cons of each of them in a transparent manner, so that they can also be assessed separately, on this more detail level.

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131 https://ec.europa.eu/info/sites/default/files/energy_climate_change_environment/events/presentations/07.02_mf35-presentation-cen-wires_on_gas_quality_standard-schulken.pdf .

132 JRC (2021) Blending hydrogen from electrolysis into the European gas grid, JRC126763,

5.3.2.1 Option 0: Business as Usual (BAU)

In the business as usual, none of the EU-level policy measures for the problem areas are in place. New developments would arise from the measures foreseen in the 3rd energy package and Regulation on gas energy security, from the process for developing or amending network codes and guidelines, legislative initiatives by Member States, and voluntary cooperation at the regional and national levels.

Stakeholders' opinions: All stakeholders from all categories in the public consultations agree on a need to revise current regulatory framework (Gas Directive and Gas Regulation) to help to achieve decarbonisation objectives, and on the need to align the SoS Regulation.

5.3.2.2 Option 1: Allow renewable and low carbon gases full market access

Option 1 includes policy measures that provide **access to markets and infrastructure** for renewable and low-carbon gases injected at the distribution or transmission level, and promoting cooperation between Member States. The detailed measures include requirements to including the distribution level into the definition of the entry-exit zones and requiring network operators to ensure physical reverse flow capabilities. Establishing a gas specific DSO coordination as part of the DSO-entity from electricity sector may help to facilitate coordination between TSOs and DSOs in this option.

As regards the **gas quality regulatory framework**, this option provides for a reinforced cross-border coordination between Member States on gas quality issues, building on the existing cross-border dispute settlement process (Interoperability Network Code). It strengthens the role of the National Regulatory Authorities and, where relevant of ACER, for cross-border issues related to gas quality and for monitoring related developments to increase transparency.

As regards **hydrogen blends**, this option includes an obligation on Member States to define a national acceptable hydrogen blending level. While under this option Member States would still have the possibility to define the acceptable blending levels as zero (as current practice in some Member States), this would provide for a clear overview and increased transparency of the applicable specifications across the EU.

Voluntary (e.g. industry-led) initiatives to improve transparency for **LNG terminals** would be encouraged without however a legal obligation.

The Commission would issue one or several recommendations to Member States and stakeholders on **extending the scope of the energy security tools** to new gases and risks and the minimum cybersecurity requirements for the gas sector.

Stakeholders' opinions: A majority of stakeholders in the public consultation, including companies/business organisations, business associations, NGOs, and half of the public authorities that responded, consider it important to ensure full market access and facilitate the injection of RES&LC gases into the existing gas grid. A majority, composed of companies/business organisations, business associations and half of the public authorities that responded, supports as well the improvement of the transparency framework for LNG terminals. There is also a strong support (mainly from companies/business organisations, business associations, and half of academia that responded) for the harmonised application of gas quality standards across the EU, for reinforced cross-border coordination and increased transparency. Respondents are more divided on hydrogen blending. The majority (companies/business organisations, business associations, and half of NGOs, academia and EU citizens that responded) agree that it provides a cost efficient and fast first step to energy system decarbonisation. However, a quarter of respondents (mainly NGOs, companies/business organisations, business associations, and public authorities) underline that blending prevents the direct use of pure hydrogen in applications where its value in terms of GHG-emission reductions is higher and that it creates technical problems and additional costs at injection and end-users points. Over a third of the respondents, represented by companies/business organisations, business associations, some EU Citizens, and one third of public authorities that responded, support setting national hydrogen blending levels in a standardised way. Some stakeholders (companies/business organisations, business associations and half of the public authorities that responded) advocate to create an EU DSO for gases similarly to the single EU DSO established in the electricity sector.

5.3.2.3 Option 2: Promote market access and security of renewable and low carbon gases

Compared to option 1, Option 2 would add an obligation for network operators to **connect renewable and low-carbon gas** producers (with a firm capacity assurance), and introduce a reduction or exemption of injection charges to those producers in order to reflect the system benefits (i.e. avoided network costs) and climate benefits.

As regards the **rules on gas quality**, this option includes in addition to option 1, setting EU rules for processes, roles, responsibilities, cost recovery and cost allocation of gas quality management as well as for reinforced regulatory oversight. This could either be set on the basis of high-level EU principles defining the different aspects of gas quality management – and thereby allowing Member States more flexibility when developing national implementation – or through concrete and detailed EU rules.

As regards **hydrogen blending**, this option defines an EU-wide allowed cap at cross-border interconnection points, meaning that TSOs would be obliged to accept blending levels that are below the cap at interconnection points. They might accept higher blends on a voluntary basis, but there would be no obligation to do so. The rules would not propose mandatory blending and leave the flexibility to Member States to set blending rules if they wish so for the domestic network.

As regards **LNG terminals**, this option includes a binding legal framework at EU level for transparency, congestion and access rules (secondary capacity).

This option would also include **energy security** rules ensuring that risks and needs related to renewable and low carbon gases are duly taken into account in the energy security Regulation, in particular concerning (a) the compliance with the infrastructure standard; (b) the risk assessments (to accommodate relevant new risks incl. climate change), (c) the national plans and the bilateral solidarity arrangements between Member States (to clarify the applicable technical and financial conditions of solidarity gas) and (d) adopting harmonised cybersecurity rules specific for the gas sector. The future gas sector would be integrated in the broader stepwise development of the EU policies on the protection of critical energy infrastructure. Cybersecurity and physical protection would converge by improving communication, coordination and collaboration.

Stakeholders' opinions: Many stakeholders (companies/business organisations, business associations, NGOs, half of academia and one third of public authorities that responded) advocate an obligation for network operators to connect RES&LC producer and introduction of an injection charge reduction. Few stakeholders ask for stronger promotion measures such as targets or quotas for RES&LC. A quarter of respondents (represented by companies/business organisations, business associations, some EU citizens, and half of academia that responded) support setting a harmonised EU-wide allowed cap for hydrogen blends, which TSOs must accept at cross-border interconnection points. One third is supporting national blending rules. The majority of respondents, mainly companies/business organisations, business associations, some EU citizens, and half of academia and public authorities that responded, support establishing EU-level principles for rules on roles and responsibilities for gas quality management for the Member States. Stakeholders (companies/business organisations, business associations, and half of public authorities and EU citizens that responded) agreed on the relevance of the energy security challenge in the context of the gas decarbonisation. The majority of the respondents (mainly companies/business organisations, business associations, public authorities and half of NGOs and academia that responded) consider gas specific cyber-security measures as important.

5.3.2.4 Option 3: Allow and promote renewable and low carbon gases full market access, and security, and tackle issue of long term supply natural gas contracts

In addition to Option 2, **Option 3** would remove privileges (derogations) for **new long term natural gas contracts** and limit duration of such contracts to 2049.

The **pancaking effect** (see Section 2.2.1.3 for explanation) would be addressed **for renewable and low carbon gases only** abolishing cross-border tariffs on all interconnection points as in Option 4. This tariff discount may be conditioned upon their carbon footprint. Rules enhancing transparency of allowed revenues and costs benchmarking will address the existing outliers of cross-border tariffs. Regional cooperation will be supported by a Commission guidance. Measures to increase **access to LNG terminals** and gas storages for renewable and low-carbon gases, including through improvements in the legal framework for transparency and third-party access rules. Long-term contracts for natural unabated gas will be forbidden as of 2050.

Stakeholders' opinions: Some stakeholders, represented by a majority of NGOs, some business associations, some companies/business organisations, and half of public authorities and academia that responded, argued for measures that disincentivise the use of unabated fossil gases. Moreover, a few directly highlighted that long-term contracts can foreclose the market. Other stakeholders do not see the abolishment of special treatment for natural gas LTCs as important.

5.3.2.5 Option 4: Allow and promote full renewable and low carbon gases market access, and security, tackle issue of long term supply natural gas contracts, remove border tariffs and set EU gas quality standard

In addition to Option 3, in **Option 4,** all intra-EU cross-border tariffs for uncongested interconnection points are eliminated[133]. Internal entry tariffs for renewable and biomethane gases would also be set to zero as well as tariffs from/to storage. Pipeline tariffs would be determined based on the capacity-weighed distance to a point in the centre of Europe, with entry tariffs for LNG terminals being set to zero (as a variant, non-zero tariffs to LNG terminals could be determined with the same method as for extra-EU interconnection points). The missing money arising from setting intra-EU cross-border and some internal tariffs to zero would be recovered from internal exit tariffs to end-consumers, possible increases at EU-external tariffs, possible revenues from congested points and an inter-TSO compensation mechanism set-up in order to re-allocate revenues.

As regards **long-term contracts,** additional steps would be introduced limiting duration of the contracts well before 2049. For instance, contracts for supply of unabated gas signed as of 2030 could not exceed 10 years duration, unless abatement takes place.

Regarding **gas quality**, this option entails EU-level harmonisation of the technical gas quality standards applicable at cross-border interconnection points. This would mean a continuation of using the quality specifications of natural gas as a basis to define quality standards for the whole EU gas network (e.g. by codifying the CEN standards for H-gas in EU legislation). A variant under this option is to harmonise gas quality standards at EU-level based on the quality specifications for biomethane applicable at cross-border interconnection points. In addition, this option cumulates relevant elements of option 1 and 2 for gas quality, namely reinforced cross-border coordination, rules for processes, roles, responsibilities, cost recovery and cost allocation of gas quality management as well as for reinforced regulatory oversight and increased transparency.

As regards **hydrogen blends**, this option sets a harmonised EU-wide allowed cap and a higher maximum threshold for hydrogen blends at cross-border points. This would mean that TSOs would be obliged to accept blends that are below the lower cap at cross-border points and would not be allowed to accept blends that exceed the maximum allowed threshold. This would avoid, that the costs of one Member State's blending pathway have to be covered by adjacent Member States (cost of adapting their infrastructure and end-use appliances to higher blending levels).

Stakeholders' opinions: Few stakeholders in the public consultation supported an option to remove intra-EU cross-border tariffs (half of academia, and some business associations, public authorities, companies/business organisations, NGOs, and EU citizens). Many respondents were, however, sceptical about such solution arguing that that current cross-border tariff setting is satisfactory and does not require fundamental design change. While there is no majority for defining an EU-level binding gas quality standard, even those

[133] For storage, tariffs are considered to remain unaltered. Biomethane is supposed to rely on public support and being produced in any case (and at any cost including tariff) in all scenarios. Other renewable gases are not explicitly considered.

supporting this option are divided. A third of them (represented by a majority of companies/business organisations, some business associations and public authorities) support such a standard based on the quality standard for natural gas, while another third, with an equal proportion of business associations, companies/business organisations, half of EU citizens and academia that responded, support a standard taking fully into account renewable and low-carbon gases.

5.3.3 Options discarded at an early stage

An additional option considered would not aim at facilitating or promoting access of renewable gases to the internal gas market. Instead, in the expectation of increasing importance of locally produced biomethane in the EU, this option would contain measures merely focusing on incentivising the injection of local renewable and low-carbon gases at the distribution level. The wholesale market and transmission level would remain dominated by natural gas, until its use diminishes.

Measures included in this option would include the obligation for network operators to provide a connection with associated firm capacity to producers, and for Member States to provide exemptions or reductions of injection charges for renewable and low-carbon gases – as in Options 1-4 above. Moreover, specifically for this option, measures facilitating energy communities would be in place, particularly allowing them to supply and trade gas locally. Gas quality measures would be limited to reinforced cross-border coordination and transparency on gas quality and on national hydrogen blending rates, similarly to option 1. Likewise, measures for LNG terminals and storage would be limited. An option for Member States opting for a negotiated access to the LNG terminals could be introduced (as currently is possible for gas storages).

This option is discarded as it is difficult to reconcile with the main objectives of the initiative i.e. facilitating decarbonisation of the gas market, at all levels, and adapting regulatory framework so that decarbonisation takes place on the basis of competitive, integrated market. It would also run against the recommendations of the Hydrogen Strategy[134] and Sector Integration Strategy[135] which set out how the energy markets could contribute to achieving the goals of the European Green Deal. Biomethane development at the distribution level would be driven exclusively by energy communities and local production, promoted by specific policy measures.

In this option, the biomethane production levels would be lower than in the MIX-H2 scenario, even if specific Member States may achieve or exceed those levels in 2030. New biomethane plants would be connected mainly at the DSO level without access to the wholesale market and transmission grid. The drivers and problems identified in Section 2 would therefore not be addressed. The lack of reverse capacity between DSO and TSO, may

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134 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.

135 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the committee of the Regions - Powering a climate-neutral economy: An EU Strategy for Energy System Integration; COM(2020) 299 final.

restrict the capacity of biomethane that can be connected to distribution networks with low local gas demand.

The aggregated biomethane production levels are lower than in the MIX-H2 scenario. Nevertheless, some elements of this option, such as in particular the energy communities, will be further considered for the legislative process to enable adjustment of the supply of biomethane to the local needs and conditions and facilitate consumer's choice for renewable gases. This would allow to tackle problems identified in Problem Area IV.

Stakeholders' opinions: A vast majority of stakeholders (mainly companies/business organisations, business associations, NGOs, and half of public authorities) was not in favour of this particular option in the public consultation pointing out inter alia that decarbonisation shall take place on the basis of competitive and integrated market, not solely a local one. Regarding the more specific measure associated in this option, some stakeholders (represented by some companies/business organisations, some business associations, some public authorities, NGOs and academia) strongly support the adaptation of energy communities to gas to align it to the electricity framework.

5.3.4 Summary of policy options

Table 6: Summary of policy options in Problem Area II: Renewable gases

Measures	BAU No additional measures	Option 1	Option 2	Option 3	Option 4
Access of RES&LC gases to hubs and transmission grids	Access of RES&LC gas is not explicitly dealt with in the current framework. General principle of non-discrimination and the objective for NRAs to help to integrate production of gas from renewable energy sources in both transmission and distribution.	Access of locally produced RES&LC gases to the hubs and transmission grid enabling physical reverse flows (including for RES&LC gases).	As Option 1 plus: Connection obligation with firm capacity for new RES&LC gases. Reducing costs of injection for renewable gases.		
Treatment of cross-border tariffs (pancaking)	Cross-border tariffs for transport of gases are set on interconnection points between MSs. No detailed rules to facilitate regional mergers.			Removing cross-border tariffs from interconnection points within EU for RES&LC gases only. Eligibility would be based on presenting the GOs to the TSO Facilitating voluntary regional gas market mergers (Guidance by the Commission). Measures for transparency of allowed revenues, costs benchmarking.	Removing cross-border tariffs from interconnection points within EU for all gases in the methane network.
LTCs for Natural Gas	No sector specific rules exist as regards gas supply contracts in terms of their duration. Derogations from third party access possible on the take-or-pay obligations concluded in long-term supply contracts (Art. 35 and 48 of the Gas Directive).			As Status Quo plus: Remove privileges (derogations) for new long term natural gas contracts, signed after [entry into force of the GR], and limit duration of such contracts to 2049.	As Option 3 plus: Introduce time limit for long-term contracts already before 2050.
Gas quality	Do nothing. Stronger enforcement on gas quality. Revision of CEN standards to include renewable and low-carbon gases.	Reinforced cross-border coordination on gas quality management and transparency.	EU rules setting principles for processes, roles, responsibilities, cost recovery and allocation, regulatory oversight and reinforced cross-border coordination of gas quality management. Variant: Setting detailed EU rules		As Option 2/3 plus: EU-level harmonisation of gas quality standard for cross-border interconnection points, based on the quality of natural gas.

					Variant: Quality standards based on biomethane quality parameters.
Hydrogen blending cross-border framework	Do nothing. As no rules for cross-border flows of hydrogen-gas blends exist, no implementation or enforcement would take place.	Reinforced cross-border coordination and transparency on national hydrogen blending levels.	EU rules setting an allowed cap for hydrogen blends that Member States must accept at cross-border interconnection points and reinforced cross-border coordination.		As Option 2/3 plus: Prohibition against the acceptance of blending levels above maximum cap of hydrogen blends at cross-border interconnection points.
LNG terminals	LNG terminals are regulated with third party access (exemptions are possible). No clear rules on capacity allocation and congestion management. Tariff discounts may be granted.	Principles concerning transparency, voluntary (e.g. led by industry) initiatives and supported by EU guidance	Binding legal framework at EU level for transparency, congestion and access rules	As Option 2 plus: Mandatory market test/screening and development plans for LNG terminals (and gas storage) operators on the acceptance of RES&LC gases, including liquid hydrogen.	As Option 3 plus: Removing the entry tariff discount in favour of LNG natural gas or extending existing discount also to RES&LC gases
Energy security	Do nothing.	Commission non-binding guidance on: Extending the scope of the emergency tools to new gases and risks and minimum cybersecurity requirements for the gas sector	Amend the gas security of supply Regulation to address the needs and risks of the future decarbonised gas sector and develop rules for cybersecurity in the gas sector.		

5.4 Options in the Problem Area III: Network planning

Integrated planning practices at all levels will be needed in order to ensure the achievement of energy and climate policy objectives at the lowest cost, while maintaining security of energy supply. The below options include measures to increase the level of planning integration. The options build up on each other, i.e. the elements described in Option 1 are also part of Option 2 and those of Option 2 are part of Option 3. Guaranteeing coherence with the relevant provisions of the SoS Regulation (e.g. Union wide simulation of disruption scenarios, national/regional risk assessments) is a common element to all options.

5.4.1 Baseline

No further EU-level legislation would be developed regarding **integrated network planning.** National plans are to be developed only in Member States where ITO and ISO certified TSOs are operating. While most Member States that have a single gas NDP within which gas TSOs cooperate, there is still limited cross-sector cooperation.

5.4.2 Description of the policy options

5.4.2.1 Option 0: Business as Usual (BAU)

In the BAU option, there would be no change to the current situation. Some Member States, national regulators and/or network operators may adopt additional measures.

Stakeholders' opinions: A big majority of stakeholders from all categories except EU citizens support the measures that are contained in any of the options below. Only a few stakeholders do not see a need for alignment or any other measure supporting sector integration.

5.4.2.2 Option 1: National Planning

This option requires a consolidated network plan including storages, LNG Terminals and production per Member State, irrespective of the unbundling model chosen and the number of gas TSOs in the country. Member States may also opt to develop a joint regional plan instead. The national network development plan needs to be drawn up every two years to align it with the TYNDP timing. The network plan remains binding only for ISO and ITO certified TSOs, which means no change to what is required by the current Gas Directive.

The NDP should include information to what extent and from what point in time certain methane infrastructure is not required anymore and could be used for other purposes. A sustainability indicator to be developed under the guidance of the NRA, should lead to preferring investments that allow gases with low or no carbon impact to be transported in the network.

Stakeholders' opinions: A good majority of stakeholders (with a majority of NGOs, half of public authorities, companies/business organisations, business associations, and some EU citizens) indicate support to align the timing of the NDPs with the TYNDP and require a single plan irrespective of the unbundling model chosen.

5.4.2.3 Option 2: National Planning based on European Scenarios

This option extends Option 1 by requiring a joint scenario, built on the gas and electricity development plans and including the distribution system level. At least one scenario used for the national plan needs to be in line with the European Union climate targets and energy efficiency and renewable energy 2030 and 2050 targets. This can also be ensured linking it to the relevant National Energy and Climate Plan[136] (NECP), which is required to be in line with the climate goals. Building joint electricity and gas scenarios would ensure that indirect interlinkages are treated in a consistent way in subsequent processes by TSOs, and that investment decisions are taken with a common vision of the future. The way direct interlinkages are taken into account can have an impact on the assessment of projects. This latter point is treated in Option 3.

Establishing joint scenarios at the Member State level would mirror the EU-level situation where ENTSO-E and ENTSOG are, since 2018, developing TYNDP scenario jointly. Although there would be still sector specific plans for project identification, the process leading up to the plans could be based on a conceptual integrated plan, or the draft plan should be cross-checked between the sectors on the consistency between the gas and electricity NDPs. This process will build on the collaboration between the electricity and gas TSOs that has to be established to build scenarios. The role of these sanity checks is to examine the potential inconsistencies resulting from the assumptions made by TSOs regarding technologies that are at the interface between the gas and electricity sectors (gas-to-power, power-to-gas, hybrid consumption technologies).

As regards hydrogen development planning, the NRA is empowered to assess the actual need of the hydrogen network based on specific information submitted by hydrogen network operators, such as the actual usage of natural gas pipelines that become available for hydrogen transport. The submitted information should enable the NRA to base its examination on a realistic but forward looking hydrogen demand projection. Hydrogen network operators will publish at regular intervals a joint report on the development of the hydrogen system. This can be done in a more flexible way also outside the bi-annual NDP to cater for a situation of an emergent market. Several governance options are compatible with Option 2. They range from the production of a consolidated and integrated network planning document to the publication of sectorial NDPs produced using a concerted process, while hydrogen could be included based on the development stage of the sector.

Stakeholders' opinions: A significant majority of stakeholders from all categories except EU citizens support a joint electricity and gas scenario. Support was even stronger than for the elements contained in Option 1. Only a few stakeholders are against a joint scenario building. A significant number of stakeholders, including companies/business organisations, business associations, half of academia and public authorities, few EU citizens and NGOs, ask for the inclusion of hydrogen projects in the NDP. Stakeholders most preferred choice as regards the role of Distribution System Operators was to provide and share information. While several

[136] Regulation 2018/1999 is about the implementation of strategies and measures designed to meet the objectives and targets of the Energy Union and the long-term Union greenhouse gas emissions commitments consistent with the Paris Agreement as well as the climate-neutrality objective as set out in Article 2(1), of Regulation (EU) 2021/1119. It covers in this regard also projections of network expansion requirements that need to be in line with the objectives and is hence an important element for the building of scenarios used for network development plans.

stakeholders also support that DSOs provide their own plan including system optimisation across different sectors.

5.4.2.4 Option 3: European Planning

This option would require the creation of a single system-wide network development plan at European level, covering all relevant energy carriers (electricity, methane gas, and hydrogen) per Member State. This system-wide TYNDP would furthermore need to consider investments and investment plans for unregulated energy infrastructures, such as district heating networks. This requires, inter alia, that the system operators provide their complete network information to ENTSOG to enable that the TYNDP can identify and assess projects on the basis of hydraulic modelling, while at the same time integrating and assessing the electricity side, both on TSO and DSO level.

Stakeholders' opinions: Asked about whether stakeholders prefer a joint scenario, but still separate plans, there was slightly more support for a joint plan than those supporting joint scenarios but separate plans. Several stakeholders, mainly supported by companies/business organisations and business associations, pointed out that a joint methane and hydrogen plan, keeping a separate electricity plan would be the preferred option, while this was not being asked explicitly in the consultation.

5.4.3 *Summary of policy options*

Table 7: Summary of policy options in Problem Area III: Network planning

Network Planning	**Objective**	Ensure transparent and inclusive infrastructure planning		
	BAU **No additional measures**	Option 1 **National Planning**[137]	Option 2 **National Planning based on European Scenarios**	Option **European Planning**
Measures	Baseline: Do nothing Note: Inclusion of hydrogen in the EU-wide network development plan (TYNDP) as proposed in the TEN-E	One single network plan (NDP) (including also storages, LNG and production) per Member State irrespective of the unbundling model chosen and the number of gas TSOs in the country. Instead of providing a national plan, Member States can also opt to come up with a regional plan instead. The NDP needs to be drawn up every two years (now: every year). The network plan remains binding only for ISO and ITO certified TSOs to the extent valid today. National regulatory authorities are empowered and required to ensure a transparent process. The NDP includes information to what extent and from what point in time certain methane pipelines are not required anymore and could be used for other purposes (e.g. hydrogen-transport). Introduction of a sustainability indicator.	Integrated planning on national level by requiring joint scenario building between gas and electricity. The joint scenario needs to be aligned with the at least one scenario used for the TYNDP. This can also be ensured linking it to the relevant NECP, which is required to be in line with the climate goals. Creation of a competence for NRA's to perform an assessment on the actual need for hydrogen pipelines. Distribution system operators as well as LNG and storages need to be involved in the scenario building. NRAs may take decisions for setting a framework for the involvement (de-minimis rules, national DSO association). Other energy carriers (e.g. hydrogen, district heating) as well as CO2 need to be taken into account in the scenarios, but not in the plan itself. Provisions for national electricity plans needs to be amended to require joint scenario building.	Drawing up a system wide network development plan (i.e. going beyond joint scenario development), including gas, hydrogen and electricity on European level only. Unregulated infrastructure investments and investment plans are taken into account when elaborating the national network development plan.

137 Note: Options build up on each other. All elements included in Option 1 are included in Options 2, all elements in Option 2 are included in Option 3.

5.5 Options in Problem Area IV: Low level of customer engagement and protection in the green gas retail market

Each policy option consists of a package of measures that addresses the problem drivers in Section 2.4 of this Impact Assessment with increasing depth of the intervention. They aim to increase consumer engagement and tackle the existing competition and technical barriers to the emergence of new services, better levels of service, and lower consumer prices, whilst ensuring the protection of energy poor and vulnerable consumers.

5.5.1 Baseline

In the current scenario, the development of the decarbonised gas markets and its impact on consumer rights and protection is based on enforcing current rules to address the limited competition of the green gases retail market, linked to high levels of market concentration and other rigidities, and low levels of innovation.

5.5.2 Description of the policy options

In the summary *Table 54* of Annex 9, a complete overview of the policy options is provided.

5.5.2.1 Option 0: Business as Usual (BAU)

In the BAU option, there would be no change to the current situation. Some Member States, national regulators and/or network operators may adopt additional measures.

Stakeholders' opinions: A large majority of stakeholders from all categories support the measures that are contained in any of the options below. Only a few stakeholders do not see a need for alignment or any other measure supporting sector integration.

5.5.2.2 Option 1: Strengthened enforcement and soft implementation measures to better apply current rules

This option addresses the problem drivers to the greatest extent possible through enforcement and implementation measures.

This option assumes that the future situation improves through enforcement measures following the development of the decarbonised gas market without further legislation. The Commission promotes better enforcement by tackling cases of the non-transposition or incorrect application of existing legislation, reinforced administrative cooperation with and between national authorities, capacity building and guidance such as interpretative notes on the existing provisions in the Gas Directive (e.g. on switching-related fees, REC). Enforcement action is taken should Member States' interventions in price setting be either disproportionate or unjustified by the general economic interest or not compliant with the current EU acquis[138, 139].

Stakeholders' opinions: A vast majority of respondents from all categories consider that there is a need to be more ambitious when it comes to a citizen and/or consumer focus in the

[138] Article 3(2) of the Electricity Directive and of the Gas Directive.

[139] Section 7.1.1 of the Evaluation Report argues that the regulation of gas prices limits consumer choice, restricts competition, and discourages investment.

legislation than what is currently encompassed. Only a small number of respondents believe there is no need to further upgrade.

5.5.2.3 Option 2: Non-regulatory approach: strengthened enforcement, enhanced implementation measures and intense consultations with stakeholders.

This option addresses all problem drivers through enforcement and enhanced implementation measures, topped up by intense consultations with stakeholders.

The number of gas users and volumes of gas consumed will be falling over the next 10-15 years. In such a shrinking sector, both public and private actors may struggle to implement new measures. Under this option, the problem drivers are addressed without resorting to new legislation, while implementation and enforcement measures are topped up by intense consultations with Member States and issuing Commission recommendations on **price regulation**, billing information and price comparison tools. Support to the EU Energy Poverty Advisory Hub is enhanced and as such the role of networks of expert organisations is strengthened to deliver better energy poverty solutions at local level. Similarly, the Commission strives to make the most out of the current framework for **REC** through local initiatives and an interpretative note. All **smart metering** provisions are placed in one single legislative act and **data management arrangements** remain with Member States.

Stakeholders' opinions: There are no respondents who explicitly stated their preference for the non-regulatory approach. Stakeholders from all categories expressed the need for free-of-charge access to price comparison tools, information on switching possibilities as well as the deployment of smart meters, which could potentially be addressed without additional legislation.

5.5.2.4 Option 3: Flexible legislation addressing all problem drivers

This option addresses all problem drivers through new legislation, mostly mirroring the electricity market directive that leaves sufficient discretion to the Member States to adapt their laws to the conditions in national markets. Option 3 is also in line with proposed measures to support a just transition and protecting end-users in the Commission's Communication on Energy Prices.[140]

The framework for **price regulation** is better defined and limited to household customers (including vulnerable and energy poor households) and micro-enterprises. With regard to the higher protection of vulnerable customers and energy poor households, the recast EED definitions and requirements are cross-referenced, as the EED becomes the reference framework for this area. This will result in a framework that is streamlined with the revision of the ETS and extension to buildings and transport and its accompanying Social Climate Fund, where the main focus is on structural investments while direct income support is allowed, but not favoured and will need to be temporary and lead to results.

The Social Climate Fund shall be directed to reduce the reliance on fossil fuels through increased energy efficiency of buildings, and particularly synchronised with the revised gas

140 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on tackling rising energy prices: a toolbox for action and support COM(2021) 660 final

legislation as it directs investments towards decarbonisation of heating and cooling of buildings, including the integration of energy from renewable sources, to the benefit of vulnerable households, vulnerable micro-enterprises and vulnerable transport users. Decarbonisation targets will be further supported by the direct funding to ensure improved access to zero- and low-emission mobility and transport. Key principles and **data management rules** are put in place to mirror, where relevant, the respective provisions for electricity. This could include enhanced **smart metering** rollout or even a deployment target. Customers would also be entitled to request a smart meter at their expense. Minimum requirements for **contractual conditions** are established in particular **contract termination fees** would be **restricted**. Other areas which would be mirrored include faster and free-of-charge switching and the enabling framework for **citizen energy communities (CEC)**.

Stakeholders' opinions: The vast majority of the stakeholders support the introduction of new legislation mirroring provisions in the electricity market. Some emphasize mirroring of billing information and energy poverty provisions to ensure consumers are not paying the cost of switching to clean gas based options. Some consumer organisations would keep regulated prices for energy poor and vulnerable consumers. Almost half of all respondents want provisions on comparability of offers and accessibility of data, transparency, smart metering systems, and switching to be reinforced. A minority of stakeholders represented by some companies/business organisations, some business associations, some public authorities and some NGOs indicated that provisions on CEC and active customers could be mirrored to a large extent.

5.5.2.5 Option 4: EU Harmonization and extensive safeguards for customer addressing all problem drivers

This option addresses all problem drivers through new legislation that aims to provide full protection to consumers and extensive harmonisation of Member State action throughout the EU.

One of the key conclusions in relation to addressing Problem Area II is that there is significant benefits from ensuring that the market for Renewable and Low Carbon Gases is 'European' from the beginning. A European wholesale market should be complemented by a European retail market. Under this option, all problem drivers are addressed through new legislation that aims to provide extensive harmonisation throughout the EU. To improve competition, Member States phase out **price regulation** for non-vulnerable customers and energy poor households[141]. With regard to the higher protection of vulnerable customers and energy poor households, Option 3 is enhanced by additional gas specific provisions and stronger restrictions on disconnections[142].

Other notable elements include a standard consumer **data handling** model with standardised formats. The rollout of gas **smart metering** becomes mandatory throughout the EU. **Switching**-related fees are banned, including contract termination fees and the format and

141 However, similar to Option 2, exemptions to price regulation are defined at the EU level for vulnerable customers and energy poor consumers, allowing a case-by-case assessment of the proportionality of exemptions to price regulation.

142 Including: i) before a disconnection from the first unpaid bill; ii) notice by competent authorities to customers at least two months information on sources of support; iii) and the possibility to delay payments or restructure their debts.

content of **energy bills** is significantly harmonised – notably on the renewable and low carbon gases. Gas **CEC** would be made more citizen centred and harmonised with a supporting framework similar to Article 22 of the Renewable Energy Directive.

Stakeholders' opinions: Respondents mainly from companies/business organisations, business associations, and half of academia that responded did not explicitly discuss the harmonisation of the consumers' provisions and safeguards on the EU level. However, some stakeholders, represented by companies/business organisations, Business associations, and some public authorities support the strengthening and harmonization of gas quality standards that would ultimately enable better and more accurate information for the consumers. Furthermore, certain stakeholders (academia, a good proportion of public authority, some companies/business organisations and business associations have mentioned that responsibility for data handling would adequately correspond to TSOs when it comes to establishing blending rules. A minority of the stakeholders believed that the provisions for smart metering systems could be fully mirrored.

5.5.3 Summary of policy options

Table 8: Summary of policy options in Problem Area IV: Measure on retail market, consumer protection and engagement

Retail markets, consumer protection and engagement	**Objective**	Ensure adequate levels of customer empowerment and protection in the decarbonised market			
	Option 0 **No additional measures**	Option 1 **Strengthened enforcement and soft implementation measures**	Option 2 **Strengthened enforcement, enhanced implementation measures and intense consultations with stakeholders**	Option 3 **Flexible legislation**	Option 4 **Harmonization and extensive consumer safeguards**
Price regulation	No rules	Step up enforcement of existing legislation on price regulation	Enforcement measures under Option 1 are complemented by bilateral consultations with Member States to try to progressively phase out price regulation + COM Recommendation on price regulation.	Member States phase out blanket price regulation. Exemptions for households, micro-enterprises as well as vulnerable and energy poor households are defined at the EU level, similar to the Article 5 in the electricity market directive.	Member States phase out blanket price regulation. Exemptions for vulnerable and energy poor households are defined at the EU level.
Energy poverty and vulnerable customers	No rules	Sharing of good practices	Support to the EU Energy Poverty Advisory Hub is enhanced and as such the role of networks of expert organisations and individual practioners is strengthened to deliver better energy poverty solutions at local level.	The recast EED definitions and requirements for energy poverty and vulnerable customers are cross-referenced	Option 3 is enhanced by additional sector specific provisions to strengthen the protection of gas customers considered energy poor and vulnerable. Stronger restrictions on disconnections are also included.

Switching, price comparison tools and billing	No rules	Step up enforcement existing legislation on switching and billing + interpretative notes on the existing provisions in the Gas Directive	Improved EU guidance and Recommendations on facilitating switching, price comparison tools and billing	Aligning the provisions with those included in the Electricity Directive: Introducing a right to access objective and certified price comparison tools Introducing minimum period for technical switching (however, due to the technical specifics of gas supply, a longer period may be relevant than for electricity) Introducing additional requirements to be included in bills, mirroring the Electricity Directive (i.a. information on ADR, sources of energy, etc), to ensure clear and transparent billing (restricting exit fees, see next table)	Introducing switching requirements beyond those in electricity: Banning all switching-related fees, including contract-termination fees Harmonising the format and content of energy bills across Member Sates NRAs offer (or fund) price comparison tools.
Contractual conditions	No rules	Step up enforcement existing legislation on contractual conditions	Improved EU guidance and Recommendation on basic contractual conditions	Aligning the provisions with those included in the Electricity Directive: Minimum contractual conditions are established for contracts and termination fees restricted	Banning all switching-related fees, including contract-termination fees
Smart metering systems	No rules	Step up enforcement of existing legislation	Enforcement measures under Option 1 are complemented by consolidating all smart metering provisions in one single legislative act (but not introducing extra regulatory requirements)	While the decision for deployment remains with Member States, additional smart metering requirements are adopted for an enhanced deployment, including set functionalities, a deployment target, the right to a smart meter, regular revision of negative assessments; while encouraging selective, targeted rollouts	Mandatory rollout throughout the EU with fixed functionalities mirroring all those of electricity smart metering systems, irrespectively of the national cost-benefit assessment

Data management	No rules	Step up enforcement of existing legislation	Enforcement measures under Option 1 are complemented by further promoting best practices, while data management arrangements are primarily left with Member States	EU data management rules are set up, along with measures for transparent and non-discriminatory access to data, and data interoperability irrespectively of the data management model used	One single data handling model introduced throughout the EU along with standardised formats for exchange of data
Energy communities	No rules	Step up enforcement of existing legislation on renewable energy communities	Enforcement measures under Option 1 are complemented by an interpretative note on renewable energy communities and flanked by existing initiatives, such as the Energy Community Repository and the Rural Energy Community advisory hub.	The concept and enabling framework for 'citizen energy communities' is mirrored into EU gas legislation.	In addition to the measures proposed under Option 2, the concept of 'citizen energy communities' is made more citizen-centred (51% voting right allocation to natural persons) and the enabling framework coupled to additional support measures (removal of barriers, access to finance and information etc.)

6 WHAT ARE THE IMPACTS OF THE OPTIONS?

6.1 Assessment of options for Problem Area I: Hydrogen infrastructure and markets

6.1.1 Methodological approach

The assessment of the policy options combines **qualitative with quantitative elements**. The focus is set on 2030 and the assumption that a transport network will exist in light of the expected increase of hydrogen production and consumption in the MIX-H2 scenario.

Firstly, a holistic, **qualitative** assessment is carried out primarily by drawing on lessons from the existing (and regulated) gas and electricity market. The impact of the policy options on the **future hydrogen market structure**, on the level of **cross-border market integration**, on **investment incentives in hydrogen networks** and on **aligned hydrogen quality is assessed**. These assessment criteria thus correspond to the drivers identified in Section 2.1. The administrative impact on business and public authorities is also assessed under the light of **economic impacts** (and further detailed in Annex 3). In view of the uncertainty on the actual development of the hydrogen value chain, the expected **environmental impact** of the policy packages is described in more general terms.

Secondly, in order to model their **quantitative** impact, the different policy options as proposed in this Impact Assessment have been **translated into hydrogen infrastructure scenarios**. The quantitative assessment is performed in the METIS model. The scenarios are based on **the expected effect the policy packages will have on the development of (cross-border) hydrogen transport capacity (i.e. network infrastructure) and costs**. The effect of different policy options on the development of (cross-border) hydrogen transport capacity can only be identified **in terms of direction**, i.e. different regulatory measures that are part of the policy options can increase or decrease the likelihood that (cross-border) hydrogen infrastructure gets built. Quantitative indicators are then calculated for all scenarios. The key quantitative indicators calculated for each of the scenarios are **the effect on costs of hydrogen delivered and the full costs of hydrogen, which include the change in total energy system cost due to the deployment of hydrogen.** Cost of hydrogen delivered reflect the total cost for hydrogen production (renewable energy sources, electrolysers) and hydrogen infrastructure (storage and network). Total energy system costs cover all cost components of the energy system consisting of gas and hydrogen supply and electricity generation.

Interpreting the results and the expected impact of the policy options thus requires a reflection on both the qualitative and quantitative assessment.

6.1.2 Qualitative assessment

Each option exists as a package of more detailed measures. For each of these detailed measures, advantages and disadvantages are also provided in the tables in Annex 6.

6.1.3 Impacts of Option 0: Business as usual (BAU)

6.1.3.1 Economic impacts

Without regulation, companies can invest in hydrogen pipelines and operate these pipelines with a large degree of commercial freedom. Accordingly, hydrogen producers may enter into long-term supply contracts with (industrial) hydrogen consumers (or groups of companies) and offer the whole service of hydrogen production, transport, and structuring/storage/balancing (no vertical unbundling rules). The partners could agree freely on commercial terms (no tariff regulation) and the vertically integrated company could act as the sole user of the pipeline (no TPA).

(Cross-border) market integration: Without regulation, pipeline networks will be developed in a bottom-up approach, which is likely to result in dispersed, uncoordinated network development across the EU and with third countries. Unregulated (private) investors will build pipelines where this is most profitable and not primarily where (cross-border) hydrogen needs are most urgent in light of decarbonisation efforts. No regulation is assumed to lead to less cross-border integration of hydrogen transport infrastructure than in the case of cross-border harmonisation of rules. Accordingly, cross-border integration cannot contribute to a reduction in hydrogen costs by reallocating renewable hydrogen production to the most favourable production sites. The lack of EU approach on terminology and certification system hampers cross-border trade in LCH and LCF.

Investment incentives (new and repurposed infrastructure): The commercial freedom to enter into long-term agreements and secure investments at bilaterally agreed-upon terms may facilitate investments in an early phase of hydrogen market development, where there is not a solid customer base to socialise high initial costs. This holds for investments in new pipelines and investments required to repurpose natural gas pipelines for hydrogen.

Market structure: Under Option 0, owners of infrastructure having the characteristics of a natural monopoly are unconstrained and no regulation avoids the risk of charging monopolistic priced network tariffs and/or conduct resulting in market foreclosure. Market foreclosure of upstream (hydrogen producers) and downstream (hydrogen consumers) markets can easily result in monopolistic prices being passed-on down the entire hydrogen value chain with negative implications for hydrogen uptake and ultimately the achievement of decarbonisation targets. Additional consumers will only be connected if that is commercially attractive for the network owner. It is likely to require ex-post regulatory measures to remedy the downsides of these monopolistic tendencies.

Aligned hydrogen quality: The lack of an aligned cross-border approach with regard to hydrogen quality specifications would raise the risk of cross-border flow restrictions and market segmentation.

6.1.4 Impacts of Option 1: Rights for network operation tendered

An in-depth assessment of Option 1 was not performed.

Like in the BAU-scenario, this option entails a ‘competition for the market’ model. It differs from BAU in several aspects e.g. it can be expected that some of the monopoly rents of unregulated networks would accrue to the Member State through tendering revenues. However, monopolistic conduct will still negatively affect network users and tender revenues mainly represent a distributional effect. Relative to BAU, the building of parallel networks would be avoided and, depending on tender designs adopted at national level, it may be somewhat more conducive in comparison to BAU to (intra-EU cross-border) market integration provided that a level of coordination between Member States takes place. The same does not apply to third countries however. Moreover, creating appropriate repurposing investments is challenging in a tendering approach as private parties and TSOs (which may be allowed to participate) would not participate in such a tender on equal terms[143].

However, these differences still means that the impacts of Option 1 are unlikely to be materially different from BAU. It is thus highly unlikely that Option 1 would be retained as a

143 See also Guidehouse/Frontier Economics (2021) page 44.

preferred option (as opposed to Option 2 and 3) once BAU is rejected as the preferred option whereas the benefits of BAU could also be analysed in comparison with Options 2 and 3.

6.1.5 Impacts of Option 2a: Main regulatory principles only

6.1.5.1 Economic impacts

(Cross-border) market integration: As negotiated TPA implies the absence of tariff regulation, divergent (national) TPA-regimes can accordingly develop which may impede the development of interconnections between EU member states and thereby cross-border trade. A limited degree of cross-border market integration affects the ability of operators in certain Member States to have access to large scale storage and imports. Defining LCFs and having a light Guarantees of Origin (GO) system in place addresses cross-border issues to a certain extent. However, this solution can lead to a duplication of regulatory structures and incoherencies and would put RES-based hydrogen and fuels at a disadvantage compared to LCH and LCFs. There is also a risk of ineffective application of main regulatory principles to hydrogen interconnectors with third countries.

Investment incentives (new and repurposed infrastructure): The limitation of full commercial flexibility following the introduction of regulation under this option might hamper investments, but the introduction of negotiated TPA provides ample room for network operators to enter into long-term transport agreements to finance (initial) network investments. The option to operate gas and hydrogen networks in a joint asset base (common RAB allowed/no horizontal unbundling) is likely to facilitate repurposing as network operators have the option to finance and de-risk networks across users of both natural gas and hydrogen infrastructure. This could be relevant during the hydrogen market ramp-up phase over the coming decade, where utilisation of hydrogen pipelines is likely to be low relative to capacity, and hydrogen network tariffs can be expected to be high otherwise. A common RAB approach will enable operators to spread these costs to the larger group of network users thereby enable them to offer more attractive tariffs to early hydrogen network users neutralising investment risks. The option of a common RAB does however entail the risk of overinvestments in repurposing pipelines, also because it does not address the externality/risk that gas-TSOs will finance the domestic hydrogen network with revenues collected from natural gas network users in other Member States through cross-border tariffs. The lack of any regulation on import terminals means that investments incentives are not affected by EU rules. Storage operators would lose some of their commercial freedom, but remain relatively free to choose their contract partners and structure investments.

Market structure: The introduction of vertical unbundling in combination with the requirement of TPA ensures that network operators do not have the incentive to discriminate against users of their network, and it enables access of all parties to hydrogen networks (no market foreclosure). This enables the emerging hydrogen market to become a competitive market that is characterised by a higher uptake of (renewable) hydrogen and lower prices than in the absence of regulation. A joint RAB and absence of horizontal unbundling could distort the level playing field between incumbent gas network operators that want to repurpose their assets for hydrogen transport and other (private) parties that have an interest in investing in and operating hydrogen networks. The latter group does not have the option to finance the development of pipeline infrastructure from (regulated) revenues obtained from the operation of natural gas networks. With a joint RAB, hydrogen and natural gas network tariffs would no longer be cost reflective as natural gas users could end up financing the hydrogen network. Accordingly, a distributional effect of hydrogen network costs is expected under the absence of horizontal unbundling as hydrogen and gas consumer groups may differ substantially in an early phase. (Initially hydrogen is expected to be largely used by industrial consumers while natural gas consumers also include smaller (e.g. household) consumers.) Whilst such risk may be low, in view of the potential competition from other forms if imports, potential market power by terminal owners is not contained in any way. Negotiated access to large scale storage would ensure a minimum degree of non-discriminatory third-party use of hydrogen-ready underground storage but is more prone to abuse, especially when commercially important and rare especially at early stages of market development.

Aligned hydrogen quality: The obligation on Member States to agree on cross-border hydrogen quality aspects would limit the risk of cross-border disputes and market segmentation. However, the lack of a harmonised EU approach still represents a risk to cross-border flows and to hydrogen end-users, which can be only partially remedied by establishing a cross-border dispute settlement tool. At the same time this options leaves flexibility to the Member States on hydrogen quality standards in the domestic network without interference with national specificities of hydrogen production and qualities.

6.1.6 Impacts of Option 2b: Main regulatory principles with a vision

6.1.6.1 Economic impacts

Market integration: The introduction of strengthened regulation under this option is expected to further facilitate cross-border integration. Regulated TPA and tariff regulation implies policymakers and NRAs requiring certain forms of top-down cross-border coordination and creates more uniform market conditions. The introduction of regulated TPA at EU level ensures non-discriminatory access to cross-border infrastructure (including for interconnections with third countries), whereas transparent and uniform tariffs at EU level ensure better conditions for integrating the hydrogen network. The common terminology and a harmonised certification system for LCH and LCFs will ensure that all related GHG emissions are correctly accounted for in a life cycle analyses approach and enable Member States and economic operators alike to effectively compare their carbon footprint solutions. This will foster cross-border trade in LCH and LCFs. Such communality of main principles avoids regulatory divergence and barriers. The application of the main regulatory principles to interconnectors with third countries is assured via the requirement to conclude an intergovernmental agreement (IGA) on the operational rules.

Investment incentives (new and repurposed infrastructure): The combination of regulated TPA and tariff regulation under this option is expected to reduce revenue risks which may facilitate investments once a secure and vast customer base for the hydrogen transport network has developed. Restricting commercial leeway with the introduction of regulated TPA and tariff regulation may render initial investments in the hydrogen network less attractive. This effect will however be eased by allowing negotiated TPA in the market-ramp up phase towards 2030 under this option. Temporarily allowing the cross-subsidisation of hydrogen networks via revenues obtained with gas network activities is expected to accommodate investments in repurposing pipelines for hydrogen transport whilst the externality that these are financed by natural gas network users in other Member States is addressed. (This risk of overinvestments is also contained by empowering the NRA toassess the need for hydrogen networks based on concrete information that should be submitted by hydrogen network operators to the NRA, a measure developed under Problem Area III.) The grandfathering of existing rights and permits of methane infrastructure when used as hydrogen infrastructure as well as guidance in this regard for newly built pipelines will take away a potential barrier for investments in hydrogen infrastructure and improve investment incentives by avoiding regulatory bias between investment projects. The introduction of a regulated access regime for storage is expected to be conducive to investment incentives as both renewable hydrogen producers and consumers are dependent on the intermittent character of renewable electricity production to optimise their economic activities. In addition, in the ramp-up phase storage is one of the few means available to cover energy security risks. Typical early consumers of hydrogen and natural gas will have equivalent rights assuring that choices between these energy carriers are made on the basis economic considerations as opposed to regulatory arbitrage.

Market structure: Alongside the vertical unbundling requirement, regulated TPA further improves the rights for (potential) third party network users and increases transparency, which facilitates the market entry of upstream (hydrogen producers) or downstream (hydrogen consumers) market parties. This is expected to be beneficial for renewable hydrogen producers that require network connection or suppliers that want to supply consumers with hydrogen. Tariff regulation for transportation and large scale storage sets an upper limit for profits and helps address the adverse impacts of market power in a natural monopoly as firms cannot charge excessive prices. These are to be cost-reflective and set under regulatory control. It will also have the benefit of containing the distortions of the level playing field between gas network operators that want to repurpose their pipelines for hydrogen transport and other parties interested in investing and operating hydrogen networks.

Aligned hydrogen quality: Setting an EU-wide acceptable hydrogen quality (purity) level for cross-border points ensures a harmonised approach across the EU and thereby eliminates the risk of cross-border disputes on hydrogen quality issues and provides clarity to investors, operators and users on acceptable quality. This option also ensures a harmonised approach across the EU on quality management but retains flexibility for Member States to define the acceptable hydrogen quality levels for their domestic networks, i.e. respecting the specificities of domestic hydrogen production technologies.

6.1.7 Impacts of Option 3a: Hydrogen rules by Big-Bang

6.1.7.1 Economic impacts

Market integration: Vertically integrated firms that are not unbundled are expected to have fewer incentives to develop integrated (cross-border) markets as this could lead to higher competition in the integrated firm's (domestic) market threatening profits in associated upstream and downstream markets. Ownership unbundling is expected to target this potential negative effect on market integration[144]. Trade in LCH and LCFs is facilitated like under Option 2b. The application of main regulatory principles to inter-connectors is assured with a strong role for the EU.

Investment incentives: The introduction of the strictest form of vertical unbundling in combination with the requirement of separate RABs and legal horizontal unbundling considerably reduces the commercial freedom to invest in (repurposing) hydrogen pipelines. It entails a stronger disruption of gas TSO operating under an ITO model and vertically integrated private operators. The immediate introduction of regulated TPA and tariffs can secure investments but puts constraints on projects that seeks a more project based finance

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[144] The Impact Assessment on Gas (European Commission, 2007) showed that fully unbundled TSOs reinvest a higher share of their congestion revenue in new capacity. According to the EC, this is because 'vertically integrated companies have an interest to protect their supply business in their home market by limiting cross-border capacity' (European Commission, 2007, S. 34). Ownership unbundling increases incentives for network operators to integrate markets by removing.

model in the transition phase. An EU system of permitting and land-use rights for hydrogen pipelines may provide a better level playing field for investments (but will come at high costs). Like under Option 2b, a regulated access regime for storage is expected to be conducive to investment incentives by hydrogen producers and consumers.

Market structure: The introduction of regulated TPA with the strictest form of vertical unbundling creates optimal conditions for a competitive market with non-discriminative market entry. The separation of RABs combined with the requirement of stronger horizontal unbundling prevents that network operators that pursue both hydrogen and gas network activities can redistribute the (high) costs for initial hydrogen network users to remaining users of the natural gas grid. Like under Option 2b, a proportional response exists to the potential threat of market power by large scale storage operators and import terminals.

Aligned hydrogen quality: The same impacts are expected as under Option 2b as the same approach is taken under Option 3a for hydrogen quality.

6.1.8 Impacts of Option 3b: Hydrogen rules by Big Bang plus

6.1.8.1 Economic impacts

As Option 3b builds further upon Option 3a, the economic impacts of Option 3b are expected to be similar to the economic impacts of Option 3a. However, as it provides an alternative to ownership unbundling (as under Option 3a) for currently vertically integrated network operators, it has lower implementation costs and is less disruptive. Moreover, the creation of an EU TSO tasked with operating and developing an EU hydrogen network under this option is expected to profoundly accommodate **cross-border market integration** as it internalises the coordination of the development of the (regulated) cross-border hydrogen network within the EU. It also has synergies with other main regulatory principles, for instance, it can facilitate setting up the ITC mechanism (that may be required in view of the prospect of avoiding cross-border tariffs) and network planning.

6.1.9 Who would be affected and how?

Whilst regulatory burden and administrative costs vary between options, they are expected to be easily outweighed by the economic benefits under all options[145]. The concrete effects on specific parties is further described in Annex 3.

Table 9: Who is affected and how by the options in Problem Area I (in terms of administrative and economic costs)
'0' = neutral, '-' = negative effect on costs; '+' = positive effect on costs

Problem Area I	BAU	Option 1	Option 2		Option 3	
			Option 2a	*Option 2b*	*Option 3a*	*Option 3b*
Hydrogen producers	0	-	-	-	--	--
Hydrogen consumers	0	-	+	++	++	++
ACER	0	0	-	--	--	--

145 See also assistance report to the Impact Assessment for designing a regulatory framework for hydrogen, p. 7 (Guidehouse/Frontier Economics, 2021).

NRAs	0	-	-	--	--	--
Public administrations/MSs	0	-	-	-	--	--
Natural gas TSOs pursuing hydrogen transport activities	0	0	-	--	--	--
Private hydrogen network operators	0	-	-	--	--	--
Terminal operators	0	0	0	-	-	-
Large scale storage operators	0	0	-	--	--	--

6.1.10 Environmental impacts of options related to Problem Area I

A lower level of regulation and accordingly cross-border integration (as assumed under the BAU-scenario and Option 2a) is expected to have negative effects on the cost-efficient uptake of (large volumes) of renewable hydrogen as it will become more difficult to connect favourable renewable hydrogen production locations with distant demand centres. Due to the market structure that might develop, higher entry barriers are expected for new and mostly renewable hydrogen producers vis-à-vis current fossil based hydrogen producers. A higher level of regulation is expected to be beneficial for renewable hydrogen producers that ask for network connections or suppliers that want to supply (distant) consumers with (cross-border) produced renewable hydrogen. Fostering access to large scale storage, allowing renewable hydrogen producers to balance intermittent production with stable off-take requirements will equally foster renewable hydrogen production.

6.1.11 Quantitative assessment - summary of modelling results for Problem Area I

Four different scenarios are considered for the European hydrogen grid, as shown in the table below.

Table 10: Hydrogen network scenarios for the assessment with the METIS model

Scenario	Minimum cross-border capacity	Maximum cross-border capacity	Optimisation of cross-border capacity	Most likely to happen in regulatory option
Business as usual (BAU)	None	0	No	0 or 1
A constrained	EHB 2030	None	No	2a, 2b, 3a, 3b (lower end)
A optimised	EHB 2030	None	Yes	2a, 2b, 3a, 3b (higher end)
B optimised	EHB 2035	None	Yes	Additional drivers

The BAU scenario assumes no cross-border transport of hydrogen via pipelines except for existing commercial pipelines. This reflects the expected situation under regulatory Options 0 and 1, where a lack of European regulation could prevent the execution of projects.

Scenarios 'A constrained' and 'A optimised' assume cross-border capacity based on the updated 2021 European Hydrogen Backbone (EHB) 2030 vision for dedicated hydrogen infrastructure in Europe[146]. Capacities are fixed in scenario 'A constrained' while the METIS

[146] Guidehouse (2021). Extending the European Hydrogen Backbone: a European hydrogen infrastructure vision covering 21 countries. Utrecht: Guidehouse.

model may add additional cross-border interconnections in scenario 'A optimised'. These two scenarios represent the respective lower and higher ends with respect to network investments, if sufficient regulation to allow for cross-border connections is in place, such as in regulatory Options 2a, 2b, 3a, and 3b.

Scenario 'B optimised' increases the minimum cross-border capacity to the EHB vision for the year 2035. This scenario corresponds to a very high roll-out of cross-border hydrogen networks leading to an oversized hydrogen network with low utilisation rates. Such a scenario is not expected to materialise if driven alone by the regulatory options considered but would require additional drivers.

Table 11 shows the main modelling results for the different hydrogen grid scenarios assessed. For the four different scenarios, it shows the GW of interconnection capacity (both repurposed and new) between EU Member States as well as two measures for the costs of hydrogen: **hydrogen market prices and total costs of hydrogen**[147] as identified by the METIS model.

Table 11: Main hydrogen modelling results

Scenario	Inter-connection repurposed methane [GW]	Inter-connection new hydrogen [GW]	Inter-connected region	hydrogen storage capacity [TWh]	hydrogen prices [EUR / kg]		hydrogen total costs [EUR / kg]	
					average	range	average	range
BAU			none	20,8	3,2	7,6	4,2	6,8
A constrained	19	10	BE-DE-FR-NL	18,3	2,7	5,0	3,6	4,3
A optimised	44	27	EU	17,9	2,5	0,1	3,3	1,5
B optimised	54	130	EU	17,7	2,5	0,1	3,4	2,0

The assessment confirms the economic advantage of encouraging a European hydrogen network. A rightly sized cross-border interconnection capacity can reduce the costs of hydrogen and would lead to an EU average hydrogen price of 2,5 EUR/kg. There is a strong convergence in hydrogen prices across Member States when cross-border infrastructure is available, as shown by the narrow range in hydrogen prices under the optimised scenarios

Moving from the BAU scenario to a scenario with only a limited exchange capacity of 29 GW (the sum of repurposed methane and new hydrogen pipelines) between 4 MS (scenario 'A constrained') reduces the average price of hydrogen by 19% (from 3,2 to 2,7 EUR/kg). If the regulatory frameworks are sufficiently aligned to enable cross-border trade across the European Union, 71 GW of interconnections (44 GW of which repurposed) are built, creating an integrated EU hydrogen network and market. This further lowers the average hydrogen price to 2,5 EUR/kg, a reduction of more than 20% in comparison with the BAU scenario. If the expansion of cross-border connections is further increased as in the 'B optimised'

[147] This analysis assumes that hydrogen would be priced on wholesale markets according to marginal production costs. Those include the costs of buying electricity on the market as well as other variable costs of electrolysers. The total costs of hydrogen (shown in the last two columns) also include the necessary investments in electrolysers and network infrastructure.

scenario, prices would not decrease any further while total costs would increase due to the additional network infrastructure, a clear sign that such a network would be oversized for the purpose. In addition, such an oversized grid could cause infrastructure costs to be spread unevenly across the different MS as can be seen from the higher spread in total costs in the 'B optimised'-scenario as compared to 'A optimised'.

6.2 Assessment of options for Problem Area II: Renewable and low carbon gases in the existing gas infrastructure and markets, and energy security

6.2.1 Methodological approach

The analysis of options builds upon the more detailed analysis of policy measures, presented in Section 5. The focus is set on the year 2030. In the modelling of the results, different approaches were applied, depending on data availability and appropriateness. They range from dedicated, scenario-based modelling exercises with the EU energy system model METIS, over semi-quantitative estimations to qualitative analyses. The analysis relies on quantitative framework data from the MIX-H2 scenario.[148]

Any increase in biomethane production brings an increase in overall system costs, as long as production costs for biomethane remain high and CO2 prices relatively low. However, the enhanced utilisation of biomethane provides secondary benefits, such as improved energy security and reduced energy imports. Moreover, supplying renewable gases on the basis of a market framework allows to exploit the production costs differences and hereby lower the amount of necessary public support.

6.2.2 Impacts of Option 0: Business as usual (BAU)

6.2.2.1 Economic impacts

In the baseline scenario, biomethane would develop on average below recent growth rates, as increased biomethane development may be restricted in some Member States by non-existing or inadequate regulation or technical specifications. Biomethane production could amount to a rough estimation of around 44 TWh, or around 2-3% of gross gas supply in 2030. In the baseline, the injection of synthetic methane would not be significant in 2030.

The reliance on national and voluntary initiatives to address barriers in the LNG sector would have more moderate effects on terminal utilisation, tariffs and total LNG inflows.

The current SoS Regulation would apply focusing on natural gas. The resulting poor management of possible disruptions could erode the public support in the transition. The economic impact of doing nothing cannot be quantified.

6.2.2.2 Environmental impacts

Compared to the MIX-H2 scenario, natural gas consumption could in the baseline increase slightly to compensate for the reduced biomethane production. If natural gas does fill in the biomethane production gap, this would lead to a slight increase in total greenhouse gas emissions of the EU energy system.

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148 See in Annex 4 for a more detailed description of the methodology.

6.2.3 *Impacts of Option 1: Allow renewable and low carbon gases full market access*

6.2.3.1 Economic impacts

Option 1 allows for **integration of the biomethane potential** at lower costs than baseline. The **access of locally produced renewable and low-carbon gases to the VTP** would grant producers a price for biomethane EUR 1/MWh (5%) higher than under the bilateral agreements. In this case, public support schemes could be reduced by some EUR 10 m annually in the Member States where the access to VTP is not yet implemented[149]. The costs of reverse flows depend on the size of the compressors and costs of deodorisation. In general terms, these costs add to about EUR 1.9/MWh[150]. A sensitivity analysis, assuming that 10% of biomethane plants would be facing oversupply, shows that reverse flow investments would allow to additionally integrate 2.2 TWh of biomethane in the EU per year, corresponding to 4.4% of the 50 TWh/year total biomethane production in the EU projected for 2030[151].

The **framework of strengthened cross-border coordination on gas quality** and the obligation on Member State to set and publish the national allowed levels of hydrogen blends[152] may lead to a large-scale introduction of hydrogen blending at the TSO level. Based on the national plans and national thresholds for maximum acceptable hydrogen blends announced by several Member States, blending clusters in Europe are expected to emerge:

- a Western-European (with 10% as the joint blending threshold, i.e. aligned with the highest blending threshold in the cluster)[153];
- an Eastern-European (with 1,9% blending threshold, i.e. aligned with the highest blending threshold in the cluster); and
- a UK-Ireland cluster (at 1,1%, the UK's national blending threshold).

This scenario would result in up to 50 TWh/year of hydrogen injected in the transmission network[154], at an adaptation cost of the gas system of up to EUR 4 bn/year.

For **energy security** this option would result in slightly enhanced quality and reduced costs for identifying and implementing the appropriate measures due to reusability of existing good practices. However, the impact of non-binding guidance could be qualified as marginal, because of lack of assurance. The resulting cross-border asymmetry would be sub-optimal in particular as regards the bilateral solidarity and cybersecurity.

6.2.3.2 Environmental impacts

Option 1 ensures compliance with the 55% GHG emission reduction target, closing the potential gap that may occur under the baseline. Not having these option in place might put at risk the target achievement, i.e. falling short of the 50 TWh renewable gas by up to 10%. This would imply additional emissions of about 1 Mt CO2 annually.

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149 Artelys (2021).

150 This corresponds to EUR 70 m of investment costs and EUR 3 m/year of operational costs.

151 The results of this sensitivity analysis are highly dependent on a set of parameters, Artelys (2021).

152 More details are included in Annex 7 on gas quality: Hydrogen blending cross-border framework.

153 Composed of Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Portugal, Spain and Switzerland.

154 This estimate is independent from the MIX-H2 scenario (which does not foresee any blending), but relies on national legislation in terms of blending acceptability and assumes that the required hydrogen quantities would be available.

The injection of hydrogen could decrease the CO2 emissions of the gas system, saving up to 7 Mt CO2/year (at significant abatement costs).

6.2.4 Impacts of Option 2: Promote market access and security of renewable and low carbon gases

6.2.4.1 Economic **impacts**

Compared to Option 1, under Option 2, the integration of biomethane production may be realised at lower total costs, whereas biomethane volumes are expected to remain unaltered. Assuming a 1%-point decrease in WACC, this option would bring cost savings of 2% or about EUR 10 m/year in the countries without connection obligation granting public support. **Connection cost allocation** in favour of the biomethane producer might be a more relevant lever, significantly reducing the burden on the producer but increasing the burden on the gas consumers that are likely to face higher gas tariffs.

Reduced injection tariffs for renewable and low-carbon gases are expected to have no major effect as these tariffs are marginal compared to the overall LCOE (<1%). Under support schemes, removal/reduction of injection tariffs would merely represent a reallocation of costs from gas consumers to tax payers. In the absence of a support scheme, the removal of injection tariffs would enhance competitiveness, yet to a marginal extent (<EUR 1/MWh compared to an overall LCOE of EUR 88/MWh on average).

The impact of an **EU-harmonised allowed cap for hydrogen blends** will strongly depend on the actual blending level chosen. Below a value of 10% the allowed cap will impact only the Member States in the Eastern cluster, and above a value of 10% it will impact all Member States, giving rise to one unique European cluster. The level of adaptation costs is expected to increase from EUR 3,6 bn/year for 5% (with some countries being already at 10%), EUR 5,4 bn/year for 10%, EUR 12,5 bn/year for 20% and to EUR 37,4 bn/year for 30% of blended hydrogen, while the volume of hydrogen injected would follow a proportional increase, from 70 TWh (or 5% volumetric blending level) to 300 TWh (or 30% blending level) per year155. Instituting a hydrogen blending threshold above 5% would allow a significant part – if not all – of the Member States' 2030 national electrolyser target capacity to connect to the gas grid156.

Aligning the rules on **energy security** to the transition of the gas sector is expected to have a high positive economic impact. It would limit the risks for the energy security and cost of possible disruptions (and save time and resources). Effective cross-border solidarity would reduce the cost of national security measures. A harmonised approach on cybersecurity in gas would strengthen security specific requirements for the gas companies, unifying risk management approaches in the domain of digitalisation of gas infrastructure and providing an adapted list of key security measures.

6.2.4.2 Environmental **impacts**

This option ensures the effective integration of biomethane to meet the 55% GHG emission reduction target. The connection obligation with firm capacity for biomethane could reduce GHG emissions marginally by 0.1 Mt CO2 if exceeding the biomethane production volume assumed under Option 1. Higher transparency and better access regime to LNG terminals may

155 Theoretical upper values, highly dependent on actual blending levels in the Member States, on the production process (see JRC126763).

156 JRC (2021) Blending hydrogen from electrolysis into the European gas grid, JRC126763.

have a positive impact on share of renewable and low carbon gases imported in the EU replacing natural gas imports and reducing emissions at the same time.

The impact of hydrogen blending at the TSO level would depend on the actual allowed cap. The avoided CO2 emissions could range from 8 Mt CO2/year (for a 5% allowed cap, with some countries being already at 10%) to 33 Mt CO2/year (for a 30% allowed cap). However, as equipment must be adapted for higher blending thresholds, the associated GHG abatement costs would also increase from EUR 433/tCO2 (5%, with some countries being already at 10%), EUR 509/tCO2 (10%), EUR 568/tCO2 (20%) and to EUR 1114/tCO2 (30%).

6.2.5 Impacts of Option 3: Allow and promote renewable and low carbon full market access, and security, and tackle issue of long term supply natural gas contracts

6.2.5.1 Economic impacts

Limiting the duration of new long-term supply contracts as of 2050 would tend to increase the market price of natural gas. However, by 2030, and possibly also by 2040 this effect is expected to be marginal as major shares of gas supply are already covered via the existing LTCs and under this option such contracts will be possible unless the duration exceeds the date 2050. Similar effects are expected from **removing derogations from Article 32** for take-or-pay contracts for natural gas.

The impacts of addressing **pancaking for renewable and low carbon gases only** will reduce overall costs of renewable and low carbon gases when transporting them across the border. More importantly, such measure will increase gas-to-gas competition for renewable and low carbon gases. This means that the cheapest producers will be able to sell gas all across EU. In this way, the differences of costs of production of biomethane between Member States can be exploited reducing overall costs biomethane and the need for state aid to the level of the production costs of the cheapest producer. This measure is therefore a chance to increase competition, liquidity and trade for renewable gases to the benefit of the end-consumers. Moreover, transparency and benchmarking of costs of the TSOs may help to peer review the level of tariffs applicable at cross-border points.

A priori, the **market tests for accepting of renewable and low carbon gases** at the LNG terminals and storages would not result in a significant import of biomethane per se as it is too expensive[157] in comparison to standard natural gas in 2030, unless the price for guarantees of origin or the carbon price reach high values (EUR 15/MWh HHV[158] or EUR 80/tCO2). Market test will, however, increase transparency between producer and consumers.

6.2.5.2 Environmental impacts

In 2030, no additional environmental impacts are expected for this option compared to Option 2. Limiting the duration of natural gas LTCs might create additional room for renewable and low-carbon gases. However, as long as renewable and low-carbon gases are not economically competitive, the gap still is likely to be filled by short-term natural gas contracts. Abolishing cross-border tariffs for renewable gases may narrow this gap.

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157 Low-cost biomethane potentials exist outside the EU which are competitive with natural gas. However, it is considered rather unlikely that these potentials would be exported to the EU instead of being used locally.

158 Higher heating value.

6.2.6 *Impacts of Option 4: Allow and promote full renewable and low carbon market access, and security, tackle issue of long term supply natural gas contracts, remove border tariffs and set EU gas quality standards*

6.2.6.1 Economic impacts

Limiting duration of the long-term contracts already as of 2030 would strengthen the impacts of Option 3. However, it would not fundamentally change their nature.

The **elimination of intra-EU cross-border tariffs** for all gases will have a significant impact on the European gas market. The wholesale gas prices are likely to increase slightly in the transit countries and to decrease in the peripheral countries. These changes of gas wholesale prices and internal exit tariffs may trigger a shift in the merit order between gas fuelled power plants (notably open cycle gas turbines) and coal power plants in both directions (coal to gas or gas to coal) for a few EU Member States.

The impact on welfare between the different gas stakeholders (consumers, producers, TSOs etc.) depends on the parameters of the measure. It seems to benefit EU gas consumers of up to about EUR 500 m/year. Variants where the third country entry tariffs were increased or where entry tariffs were applied to LNG terminals have shown to reduce this gain, even shifting it to a negative impact on the EU consumers if entry tariffs are too high. The above impacts were analysed in case Nord Stream 2 is put into operation and the other import pipelines remain in place. The contemplated abolishment of intra-EU tariffs would benefit the Member States in South-Eastern Europe and Baltic States. The above impacts could be readjusted by the means of an inter-compensation mechanism among the TSOs. As sensitivity, a scenario without Nord Stream 2 was conducted, showing an overall wholesale market price level increase.

The impacts of **biomethane setting the gas standard** depends on which gas type under which framework conditions becomes the complementary gas within a gas grid section. If the share of biomethane outweighs natural gas in a gas grid section and the conditioning of biomethane would be more expensive than the adaptation of natural gas to the quality properties of biomethane, then the regulatory framework should allow biomethane to become the determining gas type. From an overall systemic point of view, however, this would only make sense if the (financial) efforts for adapting the quality of biomethane to natural gas were greater than adapting natural gas to biomethane[159].

As high **hydrogen blending levels** are unlikely to be implemented at the TSO level on a voluntary basis, the adoption of a maximum blending cap is expected to play a role only in the case where both the maximum and minimum allowed caps are set at 5%, above which adaptation costs become very high. In this particular case where all Member States are obliged to accept blends with 5% hydrogen at cross-border interconnection points, the injection of blended hydrogen equals 50 TWh/year in 2030 with adaptation costs reaching around EUR 733 m/year. An EU-wide maximum allowed cap could ensure the homogenisation of blending rates and prevent isolated initiatives that could lead to unwanted increase of adaptation costs for several neighbouring countries.

[159] As the currently applicable CEN standard is not binding, Member States have already today the possibility to create such a framework. However, the prerequisite must always be that the gas quality requirements of the transported gases do not lead to any damage in the gas grid or for consumers and that consumers can use these gases without disruption.

6.2.6.2 Environmental impacts

The change in gas tariffication is not expected to have a significant environmental impact apart from possible switches in the merit order between coal and gas, which are to be limited would an inter-compensation mechanism between TSO be adopted. Setting both the lower and the higher (maximum) cross-border allowed caps for hydrogen blends at EU-level would lead to a decrease in CO2 emissions, however at increasing abatement cost (depending on the actual blending levels chosen).

6.2.7 Who would be affected and how?

Table 12: Who is affected and how by the options in Problem Area II (in terms of administrative and economic costs)

Problem Area II	BAU	Option 1	Option 2	Option 3	Option 4
ACER	0	-	N/A	-	-
NRAs	0	+/-	-	-	--
Public administrations/MSs	0	+/-	-	-	-
Consumers	0	+/-	+/-	+/-	+/-
Biomethane Producers	0	+	+	++	++
End grid users	0	0	-	+/-	-
TSOs	0	-	-	-	--
DSOs	0	+	+	+	-
LNG Terminals	0	0	+/-	+/-	-

6.3 Assessment of policy option in relation to Problem Area III: Integrated network planning

6.3.1 Methodology and key assumptions

The assessment of options are based on a qualitative methodology. Analysis of the status quo of NDP preparation (one vs. several NDPs) across MSs, are notably based on the ACER report, in order to evaluate the order of magnitude of the expected impact of the option (how many MSs are actually concerned by this option). The analysis also assessed current NDPs regarding their compliance with the elements for all options other than BAU (i.e., involved stakeholders, integration of EU climate targets etc.).

Qualitative assessment of costs/efforts related to enhanced coordination between TSOs (e.g., in terms of number of stakeholders that need to coordinate) is based on a review of recent literature[160].

6.3.2 Impacts of Option 0: Business as usual (BAU)

Keeping the current framework does not resolve insufficient integrated planning and would not lead to more transparency on infrastructure that can be repurposed. This leads to less efficient and non-cost effective planning.

160 He, Wu, Zhang, & Shahidepour, 2018, IRENA, 2020; ACER, CEER, 2017; CEDEC, EDSO, ENTSO-E, Eurelectric, GEODE, 2016; SINTEF et al., 2020.

6.3.3 Impacts of Option 1: National Planning

6.3.3.1 Economic impacts

More holistic network planning may ensure a more efficient and cost-effective grid planning that factors in additional framework conditions, which may affect the need for grid infrastructure. Requiring a single, consolidated NDP ensures that potential incoherencies between the visions of different gas TSOs operating in the same country (e.g. in France) are identified, discussed and eliminated, leading to a more coherent, cost-efficient network planning procedure, lowering the risks of over-dimensioning the system or stranded assets.

The transparent involvement and management of all relevant stakeholders may allow to anticipate new trends (e.g., with respect to the deployment of synthetic methane production, the use of ammonia, etc.), enhance the anticipation of the evolution of gas production and demand (e.g. level of energy efficiency efforts, flexibility of the demand), thereby bringing the planning closer to reality and enabling appropriate investment decisions. It may further raise the acceptability for gas infrastructure projects, thereby minimising the risk of opposition and lawsuits and related costs.

Joint planning of pipelines, storage and LNG may reduce investment needs, as all these assets provide flexibility but are owned and operated by different stakeholders. A coherent approach saves infrastructure costs that are typically socialised via grid tariffs.

The main benefit of reporting on decommissioning of methane pipelines is that it enables more efficient investment decisions, notably with respect to the repurposing of gas pipelines for hydrogen instead of constructing new ones (which features CAPEX savings of 70 to 90%[161]) and the exploitation of cross-sectoral synergies.

6.3.4 Impacts of Option 2: National Planning based on European Scenarios

6.3.4.1 Economic impacts

Building joint electricity and gas scenarios would ensure that indirect interlinkages are treated in a consistent way in subsequent processes by gas and electricity TSOs. This ensures that the planning exercises are carried out using a common vision of the future, thereby eliminating risks that electricity and gas TSOs plan the evolution of their systems based on incompatible assumptions (e.g. electricity TSOs assuming a strong deployment of heat pumps in the residential sector while gas TSO assume a deployment of gas boilers). The participation of DSOs, LSOs and SSOs in scenario building activities would ensure a common vision of the different stakeholders implying that investment decisions (which are still taken independently) are more aligned, avoiding conflicting or redundant investments, thereby savings in societal costs. The implementation would entail moderate cost, as joint scenario building does not require to establish a common simulation model, but rather to coordinate on a set of core assumptions.

The economic benefits of the introduction of sanity checks emerge from the higher level of consistency between the gas and electricity NDPs, notably in terms of the identification of best suited areas for electrolysers, leading to consistent interventions on electricity, methane (e.g. via repurposing) and hydrogen networks at the local level.

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161 CAPEX data based on (Guidehouse/Frontier Economics, 2021).

Integrating one scenario in line with EU climate targets ensures that the network planning takes into account the decarbonisation strategies at the national and EU levels, reducing the risk of potential lock-ins or stranded assets. Linking the NDP scenario framework to NECPs and LTS would increase the coherence of energy system planning – both across sectors and across Member States.

6.3.5 Impacts of Option 3: European Planning

6.3.5.1 Economic impacts

There are important benefits to jointly plan the evolution of the location of electrolysers, electricity, methane and hydrogen grids. Given the long lifetime of infrastructure assets (typically around 50 years), the transition of infrastructure use from natural gas to other renewable and low-carbon gases needs to be planned as early as possible in order to take comprehensive and robust investment decisions that imply minimal costs for society. Furthermore, a joint planning ensures that the efficiency of investments in the gas sector (incl. hydrogen) is compared to alternatives such as electricity networks, and that the most economically, environmentally sound and secure option is identified and selected.

6.3.6 Who would be affected and how?

Table 13: Who is affected and how by the options in Problem Area III (in terms of administrative and economic costs)

Problem Area III	BAU	Option 1	Option 2	Option 3:
ACER	0	0	+	--
NRAs	0	-	-	-
Public administrations/MSs	0	N/A	N/A	N/A
Producers	-	+	+	+/-
TSOs	0/-	+/-	+/-	--
DSOs	0/-	+/-	+/-	--
LSOs and SSOs	0	0	+/-	--
Consumers/ Society	-	+	+	+/-

6.3.7 Environmental impacts of options related to Problem Area III

Implementing sustainability indicators in NDPs under Option 1 could contribute to selecting future-proof projects only. If implemented in a rather light form as informative indicator it could contribute to market transparency. If implemented as a mandatory criterion, a sustainability indicator could be used to help select (societally) beneficial projects that otherwise might not be realised.

More integrated power, gas and hydrogen network planning paves the way for a deep integration of renewable and low-carbon gases with the electricity system, and is thus expected to feature significant emission reductions.

Finally, by reducing the risk of over-investments by ensuring investments are based on a common vision of the future, all options have a positive environmental impact by reducing the footprint of the overall energy system. Reporting on decommissioning has positive environmental impacts as it can lead to a better identification of repurposing potentials, and thereby avoid building a new infrastructure, resulting in a lower environmental footprint of the infrastructure, including the use of raw materials required for building the asset.

6.4 Assessment of policy option in relation to Problem Area IV: Lack of customer engagement and protection in the green gas retail market

6.4.1 Methodological approach

In a context where gas continues to be a major, even if declining, element in household energy consumption, this section assesses the policy options on the modelling used for the whole Impact Assessment as well as on the basis of qualitative methodology in relation to the barriers to customer engagement in the gas market as part of the energy transition and effective customer protection. When available, quantitative information has been used, while where economic impacts cannot be quantified, desktop research and case studies are used to inform estimates of the extent of possible impacts as well as possible winners and losers.

6.4.2 Impacts of Option 0: Business as usual (BAU)

Keeping the current framework does not resolve insufficient customer protection, lack of participation and rigid competition which makes the green methane gases difficult to access the retail market.

6.4.3 Impacts of Option 1: Strengthened enforcement and soft implementation measures to better apply current rulesNo action (BAU), beyond enforcement and soft implementation measures

Option 1 represents the baseline scenario, as there would be no legislative measures adopted to change to the situation existing today, which would be improved through usual enforcement actions, namely reinforced administrative cooperation and guidance from the Commission). Under this option, the identified issues are not considered urgent enough to justify a more decisive intervention in a of decarbonised gas market still at an embryonal stage with its uncertainties. Costs of this non-action would result from not addressing lack of competition and existing high costs for consumers.

6.4.3.1 Economic impacts

This option relies on voluntary measures that risk leaving problems resulting from outdated legislation unaddressed, notably on smart energy management, billing information with termination and exit fees for consumers switching to renewable and low carbon gases. Consistent standards of customer protection seem unlikely to be timely and efficiently achieved by all EU countries. Moreover, this option does not open up the full potential of energy communities in terms of (cost-effective) renewable and low-carbon gas uptake due to the absence of geographical flexibility.

6.4.4 Impacts of Option 2: Non-regulatory approach: strengthened enforcement, enhanced implementation measures, and intense consultation with the Member States

6.4.4.1 Economic impacts

In addition to the benefits from enhanced enforcement, a non-legislative approach to harmonising price regulation based on Commission guidance could facilitate the removal of barriers to competition and innovative renewable gas products. However, continued market uncertainty in this regard would be a barrier to rolling out new products.

Some indirect improvements to the health and well-being of energy poor consumers from the exchange of good practices stemming from the activities of the EU Hub for Energy Poverty may be gained. In the absence of new, ambitious legislative measures, smart metering deployment remains geographically limited. Nevertheless, this option is efficient to a certain extent as it mandates the transfer in a single act of all relevant smart metering provisions.

6.4.5 Impacts of Option 3: Flexible legislation addressing all problem drivers

6.4.5.1 Economic impacts

Improved retail competition should result from the phase-out of blanket **price regulation** for large, medium-sized and small enterprises in six Member States[162]. Small and medium-sized retail suppliers and consumers in particular are expected to benefit significantly from better functioning and opening of retail gas markets. Moreover, as a potential majority of new entrants on the market, SMEs could benefit from more efficient switching periods. **Switching** to a more competitive offer has a significant savings potential, varying per Member State, with the highest potential in Germany where households could save up to EUR 694 annually[163].

Through accurate **billing information**, faster and free-of-charge individual and collective **switching** and trustworthy **price comparison tools**, consumers will be enabled to better manage their gas consumption costs, including at times of price hikes. Moreover, allowing **price regulation** under certain conditions for vulnerable and energy poor customers would allow for short-term interventions to protect these categories of consumers from sudden price increases.

Non-discriminatory **access to consumer data** and nationally harmonised arrangements, mirroring those for electricity as well as measures facilitating interoperability within the EU will help new suppliers and service providers, including SMEs, to enter the market, develop innovative products, resulting in increased competition, consumer engagement and economic benefits. Moreover, such interoperability rules for access to data will foster the creation of the energy data space[164] and will facilitate data sharing across the EU. **Smart metering** supporting the flow of such data could reinforce these trends. DSOs will be in a position to lighten and improve administrative processes and offer increased customer services. Moreover, smart meters can be made available at consumers' request and expense, when there is no systematic deployment. However, direct consumer benefits (i.e. no systemic impact) are generally found to be lower than direct costs of EUR 100-350 (on average, benefits close to EUR 225)[165]. Member States will face an additional administrative impact for re-evaluating their national smart metering deployment case.

Mirroring the framework for CEC of the Electricity Directive into the Gas Directive[166] would enable consumers and SMEs to buy renewable and low-carbon gases irrespective of their

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162 Deregulated prices will help consumers benefit from better choice and services in a context of better functioning retail competition. As indicated in ***Error! Reference source not found.***, more liberalised markets tend to have a higher average number of offers, percentage of green offers and average switching rates. See also 2019 ACER market monitoring report, p. 50.

163 Quarterly report on European Gas Markets with focus on the European barriers in retail gas markets, Market Observatory for DG ENERGY, Volume 13, issue 4, fourth quarter of 2020. See also ***Error! Reference source not found.***.

164 European Data Strategy COM/2020/66 final; Data Governance

165 Frontier study (2021), quoting data from recent gas smart metering deployments. Also Tractebel report on benchmarking smart metering deployment in the EU-28 (2019).

166 On the importance of an enabling legal framework for the development of energy communities, see JRC report, 'Energy communities: an overview of energy and social innovation', p. 32. See also

geographical location as well as bring benefits for the local economy[167], increase public acceptance and uptake of renewable gas[168] and help mobilise private capital investments[169] in renewable and low-carbon gases[170].

Furthermore, better measurement of the number of households on energy poverty will allow more adequately targeted policies at EU, national and local level. A generic definition of energy poverty in the legislation will clarify its concept, improving the functioning of the current provision and further helping knowledge dissemination and synergies across EU policies in energy efficiency providing structural solutions and consumer protection.

6.4.6 Impacts of Option 4: EU Harmonization and extensive safeguards for customers addressing all problem drivers

6.4.6.1 Economic impacts

Overall, this option has the potential for significant economic gains from much more integrated retail gas markets across the EU, with clear and consistent rules and standards of protection – in particular with lower costs for renewable and low carbon gases.

Phasing-out blanket **price regulation** for household customers would lead to significantly increased market opening, effective retail market competition and higher consumer satisfaction levels. On the other hand, this may lead to higher mark ups and energy retail prices for households, but this may be offset by reduction in tariff deficits and higher service quality.[171] The additional set of support measures for energy communities would amplify their contribution to the deployment of renewable and low-carbon gases[172]. However, this benefit may be offset by one-off costs and ongoing labour and operational costs to implement the supporting framework[173].

This would be complemented by a single EU **data management** model for all, easier to enforce at EU level, helpful for new market entrants, and equally beneficial for alternative suppliers, service providers, SMEs as well as consumers and community energy. However, it

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Frontier (2021), 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 9 which shows that – potentially due to the framework for REC and CEC – in 2019 the amount of energy communities has increased.

167 Joint Research Centre (2020), 'Energy communities: an overview of energy and social innovation', p. 21.

168 Whilst leading to increased acceptance of renewable gas offers, the mirroring of the concept of citizen energy communities will, in comparison to the concept of renewable energy communities in the Renewable Energy Directive, not necessarily lead to increased local social acceptance of renewable gas installations. Indeed, some research suggests a positive correlation between local acceptance and local ownership. See Ellis Geraint and Ferraro Gianluca, 'The social acceptance of wind energy: where we stand and the path ahead', 2016, p. 42; and Jarra Hiks and Nicola Ison, 'An exploration of the boundaries of 'community' in community renewable energy projects: navigating between motivations and context', Energy Policy Volume 113, February 2018, p. 529.

169 The potential of Energy Citizens in the European Union, CE Delft, 2016: '83% of the EU's households could potentially become an energy citizen and contribute to renewable energy production'.

170 Artelys (2021).

171 Trinomics, 'Study on Energy Prices, Costs and subsidies and their impact on industry and households' (2018), p. 18.

172 Artelys (2021); Amecke, H., 'German Landscape of Climate Finance, Climate Policy Initiative' (2012) Climate Policy Initiative 2016, p. 4; and GRDF, 'Méthanisation Agricole Retour d'expérience sur l'appropriation locale des sites en injection', 2016.

173 Frontier study (2021), 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', pp. 15-17.

would have very high implementation costs. Similarly, mandating a rollout for **smart meters** throughout the EU, irrespectively of the outcome of the national cost-benefit analyses, is not a cost-effective operation[174] as it ignores the national context.

6.4.7 Who would be affected and how?

Table 14: Who is affected and how by options in Problem Area IV (in terms of administrative and economic costs)

Problem Area IV	Option 1	Option 2	Option 3	Option 4
NRAs	-	-	--	--
Public administrations/MSs	-	-	-	-
Consumers	+/-	+	++	++/-
DSOs	-	-	+/-	-
Suppliers	+/-	+/-	++/-	+/--
New entrants (innovative services)	-	-	+	+

6.4.8 Environmental impacts of options related to Problem Area IV

The legislative options examined above – Option 3 (Flexible legislation) and Option 4 (Harmonization and extensive safeguards) – are each expected to have significant, albeit indirect, environmental benefits from higher levels of renewable gas penetration. The measures will benefit citizens and communities in particular, which the analysis has shown represents an important ally in increasing social acceptance, mobilising private capital and thus facilitating the deployment of renewable and low-carbon gases. The strengthening of rights fosters sustainable choices, both by providing consumers a clear overview and control of their consumption as well as awareness about the origin of their energy. Option 3 appears to be most effective for this purpose. Phasing out blanket **price regulation** – particularly in Member States with very low margins – will help address the high levels of gas consumption caused by artificially low prices.

6.4.9 Impacts on fundamental rights regarding data protection

Safeguarding EU values and citizens' fundamental rights and security in a developing green, digital energy environment, is of paramount importance. The proposed policy measures on **data management** were developed with this in mind, aiming at ensuring widespread access and use of digital technologies and data-driven services while at the same time guaranteeing a high level of the right to private life and to the protection of personal data, as enshrined in Articles 7 and 8 of the Charter of Fundamental Rights of the EU[175], and the General Data Protection Regulation[176].

6.5 Social impacts

The energy transition and decarbonisation policies play a key role in developing Europe's competitive edge as growth and jobs increasingly will have to come from innovative products

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174 Tractebel report 'Benchmarking smart metering in EU-28' (2019).

175 Charter of Fundamental Rights of the European Union (2000/C 364/01) text_en.pdf (europa.eu)

176 Regulation (EU) 2016/679 of the European Parliament and of the Council of 27 April 2016 on the protection of natural persons with regard to the processing of personal data and on the free movement of such data, and repealing Directive 95/46/EC (General Data Protection Regulation) EUR-Lex - 32016R0679 - EN - EUR-Lex (europa.eu)

and services which are closely linked to sustainable and smart solutions. More in specific, the measures assessed in this Impact Assessment are expected to produce several social benefits in each of the problem areas. They would increase the energy security by diversifying gas sources and reducing external energy dependency, for the benefit of the whole society.

6.5.1 Social impacts of the options in Problem Area I

The measures analysed to facilitate the emergence of interoperable hydrogen infrastructure and hydrogen markets (Problem Area I) would foster sustainable growth and jobs although the positive impact on employment is difficult to concretely estimate given uncertainties in market development for each option separately. However, the preferred option is the most likely to foster competitive market and pricing, investments and lower costs for hydrogen supplies and hence contributes to economic growth and jobs.

Initially, hydrogen is expected to be largely used by industrial consumers whereas natural gas consumers also extent to SMEs and households. Consequently, a distributional effects could occur at an early phase in those Member States where operators of both natural gas and hydrogen networks are allowed to create financial flows between natural gas and hydrogen asset bases (Options 2a and 2b). However, under the preferred option (Option 2b) these are contained and under regulatory control whilst Options 3a and 3b do not allow for financial flows, this does not necessarily mean that no distribution effects occur. Member States can (and, in fact, some appear to prefer doing so) also support the roll-out of hydrogen network via subsidies. Such subsidies can also give rise to distributional effects depending on the origin of the used tax revenues, much like direct financial flows funded by network tariffs.

6.5.2 Social impacts of the options in Problem Area II

The possible measures analysed in Problem Area II would allow to integrate renewable and low-carbon gases at lower costs while ensuring energy security. They would increase the potential for cross-border trade and ensure the interoperability of markets, leading to more competition and better possibilities to level out production and demand differences across larger areas; at the same time they would reduce our external energy dependency. The analysed measures increasing biomethane production may lead to a creation of 2 000 to 4 000 additional local jobs and local added value. The measures can also be expected to have a positive impact on competitiveness and households. This measure would ensure access to all citizens and businesses of renewable and low carbon gases in order to protect energy poor and vulnerable consumers.

While Options 1 and 2 foresee full access to the low-carbon gas market, tariff and economic impacts of the envisaged measures on consumers and society as a whole remain marginal in particular for the limited degree cross-border level of integration since the two options do not foresee any detailed rules to facilitate regional markets.

The presence of tariff barriers between national energy systems prevents the balancing of prices between national markets, thus affecting consumers in those markets where initial costs of implementation of measures provided in Option 1 and 2 are higher.

In case of Option 3, the integration of the transmission system development at European level increases public expenditure efficiency, while reducing the risk of over-investments.

Although initial cost for implementing measures under Option 3 are foreseen, in the medium and long-term energy and ancillary services prices are expected to decrease thanks to better integration of the systems and the contribution of low carbon gases. This effect has a progressive social impact as energy prices tend to affect households with smaller budgets over-proportionally. Overall, Option 3 also allows a wider range of stakeholders to participate in the energy market, with positive effects on both consumers and small energy producers.

Option 4, given its higher-ranking of completeness in terms of policy measures to be implemented, implies higher administrative cost. The effects on gas consumers are more profound to an increased gas-to-gas competition.

6.5.3 Social impacts of the options in Problem Area III

In a similar manner, the analysed measures to ensure transparent and inclusive network planning (Problem Area III) options are likely to have a positive impact for EU citizens and businesses. Gas consumers would benefit from a more cost-efficient planning as infrastructure costs are typically socialised via tariffs. Better anticipated grid planning avoids stranded assets as much as delayed network expansion and resulting grid bottlenecks (e.g. for new energy carriers such as hydrogen) which comes ultimately at a lower cost for the consumer. These expected savings have to be traded-off against the costs of implementing the preferred measures, which have however been estimated to be small or even slightly negative in the longer term. The net effect would therefore translate into lower prices for energy facilitating overall competitiveness. Lower prices for energy services also have a progressive social impact as energy prices tend to affect households with smaller budgets over-proportionally. Empowering the NRA to assess the actual need for a dedicated hydrogen network should enable it to ensure that (in Member States that choose to make use of the option) the actual amount of financial flows between natural gas and hydrogen asset bases to co-fund the creation of hydrogen networks, will not lead to a disproportionate tariffs for natural gas consumers.

For the reasons listed above, measures entailed in Option 2, national planning based on European Scenario, would guarantee the higher effectiveness in terms of social impacts. Not taking into consideration a network integration at European level, Option 1 would prevent producers and consumer to fully benefit of advantages in markets different from the national one in which they operate. Conversely, Option 2 would allow not only to spread social benefits across border, but also to better coordinate national decarbonisation strategies at the EU level with a positive impact on the entire society. Option 3 is at the same level as Option 2 in terms of positive social impacts, although in the case of the latter it is expected that the planned policies will be implemented in a more progressive manner so that to avoid unpredictable and potentially negative effects on main energy market players.

6.5.4 Social impacts of the options in Problem Area IV

Finally, the analysed measures to increase the level of consumer engagement and protection in the decarbonised retail market (Problem Area IV) will result in greater benefits for local economies, increase public acceptance of renewable gas and help mobilise the private capital investments needed to facilitate the energy transition. Energy communities in rural areas especially have the potential to have positive social impacts by allowing farmers to participate in the development of a green gas economy. Customers will greatly benefit from more and greener offers, better information on sources of energy and as well as their consumption history enabling them to better manage their consumption costs. Decarbonisation will result in low income households bearing a relatively higher burden in terms of heating fuel expenses. Targeted socio-economic measures will thus be needed to minimise such an impact on energy poor and vulnerable consumers and energy policy will need play its role together with social policy. In particular, energy policy has a significant role to play, especially where energy poverty is linked with poor energy efficiency of homes.

6.6 Impacts on SMEs

6.6.1 Impacts on SMEs of the preferred option in Problem Area I

The preferred Option 2b will have important beneficial effects for SMEs as, relative to BAU, market entry into the production and supply of hydrogen does not require to be vertically integrated with transportation. Moreover, SMEs will be protected from market abuse by access rules to critical infrastructure that are non-discriminatory. The use of regulated third party access to network and storages renders access rules easier for SMEs as they are transparent, do not require negotiations and are set under a strict governance regime.

Overall, the measures will ensure that SMEs have access to an EU hydrogen market on terms that apply regardless as to the size of the company concerned.

6.6.2 Impacts on SMEs of the preferred option in Problem Area II

Measures introduced in relation to Problem Area II will also benefit SMEs to the extent they are renewable and low carbon gas producers as the measures improve access to markets for decentralised production for renewable and low-carbon gases.

For instance Option 3 contains far-reaching measures to support renewable and low carbon gases (including limitation of long-term contracts for natural gas). This will help new entries to the market which often are SMEs.

A higher level of integration at gas and electricity distribution system level, as expected in Option 4, could lead to fundamental changes in terms of the functioning of the internal market, the abolition of cross-border tariffs and the addition of external tariffs. The definition of a new system would lead to an imbalance which would not necessarily benefit the actors involved; it could be expected that the increase in transactional costs weighs more heavily on SMEs than on larger operators.

6.6.3 Impacts on SMEs of the preferred option in Problem Area III

A more comprehensive grid planning might benefit small producers of renewable and low carbon gases lowering administrative barriers while a more stable regulatory framework would help create new business opportunities for SMEs and lower energy prices.

6.6.4 Impacts on SMEs of the preferred option in Problem Area IV

SMEs, either in the capacity of final customers, retail suppliers or renewable gas producers, can benefit in particular from the measures to address Problem Area IV.

Start-ups and small enterprises can be expected to benefit from lower barriers to enter retail gas markets due to the phase out of price regulation, expedited switching procedures as well as new business opportunities. In particular, non-discriminatory access to consumer data and nationally harmonised arrangements, mirroring those for electricity as well as measures facilitating interoperability within the EU, new suppliers and service providers, including SMEs, are expected to enter the market, develop innovative products, resulting in increased competition, consumer engagement and economic benefits. Moreover, data interoperability can be expected to reduce administrative and compliance costs considering less alterations in basic business models will be needed for SMEs to operate in different Member States.

SMEs in general will benefit from high quality services and increased consumer satisfaction as a result of better functioning and opening of retail gas markets. Furthermore, small enterprises are expected to benefit from the preferred option in a similar way as households considering the similarities between the two in how they participate in the retail market. They need better information, and new and innovative products that meet their needs. In particular, transparent contracts and bills can be deemed very important in helping SMEs to better control their energy consumption and costs.

Lastly, through the new provisions on energy communities, SMEs can form 'cooperative' approaches to producing and purchasing their gas. On the one hand, this might coincide with an increase in administrative costs as Member States and competent authorities might require to provide information (statutes, organic structure, number of employees etc.) to ensure the community meets the legal governance criteria. On the other hand, through the vehicle of energy communities, SMEs may benefit from less burdensome procedures (registration, licensing etc.) which is expected to bring down administrative costs.

7 How do the options compare?

7.1 Comparison of options in Problem Area I: Ensuring emergence of cost-effective hydrogen infrastructure and contestable hydrogen markets

The options under Problem Area I compare to each other as follows;

Option 2a: In comparison with the base-line, under which companies are fully unconstrained and 'competition for the market' will continue to predominate, Option 2a, sets the stage for competition 'in the market'. Option 2a entails the introduction of main regulatory principles aimed at countering market power, removing some barriers to cross-border hydrogen trade and fostering market integration, thus improving upon the base-line. It does, however, not have the same depth and scope of the market design of the mature gas and electricity markets and leaves a large degree of freedom to economic actors. The main regulatory principles are to a certain degree adapted to the specificities of the hydrogen market and seek to remove barriers to reuse existing infrastructure for hydrogen. Option 2a represents a first step with ample flexibility for companies to overcome the early stages of market ramp-up. However, it does not provide further guidance as to where the regulatory framework in which hydrogen markets need to develop will go. Thereby, it does not attempt to avoid the costs associated with ex-post interventions that may be needed at a next step when hydrogen markets have become more mature. In this sense it may offer economic benefits and efficiencies relative to the base-line, but for the transition only.

Option 2b: In comparison to Option 2a, the main difference is that it defines a clear stepwise approach. Whist avoiding large immediate changes to the way infrastructure operators act today and leaves them ample scope to overcome the early stages of a hydrogen market ramp-up (much like Option 2a), it defines more clearly the regulatory system that will exist once markets have matured. It sets some constraints on the flexibility existing during the transition phase but these aim at avoiding costly ex-post interventions to move to a more mature and deeply integrated, efficient hydrogen market later and in which infrastructure is operated and financed in accordance with economic principles proper to a more mature hydrogen system. It takes into account lessons learnt from the liberalisation of the gas and electricity sectors and exploits the fact that we can take a 'greenfield' approach to regulation, in which choices aimed at creating a competitive market can still be made unconstrained by an entrenched factual or regulatory situation. In this sense, it provides for economic benefits and efficiencies not only for the transition phase, but also sets the stage for efficient and well-integrated hydrogen markets later and avoids the ex-post interventions that would be required under Option 2a and the sunk investment of investors that are affected by them.

Option 3a and 3b: introduce like Option 2a and 2b 'competition in the market'. Contrary to Option 2a and 2b, it reflects an ambition of setting-up a separate regulatory regime for hydrogen that, whilst adapted to the specificities of the hydrogen value chain and removing barriers, does so without a transition period that seeks to cater for the specific needs of an still immature sector that needs investments for its ramp-up. It prioritises creating regulatory clarity at the cost of the flexibility. By doing so, it creates economic benefits and efficiencies by setting a stage for efficient hydrogen markets but at the expense of the conditions that are required for it to transition towards that objective and thus by itself may constitute a barrier for rapid deployment and market development. The EU ISO that is a design feature of Option 3b would foster market integration, however, lowers regulatory costs for and can have synergies with other main regulatory measures.

Table 15: Overview of the impacts of the options under Problem Area I

Options relative to BAU	Option 2a	Option 2b	Option 3a	Option 3b
Economic impacts	+	+++	+/++	++
Environmental	+	++	+	+
Efficiency	+	++	+	+
Effectiveness on sub-objectives as described in paragraph 5.2				
- Enable the emergence of an efficient, integrated EU hydrogen market	+	++	++	+++
- Remove barriers and ensure incentives to invest in hydrogen infrastructure	++	+++	++	++
- Address risk that the natural monopoly character of hydrogen infrastructure gives rise to non-competitive market structures	+	++	++	++
- Ensure cross-border integration, unhindered hydrogen (cross-border) flows and required quality for end-users	+	++	++	++
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)				

7.2 Comparison of options in Problem Area II: Ensuring access of renewable and low carbon gases to the existing natural gas networks and market

The options under Problem Area II compare to each other as follows:

Option 1: In comparison to the baseline, Option 1 will provide locally produced renewable gases with access to the hubs and transmission grid through enabling physical reverse flows. This will allow for full integration of the biomethane potential projected under the MIX-H2 scenario, facilitating compliance with the 55% target. It may also help to reduce support scheme costs for locally injected renewable gases and thus the costs on consumers as well as improve their marketing options. However, costs of reverse flow investments will be borne by consumers of gas. This option will limit the risk of cross-border flow restriction and market segmentation and implies several European hydrogen blending clusters at the TSO level. The limited nature of intervention under this option will leave flexibility to Member States for setting national allowed blending levels. While the administrative costs remain limited, the gas quality cross-border coordination framework cannot fully eliminate the risk of cross-border disputes. This option will, however, not ensure effective emergency preparedness during the transition and that the security risks related to the development of renewable and low carbon gases are fully considered by 2030 at the latest. It will not significantly improve the resilience to new cyber threats in the gas sector.

Option 2: In addition to the impacts of Option 1, Option 2 promotes the integration of biomethane which may potentially reduce the costs of production, making state aid less needed. Reducing injection tariff and access tariff is not respecting fully the principle of costs-reflectivity and avoiding cross-subsidisation. Therefore, the costs of tariff discounts need to be borne by consumers of gas. This option will bring harmonisation of cross-border blending thresholds across the EU with a pre-defined allowed cap and will reinforce cross-border coordination limiting the risk of flow restriction and market segmentation to a minimum. At the same time, it leaves flexibility to Member States on the application of gas quality standards and blending thresholds for the domestic network. Proposed LNG rules will bring improvement of transparency, market access and congestion management resulting in more efficient utilization and potentially additional available capacities for RES&LC gases. This option addresses in an effective and efficient way the handling of energy security risks related to supply of renewable and low carbon gases and the risks related to cybersecurity.

Option 3: Option 3 will bring similar results to Option 2 in many aspects especially when it comes to integration of renewable and low-carbon gases, in particular biomethane. However, the abolishment of tariffs will enable more physical cross-border trade with renewable gases based on production costs differentials in the Member States. These benefits may reduce the costs of facilitating injection of biomethane into the grid as identified in Option 1 and 2. Moreover measures on allowed revenues will reduce the outliers on cross-border tariffs and the guidance on market mergers will help integrating smaller gas markets and harmonise approach to promotion of renewable gases. For LNG, Option 3 will bring incentive to prepare for the RES&LC gases imports through mandatory market test mechanism. Removed privileges and limited duration for long-term contracts may lead to a slight increase of wholesale gas price with a long-term effect in terms of organising the energy transition. As in Option 2, it will have an effective and efficient impact on the resilience of the new gas system and energy security.

Option 4: Option 4 will, in addition to the impacts of Option 3, remove border tariffs for natural and renewable gases in the EU, which will increase overall welfare for consumers and bring more gas-to-gas competition in the market. This will inevitably increase internal exit tariffs in most Member States and possibly the EU-external tariff, and bring overall impact on import gas flows as well as on the European gas market. Option 4 will also reduce the risk of high blending levels taken as a local initiative and ensure EU-level harmonisation of gas quality standards for cross-border interconnection points. For LNG, Option 4 will mean incentives for renewable gases imports as entry tariffs discounts will be removed for natural gas. With regard to long term contracts, impact of Option 3 will be strengthened. As in Option 2, it will have an effective and efficient impact on the resilience of the new gas system and energy security.

Table 16: Overview of the impacts of the options under Problem Area II

Options relative to BAU	Option 1	Option 2	Option 3	Option 4
Economic impacts	+	+	++	++
Environmental	++	++	+++	+++
Efficiency	+/-	+	+	-
Effectiveness on sub-objectives as described in paragraph 5.2 - Facilitating access of local production of biomethane to the gas markets across EU	+/-	+	+	++
- Facilitating connection rules and injections	+	++	++	++
- Ensuring access to LNG terminals for RES&LC gases	0	+	++	+++
- Tackle risk of negative impact on end-user in terms of gas quality	+	++	++	+++
- Avoid lock-in into LTCs for natural unabated gas	0	0	+	+
- Improve the resilience to relevant threats of the future gas system integrating renewable and low carbon gases.	0	++	++	+++
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)				

7.3 Comparison of options in Problem Area III: Ensuring integrated network planning

The options under Problem Area III compare to each other as follows:

Option 1: enhances the current design of NDPs and ensures that all MSs submit a single plan per country or Region (i.e. including more than one Member State), which allows already for a better integration into the TYNDP process providing input from the NDPs to the TYNPD that is built upon the NDPs.

Option 2: facilitates the integration of renewable and low-carbon gases as:
- DSOs are more strongly involved in the NDP process (even though this is already the case in some MSs today), reflecting that production of renewable and low-carbon gases is more likely to be linked to distribution grids in terms of numbers;
- Joint power-gas scenario building facilitates a more concerted approach in network planning, notably with respect to the balance between direct electrification and decarbonised-gas strategies (incl. indirect electrification).

Option 3: The measure would go significantly beyond the joint scenario building exercise explored in Measure 2 in the sense that a sector-integrated approach would be adopted throughout the entire NDP process, including in the quantitative modelling work supporting the selection of projects and investment decisions.

Table 17: Overview of the impacts of the options under Problem Area III

Options relative to BAU	Option 1	Option 2	Option 3
Economic	+	++	+++
Environmental	+	++	+++
Efficiency	+++	+++	++
Effectiveness on sub-objectives as described in paragraph 5.2			
- Provide transparency for repurposing existing gas networks	+	++	++
- Enable cost efficient planning on the basis of scenarios that are in line with the climate target objectives	+	+++	+++
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)			

7.4 Comparison of options in Problem Area IV: For addressing lack of consumer engagement and protection in the green gas retail market

Although there is a significant level of uncertainty in quantifying the benefits of the options in this Problem Area, all options, including Option 1, are expected to improve retail competition and integration of renewable and low carbon gases. However, the anticipated effectiveness and efficiency of the different options vary markedly.

Option 1 would lead to a very modest socio-economic benefits stemming from increased enforcement of existing rules on price regulation and guidance on switching-related fees. However, the effectiveness of Option 1 would be less than Option 2 as the increased enforcement and a limited amount of soft law measures will merely build on existing rules which have proven to be inadequate to deliver on effective retail market competition, high levels of consumer satisfaction, protection and empowerment. Renewable and low-carbon gas based energy communities will remain limited across the Member States.

Option 2 can be expected to lead to modest, albeit tangible, economic benefits primarily as a result of the voluntary phase-out of regulated prices in some Member States and the drive to eliminate all switching-related charges. Given its low implementation costs, it is a highly efficient option. However, the effectiveness of Option 2 is significantly limited by the fact that non-regulatory measures are unlikely to ensure a consistent consumer engagement and protection throughout the EU and it is not suitable for tackling the slow **smart metering** deployment and the poor **data flow** or for significantly improving **consumer engagement.** They also introduce great uncertainty around the drive to phase out price regulation.

Option 3 would probably lead to substantial economic benefits. Retail competition would be improved and customers would have better information on consumption and energy sources. Communitities-of-interest would be enabled to integrate renewable and low-carbon gases in the gas market. Taken together these are effective tools to make greener choices, this option has a potential positive impact on the environment. Energy communities-of-interest would contribute to the uptake of biomethane and low-carbon gases.

Given that Option 3 would entail moderate implementation costs (primarily from ensuring a standardised format for consumer **data**, and the various burdens, such as the costs for rolling out **smart metering**, associated with improving **consumer engagement**) it is an efficient option as these costs are considerably outweighed by the benefits. Many stakeholder groupings are likely to be positively and negatively affected by the collection of policy measures in Option 3 but none would bear a disproportionate burden that would not be offset by commensurate benefits. Likewise, the proposed measures in Option 2 respect the principle and limits of subsidiarity.

Option 4 would also lead to substantial economic benefits, albeit with a greater degree of uncertainty over the size of these benefits. This uncertainty stems from the difficulty of prescribing EU-level solutions in many areas (for example implementing a standard EU bill design). Also a high administrative cost for public authorities can be expected from setting up and rolling-out a **smart metering** as well as from implementing the additional support measures for **energy communities**.

Whilst a single EU *data management* model would be just as effective and easier to enforce, and whilst the energy poor and vulnerable consumers would be even better protected by the stronger safeguards proposed, the high implementation cost of these measures would reduce the efficiency of Option 4 compared with Option 3. Finally, as social policy is a primary competence of Member States, Option 4 may go beyond the boundaries of subsidiarity. Suppliers and DSOs in particular would face significant burdens that they would at least partially pass on to consumers i.e. socialise.

Table 18: Overview of the impacts of the options under Problem Area IV

Options relative to BAU	Option 1	Option 2	Option 3	Option 4
Economic	+	+	+++	++
Environmental	+	+	+++	+++
Efficiency	+	+	+++	+
Effectiveness on sub-objectives as described in 4.2.:				
- Increase competition in retail renewable and low carbon gas markets	+/-	+	++	+++
- Strengthening consumer engagement in such market	+/-	+	++	++
- Ensure an adequate level of consumer protection	+/-	+	++	+++
+, ++, +++: positive impact (from moderately to highly positive) 0: neutral or very limited impact -, --, ---: negative impact (from moderately to highly negative)				

7.5 Synergies and trade-offs between problem areas

7.5.1 Synergies

Vertical unbundling requirements in combination with regulated TPA as selected as the preferred option under Problem Area I facilitates access to hydrogen infrastructure and, in the longer term, and widens consumer choice as intended by the measures under Problem Area IV.

The support for CEC in Option 3 and 4 under Problem Area IV will be conducive to the objective set out under Problem Area II to increase competition, liquidity and trade for renewable gases to the benefit of the end-consumers.

The focus on facilitating decarbonisation through a competitive, integrated market as part of all of the options under Problem Area II is expected to increase gas injections and liquidity in the wholesale markets, which, in turn, is expected to contribute to the objective of the measures contemplated under Problem Area IV and improve competition in retail markets.

Phasing out price regulation as fostered with the measures envisioned under Problem Area IV will help address the high level of gas consumption caused by artificially low prices and provide accurate price signals for energy efficiency investments. The latter will mitigate security of supply concerns as targeted by the measures under Problem Area II.

7.5.2 Trade-offs

Under Option 2 of Problem Area I, Option 2a to operate gas and hydrogen networks in a joint asset base or Option 2b to allow to cross-subsidise between asset bases temporarily, are expected to lead to a situation where smaller gas consumers temporarily finance the development of hydrogen infrastructure used by industrial customers. Unless addressed through targeted energy policies to reduce/compensate it, such trade-off, will temporarily contrast with the objective of the measures envisioned under the option in Problem Area IV. This trade-off needs to be seen in the context of the possibility that Member States can also support the roll-out of hydrogen networks via subsidies that can also have distributional effects, depending on the origin of the used tax revenues.

The wholesale market and transmission level focus under the option 4 of Problem Area II entails a trade-off with incentivising locally produced and supplied biogas and biomethane by energy communities through the measures contemplated under the options in Problem Area IV. In particular, the reverse-flow obligation to avoid market segmentation might constitute a barrier in this regard. For the legislative process, energy communities will be further considered to enable adjustment of the supply of biomethane to the local needs and conditions and facilitate consumer's choice for renewable gases. This would allow to tackle problems identified in Problem Area IV.

Energy poverty measures, in particular disconnection safeguards in Option 4 of Problem Area IV, may constitute a barrier to decarbonisation and effective retail market competition to occur, and prevent associated benefits to materialise, including higher levels of services and new and innovative products.

7.5.3 Sequencing

The preferred option in Problem Area I, Option 2b, already implies a certain sequencing of measures in that it foresees measures tailored for the ramp-up phase of hydrogen infrastructure and markets as well as main regulatory principles that would apply in a more mature hydrogen market. This sequencing is having significant beneficial synergies and impacts. Indeed, whilst it sets some limited constraints on the flexibility during the transition phase, these aim at avoiding costly ex-post interventions to move to a more mature and deeply integrated, efficient hydrogen market and exploits to the full that a 'greenfield' approach to regulation can be taken.

For Problem Areas II, III, and IV, the temporal dependency is low.

8 PREFERRED OPTIONS

8.1 Problem Area I: Hydrogen infrastructure and markets

In light of the analysis the preferred option is **Option 2b** 'Main regulatory principles with a vision'. This option is best adapted to the particularities of the hydrogen sector and enshrined in Option 2b are already some of the benefits that Option 1, 2a and also 3b could have brought whilst avoiding the downsides. Option 2b can, however, still be improved by already providing the possibility to define and adopt, but only if and when required, detailed technical rules, which is part of Option 3a and b.

In more details the implementation of Option 2b could include:

- A set of main regulatory principles that provide a clear perspective on the regulatory principles that will govern hydrogen networks in the longer run and based on a ‘competition in the market approach', such as regulated, cost-reflective TPA and separate RABs and guarantees for neutral network operations based on ownership unbundling or an ISO approach. Rules for large scale storage and hydrogen terminals would seek the same objective but are adapted and rendered proportional to their particular economic circumstances;
- Measures that avoid impediments to cross-border integration and efficient markets, such as may result from hydrogen gas quality issues, and providing the prospect of a true level playing field, without cross-border tariffs;
- A transitionary phase, during which negotiated TPA and tariffs remain possible for networks and during which financial flows between RABs are not excluded, provides flexibility to finance the ramp-up phase of the hydrogen network;
- Gas TSOs provide transparency on the gas infrastructure that may be available for repurposing whilst, in order to ensure that hydrogen infrastructure is only built if and when needed, a requirement to hydrogen infrastructure operators to submit information on the market demand for network capacity should accommodate the regulatory approval of regulated investments. Such an approach seems best-adapted to the more project based infrastructure development at the earlier ramp-up stages;
- Rules that facilitate the repurposing of natural gas assets and building new hydrogen infrastructure by grandfathering e.g. permits and land-use rights and ensuring that permits and land-use rights relevant for new hydrogen permits are granted in manners equivalent to those for natural gas;
- Fosters private investments, under an exemption regime for existing and new private network investments combined with rules that foster market integration by avoiding the permanent existence of divergent regulatory regimes within the same inter-connected network. Provision can be made for private networks to also benefit from opting into the regulated system;
- A light regime of consumer protection rules, suitable for more sophisticated hydrogen consumers, aligned to those enshrined in the Gas Directive;
- A legal mandate to introduce more detailed technical rules (network codes), if and when required;
- A framework that ensures that main regulatory principles are applied to interconnectors with third countries in their entirety;
- An appropriate governance system based on NRA supervision and ACER competences where needed.

8.2 Problem Area II: Renewable and low-carbon gases in the existing gas infrastructure and markets, and energy security

In light of the analysis the preferred option is **Option 3** as it contains maximum of measures to support renewable and low carbon gases, without the market impacts, complexity of the measures (and related administrative costs) and uncertain impacts on renewable and low carbon gases, included in Option 4. As Option 3 builds on the previous options, it includes elements of Option 2. Also, some elements of Option 4 could be maintained in the preferred option.

In more details the implementation of Option 3 could include:

- Access of renewable and low carbon RES&LC to the wholesale market will be enabled by ensuring gas flows from DSO to TSO by obliging DSOs to invest in reverse flows or agree with TSOs equivalent regulatory measures;
- The costs of renewable and low carbon production would be lowered by a possibility to release producers from injection and connection costs (tariffs);
- Limitations on long-term contracts for natural gas as of 2050.
- Abolishment of cross-border tariffs for renewable and low carbon gases only, measures for transparency of allowed revenue, costs benchmarking;
- Reinforced cross-border coordination on gas quality and harmonised EU approach on gas quality management to avoid cross-border flow restriction and market segmentation.
- 5% allowed cap for methane blends at cross-border points, which TSOs must accept (but without setting a blending obligation), enabling the integration of 70 TWh/year[177] hydrogen at an adaptation cost of EUR 3 bn/year;
- Rules on energy communities from the discarder option and assessed under Problem Area IV;
- Rules on energy security (including on cybersecurity) adapted to the decarbonisation of the gas sector.

8.3 Problem Area III: Integrated network planning

The most suitable option appears to be **Option 2**. This option provides the best balance in terms of achieving the objective of more integrated planning, allowing for a conceptual energy system plan potentially indicating areas where sector coupling technologies are best located from a network perspective, but leaving the required level of detail sector specific. It addresses all identified drivers of the problem, but in a less intrusive manner than Option 3, taking into account subsidiarity and proportionality.

The implementation of the option requires regulatory authorities to structure and manage the process. In most of the Member States regulatory authorities are already experienced in this task. The implementation of the required closer cooperation, both in terms of horizontal cooperation between system operators of different network based energy carriers as well as vertical cooperation including, inter alia, the distribution level but also network users and other stakeholders, could include a specific process that regulatory authorities have to supervise on a recurrent basis.

8.4 Problem Area IV: Low level of customer engagement and protection in the green gas retail market

In light of the analysis, the preferred option is **Option 3**. Flexible legislation, which mirrors the electricity market customer protection and where relevant the empowerment provisions (as in Option 3b for smart metering). This option is most likely to be the most effective, efficient, and consistent with other problem areas. Most stakeholders would support the measures envisaged in this option, while also taking into account the opinions given by a minority of stakeholders on specific issues such as mirroring the provisions on CEC and active customers. This approach addresses problems stakeholders have highlighted in the public consultation (PC), notably calls for consistency of customer protection and empowerment across sectors, while accommodating national differences in retail markets.

[177] Theoretical upper value.

Burdens for national administrations and businesses are limited and implementation can build on the experience with the Clean Energy Package.

In more details the implementation of Option 3 could include:
- Phase out of blanket price regulation with exemptions defined for households, micro-enterprises as well as vulnerable and energy poor households at the EU level
- Cross-reference to the EED definitions and requirements for energy poverty and vulnerable customers
- A minimum period for technical switching and additional requirements to ensure clear and transparent billing
- Minimum contractual conditions for contracts and restriction of termination fees
- Additional smart metering requirements for an enhanced deployment, including set functionalities, a deployment target, the right to a smart meter, regular revision of negative assessments
- Set up of EU data management rules, along with measures for transparent and non-discriminatory access to data, and data interoperability irrespectively of the data management model used
- Mirroring of the concept of and enabling framework for CEC.

8.5 REFIT (simplification and improved efficiency)

The proposals for amending the existing legislation will be designed in accordance with the most cost-effective policy options scrutinised in this Impact Assessment. It is expected from some of the preferred options to increase administrative, implementation and enforcement costs for both regulatory bodies and market operators. For example, higher administrative exchanges between NRAs and natural gas shippers, increased coordination efforts between DSOs and TSOs, and further regulatory and implementation efforts for Member States and national authorities might stem from the proposed measures. However, lower and more efficient regulatory costs are also expected from the amended framework, as substantiated in the table below.

Furthermore, the analysis in the Impact Assessment clearly shows that the proposed measures offer the most cost-effective regulatory options to achieve the overarching objective of the initiative, namely the establishment of rules for the transmission, distribution, supply and storage of methane and hydrogen gases that can support the decarbonisation of the energy system while ensuring secure and affordable energy.

The short-term regulatory costs entailed in some of the preferred measures must be also assessed against the costs and efforts that a late integration and decarbonisation of the energy system would require in the long term. In this sense, the benefits that the options are expected to produce in terms of support for renewables sources, energy system integration, consumer protection and energy security will largely outweigh the immediate administrative and implementation costs.

The proposal further contributes to simplifying the current regulatory framework by harmonising, when necessary and appropriate, the provisions on gas infrastructure and market with the new regulatory architecture conceived by the Clean Energy Package for the electricity sector. Higher alignment between sectors is expected to benefit many regulatory areas, notably consumer empowerment and protection, governance and regulatory oversight. Similar contributions are also foreseen in the early introduction of a regulatory framework for hydrogen infrastructures and markets. Whilst these rules will likely increase the immediate administrative costs and regulatory burdens for national authorities and market operators, an early harmonisation of regulatory principles for hydrogen is expected to significantly lower future compliance costs and prevent the risk of major regulatory divergences and implementation costs.

Table 19: REFIT cost savings

REFIT Cost Savings – Preferred Option(s)		
Description	**Amount**	**Comments**
Regulation for hydrogen infrastructure and markets	N/A	It can reduce transaction and administrative costs for renewable hydrogen producers or suppliers that want to supply (distant) consumers with (cross-border) produced renewable hydrogen
Access of renewable and low carbon gases to the gas markets and infrastructure	N/A	Potential to reduce state aid with increased efficiency of biomethane production and trade
Adoption of an allowed cap for hydrogen blends cross-border	N/A	Reduces the administrative work for market operators in the gas system by increasing the homogenisation of European gas market characteristics and reduce the need for justification for exception and interaction with different TSOs
Establishing a system-wide NDP	N/A	Biomethane and hydrogen producers are expected to benefits from interacting with a single and joint planning exercise of TSOs
Ensuring non-discriminatory access to data, and in fact smart metering data	N/A	In countries where smart meters are rolled out, **DSOs** can lighten, and improve, some administrative processes (linked to meter reading, billing, disconnection, etc.), and offer increased customer services.

(1) Estimates are with respect to the baseline of the unchanged legislation;
(2) Please indicate which stakeholder group is the recipient of the cost saving in the comment section;
(3) For reductions in regulatory costs please describe the measure/action which gives rise to the cost saving (e.g. actions to reduce compliance costs, administrative costs, regulatory charges, etc.) and whether it is a recurrent cost saving.

9 HOW WILL ACTUAL IMPACTS BE MONITORED AND EVALUATED?

9.1 Future monitoring and evaluation plan

The Commission will systematically monitor the transposition and compliance of the Member States and other actors with the finally adopted measures and take enforcement measures if and when required and report on the progress made in this regard on a regular basis. For this purpose, the Commission will be supported by ACER as described below.

The annual reporting by ACER and the evaluation by the Commission are part of the proposed initiatives and described in the sections below.

The energy security impacts will be monitored as a part of the overall monitoring tasks under the SoS Regulation, such as the Commission's opinions on the national preventive action and emergency plans.

9.2 Annual reporting by ACER and evaluation by the Commission

The monitoring of the proposed initiatives will be carried out following a two tier approach: annual reporting by ACER and an evaluation by the Commission.

9.2.1 Annual reporting by ACER

ACER's duties under the Third Package[178] and the Clean Energy Package[179] include the monitoring of and reporting on the internal gas market. ACER prepares and publishes an annual market monitoring report that tracks the progress of the integration process and the performance of gas markets and identifies any barriers to the completion of the internal gas retail and wholesale markets.

Within one year of the adoption of the proposals, the Commission will invite ACER to review and update its current monitoring indicators – with the involvement of affected stakeholders – to ensure their continuing relevance for monitoring progress towards the objectives underlying the present proposals. Its mandate will be extended to include hydrogen. ACER will continue relying on the already established data sources used for the preparation of the market monitoring report, extended with relevant data on hydrogen.

ACER's annual reporting will replace the Commission's reporting obligations that currently still exist under the Gas Directive, thus streamlining reporting obligations. The detailed proposals will ensure that ACER’s monitoring is complementary to other monitoring exercises to avoid any overlaps. In particular, ACER’s reporting is complementary to the monitoring under the Governance of the Energy Union and Climate Action[180]. Under the latter Member States provide the Commission in their NECPs with relevant information on a biannual basis. Complementary to that, ACER’s yearly reporting provides an independent assessment of the functioning of the EU internal markets, including profound analyses of cross-border market developments. While the indicators for the NECP reporting are governed by a regulation to ensure continuity and consistency, ACER is fully flexible to improve existing or to develop new indicators and to focus in its reporting on specific areas.

9.2.2 *Evaluation by the Commission*

The Commission will carry out a fully-fledged evaluation of the impact of the proposed initiatives, including the effectiveness, efficiency, continuing coherence and relevance of the proposals, within a given timeline after the entry into force of the adopted measures (indicatively, 5 years).

The Evaluation Report will be developed by the Commission with the assistance of external experts and stakeholders will be informed of and consulted on the Evaluation Report. Stakeholders will also be regularly informed of the progress of the evaluation and its findings. The Evaluation Report will be made public.

9.3 Operational objectives

The key objective of the present initiative is to contribute to the EU’s decarbonisation in a cost-effective manner by facilitating the creation of a European hydrogen market and the gradual decarbonisation of gaseous fuels markets, whilst ensuring energy security. The

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178 The legal basis for the Agency’s market monitoring duties is in Article 9 of Regulation (EC) No. 715/2009. ACER equally monitors and reports on many more detailed aspects of the regulatory framework.

179 Including additional monitoring tasks as envisaged in Article 15 of the Regulation (EU) 2019/942 (recast ACER Regulation), available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0942&from=EN

180 Regulation on the governance of the energy union and climate action (EU/2018/1999).

operational objectives for the preferred options are to adopt the measures as described in Section 8.

9.4 Monitoring indicators and benchmarks

Within one year of the adoption of this proposal, ACER will be invited to review its current monitoring indicators with a view to ensure their continuing relevance for monitoring progress towards the objectives underlying the present proposals. ACER will continue relying on the same sources of data used for the preparation of the market monitoring report. Monitoring indicators could include, but not limited to, the following:

Indicators for *Problem Area I* related to the hydrogen infrastructure development and utilisation (e.g. transportation capacity, large scale storage and import terminals) and the development of a competitive, integrated hydrogen market.

Indicators for *Problem Area II* related to the levels of production, production costs, and the level of trade and access of renewable and low carbon gases to markets (including volumes and number of traders) and of the utilisation rates of LNG terminals and volumes of these gases received.

Indicators for *Problem Area III* existence of joint scenario framework, level of involvement of different sectors in network planning, level of interconnectivity and provision of flexibility between sectors, consistency of NDPs with TYNDP.

Indicators for *Problem Area IV* related to the levels of availability, security of supply and unit price for end-consumers, competition in the retail market (market shares and prices) and energy poverty.

EUROPEAN
COMMISSION

Brussels, 15.12.2021
SWD(2021) 455 final

PART 2/2

COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT REPORT

Accompanying the

Proposal for a Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast)

Proposal for a Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast)

{COM(2021) 803 final} - {COM(2021) 804 final} - {SEC(2021) 431 final} -
{SWD(2021) 456 final} - {SWD(2021) 457 final} - {SWD(2021) 458 final}

EN EN

ANNEX 1: PROCEDURAL INFORMATION

Lead DG, Decide Planning/CWP references

Lead DG: DG Energy

Agenda planning/Work Programme references:

- PLAN/2020/8564 Revision of EU rules on Gas [CWP2021] Revision of Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC
- PLAN/2020/8563 Revision of EU rules on Gas, [CWP2021] Revision of Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005

Organisation and timing

Inter-service steering group:

- An Inter-service steering group meeting was used comprising the LS, SG, ENER, AGRI, CLIMA, COMP, EEAS, EMPL, ENV, GROW, INTPA, JUST, JRC, MOVE, NEAR, REFORM, TRADE, RTD.
- Not all services participated in each ISG meeting.
- Meetings of this inter-service steering group were held on: 10 December 2020, 16 December 2020, 10 March 2021, 20 June 2021 and 8 July 2021

Consultation of the RSB

Publication of Inception Impact Assessment: 22 February 2021

Consultations of the RSB

- An upstream meeting with the RSB took place on 31 March 2021
- The Impact Assessment was submitted to the RSB on 20 July 2021
- On 15 September 2021, the Impact Assessment was discussed with the RSB.
- On 17 September 2021 the RSB issued its opinion. This opinion was positive with reservations expecting that DG ENER would rectify the following aspects: (1) The construction of the baseline and the options is not sufficiently clear. (2) The report does not adequately analyse the distributional impacts.

The opinions and the changes made in response are summarised in the tables below.

Comments made by RSB in Opinion of 17 September 2021	Modifications made in reaction to comments RSB
The conclusions of the evaluation should be fully integrated into the problem description. The report should address both the conclusions related to decarbonisation as well as those related to market issues.	All elements listed in Annex 3 of the Evaluation (the list of articles of the Directive and Regulation) are addressed in the revision set out in the Impact Assessment. To clarify this better in the Impact Assessment, it has been rendered transparent which areas listed in Annex

	3 of the Evaluation are addressed by which option in the Impact Assessment. In particular, a new annex (Annex 11) has been added that contains a detailed table based on Annex 3 of the evaluation indicating where it is covered in the Impact Assessment. A new section on the evaluation has been added in Chapter 2.
The problem definition should address how the initiative shifts the nature of energy security towards resilience.	
The report should clearly spell out the role of the initiative as part of the enabling framework of the Fit for 55 package.	Chapter 1 and Annex 12 have been improved in order to spell-out the role of the present initiative within the Fit for 55 package and the interactions with its various components.
The report should explain why there is no common approach on the baseline between follow-up initiatives to the July Fit for 55 package. It should better describe how its baseline integrates the already proposed Fit for 55 initiatives.	In Section 1.5 (alignment with the Fit for 55 Impact Assessment), Section 5.1.1. (baseline for Problem Area I) and Annex 4 (analytical methods) it is explained what the baseline actually represents. In addition, it is explained how the baseline relates to the use of common demand and supply assumptions in both this Impact Assessment and the one underpinning the already proposed Fit for 55 initiatives (e.g. the proposal for a revision of the RED II Directive) by the common use of the MIX-H2 PRIMES as the point of departure. Lastly, Section 5.1.1 and Annex 4 explain that the intrinsic assumption on the existence of policy measures to ensure cross-border infrastructure under the MIX-H2 PRIMES scenario is the actual aim of the current proposal, but that it does not lead to a divergent baseline.
The report should clarify the differences between the baseline and Option 0 and explain which one is used as point of comparison for the impact analysis and why.	In Annex 4 (analytical methods) it is explained that there are no differences between the baseline and Option 0 and that it represents 'an infrastructure policy scenario' that is the benchmark against which the policy options for this proposal are tested. In order to clarify that Option 0 and the baseline are the same, the headings in Section 6.1.3 have been changed.
The report should be clear how the options were constructed and explain why certain measures are in one option, and not in another. The construction of the options should clearly reflect the main policy choices.	For each of the policy options as described in Chapter 5, we have clarified the main (higher-level) characteristics of each option and, when pertinent, links and phases with the underlying policy initiatives. E.g. in Problem Area I, the links with the phasing and time scales of the EU Hydrogen Strategy have been emphasised. Comparability between options has been improved by inserting summary tables in Chapter 5 that, for each problem area and option, with the more detailed measures they are comprised of. It has hence been made clearer how the options were constructed whilst rendering also the differences between them more

	clear and verifiable. In the text for Problem Area II in Chapter 5, it was clarified that the options build on each other in terms of the depth of their applicability e.g. Option 3 includes elements of Option 2 and adds new measures. Option 4 includes all elements of Option 2 and 3 and adds new measures. We will also move Table 36 to the end of Chapter 5 and improve its readability. In Problem Area III, options' description have been clarified in terms of connection with other problem areas. General section describing interdependencies between problem areas added in Chapter 2 and Section on synergies, trade-offs and sequencing added in Chapter 6. Annexes 6 to 9 include details of each of the options in terms of more granular measures and present pros and cons of each of them in a transparent manner.
The impact analysis should distinguish more between different actors, in particular between natural gas and hydrogen producers and consumers. This should include an assessment of the effects of the inbuilt flexibilities on different types of actors and a risk of fragmentation between Member States in the transition period.	It has been rendered clearer how the various options can (or cannot) can deal with the uncertainties inherent to the development of a new hydrogen value chain differ and how they differ in terms of the degrees of freedom they offer to investors and operators to develop business models and foster investments. The distinction in Problem Area I between Options 2 and 3, i.e. the difference between an approaches based on 'main regulatory principles' as opposed to a fully-fledged regulatory framework has been rendered clearer. The same applies to the consequences this entails for the scope to refine the regulatory system later if it falls short of expectations.
The report should provide an assessment of how the initiative may have different impacts for SMEs compared to other (larger) companies. The report should clarify the legal delivery instruments foreseen for the measures contained in the preferred option.	We have included a more detailed assessment on how these initiatives may impact SMEs for each policy measure. See in particular Section 6.6. Annex 11 provides clarity on what legal instrument is used to address a given concern.
The report should better reflect the dissenting and minority views throughout the report, including in the problem definition, the construction of the options, analysis of impacts and the choice of preferred option.	Boxes containing stakeholder's views, such as those in Chapter 5 provide, for each option in all policy areas, what the majority and minority stakeholders views were and by whom they are held. In Annex 3, which contains detailed reports on stakeholder feedback, more detailed explanation were included, especially for the part on the public consultation, on how the certain subgroups of stakeholders, including the minority views, responded to the analysed options in the Impact Assessment.
The narrative of the report should be significantly improved. It should be re-written so that a non-expert reader understands easily all the issues at stake and the policy choices to be made. The Glossary should be	The report has been reread by non-experts and its readability improved. The Glossary has been completed.

completed.	
The cost and benefit tables (in Annex 3) should be completed in the appropriate format.	The tables have been included and, in line with the better regulation guidelines completed as far as possible. Please note that quantifying results is not possible for all options and all Problems Areas.
Other technical comments.	
Monitoring success	More details on the process of establishing monitoring indicators have been included in Chapter 9 of the Impact Assessment report.
Renewable and low carbon gases from third countries	The treatment of renewable and low carbon gases from third countries is now integrated in the problem definition and specific objectives. To the extent a problem was defined in their connection (this mostly concerns Problem Area I), we have assessment specific measures under the options in Sections 5 and beyond and added a detailed table regarding the treatment of interconnectors to third countries to Annex 6.
Social impacts	To the extent meaningful, the assessment of social impacts in Section 6.5 has been conducted for all options in all problem areas (and not only the preferred option).
Interdependency of the problem areas	We have now briefly described interdependencies in Section 2.5 and assessed synergies and trade-offs in Section 6.77 of the Impact Assessment.
Tables with over view impacts	We have adapted tables and replaced drivers with (sub-)objectives in the tables providing and the overviews of impacts for the options under each problem area and provided better explanations or legenda.
Options in Problem Area IV	The main document and the Annex with regard to Problem Area IV have been rendered clearer. For instance, a table setting out different options for different measures is now included under Section 5.4. The Annex also provides gives a general overview table with pros and cons.

Evidence, sources and quality

The present Impact Assessment is based on a large body of material, all of which is referenced in the footnotes. A number of studies have however been conducted mainly or specifically for this Impact Assessment or contributed to its scoping. These are listed and described further in the table below.

Table 20: List of studies conducted for this Impact Assessment or contributed to its scoping

Title of study	Study served to study/substantiate impact of	Contractor(s)	Published
The role of trans-European gas infrastructure in the light of the 2050 decarbonisation targets	Assessment of the role of Trans-European gas infrastructure in the light of the EU's long-term decarbonisation commitments.	Trinomics	Published https://op.europa.eu/en/publication-detail/-/publication/1796ecd6-cb71-11e8-9424-01aa75ed71a1/language-en
Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure	Assessment of the potential of biomethane and hydrogen to contribute to the decarbonisation of the EU energy system, the impacts this will have on the gas infrastructure and the extent to which gas network operators and regulators are prepared to cope with these impacts.	Trinomics LBST E3M	Published https://ec.europa.eu/energy/studies_main/final_studies/impact-use-biomethane-and-hydrogen-potential-trans-european-infrastructure_en
Potentials of sector coupling for decarbonisation, Assessing regulatory barriers in linking the gas and electricity sectors in the EU	Assessment of regulatory barriers and gaps preventing closer linking of the EU gas and electricity sectors (both in terms of their markets and infrastructure) and hindering the deployment of renewable and low-carbon gases, including cross-border aspects of gas quality and hydrogen blending.	Frontier Economics CE Delft THEMA Consulting Group	Published https://op.europa.eu/en/publication-detail/-/publication/60fadfee-216c-11ea-95ab-01aa75ed71a1/language-en
European barriers in retail energy markets	Research the extent to energy suppliers across Europe face a variety of barriers to enter and compete in the market; to identify which barriers exist and to provide some suggested solutions to those barriers.	VaasaETT, REKK MRC The Advisory House	Published https://ec.europa.eu/energy/studies_main/final_studies/european-barriers-retail-energy-markets_en
Study on gas market upgrading and modernisation - Regulatory framework for LNG terminal	Identifying and describing exiting barriers and gaps that could be addressed in order to ensure optimal use of existing LNG terminals in the EU	Trinomics REKK Enquidity	Published https://op.europa.eu/en/publication-detail/-/publication/efa4d335-a155-11ea-9d2d-01aa75ed71a1/language-en
Assistance to assessing options improving market conditions for bio-methane and gas market rules	Impact Assessment of options related to a regulatory framework for bio-methane, gas quality and network planning.	Artelys, Trinomics, Frauenhofer, JRC	Forthcoming
Sector integration – Regulatory framework for	Identifying options related to a regulatory framework for	Trinomics	Forthcoming

Title of study	Study served to study/substantiate impact of	Contractor(s)	Published
hydrogen	hydrogen	LBST	
Assessment of policies for gas distribution networks, gas DSOs and the participation of consumers	Problem definition and Impact Assessment of pitons related to Problem Area II (access renewable and low-carbon gas) and IV (energy communities, smart metering)	Frontier economics	Forthcoming
Assistance to the Impact Assessment for designing a regulatory framework for hydrogen	Impact Assessment of options related to a regulatory framework for hydrogen.	Guidehouse, Frontier Economics	Forthcoming
Upgrade of METIS and studies on sector integration – Study S2 Gaseous Fuels	METIS study on challenges related to the integration of new gaseous fuels	Artelys	Forthcoming
Quo Vadis EU gas regulatory framework	The study 'Quo Vadis EU gas regulatory framework' analysed whether the current regulatory framework in the EU gas sector is efficient in order to maximise overall EU welfare or whether changes may be necessary, and if so provide recommendations. The study identifies potential inefficiencies of the EU gas market regulatory framework and discusses possible additional regulatory measures which could potentially lead to the improvement of EU welfare.	EY REKK	Published https://ec.europa.eu/energy/studies/study-quo-vadis-gas-market-regulatory-framework_en
Blending hydrogen from electrolysis into the European gas grid. JRC Science for Policy report. JRC126763	Impact and cost of hydrogen blending in the European gas network on the cross-border flow of gases and on electrolyser capacity.	Joint Research Centre	Forthcoming
Investigating the benefits of aligning EU consumer protection and information rules in the gas and electricity sectors	To evaluate the EU legal framework for consumer protection and information in the gas and DHC sectors and assess the impacts of (partially) aligning the provisions for gas and DHC with those of the 2019 Electricity Directive.	Valdani Vicari Associati-Grimaldi Studio legale	Forthcoming
Consumer study on precontractual information and billing in the energy market – improved clarity and	Investigating minimum requirements and options for standardisation of energy offers and bills; main factors discouraging energy consumers	Ipsos-London Economics-Deloitte consortium	Published https://ec.europa.eu/info/sites/default/files/final_report_2_july_2018.pdf

Title of study	Study served to study/substantiate impact of	Contractor(s)	Published
comparability	from switching; and price comparison tools (PCTs)		
Second consumer market study on the functioning of the retail electricity markets for consumers in the EU	Investigating if a well-functioning electricity market is in place for consumers in the EU; assess how the performance of retail electricity markets for consumers has developed; the extent to which consumers are able to make informed and empowered choices and what motivates their behaviour	Ipsos-London Economics-Deloitte consortium	Published https://ec.europa.eu/newsroom/just/items/53331/en
The role of renewable hydrogen import and storage to scale up the EU deployment of hydrogen	Aspects of this study were geared towards investigating options and impacts of large scale hydrogen storage and import terminals.	Energy Transition Expertise Centre (EnTec) (TNO, Guidehouse, McKinsey, Trinomics, Universiteit Utrecht, Frauenhofer)	Forthcoming
Hydrogen generation in Europe Overview of costs and key benefits	Infrastructure costs and benefits, including repurposing, storage and imports	Guidehouse Tractebel Impact	Published https://op.europa.eu/en/publication-detail/-/publication/c4000448-b84d-11eb-8aca-01aa75ed71a1/language-en
Benchmarking smart metering deployment in the EU-28	Smart metering and access to data measures under Problem Area IV and the consumer empowerment topic	Tractebel Impact	Published https://op.europa.eu/en/publication-detail/-/publication/b397ef73-698f-11ea-b735-01aa75ed71a1/language-en/format-PDF/source-122443670
Policies for DSOs, distribution tariffs and data handling	Policy options for data handling arrangements within the EU, under Problem Area IV and the consumer empowerment topic	Copenhagen Economics VVA	Published https://ec.europa.eu/energy/sites/default/files/documents/ce_vva_dso_final_report_vf.pdf

ANNEX 2: STAKEHOLDER CONSULTATION

Apart from this Annex, stakeholder opinions are also summarised in boxes for each main policy option in Section 5 and, if appropriate, elsewhere of the present Impact Assessment.

It demonstrates that stakeholders had an opportunity to provide an opinion on all key Impact Assessment elements. This will provide clear demonstration whether and to what extent stakeholder views were taken into account, separately for each major option investigated in the Impact Assessment.

Consultation strategy

The objective of the consultation strategy for this initiative was to ensure that, across a series of consultation activities, all stakeholders have been given an opportunity to express their views and provide input into the Commission's work on all elements relevant for Hydrogen and Decarbonised Markets Package.

The consultation strategy included:

- a 4-week consultation on the inception Impact Assessment (Roadmap)
- a 12-week public consultation based on a questionnaire (both on the European Commission's 'Have Your Say' platform)
- presentations by the Commission and feedback by stakeholders at the established regulatory fora, including the Gas Regulatory Forum (29-30 April 2021)
- discussions with the Member States (28 April 2021), with members of the European Parliament and with National Regulatory Authorities
- discussions with stakeholders in a large stakeholder workshop (18 May 2021).

The consultation strategy identified a wide group of stakeholders, including:

- market players
- EU networks and associations
- International Organisations (IEA, IRENA, Energy Community, EEA)
- Public authorities
- NGOs
- Consultancy (think-tanks, law firms, professional consultancies)
- Research and academia (universities and research institutes)
- Representatives of civil society (European Consumer Organisation – BEUC).

Inception Impact Assessment

The public consultation on the Inception Impact Assessment (IIA)[182] for the 'Revision of EU rules on Hydrogen and Gas Market Decarbonisation Package'[183] was open between 10 February and 10 March 2021 and received altogether **128 replies** on the 'Have your say' platform of the European Commission. These were divided between 113 business/industry representatives (companies and associations), five NGOs, two think-thanks, two NRA representatives (one national regulatory authority and the European association of NRAs), one European consumer association (BEUC), one national authority (non-EU Member State)[184],

182 090166e5d9426cde (1).pdf
183 Proposal for a Gas Directive (PLAN/2020/8564) and for a Gas Regulation (PLAN/2020/8563).
184 Norway, Ministry of Petroleum and Energy.

one research entity, one national trade union and the Energy Community Secretariat and one EU citizen.

Stakeholders expressed general agreement with the Commission's plan to revise the gas legislation (Gas Directive and Gas Regulation) and consider legislative proposals for the regulation of hydrogen infrastructure as a key element for achieving the increased greenhouse gas emissions reduction targets and to implement the European Green Deal.

NGOs highlighted that the revised EU gas legislation must facilitate the elimination of fossil gases from the EU energy system by 2050 and called for avoiding natural gas lock-in effects. Most of their recommendations focused on legislative instruments addressing taxation and fiscal policy, ETS, methane targets and standards and renewable gases targets while their comments on the revision of the gas legislation were in line with those of other stakeholders, as presented in this summary document.

As regards a regulatory framework for hydrogen infrastructure, most respondents mentioned the importance of a well-functioning internal market. A significant number of respondents supported a hydrogen market based on the same regulatory principles (unbundling, non-discriminatory third-party network access and cost-reflective tariffs) as those currently used in the gas market while a number of them questioned the necessity to apply similarly deep regulation of pure hydrogen network operations. The majority of respondents called for technology neutrality in the design of the hydrogen regulatory framework. Responses were divided about blending of hydrogen into the gas network: Some argued that blending is important for a limited time for ramping up hydrogen production whilst others supported blending as an essential element of our decarbonisation strategy, reducing the need for parallel hydrogen and methane networks. Others pointed to the downsides of blending. There was also a strong division of views as regards the potential role of transmission and distribution system operators in owning and operating power-to-gas facilities (TSOs and DSOs strongly support this option) as opposed to establishing power-to-gas as a fully market-based activity (supported e.g. by gas consumers, energy traders, electricity industry).

A number of responses addressed the topic of how to ensure access for renewable and low-carbon gases to the infrastructure and the market. These respondents supported the aim of facilitating the market entry of renewable and low-carbon gases and removing any undue regulatory barriers ensuring a fair regulatory framework for these gases.

The majority of respondents agreed with the Commission in identifying an integrated approach to infrastructure planning and TSO-DSO cooperation as crucial elements in ensuring that decarbonisation is achieved at lowest possible cost. Many respondents welcomed that the Commission acknowledges issues around gas quality. They called for EU rules to avoid market fragmentation due to the emergence of new gases and to ensure unhindered cross-border flow and trade in gases. While not all responses reflected on consumer rights and empowerment, there were clear calls for aligning the rights of gas consumers with the framework provided by the Clean Energy Package (i.e. revision of the Electricity Directive).

A number of respondents mentioned the importance of topics that were in the scope of the Renewables Energy Directive such as an EU wide system of certification and guarantees of origin for renewable and low-carbon gases providing clarity to stakeholders that are willing to invest in related technologies. Also the need for renewable gas targets at EU-level was mentioned in some of the responses.

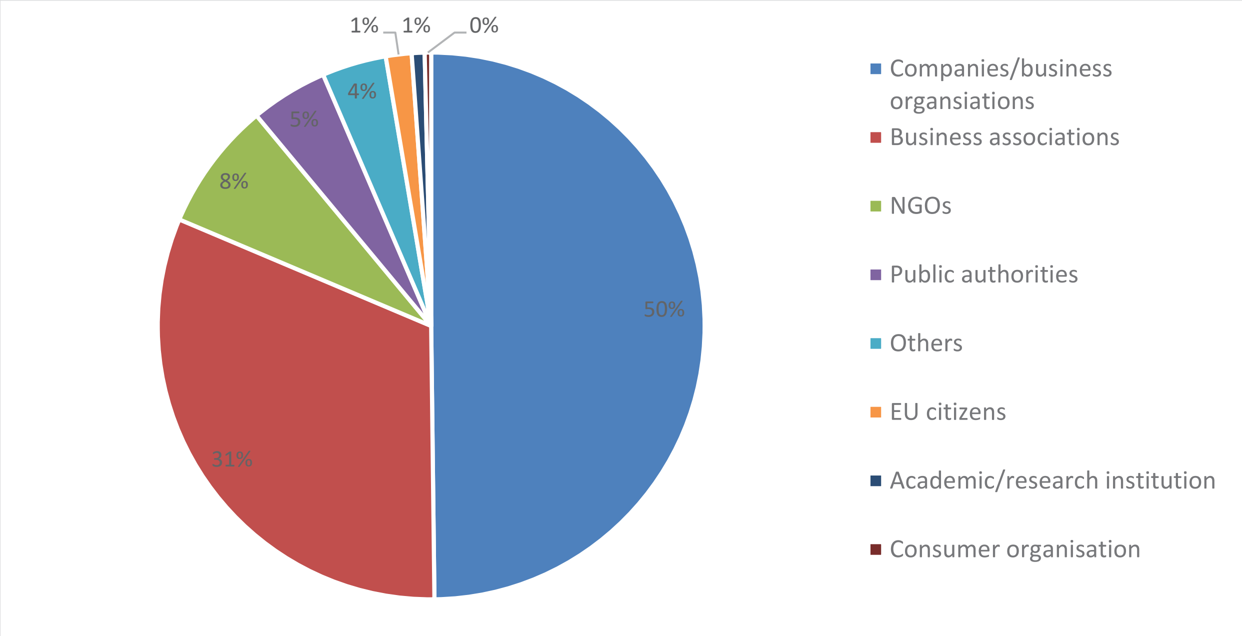
Based on the evaluation of the responses to the public consultation on the Inception Impact Assessment, it was concluded, that the public consultation document (questionnaire), in preparation at that time, covered all relevant topics and aspects for the revision of the gas legislation and for developing legislative proposals for the regulation of hydrogen infrastructure. In this sense, the consultation responses affirmed the right choice of the topics and issues included in the questionnaire for consultation.

Public consultation

The web-based, 12-week public consultation was organised in accordance with the Better Regulation Guideline between 26 March and 18 June 2021[185] and received 263 responses out of which 131 from companies/business organisations, 83 from business associations, 20 from NGOs, 12 from public authorities, ten from others, four from EU citizens, two from academic/research institutions, and one from a consumer organization and the rest from citizens and academic institutions. 90% of respondents confirmed that they see a need to revise the Gas Directive and Gas Regulation to help to achieve decarbonisation objectives. Stakeholders that did not see a need for such revision were represented by one company/business organisation and one business association. Those who did not reply to these questions include companies/business organisations, business associations, one NGO and one public authority. Moreover, over 60% respondents expect that the technological and regulatory changes necessary to decarbonise the gas market have a potential to create new jobs by 2030. Some companies/business organisations and business associations were on a balance neutral regarding this question, while a group composed in majority by NGOs did not expect the technological and regulatory changes to create new jobs by 2030. The public consultation aimed at collecting views on all Problem Areas described in the Impact Assessment.

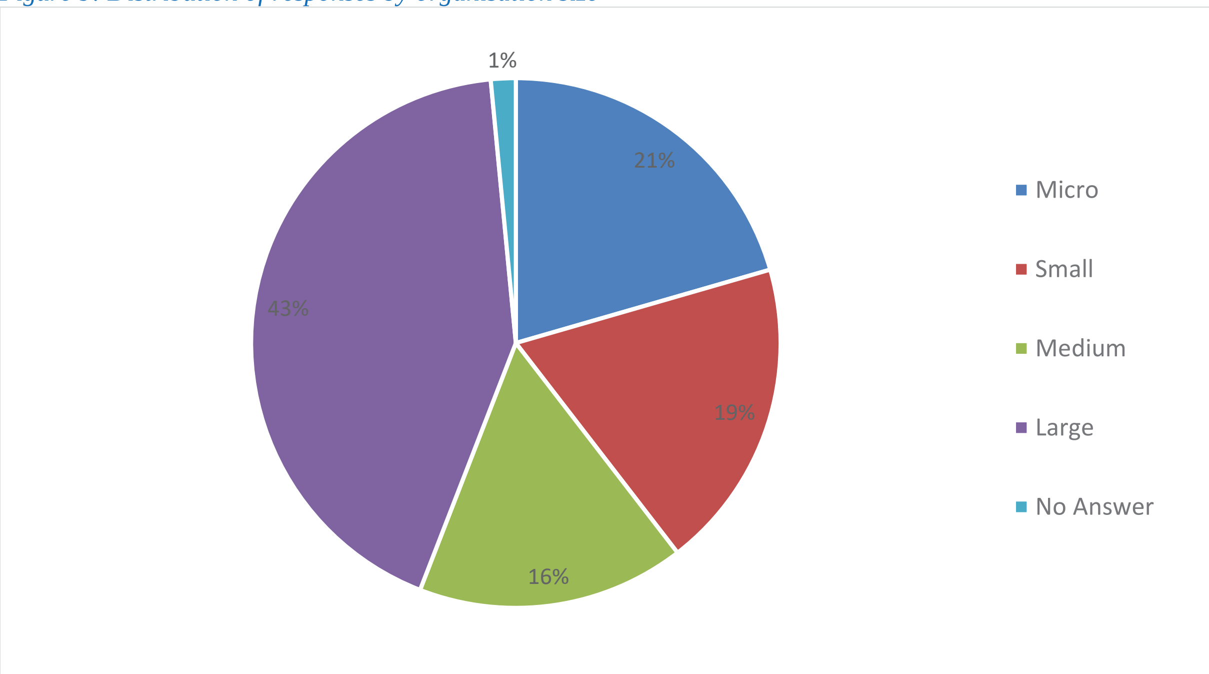
185 Gas networks – revision of EU rules on market access (europa.eu); published in the three working languages of the European Commission with the questions to the public will available in 23 EU official languages (all but Irish), with the option to send responses in any of these languages; with the option to provide additional written comments, remarks and figures.

Figure 8: Distribution of responses by category of participant



Regarding the size of the organisations which took part in the public consultation, the majority of them are considered large (250 employees), while around the 16% (16.3%) are medium (50 to 249 employees). Small (10 to 49 employees) and Micro (1 to 9 employees) represented respectively the 19% and the 29.5% of the total of the Organisations involved in the Public consultation.

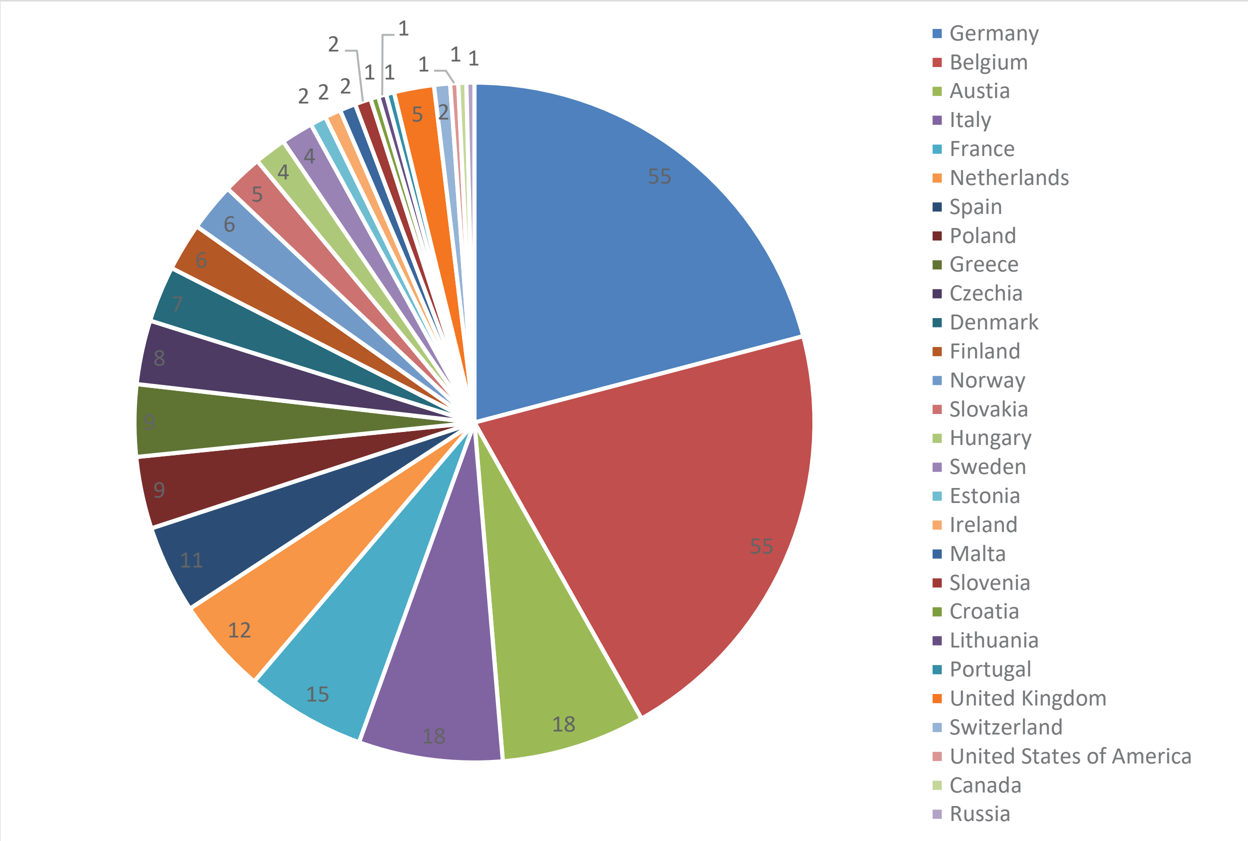
Figure 9: Distribution of responses by organisation size



In terms of geographical coverage, 55 submissions were received from Germany and Belgium, followed by Austria and Italy (18), France (15), the Netherlands (12) and Spain

(11). Nine answers were received each from Poland and Greece, eight from Czechia, seven from Denmark, and six from Finland and Norway. Five responses were received from Slovakia, four from Hungary and Sweden, two from Estonia, Ireland, Malta, and Slovenia, and one answer from Croatia, Lithuania, and Portugal. A significant number of responses also came from outside the EU, with the United Kingdom leading with five, followed by Switzerland with two, and the United States, Canada and Russia with one answer each.

Figure 10: Distribution of responses by countries



In **Problem Area I,** a large majority of the respondents support the introduction of regulation to foster the emergence of a well-functioning and competitive hydrogen market and hydrogen infrastructure, whereas none of the respondents stated that there is no need for regulation. The respondents that expressed their support to introduce regulation for the hydrogen market and its network, equally stated largely unanimously that a suitable regulatory model should be developed at EU level instead of at national level. The option of 'dynamic regulation' was supported by a small minority, mainly composed of companies/business organisations and business associations, and half academia that responded. A large majority of respondents consider that a regulatory model at EU level is suitable to foster the emergence of a well-functioning and competitive hydrogen market and infrastructure. Stakeholders also considered the need for the regulator to ensure 'competition in the market' (i.e. like the current market design for the natural gas markets), even if they varied in views as to the depth and scope of the rules needed. Most respondents considered it important or very important to define in advance the role of private parties in developing hydrogen infrastructure to facilitate the development of a dedicated hydrogen network and market framework towards 2030. Only a few respondents consider that existing private network operators should remain fully unregulated whilst a minority (mainly composed by companies/business organisations and business associations) take the view that private operators should be given a unilateral possibility to ‘opt-in’ into an existing regulated system. A large majority of respondents consider that existing private networks may be exempted from certain regulatory requirements, but only temporary. A large majority of the respondents stressed the need for rules to ensure the neutrality of hydrogen network operations via vertical unbundling, third party access (TPA) and requiring non-discriminatory network tariffs. Half of the proponents of introducing vertical unbundling, mainly representing NGOs, energy production companies (both electricity and gas) and gas TSOs, stated that network operation activities should be separated from merchant activities within a distinct legal entity. Half of the respondents in favour of requiring vertical unbundling (mainly electricity TSOs, renewable energy producers and associated stakeholder organizations, existing private hydrogen producers/pipeline operators, research institutions and storage operators) stated that ownership unbundling should be applied at EU level from the start. The large majority of the proponents to ensure TPA at European level is in favour of regulated TPA. The majority of stakeholders, mainly representing gas TSOs and DSOs, electricity TSOs, energy production companies (electricity and gas), industrial energy consumers and associated stakeholder organisations and research institutions) identified as important or very important the role of existing gas network operators (TSOs/DSOs) in developing hydrogen infrastructure and accordingly to allow them to own, operate and invest in hydrogen networks. However, respondents are divided over the question whether or not to introduce horizontal unbundling rules at EU level in order to separate hydrogen transport activities from natural gas transport activities. Less than half of the respondents, mainly representing incumbent natural gas TSOs, DSOs as well as some industrial energy consumers and their associated stakeholder organizations, expressed to be in favour the option of (partial) cross-subsidisation in order to ensure the development of dedicated hydrogen networks. A small majority of stakeholders mainly representing energy production companies, renewable energy producers and associated organisations, existing private hydrogen producers/pipeline operators, industrial energy consumers and associated stakeholder organisations, NGOs, research institutions, consumer organisations, regulators, storage operators agreed to forbid cross-subsidies between methane and hydrogen network users to retrofit their assets for hydrogen networks. A quarter of respondents specifically support establishing hydrogen quality (purity) standards at Member State level with EU-level cross-border coordination rules. There is strong support for establishing rules on roles, responsibilities and cost-allocation for the management of hydrogen quality at EU-level. According to respondents, it is the most efficient and appropriate way to ensure a harmonised approach across the EU. Also, providing information on the quality of the hydrogen supplied is considered highly important by the majority of respondents. The majority of stakeholders (half of the gas TSOs and DSOs, energy production companies, industrial energy consumers and associated stakeholder organisations, agreed that the current structure of the cross-border gas transmission tariff system is suitable for the development of the hydrogen market in the EU. A large majority of the respondents are against the introduction of an EU ISO model for hydrogen. The main justifications raised by stakeholders are that the coordination of infrastructure needs to be managed through integrated network planning and that the model would be a disproportionate way to establish a well-functioning hydrogen market.

Problem Area I also entails the definition and certification of LCH and LCFs. This issue was not directly covered in the public consultation for the present initiative, but in the public consultation for the revision of the RED II as well as the workshops that were organised in the context thereof. The outcomes of that public consultation in relation to LCH and LCF primarily concern the question whether these should be promoted and, if so, how. These outcomes are not pertinent for the present Impact Assessment as the promotion of LCH and LCF is not contemplated herein. Instead, the options in this Impact Assessment relate ‘only’ to the definition of LCH and LCFs and the means of their certification, on which information is more limited. Nonetheless, during the first stakeholder workshop, and answering to a poll, 38% of the respondents took the view that the RED II certification scheme should be extended to all emerging fuels, LCH and LCFs. 23% of the respondents think that GOs should become the only verification of a compliance system, and 21% think that the scope of RED II certification for renewable fuels of non-biological origin should be extended, beyond transport, to all sectors. 18% of the respondents think that the current certification is fit for purpose. Panellists acknowledged the necessity to have a fully-fledged certification system for all renewable fuels and low-carbon fuels across the life cycle. In addition, panellists indicated that adjusting the scope of this system is important to cover all emerging fuels including LCH and LCFs as well as renewable and low-carbon fuels.

Concerning **Problem Area II**, the majority of stakeholders is in favour of facilitating of injection and promotion of biomethane into the grid. Few stakeholders ask for stronger promotion measures such as targets or quotas for RES&LC gases, however, mainly in the context of the revision of the Renewable Energy Directive. Some respondents see the need to improve the current regulatory framework for LNG terminals, including for imports of RES&LC gases. There is also a strong support for the harmonised application of gas quality standards across the EU, for reinforced cross-border coordination and increased transparency. Respondents are more divided on hydrogen blending. Half of the respondents agree that it provides a cost efficient and fast first step to energy system decarbonisation. However, a quarter of respondents underline that blending prevents the direct use of pure hydrogen in applications where its value in terms of GHG-emission reductions is higher (such as industry and transport) and that it creates additional costs at injection and end-users points. Over a third of the respondents support setting national hydrogen blending levels in a standardised and transparent way. A quarter of respondents support setting a harmonised EU-wide allowed cap for hydrogen blends, which TSOs must accept at cross-border interconnection points, as opposed to one third supporting national blending rules. The majority of respondents support establishing EU-level principles for rules on roles and responsibilities for gas quality management for the Member States. Some stakeholders argued for measures that dis-incentivise the use of unabated fossil gases. Few stakeholders did suggest that EU-level guidance for the regional integration of the gas market, including gas market mergers can be a good instrument in the context of dealing with pancaking problem related to cross-border tariffs. Few stakeholders in the public consultation supported an option to remove intra-EU cross-border tariffs. Many respondents, however, were sceptical about such solution arguing that that current cross-border tariff setting is satisfactory and does not require fundamental design change. Some stakeholders advocate to create EU DSO for gases similarly to the single EU DSO established in the electricity sector. Lastly, some stakeholders strongly support the adaptation of energy communities to gas to align it with electricity framework. A majority of stakeholders considered that energy security will remain an important challenge, to be taken into account as renewable and low carbon gases are increasingly used; in addition, new security issues should be taken into account. Only few respondents considered that the current SoS Regulation is fit for purpose in this context; all other respondents consider that this should be amended (either immediately or based on the experience) or that it is flexible enough to cover the new challenges. A majority of responded considered it necessary to establish a comprehensive EU-level legislative framework for cybersecurity for the energy sector (covering the electricity, gas, hydrogen and heating sectors).

In **Problem Area III** (network planning) the majority of stakeholders indicate support to align the timing of the NDPs with the TYNDP and require a single plan irrespective of the unbundling model chosen. Moreover, a vast majority of stakeholders support requiring a joint electricity and gas scenario. Only a few stakeholders are against a joint scenario building. A significant number of stakeholders ask for the inclusion of hydrogen projects in the NDP. Stakeholders most preferred choice as regards the role of Distribution System Operators (DSOs) was to provide and share information. While several stakeholder also support that DSOs provide their own plan including system optimisation across different sectors.

Problem Area IV: In the public consultation, most stakeholders agree that the Gas Directive needs to be modified to better reflect the citizen/consumer focus of the Clean Energy Package for all Europeans and the Green Deal. Some say that mirroring consumer protection and empowerment rights of electricity consumers conferred by the recast Electricity Directive and by 2018 Energy Efficiency Directive would be the most straightforward approach to do so. Some contributors recognised the challenge for the vulnerable and energy poor consumers who rely on fossil fuels as the prices might rise. No respondents explicitly stated their preference for a non-regulatory approach to address current gaps in legislation concerning consumer protection and empowerment.

The vast majority of the stakeholders support the introduction of new legislation that allows for adaptations based on specificities and requirements of Member States' national markets. Stakeholders, most notably the representatives of private sector, support the plans to phase out regulated prices, while at the same time, consumer organizations stress the importance of keeping the targeted price regulation for energy poor and vulnerable consumers. Almost half of all respondents claim that the provisions on comparability of offers and accessibility of data, transparency, smart metering systems, and process of switching should be reinforced in the Gas Directive. Some respondents emphasize mirroring of billing information and energy poverty provisions to ensure consumers are not paying the cost of switching to clean gas based options.

Other consultation activities

Gas Regulatory Forum

The 35th Madrid Forum took place on 29-30 April 2021 in virtual format, gathering over 180 representatives from Member States, national regulatory authorities, gas and electricity transmission system operators, suppliers and traders, end-consumers, network users, gas exchanges and climate and energy NGOs representing civil society.

The Forum discussed how to facilitate the uptake of renewable and low-carbon gases, exchanged on topics related to the regulation of dedicated hydrogen networks and access of renewable gases to the existing methane networks[186]. In more detail, the following was discussed:

[186] For conclusions see: https://ec.europa.eu/info/sites/default/files/energy_climate_change_environment/events/documents/35th_mf_final_conclusions.pdf

- Regarding enabling **access of renewable and low carbon gases** to the existing methane networks (including to wholesale markets, transmission and distribution networks, storage and other flexibility sources) the importance of including the DSO level into the balancing zone of TSOs and enabling connection and firm capacity at DSO level were underlined (while taking into account the size of DSOs and offering de minimis rules where relevant);
- The need for the **abolishment of the regulated tariff** on intra EU Interconnection Points was debated to solve the issue of the so-called tariff pancaking while increasing gas-to-gas competition and helping decarbonising the gas market.
- There was full support for **integrated infrastructure planning** and for alignment between the network planning procedures at European and national levels. It was also discussed that scenarios used for network planning need to be in line with the European Union climate and energy efficiency targets. Further, transparency and stakeholder involvement (including involvement of the distribution system operators) as well as strengthened cooperation between ACER, the ENTSOs and stakeholders were strongly supported.
- In the discussion on the possible **regulatory framework for dedicated hydrogen markets and infrastructure**, there was agreement that the main principles of an appropriate market design for hydrogen should build on the existing EU market design for natural gas. This would include clear separation (unbundling) between regulated network activities and market-based supply and production (including Power-to-Gas) activities, non-discriminatory third-party-access, transparency, customer protection, tariff principles, appropriate supervision and governance and network development based on foreseeable demand (with the aim to avoid stranded assets and considering how to fairly allocate costs of newly built, repurposed or retrofitted hydrogen infrastructure for all consumers).
- There was clear support for a fit-for-purpose regulatory framework for hydrogen that lays the basis for a competitive and efficient pure hydrogen market in Europe with unhindered cross-border trade, including the development of building blocks to kick-start and develop traded markets. Stakeholders called for enabling market rules for the deployment of pure hydrogen by removing barriers for efficient hydrogen infrastructure development, including barriers for repurposing or retrofitting existing methane infrastructure, and addressing the risk the potential natural monopoly character infrastructure may create for the entry of new players and competitive market outcomes.
- Regarding the challenges related to **gas quality management** in the existing gas networks with the injection of biomethane and in particular hydrogen, stakeholder discussion focused on blending. A number of stakeholders, especially system operators and producers expressed their support for injecting hydrogen into the existing gas network, while end-users and NGOs opposed blending, calling for transporting hydrogen exclusively in dedicated hydrogen pipelines to avoid technical difficulties and extra costs (end-users) or lock-in effect enabling the continued use of fossil gases (NGOs).

Electricity Regulatory Forum

The present initiative represents an implementation of the Energy System Integration Strategy and the Hydrogen Strategy. The two strategies were presented and discussed at the 35th Electricity Regulatory Forum (Florence Forum) on 7-8 December 2020[187].

Subsequently, the 36th Electricity Regulatory Forum (14-15 June 2021) discussed the Hydrogen and Decarbonisation of Gas Markets Package initiative[188]. The Forum encouraged the Commission to take full account of electricity market aspects in the ongoing work on the Hydrogen and Gas Markets Decarbonisation package, for instance, in network planning.

Gas Coordination Group

The initiative was presented at the meeting of the Gas Coordination Group (GCG) on 6 May 2021. The GCG is an expert group under Article 4 of the gas SoS Regulation; it is composed of representatives of the Member States, ACER, ENTSOG and representative bodies of the industry concerned and consumers as well as the Energy Community Secretariat.

An open stakeholder workshop was organised during the public consultation period, on 18 May 2021, with the participation of the Commissioner for Energy Kadri Simson and the Director General of DG Energy, Ditte Juul Jørgensen[189]. The workshop gathered nearly 500 attendees connected simultaneously to the virtual meeting from Member States, national regulatory authorities, gas and electricity transmission system operators, suppliers and traders, end-consumers, network users, gas exchanges and climate and energy NGOs representing civil society.

The debate was organised in 4 panel sessions with a participation of a diverse range of stakeholders:

– Session 1 – Building hydrogen market: the regulatory framework
– Session 2 – Implementing sector integration: integrated infrastructure planning
– Session 3 – Renewable and low-carbon gases first: enabling access to the gas networks and markets
– Session 4 – Ensuring free flow of gases: gas quality regulatory framework

The discussion on hydrogen market showed clear support for designing a dedicated hydrogen market based on core regulatory principles with a proven track record in the European energy market. A flexible, step-wise approach with a focus on principles and 'no-regrets' has been also generally favoured for this early stage as opposed to a too detailed regulation. On financing, the participants highlighted that a fair allocation of costs of (newly-built/repurposed) hydrogen infrastructure is required – and has to be clear and balanced with sufficient financing early on. The panellist further identified integration, long-term vision and competition as the main priorities for the future infrastructure development.

The debate about implementing sector integration showed the need for a more integrated and cross-sectoral approach, as also underlined in the ESI Strategy. Further integration including between electricity and gas sectors, transmission and distribution level cooperation will be key for cost-effective decarbonisation. The panellists also stressed that scenario buildings

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187 35th Florence Forum Meeting of the European Electricity Regulatory Forum | European Commission (europa.eu)

188 36th Florence Forum Meeting of the European Electricity Regulatory Forum | European Commission (europa.eu)

189 Workshop: Hydrogen and decarbonised gas markets package | European Commission (europa.eu)

should properly acknowledge the complexity of the energy system. Integrated planning should be fully consistent with climate and energy targets while ensuring efficiency and promoting market functioning. Future planning exercised should be also jointly developed by involving all actors, following supply and demands, and being informed by regional and local conditions.

A general recognition of the benefits that markets can bring to RES&LC integration emerged from the debate. The 'smart' use of regulatory instruments can ensure that gas not only flows from TSO level to DSO level but also the other way around. The participants identified joint optimisation between TSO and DSO levels and access to balancing markets as possible solutions to ensure market access for RES&LC gases. The need to align the Guarantees of Origins system for gases with the existing system, integrating it across sectors and energy carriers was highlighted.

The discussion also underlined the role of LNG terminals and their potential as gateways for renewable and low-carbon gases from abroad. An appropriate, workable regulatory framework should facilitate this option.

Lastly, mixed views emerged on the role of hydrogen blending into the existing gas network. Major concerns regarded value losses for pure hydrogen, increased complexity and cost of gas quality management, impacts on end-consumers and the risk of lock-in effect enabling the continued use of fossil gases. Participants agreed that gas quality handling will be one of the biggest challenges which will require further TSO-DSO cooperation and a clearer cost allocation in the value chain. In this context, the importance of cooperation among all market participants and for regulatory oversight in gas quality was underlined, especially to the protection of sensitive end-consumers

The Commission has established three Working Groups in the context of the Citizens' Energy Forum, dealing with and discussing consumer issues pertaining to 'just transition', 'consumer engagement', and 'consumer protection'. These Working Groups are tackling a series of topics in the gas market that are addressed in the Impact Assessment. On 7 July 2021, the 'consumer engagement' working group has discussed with a series of relevant stakeholders (including regulators, civil society organisations and enterprises) the issue of greenwashing, also in relation to disclosure of primary energy sources in gas billing information. Many stakeholders called for mirroring the protection standard in terms of billing information in the Electricity Market Directive. On 8 September 2021, BEUC will organise the second roundtable, which will focus on the necessity to mirror consumer rights from electricity to gas. In particular, the roundtable discussions will focus on the challenges for consumer rights with digitalised gas (energy) markets/new business models (e.g. third party intermediates like automated switching tools, the need (or not) of smart meters for gas, better protection for bundled offers, digital divide, data protection/cybersecurity).

Stakeholder workshop on gas quality management in the European gas networks

A dedicated stakeholder workshop, organised by external consultants (Frontier Economics), gathered over 300 participants representing (fossil and renewable) gases, electricity and hydrogen producers, network operators, industrial and small end-users, NRAs and ACER, NGOs and academia. Participants discussed elements of a regulatory framework for gas quality management in the existing gas networks to support the integration of renewable and low-carbon gases (including biomethane and hydrogen). Participant strongly supported a harmonised approach to gas quality management and strong cross-border coordination, including on hydrogen blending. Stakeholders confirmed the need for increased transparency and information provision and for clear rules on cost allocation and recovery for gas quality management.

Council/Member States

The present initiative represents an implementation of the Energy System Integration Strategy and the Hydrogen Strategy. The Council adopted conclusions with regard to these strategies on 11 December 2020[190]. In these conclusions the Council underlined that while there are different safe and sustainable low-carbon technologies for the production of hydrogen contributing to rapid decarbonisation, emphasis should be given to hydrogen from renewable sources in view of its key role for the achievement of the decarbonisation objective. The Council called on the Commission to further elaborate and operationalise the EU hydrogen strategy, including making good use of the internal energy market's main principles to ensure competitiveness and well-balanced investment signals when developing a fit-for-purpose approach to the regulation of emerging hydrogen markets. Further, to ensure the interoperability of natural gas transport and storage systems as well as of hydrogen transport and storage systems, including by norms and technical standards. The Council also invited the Commission to improve the framework for the Ten-Year Network Development Plan (TYNDP) to include gaseous hydrogen and efficient integration interfaces between hydrogen, methane-based gas and electricity network planning.

The Commission presented the as well public consultation document at the Energy Working Party on 28 April 2021. Some Member State representatives pointed to the uncertainty of the development of hydrogen markets and networks, calling for caution in setting a regulatory framework, while also stressing the need for a regulation already from early on (DE). Others underlined the importance of clear rules on gas quality for the existing gas network while respecting specific pathways chosen by the Member States (e.g. for odorisation) and supported assessing the need for revising the tariff regulation by shifting tariffs from EU-internal to external borders. Other topics raised were the need to ensure sector integration by integrated network planning between electricity, gas and hydrogen networks. Delegations underlined the need for a definition of low-carbon gases and pointed to the need for a robust certification system for the promotion of renewable gases, allowing for traceability, including from third countries.

The initiative was discussed further during the Directors General for Energy (from Member States) meeting on 17 May 2021, where all Member States expressed their views, in particular on four predefined questions:

1. How should future dedicated hydrogen networks be regulated at EU-level: similar to existing gas market regulation or rather through high-level principles?
2. Who should be allowed to own and operate hydrogen pipelines, should a joint regulatory asset base for hydrogen and gas networks be allowed?
3. How could the revised gas legislation facilitate the access of renewable gases to the gas market? How could tariff setting improve this?
4. How can EU-rules help avoid market fragmentation due to gas quality differences, including renewable and low-carbon gases injection?

190 *st13976-en20.pdf (europa.eu)

On the question of the regulatory framework for the future dedicated hydrogen networks, most Member States expressed the view that the principles of the EU natural gas legislation (unbundling, third-party access, transparency) could serve as a basis while some MS underlined the need for providing legal certainty from the outset. The majority of Member States see a role for system operators (TSOs and DSOs) in operating dedicated hydrogen infrastructure. Many suggested avoiding a joint regulatory asset-base and cross-subsidisation between the gas and hydrogen sectors while a small number of delegations favoured allowing this option. On facilitating the access of renewable and low-carbon gases to the gas market, many Member States underlined the importance of a certification and guarantees of origin system, mentioning also the role of tariffication, support schemes.

The clear majority of Member States supported the blending of hydrogen into the existing gas network. Especially Western European Member States urged for setting an allowed cap to support blending and the development of hydrogen markets, while a group of Eastern European Member States called for an allowed cap as an option for decarbonisation. A smaller group of delegations expressed prefer avoiding blending while two Member States clearly refused this option as blending is diminishing the value of hydrogen and risk of prolonging the use of natural gas (lock-in effect).

The majority of Member States agreed on the need to address issues around gas quality at EU-level to ensure unhindered cross-border gas flows and interoperability across markets, while allowing flexibility for taking into account national differences.

A few Member States raised the issue of the possibility to abolish the regulated tariff on intra-EU IPs that could help to decarbonise the gas market, while at the same time increase gas-to-gas competition and solve the issue of the so-called tariff pancaking.

European Parliament

The present initiative represents an implementation of the Energy System Integration Strategy and the Hydrogen Strategy. On 18 March 2021, Parliament's Committee on Industry, Research and Energy (ITRE) adopted own-initiative reports on both strategies[191]. The Parliament supports – in broad lines – the Commission’s hydrogen strategy, including the identified lead markets, the different support mechanisms identified, and the general direction for markets and infrastructure provisions. This opinion calls for coherent, integrated and comprehensive regulatory framework for a hydrogen market. In that context gas market design and the Clean Energy Package could serve as basis and example for the regulation of the hydrogen market. The opinion on Energy System Integration Strategy calls inter alia on the Commission to take the necessary measures to safeguard the well-functioning of energy markets and to align consumer rights in the gas and district heating sectors with those of electricity consumers.

National regulatory authorities

The Commission exchanged on the initiative and sought the input of national regulatory authorities regularly during the public consultation period, in particular in the frame of the Board of Regulators and the Gas Working Group meetings of the Agency for the Cooperation of Energy Regulators (ACER).

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191 REPORT on a European Strategy for Hydrogen (europa.eu); REPORT on a European strategy for energy system integration (europa.eu)

ACER and CEER (Council of European Energy Regulators) adopted various papers based on consultations with national regulatory authorities, notably:

– Bridge beyond 2025, conclusions paper
https://acer.europa.eu/Official_documents/Acts_of_the_Agency/SD_The%20Bridge%20beyond%202025/The%20Bridge%20Beyond%202025_Conclusion%20Paper.pdf

– Regulatory treatment of Power-to-Gas: second Paper in the ACER/CEER European Green Deal Regulatory White Paper series
https://www.acer.europa.eu/Media/News/Pages/Regulatory-treatment-of-Power-to-Gas-second-Paper-in-the-ACERCEER-European-Green-Deal-Regulatory-White-Paper-series.aspx

– When and How to Regulate Hydrogen Networks? 'European Green Deal' Regulatory White Paper series (paper #2)
https://www.acer.europa.eu/Official_documents/Position_Papers/Position%20papers/ACER_CEER_WhitePaper_on_the_regulation_of_hydrogen_networks_2020-02-09_FINAL.pdf#search=Paper%20in%20the%20ACER%2FCEER%20European%20Green%20Deal%20Regulatory%20White%20Paper%20series

Annex 3: Who is affected and how?

Practical implications of the initiative

Table 21: Practical implications of the preferred policy option for each Problem Area

Problem Area	Preferred option	Practical implications of the preferred option of initiative by stakeholder
Problem Area I: Hydrogen infrastructure and markets	**Option 2b:** 'Main regulatory principles with a vision'	Access of **hydrogen producers** to (regulated) pipeline networks is ensured although in the market ramp-up phase producers have to negotiate the concrete terms of their access (including tariffs) with network operators. This might initially require additional resources in comparison with the situation post-2030 in which regulated tariffs would apply. Gas quality requirement will likely have an indirect effect on hydrogen **producers** in terms of the hydrogen quality they can inject in the network. Hydrogen producers will need to comply with (relatively light) consumer rights requirements. **(Industrial) hydrogen consumers** that are directly connected to the hydrogen transmission network have to negotiate the concrete terms of access with network operators in the market ramp up phase. This might initially require additional resources in comparison with the situation post-2030 in which regulated tariffs would apply. Hydrogen end-users might still face some additional cost to adapt the quality of hydrogen before its final use. **Regulated hydrogen network operators** (e.g. existing natural gas TSOs that want to pursue hydrogen network activities by repurposing natural gas pipelines) would not be allowed to own and operate hydrogen production facilities or to pursue hydrogen supply activities. Operators that are currently already ownership unbundled[11] are expected to be confronted with low, if any, administrative costs. However, operators that are not yet ownership unbundled can face administrative burden when they have to ensure convergence to the envisaged ownership unbundling or ISO model after the transition phase. However, administrative costs for ownership unbundled undertakings will be lower as there is a clearer separation of economic activities and accordingly less reporting needs to show compliance with the unbundling principles. Hydrogen network operators will have to comply with the obligation of granting negotiated third-party access (based on freely negotiated tariffs) and, later on, of granting regulated third-party access based on regulated tariffs that will be phased in post-2030. Hydrogen network operators will have to adhere to hydrogen quality standards at cross-border points and provide information on hydrogen quality to consumers. **Private hydrogen network operators** may be exempted from regulation and would then only be affected by convergence criteria and subsequently the obligations applicable to regulated network operators once such exemptions expire and/or they decide themselves to become part of the regulated network.

[11] Of the 60 gas TSOs certified by 2019, 30 (50%) are ownership unbundled.

Problem Area	Preferred option	Practical implications of the preferred option of initiative by stakeholder
		Natural gas consumers in those Member States that allow operators that pursue both hydrogen and natural gas network activities to create financial flows between natural gas and hydrogen asset bases might see an increase of their gas bill. This impact can be contained by allowing such flows under conditions and NRA control. **Operators of large scale hydrogen storage** have to show compliance with the requirement to grant regulated third-party access on the basis of regulated tariffs and potential other criteria that will be set under the regulated access regime. **Terminal operators** have to negotiate the terms of access to their facilities with customers that are interested in access. **National regulatory authorities (NRAs)** would face additional workload in the form of implementing and monitoring the requirements on hydrogen network operators, including as regards unbundling, the obligation to grant negotiated and (as of 2030) regulated third-party access, the setting or approval of regulated tariffs (as of 2030), the application of the hydrogen quality management framework and network planning at national and EU level. NRAs would also be involved in the administration of and decision-making on exemption requests for new or existing hydrogen networks, storage facilities and liquid hydrogen terminals, and the monitoring of possible derogations for specific types of hydrogen networks. The scale of these additional tasks will be dependent on the development of hydrogen supply chains in each Member State and is expected to rise gradually over the coming years. The application of the EU-level hydrogen quality management framework will imply administrative costs of implementation for the involved regulatory authorities (not necessarily NRAs) or other relevant Member State authorities (Ministries). However, the harmonised rules limit the risk and administrative impact of cross-border disputes. ACER's mandate will be extended to monitoring and reporting on the internal hydrogen market on an annual basis after the adoption of the proposals. Additional workload for ACER will mainly depend on which empowerments are envisaged for more detailed technical rules (network codes) and on the specificities of the envisaged governance system. At least in the short to medium term, the work on hydrogen would come on top of the ongoing tasks under the regulatory framework for (natural) gas. **Tax payers** might benefit from the option of financial flows between users of the hydrogen and the natural gas grid as it decreases the need to finance the initial development of hydrogen transport infrastructure via direct subsidies.
Problem Area II: Renewable and low carbon gases, and	**Option 3**: Allow and promote RES&LC gases full market access, security, tackle issue of	Biomethane **producers** are expected to benefit from access to the wholesale market and the reverse flow compressor obligation as such measures reduce uncertainty for grid injection increasing the potential for marketing and stable production. **Producers** of renewable gases will also benefit from reduced risks and costs

Problem Area	Preferred option	Practical implications of the preferred option of initiative by stakeholder
energy security	long term supply natural gas contracts and remove cross-border tariffs for RES&LC gases	linked to cross-border tariffs. **Producers** of renewable gases benefit from reduced risks linked to grid connection and interruption of gas injection linked to potential grid bottlenecks. Removal of grid injection tariffs would only have a marginal effect on producers. The **shippers** of natural gas would need to avoid long-term supply contracts for natural unabated gas and will find more flexible contracts with shorter duration. The gas **consumers** would see a slight increase of their gas bill on a long term because of the increase in gas contract prices compared to a situation where long-term contracts for natural gas would not be affected. **Consumers of gas** are also likely to face an increase in costs of gas as the connection obligations bring about an increase in overall costs. **Taxpayers** may, however, benefit from a potential decrease in specific support scheme costs as these costs will be covered by consumers of gas. Strengthened cross-border coordination on gas quality and establishing national allowed levels for hydrogen blends will imply administrative costs for **TSOs, Member State authorities and NRAs**. **Businesses** will have to ensure their equipment can withstand the level of blending (system operators and end-users). Depending on the hydrogen blending levels of their countries, **end-users** (mostly **industrial consumers**) will need to adapt their equipment. They will most likely also bear some of the grid adaptation costs linked to the deployment of blended hydrogen. For blending levels of the preferred option beneath and at 5% adaptation in the chemical and glass industries would be required, for blending shares between 5% and 10% gas turbines and industrial high temperature applications will have to be adapted, 20% implies adaptations of combined heat and power plants and blending beyond 20% requires the installation of new boilers. The application of the EU-level gas quality management framework will imply administrative costs of implementation for **NRAs** and other Member State authorities (Ministries). However, the harmonised rules – either through high-level principles or specific rules – limits the risk and administrative impact of (cross-border) disputes. Efficient energy security arrangements, fit for the future needs and risks, will benefit the society at large, and in particular the **protected customers** (mainly, households and essential services). The new rules will add legal certainty and thus facilitate the tasks of **public administrations** involved in the emergency preparedness and crisis management as well as **Ministries** responsible for energy policy, **NRAs** and other **'competent authorities'** under the SoS Regulation. The measures will streamline efforts in case of the crisis, making emergency measures, including solidarity gas more efficient.

Problem Area	Preferred option	Practical implications of the preferred option of initiative by stakeholder
		An increase in biomethane production creates **2 000 to 4 000 additional local jobs** and local added value. **TSOs/DSOs** are likely to face a limited increase in efforts due to the connection obligation as system operators would in any case need to take care of grid connection. All TSOs and DSOs would need to comply with the applicable allowed hydrogen blending cap defined by EU rules that would represent important adaptation costs for any threshold chosen. **LSOs** would be directly impacted by the obligation of improving their transparency and access to their terminal, which can increase their administrative costs, but at the same time increase their revenues thanks to a higher load factor. **NRAs** would have to ensure compliance with the measures in this option. Regarding connection obligation with firm capacity, NRAs need to adapt the rules and specificities of the firm capacity obligation (e.g. regarding the level of capacity to be guaranteed). Reduction/removal of injection tariffs requires NRAs to review the cost reallocation and its inclusion in the calculation of grid tariffs. The administrative exchanges between NRAs and natural gas shippers should increase to ensure the correct application of the measures on the long-term contracts. LSOs may face administrative costs to comply with the testing the demand for access of renewable and low carbon gases to the terminals. In case two or more NRAs have to take joint decisions, e.g. on gas quality, **ACER** would need to take the decision should the NRAs not agree. A harmonised EU approach on gas quality management would need to be implemented, or at least monitored and coordinated, by **ACER**.
Problem Area III: Network planning	**Option 2**: National Planning based on European Scenarios	**Producers** of renewable and low-carbon gases might benefit from a more comprehensive grid planning that integrates in particular the fact that gas flows might reverse compared to today, from distribution to transmission grid level (reverse flows), injections taking place from domestic sites and less from external imports. **Gas TSOs** would be required to substantially increase their coordination efforts with electricity TSOs as well as with LSOs/SSOs and DSOs. It is important to note that a too strong integration could oppose functional unbundling. **NRAs** would need to outline which elements of the scenario building should actually be harmonised, which stakeholders need to be directly involved and how to treat hydrogen in the plans (one-off implementation costs). **ACER** would have a continued role to ensure compliance with the European Plan.

Problem Area	Preferred option	Practical implications of the preferred option of initiative by stakeholder
Problem Area IV: Consumer protection and engagement	**Option 3**: Flexible legislation addressing all problem drivers	**Consumers** will benefit from better information, in particular on their consumption patterns. They will face lower financial and technical barriers to switching, and overall competition will allow them to reduce energy costs. Any consumer prices rises in the Member States phasing out price regulation would reflect previous below cost prices which encourage excess consumption of energy. Targeted measures would continue to be available for the energy poor or vulnerable consumers. Consumers would also benefit from higher levels of service and greater availability of value added products. Suppliers would benefit from increased access to the market of the Member States setting **regulated prices** above cost level for households and micro-enterprises, or phasing out blanket price regulation for large, small and medium-sized enterprises. However, **suppliers** would also likely face increased pressure on margins as the result of the modestly greater consumer engagement expected. Certain suppliers may need to adjust contractual conditions and reformat their consumer bills in order to comply with new requirements. However, this would be minimised where these requirements follow what is already in place for electricity. **New entrants** and **energy service companies** offering innovative products would benefit from quick and non-discriminatory access to data, as also supported by smart metering as well as access to consumers thanks to improved switching processes. As **TSOs and DSOs** are normally the market actors charged with data management, would need to implement further measures to ensure non-discriminatory data handling. Such costs are expected to be passed through to final customers. **NRAs** in the Member States phasing out price regulation will need to step up efforts to monitor compliance. However, these impacts may be offset by increased consumer engagement in the form of energy communities, which would naturally foster competition in the market. **ACER** would need to enhance its monitoring of retail prices and of the compliance with consumer rights in EU legislation.

Summary of costs and benefits

Table 22:Problem Area I: Hydrogen infrastructure and hydrogen markets.

Overview of Benefits, (total for all provisions) – Preferred Option (Option 2b: 'Main regulatory principles with a vision')		
Description	*Amount (if possible, otherwise qualitative statement)*	*Comments*
Direct and indirect benefits		
Economic impacts	The preferred option is expected to have the strongest economic impacts and be most efficient and effective. Lowering total hydrogen supply costs by 14-22% leading to savings of €3,0-4,6 bn/year across the EU for a total consumption of 5 Mt per year.	See also *Table 31*
Environmental impacts	Fostering the emergence of hydrogen infrastructure and efficient markets enables one of the pathways to decarbonise the gas sector. Networks and large scale storage are likely to benefit renewable hydrogen producers in as location and production profiles of renewable hydrogen production facilitates are unlikely to match end-user requirements.	

		Overview of costs – Preferred option						
		Total costs	Citizens/Consumers		Businesses		Administrations	
			One-off	Recurrent	One-off	Recurrent	One-off	Recurrent
	Costs	Additional investments in cross-border pipelines	€100- 200 m					

Table 23: Problem Area II: Renewable and low carbon gases in the existing gas infrastructure and markets, and energy security

Overview of Benefits, (total for all provisions) – Preferred Option (Option 3: Allow and promote RES&LC gases full market access, security, tackle issue of long term supply natural gas contracts and remove cross-border tariffs for RES&LC gases)		
Description	*Amount (if possible, otherwise qualitative statement)*	*Comments*
Direct and indirect benefits		
Economic impacts	Entry-exit zones including DSOs: up to €10 m/year of savings in public support costs; Enabling physical reverse flows: up to €45 m/year saved in purchasing natural gas and €18 m/year for emission rights	See study 'Assistance to assessing options improving market conditions for bio-methane and gas market rules'.
Environmental impacts	The option allows to meet the 55% GHG emission reduction target.	

		Overview of costs – Preferred option						
		Total costs	Citizens/Consumers		Businesses		Administrations	
			One-off	Recurrent	One-off	Recurrent	One-off	Recurrent
	Costs	Reverse flow compressors			€70 m	€3 m		

Table 24: Problem Area III: Integrated network planning

Overview of Benefits, (total for all provisions) – Preferred Option (Option 2: National Planning based on European Scenarios)		
Description	*Amount (if possible, otherwise qualitative statement)*	*Comments*
Direct and indirect benefits		
Economic impacts	Higher interlinkages between gas and electricity scenarios under the preferred option would ensure a common vision of the different stakeholders implying that investment decisions are more aligned, avoiding conflicting or redundant investments, thereby savings in societal costs.	
Environmental impacts	Integration of networks as envisaged by the preferred option would lead to significant emission reductions resulting in a reduction of the footprint of the overall energy system on the environment.	

		Overview of costs – Preferred option						
		Total costs	Citizens/Consumers		Businesses		Administrations	
			One-off	Recurrent	One-off	Recurrent	One-off	Recurrent
	Costs	Preferred option reduces the risk of potential lock-ins or stranded assets.	NA	NA	NA	NA	NA	NA

Table 25: Problem Area IV: Low level of customer engagement and protection in the green gas retail market

Overview of Benefits, (total for all provisions) – Preferred Option (Option 3: Flexible legislation addressing all problem drivers)		
Description	*Amount (if possible, otherwise qualitative statement)*	*Comments*
Direct and indirect benefits		
Economic impacts	Although no quantitative assessment is possible, substantial economic benefits are expected from the preferred option, retail competition would be improved and customers would have better information on consumption and energy sources. The phase-out of blanket **price regulation** will benefit to small and medium-sized retail suppliers and consumers.	Energy poor and vulnerable benefit from additional protection measures, smaller companies will benefit from price deregulation and market opening, engaged consumers benefit from measures on price comparison tools and switching related fees.
Environmental impacts	Taken together the proposed measures will help consumers make greener choices and energy communities-of-interest would contribute to the uptake of bio-methane and low-carbon gases, which will have a potential positive impact on the environment.	Benefits derived from decarbonisation for present and future generations of consumers.

		Overview of costs – Preferred option						
		Total costs	Citizens/Consumers		Businesses		Administrations	
			One-off	Recurrent	One-off	Recurrent	One-off	Recurrent
	Costs	NA		Higher energy prices in some Member States due to price deregulation.	Supplier costs associated with modifying consumer bills or adjusting contractual conditions.	Cost of supplying at regulated prices to energy poor and vulnerable households. Suppliers will also face costs related to restriction on	Costs for public authorities associated with running certification scheme for price comparison tool, or to run	NRA faces increased costs derived from enhanced efforts to monitor the market, guarantee consumer protection, and

						contract termination fees.	one independently.	ensure effective competition. Data protection authorities may face increased costs derived from implementation of the envisaged measures on data.

ANNEX 4: ANALYTICAL METHODS

This Annex describes the methodologies, tools and data sources used for the quantitative analysis and presents detailed results.

Description of the model used

METIS[12] is a mathematical model for the European electricity, gas and heat systems. It simulates the operation and the related markets for these energy carriers on an hourly basis over a year, while also factoring in uncertainties like weather variations. The original model, which was developed by a consortium, is currently further enhanced with a detailed representation of electricity networks as well as the introduction of hydrogen as an energy carrier. METIS is used by the European Commission to support evidence-based policy making in the field of electricity and gas and has been used to prepare the Commission's proposals for a new energy market design as well as renewable energy and energy security issues.

The model relies on Artelys Crystal Super Grid Platform[13], which provides a user interface and scripting capabilities to extend the software. The user interface forms the interface between the description of a model and the mathematical solver for linear problems. The main functionality is organised in several modules.

Power system

The power system is represented by a network in which each node stands for a geographical zone[14] that can be linked to other zones with power transmissions. At each node are attached assets that represent all consumption and production of energy at this node. The model aims at minimising the overall costs of the system to maintain a supply-demand equilibrium at each node, at an hourly time step. While the typical METIS models are at country-granularity, zones can also be configured to stand for either NUTS2 zones or for aggregations of country, depending on the needs of the study.

The METIS Power System Module contains a library of assets for production, consumption and transmissions that can be attached to each node of the network. The production units include nuclear, thermal fossil (mainly coal and gases), hydropower and renewable units as well as storage technologies (batteries, compressed air, pumped hydropower). Run-of-river power plants, inter-seasonal storage dams/reservoirs and pumped hydro storage units are modelled separately. The model further describes power consumption at each node, power transmission between nodes, fuel contracts (if applicable), water inflow into hydro reservoirs, reserve requirements and loss of load.

Simulations of the power system in METIS aim at determining a cost-minimising production plan that ensures a supply/demand equilibrium at each node over the study period, at an hourly time step. This is done by solving an optimisation problem.

Gas system

The gas system is represented as a network in which each node stands for a couple (geographical zone, energy). Geographical zones can be linked to one another with

12 Detailed documentation of the METIS model, reports and model input files can be downloaded from DG ENER's website: https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en
13 Information can be found on the vendor's website: https://www.artelys.com/crystal/super-grid/
14 Depending on the spatial granularity, a zone may be a subnational region, a country, a set of countries aggregated into one, etc.

transmissions (e.g. pipelines to exchange gas). Energies represented in the gas module are gas (representing natural gas), LNG. At each of the nodes, assets are attached. These assets represent all supply and withdrawal of energy at this node. The model aims at minimizing the overall cost of supplying the demand at each node and at each time steps.

Assets available for gas system modelling in the METIS asset library include gas production, gas storage, LNG terminals, LNG imports, LNG exports, LNG liquefaction trains, gas imports, gas exports, (import) pipelines, CO2 emissions and gas consumption.

Simulations of the gas system in METIS consists in finding a cost-minimising production plan that ensures a supply-demand equilibrium at each node over the study period, using a daily time step. As in the case of electricity, this is done by solving an optimisation problem:

Optimisation process

METIS simulations consist in an optimisation of the production plan over a year, at an hourly time step. For that purpose and in order to take into account operational myopia (rather than a perfect foresight approach), the optimisation problem is solved for power systems using a rolling horizon approach. The solution for the whole period is obtained by solving iteratively smaller problems. Gas system models are solved in a single run, by jointly optimising all days of the year in order to properly capture the annual management of gas storage facilities.

Description of the scenario definition methodology

PRIMES MIX-H2 scenario

The METIS modelling context used throughout this assessment is derived from the MIX-H2 PRIMES scenario, which underpins the Impact Assessment supporting the proposal for a revised Renewable Energy Directive. This PRIMES projection is aligned with the Hydrogen Strategy, in which 40 GW of renewable hydrogen electrolysers are operational in the EU by 2030. The projection also assumes that hydrogen can be traded on markets and across the borders of Member States.

PRIMES[15] is an EU energy system model that provides detailed projections of energy demand, supply, prices and investment to the future, covering the entire energy system including emissions for each individual European country and for Europe-wide trade of energy commodities. PRIMES scenarios are driven by current and announced policies from which the model derives trajectories for investments and usage. The MIX-H2 scenario, reflects the underlying policies driving the transition to GHG neutrality as proposed in by the Fit for 55 initiative.

The METIS assessment extends the MIX-H2 PRIMES scenario by exploring selected elements of the energy system in detail (e.g. options for different hydrogen pipeline deployment) while preserving the relationships between energy supply and demand. The METIS model optimises the dispatch of the electricity system and performs a joint dispatch and capacity optimisation for electrolysers, hydrogen storages and additional renewable energy sources required to produce hydrogen. This allows quantifying the optimal use of and investments in energy infrastructure.

15 A more detailed documentation on the PRIMES model is available under: https://e3modelling.com/wp-content/uploads/2018/10/The-PRIMES-MODEL-2018.pdf

Derivation of BAU and policy scenarios from PRIMES MIX-H2 scenario

Based on the year 2030 demand and supply assumptions for gaseous energy carriers in the PRIMES MIX-H2 scenario, a number of METIS scenarios are created in order to capture the impact of the different policy options explored in the respective problem areas. These scenarios are compared to a Business as usual (BAU) scenario, which projects the current status of gas market regulation (the policy baseline for this Impact Assessment). The step to derive a policy baseline (BAU) and policy scenarios from the PRIMES MIX-H2 scenario is needed as the PRIMES MIX-H2 scenario implicitly assumes the existence of cross-border infrastructure and trade of hydrogen as well as (other) renewable and low-carbon gases. The PRIMES MIX-H2 scenario assumes that at least some of the policy measures assessed in the present Impact Assessment would already be implemented. In contrast, the baseline scenario excludes cross-border hydrogen transport. Baseline and policy scenarios are quantified with the help of the METIS model, comparing different grid access and uptake scenarios that reflect the implementation of policy options.

The individual approaches for Problem Areas I and II are further explained in the following sections. Some methodological differences between the Problem Areas I and II result from the different modelling scope needed to address gas and hydrogen. While the METIS gas module captures the options related to renewable and low carbon gases of Problem Area II, an integrated model for electricity and gas is required for assessing the impacts of hydrogen related options in Problem Area I. Due to the different modelling approaches, some numerical results may diverge.

Modelling approach to Problem Area I

Cross-border scenarios

Four different scenarios are considered for the European hydrogen grid, as shown in the table below.

Table 26: Hydrogen network scenarios for the assessment with the METIS model

Scenario	Minimum cross-border capacity	Maximum cross-border capacity	Optimisation of cross-border capacity	Most likely to happen in regulatory option
Business as usual (BAU)	None	0	No	0 or 1
A constrained	EHB 2030	None	No	2a,2b, 3a,3b (lower end)
A optimised	EHB 2030	None	Yes	2a,2b, 3a,3b (higher end)
B optimised	EHB 2035	None	Yes	additional drivers

The Business as usual (BAU) scenario assumes no cross-border transport of hydrogen via pipeline except for existing commercial pipelines. This reflects the expected situation under regulatory Options 0 and 1, where a lack of European regulation could prevent the execution of projects.

Scenarios 'A constrained' and 'A optimised' assume cross-border capacity based on the updated 2021 European Hydrogen Backbone (EHB)[16] 2030 vision for dedicated hydrogen infrastructure in Europe. Capacities are fixed in scenario 'A constrained' while the METIS

16 Guidehouse (2021). Extending the European Hydrogen Backbone: a European hydrogen infrastructure vision covering 21 countries. Utrecht: Guidehouse.

model may add additional cross-border interconnections in scenario 'A optimised'. These two scenarios represent the respective lower and higher ends with respect to network investments if sufficient regulation allow for cross-border connections, such as in regulatory Options 2a, 2b, 3a, and 3b.

Scenario 'B optimised' increases the minimum cross-border capacity to European Hydrogen Backbone (EHB) vision for the year 2035. This scenario corresponds to a very high roll-out of cross-border hydrogen networks leading to an oversized hydrogen network with low utilisation rates. Such a scenario is not expected to materialise if driven alone by the regulatory options considered but would require additional drivers.

Main modelling assumptions and variables

For the demand side, the METIS context uses PRIMES output with some necessary adaptations. The energy demand per carrier is decomposed into different end use sectors, allowing to account for thermosensitivity. Gas demand is corrected for gas based power generation as the latter is optimised by the METIS model. The demand for green hydrogen, including the production of renewable fuels of non-biological origin (RFNBOs) is directly taken from the PRIMES model output. Demand for hydrogen from steam methane reforming that is currently produced and consumed within chemical complexes is not included in the METIS model. However, the hydrogen demand in 2030 in the MIX-H2 scenario includes the use of green hydrogen in refineries and the chemical industry. Moreover, the scenario does not assume the use of hydrogen produced from steam methane reforming with carbon capture and storage (CCS).

The METIS context takes directly from PRIMES the installed generation capacities for fossil, nuclear, biomass, geothermal energy as well as PRIMES assumptions on fuel prices (coal, gas, oil). An EU ETS price of EUR 45,5/tCO2 is used throughout all model runs. Capacities for the generation from PV, wind onshore and wind offshore are used as a lower bound in METIS. The model is allowed to increase solar and wind capacities if these are economic.

Installed capacities of electrolysers are optimised by the model while respecting minimum capacities, given by the Member States national hydrogen strategies. The 2035 values of the PRIMES MIX-H2 scenario provide an upper bound for electrolyser capacities.

Cross-border capacities follow the modelling logic of variable renewables. A minimum capacity is defined by different scenarios, which are derived from studies. Unless prohibited by the scenario definition (as in BAU or 'A constrained'), additional cross-border transport capacities are optimised by the METIS model.

Modelling approach to Problem Area II

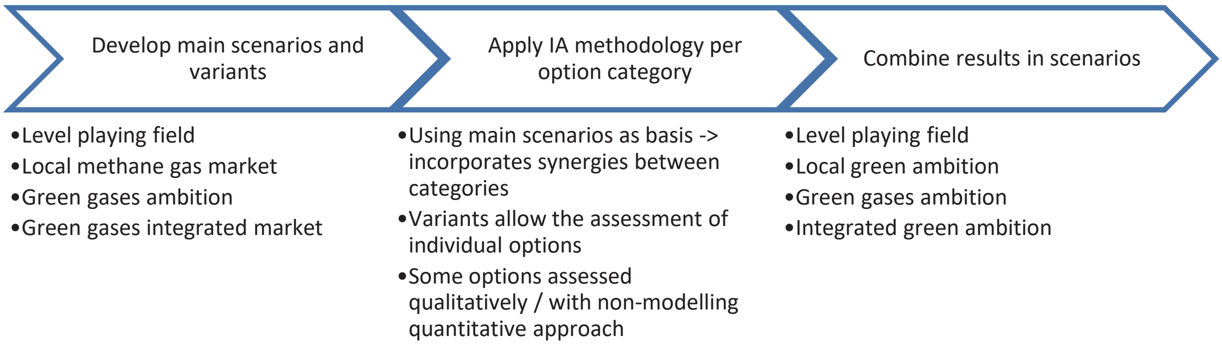
Description of the general assessment methodology

The definition of the number of scenarios and variants for Problem Area II considered the following criteria:

- Assuring the representation of the main gas sector storylines of interest to DG ENER, namely regarding the dimensions of:
    - The existence of a level playing field for gas (natural gas as well as renewable and low-carbon gases) and broader energy market participants, concerning different gas/energy carriers, network levels, and market participant type;
    - The existence of measures promoting renewable and low-carbon gases;

- The level of integration of the methane gas market (i.e. centralised vs. local);
- Ensuring that all policy options can be individually assessed through the modelling work and/or qualitatively;
- Manageable number of main scenarios and variants to account for modelling constraints.

Figure 11: Overall process for developing and accessing scenarios



The following sections describe the approaches for the different policy topics and measures

Assessment of biomethane potentials and cost estimations

The biomethane potential is derived by combining a European dataset on substrate-specific potentials available at Fraunhofer IEE and assumptions on conversion pathways. The dataset is based on three studies from the JRC[17], BiomassFutures[18] and S2Biom[19] cost supply. The JRC study is used for all manure potentials. The Biomass Futures study is used for other substrates for anaerobic biomethane production. The S2Biom study is used for all lignocellulosic biomass potentials.

All substrates mentioned above could be used to produce biogas and biomethane (as the first step of biomethane production is biogas production). In this assessment an allocation of substrates between biomethane and biogas technologies has been performed (see *Table 26*) CORINE land cover20 projection data are then used to regionalise substrate-specific potentials from the country level to the NUTS1 level. projection data are then used to regionalise substrate-specific potentials from the country level to the NUTS1 level.

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[17] Scarlat, Nicolae; Fahl, Fernando; Dallemand, Jean-François; Monforti, Fabio; Motola, Vicenzo (2018): A spatial analysis of biogas potential from manure in Europe. In: Renewable and Sustainable Energy Reviews 94, S. 915–930. DOI: 10.1016/j.rser.2018.06.035.

[18] Elbersen, B. S., Staritsky, I. G., Hengeveld, G. M., Schelhaas, M. J., Naeff, H. S. D., & Böttcher, H. (2012): Spatially detailed and quantified overview of EU biomass potential taking into account the main criteria determining biomass availability from different sources. Atlas of EU biomass potentials (IEE 08653 S12.529 241). Online available at https://research.wur.nl/en/publications/atlas-of-eu-biomass-potentials-spatially-detailed-and-quantified-, last approved 15-04-2021.

[19] Dees M., Höhl M., Datta P., Forsell N., Leduc S., Fitzgerald J., Verkerk H., Zudin S., Lindner M., Elbersen B., Staritsky I., Schrijver R., Lesschen J.-P., van Diepen K., Anttila P., Prinz R., Ramirez-Almeyda J., Monti A., Vis M., Garcia Galindo D., Glavonjic B. (2017): Delivery of sustainable supply of non-food biomass to support a 'resource-efficient' Bioeconomy in Europe.

[20] CORINE Land Cover — European Environment Agency (europa.eu); Bevölkerung am 1. Januar nach Alter, Geschlecht, Art der Vorausberechnung und NUTS 3 Regionen - Produkte Daten - Eurostat (europa.eu)

Landfill gas potentials are heterogeneous across Europe, as waste treatment techniques vary across Member States. There are countries without landfills, countries with proportionate incineration and proportionate landfill, countries with a high proportion of mechanical-biological plants for the pre-treatment of mixed waste (the aim is to reduce the biological activity of the organic fraction in household waste to such an extent that as little landfill gas as possible is produced). By 2035, landfilling of municipal waste generally is expected to be limited to 10% in Europe, and waste treatment will mainly rely on waste incineration and mechanical-biological waste treatment (biogas) but no more landfilling. Based on historical data, gas volumes are extrapolated to 2050, assuming that landfill gas continues to decline and is therefore not available for biomethane production.

Table 27: Allocation of substrates to biomethane and biogas technologies

Technology	**Substrates**

Biogas - on-site power and heat generation	- Manure
	- Phasing out existing plants:
	  o Corn
	  o Sewage gas, landfill gas

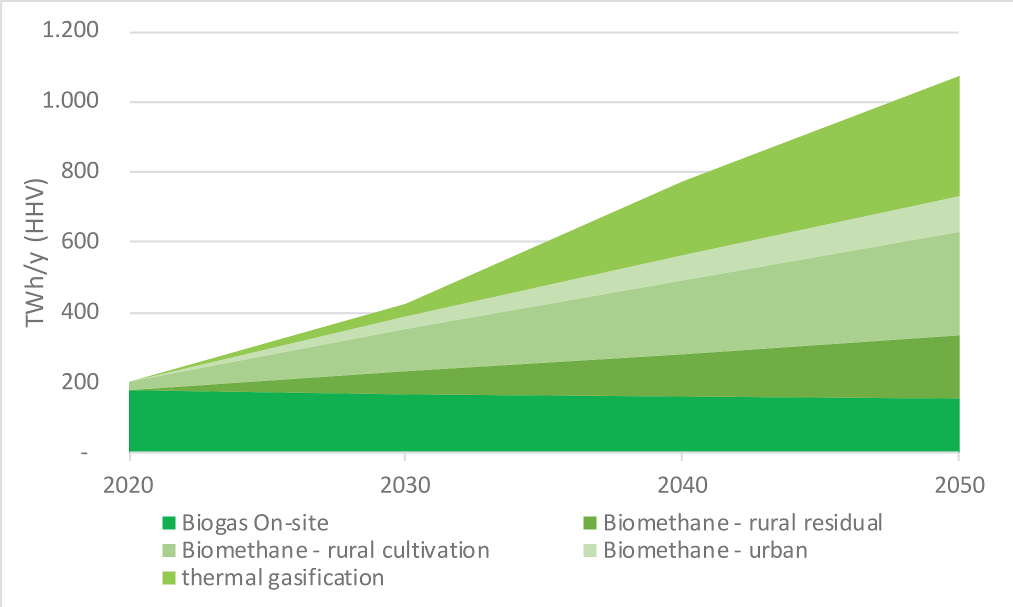
Biomethane Anaerobic digestion - rural residues	- Straw - Grass cuttings abandoned grassland - Animal waste
Biomethane Anaerobic digestion - rural cultivation	- Perennials: grassy - Sequential cropping - Phasing out existing plants: corn
Biomethane Anaerobic digestion - urban	- Common sludge - Sewage gas - MSW (not landfill, composting, recycling) - Verge grass
Biomethane – thermal gasification	- Stem wood from thinning and final fellings - Logging residues from final fellings (tops and branches mainly) - Stumps from final fellings

Sewage gas production is currently implemented with varying intensity in Europe. Historical data is used and updated, assuming a comparable penetration in relation to population expectations in 2050, which will establish itself in the long term at the high level of countries that have already implemented sewage gas intensively today.

In 2020, sewage gas is part of biogas on-site electricity and heat generation. In year 2050, sewage gas is assumed to be used at 100% for biomethane production. This builds upon the hypothesis that in the long term the incentives for generating electricity for on-site consumption will be lower, that the sewage treatment plants can therefore be supplied with electricity from external sources and the heat can be provided efficiently via heat pumps. A higher proportion of the plants are large plants and the gas infrastructure for the feed-in of biomethane will be available. In 2020, sewage gas is entirely assigned to on-site electricity generation. In the years 2030/2040 a linear interpolation will be applied.

Figure 12 TWh/y (HHV) of biogas by 2050, including 919 TWh/y of biomethane. By 2030, however, potentials only equal 428 TWh/y (HHV) of biogas, including 259 TWh/y of biomethane.

Figure 12: Scenario for EU biomass development



Production costs of biomethane from thermal gasification as well as the market ramp-up rely on a study by Navigant[21]. No major cost digression is expected until 2030, as the market ramp-up is limited and further technological developments are necessary. It is thus assumed that the LCOE of biomethane from thermal gasification equals EUR 80/MWh in 2030.

Using the ratio of length of gas transmission network and agricultural area at NUTS1 level, a connection cost proxy may be determined for all NUTS1 regions in Europe. This indicator allows a rough classification of the additional connection costs as a function of the connection length. We assume that the processing plants are always located in the immediate vicinity of the gas grid.

For the quantification of biomethane LCOE, two scenarios following two feedstock-type-ratios for biogas plants using agricultural substrates are defined: 'no sequential cropping, less straw' and 'sequential cropping, less straw'. These two scenarios lead to different energetic shares of feedstocks used for the production of biogas. Six different biogas plant types with respective mass-related feedstock compositions are assumed for the conversion process.

Investment costs for all biogas plants are based on the cost calculator of KTBL[22]. Investment costs for BGUPs and BMIPs are based on Beil et al. (2019)[23] and additional data sets of Fraunhofer IEE. Integrating renewable and low-carbon gases into the market.

Estimation of local gas oversupply due to new biomethane volumes at the distribution level was assessed based on the balance between biomethane injection and local gas consumption at the level of distribution networks has been conducted for 2030 at the NUTS1 level, in order to estimate the **actual need for reverse flow compressors by 2030**.

21 Navigant (2019): Gas for Climate - The optimal role for gas in a net-zero emissions energy system.

22 https://daten.ktbl.de/biogas/navigation.do?selectedAction=Startseite#start
https://daten.ktbl.de/biogas/navigation.do?selectedAction=Startseite#start

23 Beil, M.; Beyrich, W.; Kasten, J.; Krautkremer, B.; Daniel-Gromke, J.; Denysenko, V.; Rensberg, N.; Schmalfuß, T.; Erdmann, G.; Jacobs, B.; Müller-Syring, G.; Erler, R.; Hüttenrauch, J.; Schumann, E.; König, J.; Jakob, S.; Edel, M. (2019): Schlussbericht zum Vorhaben 'Effiziente Mikro-Biogasaufbereitungsanlagen (eMikroBGAA)'.

First, projected gas demand for 2030 has been decomposed by sector, usage, NUTS1 zone type of profile (thermosensitive or not) and network (distribution or transmission). The projected gas demand for 2030 has been taken from the MIX-H2 scenario, decomposed by sector and Member State.

The decomposition by usage being too rough in the MIX-H2 scenario, keys from IDEES database (from year 2015) have been used, for instance for the split between cooking and water heating gas demand in the residential sector. Disaggregation keys have then been used to split the gas demand between NUTS1 zones in each Member State.

The decompositions by network (distribution or transmission) and type of profile (thermosensitive) have been made based on keys. Specific values have been used for Member States where data were available. A similar analysis has been conducted to estimate the biomethane daily injection by 2030, in each NUTS1 zone. Projected biomethane demand in each MSs has been taken from MIX-H2 scenario.

Based on biomethane cost and potential estimations conducted in the framework of the present assessment (cf. § 6.1), potential LCOE of biomethane have been built for each Member State. Two major factors influence biomethane costs: biomethane technology and distance to the gas network (see *Figure 13*). The distance to the gas network is approximated with a fixed value in each NUTS1 zone, depending on the gas network density.

Figure 13: Assumptions for connection length and costs

Parameter	Probable distance	Connection cost
1 (dense gas network)	0 km raw biogas pipeline	€0/MWh biomethane
2 (medium gas network)	8 km raw biogas pipeline	€7/MWh biomethane
3 (low gas network)	14.5 km raw biogas pipeline	€12/MWh biomethane
4 (no gas network at NUTS1 region)	21 km Bio-LNG	€19/MWh biomethane

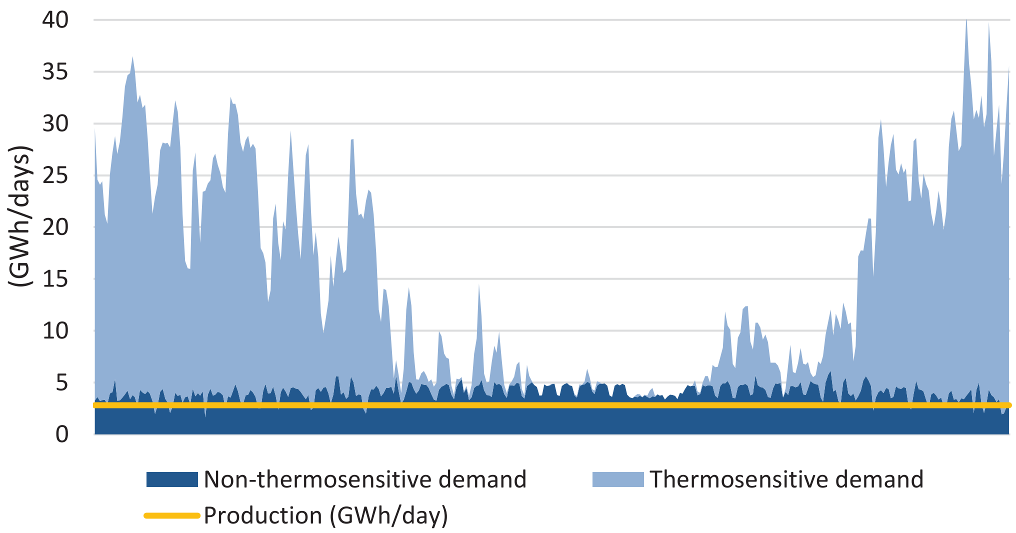
Based on cost-curves, a least-cost potential allocation has be made to meet the biomethane production projected in the MIX-H2 scenario in each Member State. In order to get an upper bound of the seasonal local oversupply, it has been assumed that 100% of the biomethane would be injected at the distribution level. In reality, the level of biomethane injection depends on the technology, the plant size and the Member State

Moreover, a flat injection profile has been assumed, considering the low variability and the absence of seasonal trend in biomethane injection profiles (cf. Indicator 1.8: Biomethane injection profile).

Combining the gas demand profile on distribution network with the biomethane injection projected by 2030 in MIX-H2 scenario for each NUTS1 zone enables an estimation of reverse flow needs.

If biomethane production exceeds demand, there is a need for remedial measure. For instance, *Figure 14* underlines the absence of need for reverse flow in the zone DE8, as biomethane injection stays below local gas demand on distribution networks during the whole year.

Figure 14: Daily demand and injection on distribution networks by 2030 in DE



Source: Artelys

The injection margin, defined as $((demand)-Injection)/Min(demand)$, has then been calculated for each NUTS1 zone. Injection margin of 80% means that injection can be increased by 80% without requiring reverse-flow.

Negative injection margin means that reverse-flow is required. This approach may underestimate the actual need for reverse flow due to the low granularity used. Indeed, as

NUTS1 zones contain more than one distribution network, the NUTS1 assessment tend to smooth local oversupply that could happen in some distribution networks (especially in rural areas). This result is however in line with other recent studies[24].

Reform of the current entry/exit tariffication system

The METIS gas module is used to assess the impact of different entry/exit tariffication systems. In the model, each pipeline is associated to one external entry and one external exit tariff (extracted from the TYNDP2020 and equal in the baseline context). The analysis represents the European gas market including all flows between European MSs and from third country exporters[25] towards the EU through the gas transmission network and via LNG terminals. It includes two sub-measures:

- Sub-measure 1, where all **intra-EU cross-border tariffs are removed**. Other points that will be priced at a zero tariff are entry points from renewable/low carbon production and entry points from LNG terminal to the gas grid. Entry-points from third countries will be priced on the basis of distance to the middle of the EU.
- Sub-measures 2, where **entry tariffs at LNG terminals will be priced** on the basis of distance to the middle of the EU, similar to pipeline imports from third countries.

Both sub-measures are compared to a baseline model run representing the gas market in 2030 with the measures supporting the integration of low carbon gases activated, especially for the LNG terminals that have the same tariffs and a 100% availability. In addition to the baseline model run (used to obtain TSO revenues under current rules), two iterations are performed in the present analysis:

- **Iteration 1: Model run without intra-EU cross-border tariffs:** A first run is performed with tariffs based on the distance of the entry and/or exit cross-border point to a virtual point placed in centre of Europe (Tillenberg, CZ).
- **Iteration 2: Model run with adapted external entry/exit tariffs:** As the distance-based tariffs of the first iteration are not necessarily similar to the current tariffs, the total revenues generated via the external entry exit tariffs and congestion rent are expected to be substantially different in the first iteration compared to the baseline. An adjustment of the distance-based tariffs is performed in a second iteration to align the TSO revenues with the baseline level. This adjustment is based on the revenue results of the first iteration.

All the results are reported in a set of KPIs that capture the dynamics, costs and benefits related to the European gas system, distinguishing EU MS and third countries if relevant.

Nord Stream 2 sensitivity

A sensitivity is performed to evaluate the impact of a possible absence of the Nord Stream 2 (NS2) pipeline connecting Russia to Germany. The second iteration is repeated with the capacity of NS2 being removed, reducing the interconnection capacity between Russia and Germany 147 GWh/h to 75 GWh/h in the sensitivity without NS2.

[24] See for instance (Trinomics, LBST, 2020).

[25] Algeria, Azerbaijan, Eastern countries (Russia, Belarus, Ukraine), Libya, Norway, Turkey, United Kingdom, LNG (Northern Africa, Australia, Middle East, Norway, Peru, Sub-Sahara, Trinidad and Tobago, United States).

Impact on power generation merit order

In order to estimate the impacts of the sub-measures on the power system that are not captured by the model runs explicitly (as all the gas demand is inelastic), the reference power merit order in each country is assessed through a post processing analysis under the baseline model run for the gas-to-power plants and an estimation of the cost of marginal power generation costs for coal and lignite power plants in 2030.

Data collection methodology

Data collected for the problem description focuses on 2018-2020 data where available, unless indicated otherwise. Only data related to the methane gas infrastructure and markets was collected (including on hydrogen blending).

Energy content data is presented in TWh (higher heating value). Where applicable, power/energy refers to equipment output, and is presented in MW_{output} or MWh_{output} (higher heating value where applicable), unless stated otherwise. Costs and prices are converted to EUR_{2020} using Eurostat annual exchange rates.

The steps for collecting data under Task 1 were:

1. Definition and agreement on the data collection indicators
2. Desk research to complete available indicators
3. Development and submission of questionnaire to cover remaining data gaps
4. Internal data quality control

Given the challenges in collecting reliable data for multiple data parameters, especially related to adaptation costs to hydrogen blending and representative distribution networks, a questionnaire was elaborated and sent to national regulators, network operators and biogas/biomethane associations.

Between March and April 2021, 15 separate responses were received from stakeholders from 7 Member States. Some stakeholders combined their responses in a single submission. In general, the information received was highly useful to develop the infrastructure and equipment/appliance cost analysis as well as to obtain data on the distribution network archetypes.

Table 28 presents all indicators collected and compiled under task 1, organised per policy category. The 'format' field indicates whether the information is presented in textual form (i.e., in this report) or in a separate Excel spreadsheet. The 'granularity' field indicates whether the data is on an EU-level, MS-level or global. MS-specific information does not necessarily mean that data is available for all MS. For all indicators presented in the Excel a brief summary is given in this chapter. The following sections present the collected information for all indicators.

Table 28: Overview of indicators collected in Task 1 for the four policy categories

Category	Indicator		Format	Granularity[26]
Renewable and low	1.1	Number and capacity of biogas plants	Excel	MS-specific
	1.2	Number and capacity of biomethane plants	Excel	MS-specific

26 MS-specific data has Member States as the unit of analysis. The data may cover all Member States or a sub-set depending on data availability.

Category		Indicator	Format	Granularity[26]
carbon gases integration	1.3	Annual production of biomethane	Excel	MS-specific
	1.4	Number and capacity of power-to-hydrogen projects	Excel	MS-specific
	1.5	Number and capacity of power-to-synthetic methane projects	Excel	MS-specific
	1.6	Current use for biomethane	Word/Excel	MS-specific
	1.7	Production potential of biomethane and biogas	Word/Excel	EU-level
	1.8	Biomethane injection profile	Excel	Other
	1.9	Potential and costs of biomethane imports	Excel	Global regions
	1.10	Current and potential costs of synthetic methane imports until 2030	Word	Global regions
	1.11	Total cost of transport of biomethane and synthetic methane from third countries	Word/excel	Techno-economic
	1.12	Domestic natural gas production in the EU	Excel	MS-specific
	1.13	Capacity of cross-border pipelines between Member States	Excel	MS-specific
	1.14	Entry/Exit tariffs for intra/extra-EU IPs and for LNG terminals	Excel	MS-specific
	1.15	Long-term booked capacity	Excel	EU-level
	1.16	Injection and withdrawal capacities of large natural gas storages	Excel	MS-specific
	1.17	Tariffs for large natural gas storages	Excel	MS-specific
	1.18	Distribution network archetypes	Separate excel	MS-specific
	1.19	Available pipeline capacity in the EU that can be used for decarbonised gas imports in 2030	Excel	MS-specific
	1.20	Flexible methane demand	Word	EU-level
	1.21	Number of DSOs per Member State	Excel	MS-specific
	1.22	TSO & DSO expenditures	Excel	MS-specific
	1.23	TSO allowed revenues	Excel	MS-specific
	1.24	TSO & DSO network length	Excel	MS-specific
	1.25	Supply costs of biogas	Excel	Other
	1.26	Cost of biogas upgrading to biomethane	Word	Techno-economic
	1.27	Cost of hydrogen methanation	Word	Techno-economic
	1.28	Costs of connection of biomethane plant to DSO or TSO grid	Word	Techno-economic
	1.29	Cost allocation of biomethane plant connection	Excel	MS-specific
	1.30	Biomethane connection obligation/request denials	Excel	MS-specific
	1.31	Costs of other key components in methane network	Word	Techno-economic
	1.32	Costs of reverse flow installations	Word	Techno-economic
	1.33	Cost of de-odorization in case of reverse flow from DSO to TSO.	Word	Techno-economic
	1.34	Grid injection tariffs for biomethane, synthetic methane and hydrogen	Excel	MS-specific
	1.35	Expected cost reductions for techno-economic parameters	Excel	Techno-economic

Category		Indicator	Format	Granularity[26]
	1.36	Current MS status regarding the policy options for the integration of renewable and low-carbon gases	Excel	MS-specific
Gas quality	2.1	Overview of technical hydrogen admixture thresholds	Word	Techno-economic
	2.2	Analysis of needed adaptations in the gas infrastructure network	Word	Techno-economic
	2.3	Costs of adapting distribution and transmission infrastructure to hydrogen blending	Word	Techno-economic
	2.4	Costs and feasibility of adapting end-use appliances to hydrogen blending rates	Word	Techno-economic
	2.5	Feasibility of using gas storage for hydrogen blended gas	Word	Techno-economic
	2.6	Potential administrative costs of reinforced cross-border regulatory framework for gas quality	Word	Techno-economic
	2.7	Current national hydrogen admixture regulation	Excel	MS-specific
LNG terminals	3.1	Costs of adapting LNG terminals	Word	Techno-economic
	3.2	Transport costs of re-exporting decarbonised gas within the EU via LNG route.	Excel	Techno-economic
	3.3	Number and capacity of current LNG terminal projects	Word/Excel	MS-specific
	3.4	Number and capacity of planned LNG terminal projects	Excel	MS-specific
	3.5	Available LNG storage capacity in the EU that can be used for decarbonised gas imports in 2030	Excel	EU-level
	3.6	Supply potential and supply costs for LNG imports	Excel	Main suppliers
	3.7	Utilization profile of LNG terminals per hour/day	Excel	Other
System integration planning	4.1	Costs and benefits of changes in unbundling of DSOs to avoid conflicts of interests	Word	Literature review
	4.2	Costs and benefits of additional coordination and cooperation requirements (electricity/gas, TSO/DSO, storage)	Word	Literature review
	4.3	Analysis of current planning procedures in MSs	Excel	MS-specific
	4.4	Current MS status regarding the policy options for integrated network planning	Excel	MS-specific

Annex 5: Modelling results for Problem Area I: Hydrogen infrastructure and markets

Infrastructure needs

Table 28 shows a breakdown of the cross-border capacities in the main scenarios. The table distinguishes between refurbished pipelines for natural gas and newly built hydrogen pipelines. It further shows the 'minimum' capacities as reported in the EHB study and additional 'optimised' capacities that were identified by the METIS model. It can be seen that, when allowed as in the scenarios 'A optimised' and 'B optimised', additional interconnections to those identified by the EHB study would lead to a more cost optimal EU-energy system.

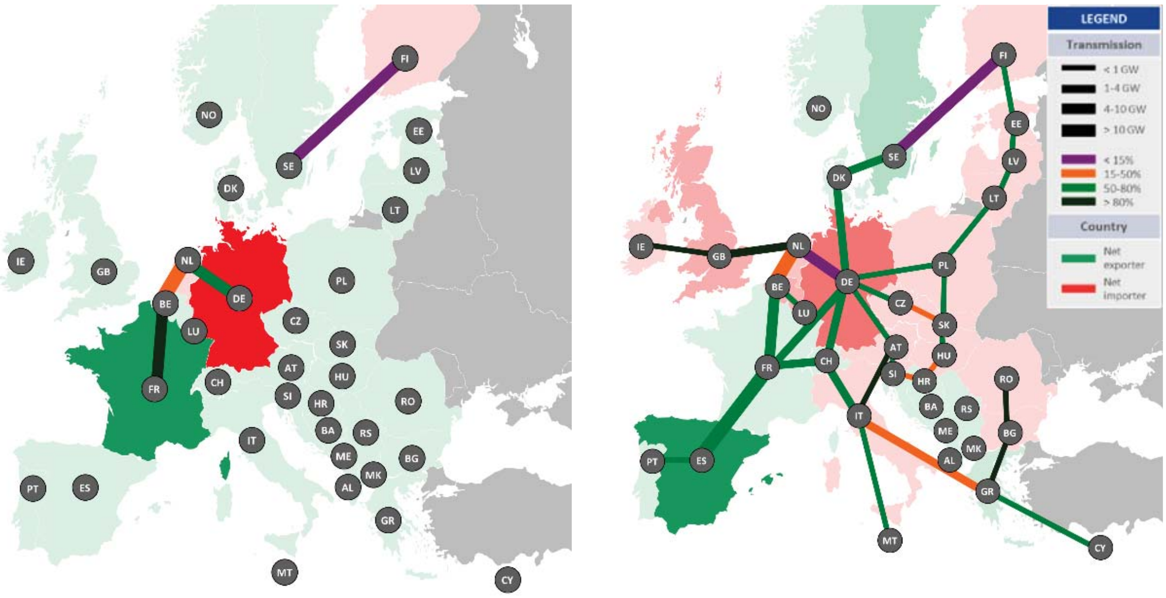
Table 29: Cross-border capacities in main scenarios

Scenario	Repurposed methane interconnections [GW]		New hydrogen interconnections [GW]		Total interconnections [GW]
	minimum	optimised	minimum	optimised	
BAU	-	-	-	-	-
A constrained	19		10	-	29
A optimised	19	25	10	17	71
B optimised	47	8	120	10	184

As can be seen in *Figure 15*, scenario 'A constrained' assumes cross-border capacities only between Belgium, France the Netherlands and Germany (19 GW of repurposed natural gas pipelines and 5 GW of new hydrogen pipelines) as well as between Finland and Sweden (5 GW of new hydrogen pipelines).

A total of 103 TWh of hydrogen is exchanged in the 'A constrained'- scenario, of which 36 TWh between Belgium and the Netherlands and 33 TWh between France and Belgium and 31 TWh between Netherlands and Germany. Total exchanges increase to 332 TWh in the 'A optimised' scenario. The exchange between Spain and France (69 TWh) becomes the most active cross-border connection, followed by France and Belgium (52 TWh) and Belgium and the Netherlands (33 TWh). Hydrogen trade reaches a pan-European dimension in this scenario. If the network extends even further as in the 'B optimised'-scenario, total exchanges increase only by 8% to 359 TWh, which shows that this grid configuration would be oversized for the projected hydrogen production and consumption in 2030.

Figure 15: Hydrogen grids in the 'A constrained' (left) and the 'A optimised (right)' scenarios



Hydrogen storage is required in all scenarios (as shown in *Table 30*), either to cope with domestic supply-demand equilibrium or with import/export patterns as hydrogen transits through a country featuring storage. The storage needs fall with increasing cross-border connection meeting part of the flexibility needs. Also, storage capacities increasingly move to the Iberian Peninsula in scenarios where better grid connection is provided.

Table 30: Hydrogen storage capacities

Scenario	Storage capacity	
	Total	**Largest share**
BAU	20,8	DE (40%)
A constrained	18,3	DE (25%)
A optimised	17,9	ES (43%)
B optimised	17,7	ES (42%)

A further optimisation can be observed for the electrolyser capacity as shown in *Table 30*. Between the BAU and the 'A optimised' scenarios, the electrolyser load factor increases from 42% to 60% as investments are relocated to more favourable locations. However, as the scenario construction implied a minimum electrolyser capacity corresponding to 80% of the national strategies announcements[27], this geographical redistribution is somewhat constrained.

Table 31: Electrolyser utilisation

Scenario	Total Hydrogen Production (TWh)	Total Electrolyser Capacity (GW)	Electrolyser Utilisation (h)
BAU	194	53	42%
A constrained	198	47	48%
A optimised	220	42	60%
B optimised	220	43	59%

[27] See **Error! Reference source not found.** on p. 8: approximately 27.5-28.5 GW of electrolyser targets follow from national hydrogen strategies.

Costs of hydrogen

Table 32 the total costs of hydrogen for the main scenarios considered. Total costs cover both fixed and variable costs of hydrogen production. Fixed costs consist in the investments needed to build the electrolysers, hydrogen storage and hydrogen transport pipelines. Variable costs are largely given by the electricity price that has to be paid by an electrolyser to produce an additional unit of hydrogen. They are responsible for about 75% of all costs (varying between 74% in 'A constrained' and 76% in 'A optimised'). Building a pan-European hydrogen network allows producing hydrogen in regions with lower electricity costs and consequently lowering the average production costs in Europe. Higher cross-border integration reduces costs of hydrogen from EUR 3,2 to 2,5/kg (by 22%) between the BAU and the 'A optimised' scenarios. This reduction of production costs is entirely given relocating electrolysers from regions with high electricity prices to low electricity price regions. costs is entirely given relocating electrolysers from regions with high electricity prices to low electricity price regions. costs is entirely given relocating electrolysers from regions with high electricity prices to low electricity price regions.

Relocating electrolysers also lowers the (per kg) capital costs of electrolysers as, with increasing interconnections, a lower installed capacity is required that can run with a higher load factor. As shown in *Table 32* his effect translates into costs falling from EUR 0,77 to 0,55/kg (by 38%) between the BAU and the 'A optimised' scenario. The decrease of storage capacities required between the BAU and the 'A optimised' scenarios translates to costs falling from EUR 0,28 to 0,21/kg between the respective scenarios. At the same time, costs for pipelines double between the 'A constrained' and the 'A optimised' scenarios, yet the related costs are lower the savings obtained up to the 'A optimised' scenario.

Total costs rise between the 'A optimised' and the 'B optimised' scenario as only little further optimisation of the electrolyser fleet and storages can be achieved by investing in the additional cross-border transport capacity. The cross-border network of the 'B optimised' scenario would thus not be economically efficient for the hydrogen demand in 2030 as projected in this scenario.

Table 32: Total costs of hydrogen (EUR/kg)

Scenario	H2 production price	Electrolyser Capex	Storage	Pipelines	Total
BAU	3,17	0,77	0,28	-	**4,22**
A constrained	2,69	0,66	0,24	0,02	**3,62**
A optimised	2,51	0,55	0,21	0,04	**3,30**
B optimised	2,51	0,55	0,21	0,09	**3,36**

ANNEX 6: DETAILED MEASURES FOR PROBLEM AREA I: HYDROGEN INFRASTRUCTURE AND MARKETS

Each option for Problem Area I: Hydrogen infrastructure and markets considered in Section 5.1 of this Impact Assessment comprises (or not) a set of more detailed measures. Please see also the summary table at the end of Section 5.1 in this regard.

This Annex contains an assessment for each of these more detailed measures.

Tables assessing individual measures

Table 33: Measures on vertical unbundling

Vertical unbundling	**Objective**	Vertical unbundling has the objective of preventing conflicts of interests which may result from a vertical integration of hydrogen network operations and hydrogen production/supply activities.				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big Bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	NA	OU/ITO/ISO	OU + ISO model	Ownership unbundling	EU TSO (ISO model) for hydrogen networks
Pros	May incentivise hydrogen network development by vertically integrated hydrogen producers. No administrative burden/regulatory costs.	Similar to BAU	Carry-over of current unbundling models of natural gas TSOs to hydrogen could simplify implementation. No costs for change in unbundling regime incurred by incumbent natural gas network operators when pursuing hydrogen transport activities and that are currently organised on basis of the ISO/ITO model.	Ownership unbundling ensures that hydrogen network operators do not have the incentive to discriminate among users of their network. Vertical integration in hydrogen is limited, so regulatory costs of unbundling are low compared to developed sectors (natural gas and electricity). Use of the ISO model would allow vertically integrated hydrogen producers to retain ownership of existing hydrogen networks, while providing	Ownership unbundling ensures that network operators do not have the incentive to discriminate among users of their network. Blanket ownership unbundling for hydrogen networks could allow for less stringent TPA requirements.	Addresses conflicts of interests resulting from vertical and horizontal integration. Allows existing vertically integrated hydrogen producers to retain ownership of existing hydrogen networks. EU TSO well placed for EU-level network planning and development. Facilitates ITC mechanism (needed if for rTPA without cross-border tariffs. (See table

				adequate safeguards for third-party users of these networks. In transition: ITO can be allowed until 2030.		on tariffs below)
Cons	Vertically integrated network owners incentivised to restrict third-party access and cross-border connections, thereby limiting competition and cross-border integration of hydrogen markets.	Similar to BAU	Use of historic unbundling models in the natural gas sector would constitute a missed opportunity to introduce a structural unbundling model at low cost due to small number of existing vertically integrated hydrogen producers. The ISO and ITO modes are associated with a higher regulatory cost and administrative burden for operators and monitoring authorities.	Limits the commercial freedom of hydrogen producers/suppliers and hydrogen network operators. The ISO and ITO models are associated with a higher regulatory cost and administrative burden for operators and monitoring authorities.	Limits the commercial freedom of hydrogen producers/suppliers and hydrogen network operators. Would require divestment of existing hydrogen networks by vertically integrated hydrogen (and gas) producers.	May require ITC mechanism to allocate revenues. Enabling certain functions (e.g. EU-level network planning) would require imposing financing obligations on networks owners (similar to ITO/ISO unbundling models).
Most suitable option:	**Option 2b**	OU + ISO: Ownership unbundling fully eliminates conflict of interests via structural separation of transport and production/supply activities and is thus effective at safeguarding competition and incentives for cross-border integration, has lower monitoring costs for regulatory authorities and allows for greater flexibility in network access rules. ISO model would allow vertically integrated hydrogen producers to retain ownership of existing hydrogen networks, while providing adequate safeguards for third-party users of these networks. Use of ITO model until 2030 creates greater flexibility in the ramp-up phase.				

Table 34: Measures on horizontal unbundling

Horizontal unbundling	**Objective**	Horizontal unbundling has the objective of preventing conflicts of interests arising from the operation of different types of energy networks by a single entity				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big Bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	NA	Combined hydrogen/CH4 TSO	Legal + Accounts unbundling	Legal + Functional	Accounts unbundling (assets operated by EU TSO (ISO)
Pros	No administrative burden.	-	No additional administrative burden (as BAU for natural gas). Facilitates repurposing of natural gas network.	Reduces risk of conflicts of interest regarding repurposing and de-commissioning of gas network infrastructure. Gas TSOs can retain ownership of repurposed gas pipelines within company group structure.	Considerably reduces risk of conflicts of interest regarding repurposing and de-commissioning of gas network infrastructure. Gas TSOs can retain ownership of repurposed gas pipelines within company group structure.	Considerably reduces risk of conflicts of interest regarding repurposing and de-commissioning of gas network infrastructure. Gas TSOs can retain ownership of repurposed gas pipelines (operated by EU TSO).
Cons	National rules may prevent combined Hydrogen/CH4 operators in some Member States.	-	Risk of conflicts of interest regarding repurposing and de-commissioning of gas network infrastructure.	Administrative burden and regulatory cost for operation and monitoring, but relatively low.	Higher administrative burden and regulatory costs for operation and monitoring.	Higher administrative burden and regulatory costs for operation and monitoring.
Most suitable option	**Option 2b**	The choice of horizontal unbundling requirements is linked to the rules on the regulated asset base (RAB), since a joint asset base is possible only in the absence of horizontal unbundling requirements. Where a separate RAB is the preferred option, this allows for the choice of different horizontal unbundling requirements (from accounts unbundling up to ownership unbundling). Compared to vertical integration, the risk of conflicts of interests as a result of combined operatorship of different types of networks is present but less severe. The remaining risks can be managed effectively via monitoring and approval by regulatory authorities. Therefore, legal and accounts unbundling (but without functional unbundling), as a low level of horizontal unbundling, can be considered sufficient. This allows for the combined operation of natural gas and hydrogen networks within a group of undertakings (i.e. by creating a subsidiary). The possibility for gas TSOs to retain ownership of methane infrastructure intended for into hydrogen transport within their group structure reduces regulatory costs and facilitates infrastructure repurposing.				

Table 35: Measures on TPA for hydrogen networks

TPA for hydrogen networks	Objective	Rules on non-discriminatory third-party access (TPA) to hydrogen networks should enable competition by ensuring access to hydrogen commodity markets for all market participants.				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	No rules	Negotiated TPA (nTPA)	Regulated TPA (rTPA) + no cross-border tariffs (but nTPA possible until 2030)	Regulated TPA (rTPA) + no cross-border tariffs	Regulated TPA (rTPA) + no cross-border tariffs
Pros	May incentivise investment in hydrogen networks (by vertically integrated hydrogen producers/suppliers).	Similar to BAU	Assures minimum degree of non-discriminatory third-party use of hydrogen networks, thereby enabling competition. Lower regulatory burden than rTPA. Provides room for network operators to enter into long-term transport contracts that could increase investment certainty/incentives in networks.	Ensures non-discriminatory third-party use of hydrogen networks, enabling competition. Ensures cost-reflectiveness of access tariffs. Harmonised TPA regimes would facilitate interconnections and thereby cross-border trade. TPA supported by stakeholders. Prohibition on cross-border tariffs fosters cross-border trade. Option: nTPA would allow for more flexibility in ramp-up phase (see Option 2a).	Regulated TPA would ensure non-discriminatory third-party use of hydrogen networks, thereby enabling competition. Regulated TPA, based on regulated tariffs, would ensure the cost-reflectiveness of access tariffs. Harmonised TPA regimes would facilitate interconnections and thereby cross-border trade. Prohibition on cross-border tariffs fosters cross-border trade.	Like Option 3a

Cons	Risks of non-competitive market outcomes limited market access and impediments for interconnection and cross-border trade.	Similar to BAU	Reduces the commercial freedom of hydrogen network operators. Negotiated TPA is more prone to abuse, in the absence of regulated access tariffs. Risk of competition distortion between Member States if national rules envisage regulated TPA. Monitoring by regulatory authority required.	Limits the commercial freedom of hydrogen producers/suppliers and hydrogen network operators. Increased regulatory costs. Prohibition on cross-border tariffs likely to require ITC mechanism by 2030. Monitoring by regulatory authority required.	Like Option 2b but no flexibility in transition	Like Option 2b but no flexibility in transition
Most suitable option	**Option 2b**	Regulated third-party access is effective in ensuring non-discriminatory market access to and competition in hydrogen commodity markets (including across Member States borders). Clear rules on TPA were considered important by stakeholders. The preferred option envisaged greater flexibility in the ramp-up phase in the form of negotiated TPA. The pre-set date for the transition to regulated TPA provides visibility for investors and network users.				

Table 36: Measures on TPA for hydrogen large-scale storage

TPA for large-scale hydrogen storage	**Objective**	The objective of third-party access for large-scale hydrogen storage is to ensure the access of all hydrogen producers and consumers to scarce storage facilities, to prevent that hydrogen producers and consumers are dependent in their activities on the (seasonal) variability of renewable electricity that is used for the production of renewable hydrogen.				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	No rules	Negotiated TPA (nTPA)	Regulated TPA (rTPA)	Regulated TPA (rTPA)	Regulated TPA (rTPA)
Pros	May incentivise investment in hydrogen terminals in particular by vertically integrated operators. No administrative burden.	Like BAU	Would ensure a minimum degree of non-discriminatory third-party use of hydrogen-ready underground storage (not available in all MS), thereby enabling competition and cross-border integration. Lower regulatory costs (compared to rTPA).	Regulated TPA would ensure non-discriminatory third-party use of hydrogen-ready (underground) storage (not available in all MS), thereby enabling competition. Regulated TPA, based on regulated tariffs, would ensure the cost-reflectiveness of access tariffs. Storage will, in particular at the early stages of infrastructure development be one of the few means to cover energy security risks, emphasising the need for fair access conditions.	Like Option 2b	Like Option 2b
Cons	High risk of non-competitive market outcomes (due to commercial value of storage) and market integration (as storage not available in all MS)	Like BAU	Reduces the commercial freedom of hydrogen storage operators. Negotiated TPA is more prone to abuse, in the absence of regulated access tariffs. Risk of competition distortion between MS.	Higher administrative burden/regulatory costs due to tariff regulation. May disincentivise conversion of underground gas storage subject to nTPA.	Like Option 2b	Like Option 2b

Most suitable option	**Option 2b**	Ensuring access to large scale storage is expected to be conducive to investment incentives in renewable hydrogen production (e.g. via electrolysers) and consumption and therefore considered to be an important driver for the development of competitive upstream and downstream hydrogen markets. Ensuring access to large scale storage will allow renewable hydrogen producers to decouple production from consumption thereby allowing them to optimize their electrolyser operations on the basis of price variations for renewable electricity. It enables a stable hydrogen supply for initial (industrial) consumers. As large scale storage is expected to be scarce (especially during the hydrogen ramp-up phase) and only available in certain member states due to geological conditions, a strict access regime is justified.

Table 37: Measures on TPA for hydrogen terminals

TPA for hydrogen terminals	**Objective**	The objective of TPA for hydrogen terminals is to ensure non-discriminatory access to terminals for the import of liquid hydrogen for hydrogen producers and consumers.				
	<u>BAU</u> **No additional measures**	<u>Option 1</u> **Rights for network operation tendered**	<u>Option 2</u> **Main regulatory principles**		<u>Option 3</u> **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	No rules	No rules	nTPA	regulated TPA (rTPA)	regulated TPA (rTPA)
Pros	May incentivise investment in hydrogen terminals in particular by integrated operators. No administrative burden.	Like BAU	Similar to BAU	Minimum degree of non-discriminatory third-party use of liquid hydrogen terminals, thereby enabling competition. Reduces regulatory costs and administrative burden (relative to regulated TPA).	Regulated TPA would ensure non-discriminatory third-party use of liquid hydrogen terminals, thereby enabling competition. Regulated TPA, based on regulated tariffs, would ensure the cost-reflectiveness of access tariffs. Ensures consistency with LNG terminal regulation, given the high likelihood of combined terminals.	Like Option 3a
Cons	Risk of competitive market outcomes and market integration terminals not possible in all MS). Means of hydrogen (and derivatives) imports uncertain. Other means than liquefied hydrogen may exert competitive pressure on terminal operators.	Like BAU	Similar to BAU <u>BUT</u>: access rules to network are NOT determined by an integrated operator.	Reduces the commercial freedom of liquid hydrogen terminal operators. Negotiated TPA is more prone to abuse, in the absence of regulated access tariffs. Risk of competition distortion between MS. Administrative burden and regulatory cost (but lower than rTPA).	Limits the commercial freedom of hydrogen producers/suppliers and hydrogen network operators. Increased regulatory costs due to tariff regulation and monitoring of capacity allocation rules.	Like Option 3a

Most suitable option	**Option 2b**	Hydrogen (and its derivatives) can be economically imported by various means. It is unclear at this stage whether hydrogen will be imported in liquefied form or otherwise whereas, in the earlier stages of a developing hydrogen market, imports may anyway be limited. This uncertainty and the likelihood that alternative means of importing hydrogen will exert sufficient competitive pressure on terminal owners, means that a heavy-handed regime for liquefied hydrogen terminals seems unnecessary and, probably, too early.

Table 38: Measure for hydrogen quality

Hydrogen quality	Objective	Cross-border market integration; to ensure unhindered cross-border hydrogen flows and required quality for end-users				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	**No rules** at EU level on technical aspects, including on hydrogen purity. The operating conditions are negotiated between network operators and users (tailored towards the concrete demand of, mostly, industrial consumers).	**MS** to ensure that hydrogen quality is addressed in the tendering.	**Cross-border coordination framework and dispute settlement** Obligation on Member States to agree on the acceptable hydrogen purity levels for cross-border points; cross-border dispute settlement procedure with the involvement of the concerned regulatory bodies (similar to that of the Interoperability Network Code for methane networks, with specific roles for network operators, NRAs and ACER); EU-level principles on roles of hydrogen producers and network operators, on regulatory oversight and transparency on hydrogen purity.	**EU-wide acceptable hydrogen purity level for cross-border points** (detailed technical specifications in either a delegated or implementing act); cross-border dispute settlement and EU-level rules on roles of hydrogen producers and network operators, on regulatory oversight and on transparency as in Option 2a.	EU-wide acceptable purity level for cross-border points (like Option 2b)	EU-wide acceptable purity level for cross-border points (like Option 2b)
Pros	Limited administrative burden as no new	Limits the risk of cross-border flow restriction and market	Ensures common approach on hydrogen quality for cross-border points across the EU	Ensures a fully harmonised approach on hydrogen quality at cross-border points.	Like Option 2b	Like Option 2b

	legislation is introduced.	segmentation. Limited intervention; leaves flexibility to the Member States on defining acceptable hydrogen quality standards both cross-border with adjacent Member State and in domestic network. Limited administrative costs for system operators and regulatory authorities.	limiting the risk of cross-border disputes, flow restrictions and market segmentation to a minimum. Ensures strong coordination between Member States in case cross-border disputes still arise due to actual quality differences. Ensures a harmonised approach across the EU on quality management by setting rules on roles, responsibilities, regulatory oversight and transparency on hydrogen quality. Supports the development of a cross-border hydrogen infrastructure and trade in the EU. Limited intervention; leaves flexibility to the MS on hydrogen quality standards in the domestic network without interfering with national specificities of hydrogen quality. Support by stakeholders for establishing hydrogen quality (purity) standard at Member State level with EU-level cross-border coordination rules. Stakeholders also support establishing rules on roles, responsibilities and cost-allocation for the management	Eliminates the risk of cross-border disputes on hydrogen quality standards. Ensures a harmonised approach across the EU on quality management by establishing EU-level rules on roles of hydrogen producers and network operators, on regulatory oversight as well as on transparency and quality monitoring (including European level monitoring tasks). Supports the development of a cross-border hydrogen infrastructure and trade in the EU. Retains flexibility for Member States to define the acceptable hydrogen quality/purity levels for the domestic network. Provides clarity to investors, operators and users on acceptable quality providing for more investment stability. Very strong support by stakeholders for establishing binding hydrogen quality (purity) standard at EU-level.		

			of hydrogen quality at EU-level.			
Cons	Applicable rules on hydrogen quality would remain undefined or set at national level; their application cross-border would not be aligned risking cross-border flow restrictions and market segmentation. Potential of cross-border disputes due to differences in hydrogen quality standards. Additional costs for market participants incurred for the implementation of different voluntary approaches. Stakeholder do not support this option.	Lack of cross-border coordination on hydrogen quality can lead to cross-border flow, trade restrictions and market segmentation. Lack of visibility and oversight of hydrogen quality patterns at production and needs at user side can lead to mismatch and consequently to increased cost of quality adaptation. Stakeholder do not support this option. I.e. this option does not impose EU-level regulation on hydrogen network operation.	Risk of cross-border disputes due to differences in quality standards and/or the actual quality (purity) of the hydrogen transported cross-border remains. Lack of a harmonised approach to acceptable hydrogen quality levels across Europe can hamper investments in the hydrogen market. Additional cost for deblending, especially at end-user points. Administrative costs due to implementation tasks for the involved authorities (incl. for the European-level tasks) and market participants, including for hydrogen system operators. Administrative costs for cross-border dispute settlement (including for European level coordination).	Limited risk of disputes due to differences in the actual quality (purity) of the hydrogen transported cross-border remains. Limits the flexibility of Member States to agree on specific quality rules cross-border. Administrative costs for the implementation of the EU rules for the involved regulatory authorities (including for the European-level monitoring) and market participants (including for hydrogen system operators).	Like Option 2b	Like Option 2b
Most suitable option	**Option 2b**	Under the preferred option, hydrogen quality would be governed by a harmonised EU approach for cross-border interconnection points. Even if the emergence of dedicated pipelines and the conversion of existing gas pipelines might be limited to the local level in short and mid-term, a joint European standardisation approach would enable the later connection of these hydrogen pipelines to a cross-border network. EU-level technical rules are crucial for managing cross-border hydrogen flows within and into the EU. Option 2b achieves the objective of cross-border market integration by setting a harmonised EU-level purity requirement for cross-border points, establishing a harmonised EU-approach for cross-border dispute settlement should problems still arise and setting harmonised rules for the management of hydrogen purity, thereby enabling unhindered cross-border flows and ensuring that end-users receive the hydrogen quality needed				

		for their uses. These elements provide an increased clarity and visibility on hydrogen quality and related processes also for end-users. In addition, especially the EU-level rules on hydrogen quality management address the risk of negative impacts of different hydrogen qualities for end-users by allocating roles and responsibilities for quality handling to market participants, by increasing transparency on actual and forecasted cross-border qualities, and by ensuring proper regulatory oversight. The preferred option provides a proportionate approach by limiting the intervention to cross-border interconnection points to avoid market segmentation, without imposing hydrogen purity standards for the Member States' domestic hydrogen networks. Under the preferred option, Member States will still have the flexibility to define hydrogen quality requirements for their domestic networks which take into account the specificities of domestic hydrogen production technologies. It also provides a proportionate approach by setting the detailed technical specifications for the acceptable cross-border hydrogen purity level in either a delegated or implementing act. Given that as of today, there is limited availability of data on hydrogen purity levels and their implications for the infrastructure and end-use, this approach ensures that these very technical topics are addressed in the most proportionate manner, allows for strong stakeholder involvement, for the involvement of technical experts and for the assessment of emerging data and experience. This approach was used in the past to define technical rules for the natural gas market in the framework of network codes (equivalent to today's delegated acts and implementing acts). In terms of subsidiarity, EU action is needed as, voluntary standards – while they could in theory lead to an alignment of hydrogen purity levels between Member States – would lead to a convergence across Europe only slowly, or not at all. Further, fostering efficient and integrated EU hydrogen markets requires a harmonised and coordinated approach by the Member States, which can only be achieved efficiently by EU action (not by individual Member States). The preferred option avoids the distortive effects of uncoordinated, fragmented policy initiatives which may occur if Member States develop national approaches with regard to acceptable hydrogen purity levels. EU action has significant added-value by ensuring a coherent approach across all Member States. The preferred option imposes administrative costs on Member State authorities, including regulatory authorities, and on network operators, as they will need to implement the EU-level rules. At the same time, this option limits the costs of cross-border dispute settlement for all involved market participants (while these costs can still be significant under Option 2a, where cross-border disputes can still arise due to differences in the actual quality of transported hydrogen).

Table 39: Measures on transition of the regulatory principles I

Transition	**Objective**	Exemptions provide tailored waivers from certain regulatory requirements if this creates welfare benefit and a detrimental market impact is unlikely.				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	NA	**Individual exemptions for new and/or existing infrastructure**	**Like Option 2a, but:** Exemptions for infrastructure are granted with conditions that ensure convergence on the main regulatory principles. For example: Exempted networks (later) integrated in meshed network must comply with main regulatory principles. Exempted private networks have unilateral opt-in into regulated system. .	Only new infrastructure can be exempted (like Art. 36 Gas Directive)	Like Option 3a
Pros			Allows for assessment of market impact of each exemption. Temporary exemptions will eventually result in comprehensive applicability of regulatory requirements, thereby reducing potential distortions of competition.	Like Option 2a but: Requirement of convergence avoids regulatory barriers once network become more interconnected. It assures level playing field and avoids cherry picking. Unilateral opt-in for existing private network is low hanging fruit.	Main regulatory principles apply immediately throughout network. Lower regulatory costs (compared to Option 2).	Like Option 3a

				Provides roadmap for users' private infrastructure to inter-connected hydrogen grid and connected customers and producers.		
Cons			Since most hydrogen infrastructure will be new or repurposed, a large share of future hydrogen infrastructure may be eligible for exemptions. Delayed convergence in regulated structure when network gets more integrated. Potential of regulatory barriers once network is extended/integrated. Regulatory costs.	Unilateral opt-in delays convergence relative to relative to more prescriptive measures under Option 3 Regulatory costs.	Disruption to operation and financing structure of existing hydrogen networks.	Like Option 3a
Most suitable option	**Option 2b**	Option 2b will incorporate the benefits of Option 2a in that it fosters private investment. However, it addresses the specific disadvantage, closely associated with the fact that the meshed network that will exist in a mature phase of a market, will have grown out of initially disconnected network elements. In order for the operation of this progressively interconnected system to support a deeply integrated hydrogen market, it needs to be avoided that regulatory barriers develop as a result of the different regulatory regimes under which the initial elements of the network were build. Convergence on the main regulatory principles for network elements that later become inter-connected needs to be build-in.				

Table 40: Measures on transition of the regulatory principles II

Transition	**Objective**	Derogations reduce the regulatory burden for infrastructure that is typically less relevant for general market access				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	NA	**Derogations for** geographically confined networks	**Like Option 2a but:** Derogations expires once additional producers are connected and/or become part of meshed network	Like Option 2b	Like Option 2b
Pro			Allows vertical integration and non-regulated operation in situations where need for TPA is less likely. May incentivise investments in hydrogen infrastructure.	Allows vertical integration and non-regulated operation in situations where competition concerns is less likely. May incentivise investments in hydrogen infrastructure. Requirement of compliance once additional producers connect or network becomes part of wider meshed network avoids cherry-picking, assures/level playing field and fosters convergence.	Like Option 2b	Like Option 2b
Cons			Potential of regulatory barriers once network is extended/integrated.	Requires clear rules on connection rights for new network users to address moral hazard (i.e. remaining isolated to avoid regulation). Increased regulatory costs for monitoring.	Like Option 2b	Like Option 2b

Most suitable Option	**Option 2b**	Option 2b envisages derogations for geographically confined hydrogen networks to reduce the regulatory burden on these types of assets during the market ramp-up and in situations where competition concerns are less likely.

Table 41: Measures on permitting and land use rights

Permitting and land use rights	**Objective**	Clarity on the validity of permits and land use rights that have been granted for the construction and operation of natural gas pipelines once the transported gaseous energy carrier changes from natural gas to hydrogen, should prevent undue delay in repurposing natural gas pipelines for hydrogen transport. Coherence in the conditions for permitting and land use rights for newly built pipelines should on the one hand ensure that a different legal regime does not lead to delay in the development of pipelines that should complement repurposed pipelines and on the other hand that operators of newly built pipelines do not suffer from a competitive disadvantage vis-à-vis incumbent gas network operators that repurpose their pipelines for hydrogen transport.				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No EU rules	No EU rules	As a general rule, existing permits and land use rights granted for the operation of natural gas transport pipelines are grandfathered for the operation of hydrogen pipelines. However, no harmonisation of national rules.	Like Option 2a + General requirement that conditions for permitting and land-use rights for new hydrogen pipelines are aligned with those currently used for natural gas. However, no harmonisation of national rules.	Harmonisation of permitting and land use rights	Like Option 3a
Pro	Discretion MS	Discretion MS	Facilitates repurposing in all MS	Facilitates repurposing and puts newly built hydrogen infrastructure at par with natural gas, thereby avoiding bias in the feasibility of infrastructure projects and lock-in of natural gas. Leaves discretion to Member States to set location specific (technical safety) rules on permits and land use rights.	Conditions for repurposing and newly built infrastructure aligned within EU.	Like Option 3a
Cons	No alignment rules between MS	No alignment rules between MS	No clarity on permits and land use rights for newly built infrastructure.	Relevant rules are currently set at national level and might not be required at EU level (subsidiarity).	Relevant rules are currently set at national level. Potential proportionality and	Like Option 3a

					subsidiarity issue.	
Most suitable option	**Option 2b**	Option 2b prevents a potential delay in repurposing pipelines as a resubmission for a request for permits and land use rights once the transported energy carrier changes from natural gas to hydrogen is not needed. In addition, it creates a level playing field between (potential different operators of) repurposed and newly built pipelines. Infrastructure projects based on both repurposed and newly built pipelines do not face different legal regimes in terms of permits and land use rights. Option 2b leaves discretion to Member States to set location specific (technical safety) rules on permits and land use rights thereby preventing potential subsidiarity issues.				

Table 42: Measures on hydrogen consumers rights

Hydrogen Consumer rights	**Objective**	Provide for a level playing field across different energy carriers for relevant consumer groups				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	NA	No rules beyond defined elsewhere (e.g. TPA, hydrogen quality)	Consumer protection rules equivalent to those for larger consumers in Gas Directive	Consumer protection rules are those valid for all gas users (including e.g. SMEs, households)	Like Option 3a
Pro	Rules set between (private) operators and connected customers bi-laterally. No regulatory costs.	Rules set between (private) operators and connected customers bi-laterally No regulatory costs.	Leaves large scope of freedom to set conditions between users and suppliers. No additional regulatory costs.	Overall, level playing field between hydrogen and other energy carriers (assuming current electricity rules are made applicable to gas users) for relevant consumer categories.	All consumers treated at par with gas users. Perfect level playing field for energy carriers (assuming current electricity rules are made equivalent to gas users).	Like Option 3a
Cons	Risk that rules are biased by the interest of monopolistic operators. Divergence between customer categories and MS.	Risk that rules are biased to interest monopolistic operators. Divergence between customer categories and MS.	Divergence between customer categories and MS.	Limited regulatory costs.	In view of likely customer base for hydrogen (larger, more sophisticated consumers) full equivalence disproportional. High regulatory costs.	Like Option 3a
Most suitable option	**Option 2b**	The preferred Option 2b provides for consumer protection rules in principle equivalent to those for larger consumers under the Gas Directive, precisely, if households are connected to the hydrogen system they do benefit from basic rights but those which encourage participation in the market e.g. citizen Energy Communities are not extended to hydrogen provisions. It is important that these typical users of a hydrogen network have the same rights as if they would be connected to the natural gas grid as it provides a level playing field between hydrogen and other energy carriers for relevant consumer categories (under the condition that current gas rules are aligned to those for electricity users, see in this regards Policy Area 4). Choices between energy carriers would be made on economic grounds as opposed to regulatory treatment. It also avoids diverging measures between Member States for similar customer categories which could limit the uptake of hydrogen, at limited regulatory costs.				

		Option 2b also provides a proportionate approach in view of the expected customer base for hydrogen (larger, mainly industrial users). An approach like under Option 3a and 3b would be disproportional from this perspective and higher regulatory costs.

Table 43: Measures on terminology and certification of LCH/LCFs

Non-reneweble low carbon fuels	**Objective**	Provide for a level playing field across different energy carriers for relevant consumer groups				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	NA	Definitions of LCH/ LCFs + legal basis for issuing GOs or reference to existing GOs article 19 of RED II.	Definitions of LCH/ LCFs + legal basis for deploying a certification system based on an adapted methodology (based on existing ones for RFNBOs and RCFs) and using existing voluntary schemes for applying and certifying it.	Like Option 2b	Like Option 2b
Pro	Less complexity in the market since only RES gases will be defined and certified under the certification system of RED II.	Like BAU	Defining LCFs will allow for their certification. The light GOs approach for certification will be less costly for suppliers to implement.	In the spirit of the EU Energy system integration strategy, this certification system can build up on the best practices using the existing tools under the RED II. In order to avoid inconsistencies and ensure positive synergies, it can rely (to the degree possible) on the existing methodologies for RFNBOs and RCFs certification. It can also use the existing system of voluntary schemes. Using such comprehensive certification system would allow to enforce a level playing field across all energy decarbonisation options and this way ensure that Member states can effectively compare these options. Since such certification system is global, no discrimination can be expected to any economic operator inside or outside the EU. Further, it would need to include a requirement applying to the Commission, the Member states and operators to include such fuels in the Union database (in a mass-balance	Like Option 2b	Like Option 2b

				system (MBS)[28]). Although, the MBS can be adapted to reflect the specifics of the gas market, this would allow to ensure certain link between the supply and demand and would not allow the trade of sustainability certificates in a fully parallel system (as it is done under a pure book & claim system of GOs). Synergies with other elements of the present proposal, in particular the proposed extension of the entry-exit system to DSO level and the abolition of cross-border tariffs for renewables and low carbon methane gas.		
Cons	Not defining and certifying LCFs would mean that they would not be an available decarbonisation option for Member States or EU initiatives in harder to decarbonised sectors. This would be a missed opportunity to speed up the decarbonisation specifically in the short and medium term.	Like BAU	The light GOs approach may be problematic to implement if there would be reluctance by Member States to issue GOs in all circumstances and to include in the GOs the GHG emission footprint as mandatory information. However, the main drawback of using this certification system would be the potentially detrimental effect on RES fuels and RES Hydrogen, which will be certified against the more complex methodology under a life-cycle analyses approach of RED II.	A comprehensive certification system can build up on the existing knowledge, methodologies, and infrastructure of RED II but will be more difficult and costly to implement.	Like Option 2b	Like Option 2b

28 The MBS allows consignments of energy with different sustainability characteristics coming in to be mixed. The sustainability characteristic of consignments going out can be flexibly assigned as long as at the moment of net mass-balance verification (normally every 3 moths), the total quantity of energy in and out with their respective sustainability characteristics match, taking also into account any available stock on the site/s covered by the MBS.

Most suitable option	**Option 2b**	The main aim of the terminology and comprehensive certification system to be put in place for LCFs/ LCH is to ensure that all related GHG emissions are correctly accounted for in a life-cycle analyses approach. This in turn will enable Member States and economic operators alike to effectively compare their carbon footprint in a portfolio of possible energy solutions. Ultimately, such certification system will make a valuable contribution to market integrity and foster cross-border trade, specifically in the segment of hydrogen and hydrogen-based energy decarbonisation options. Taking also into account that such certification system will apply a global harmonised standard of certification, no discrimination can be expected to any economic operator inside or outside the EU. Having all this in mind, Option 1b is the preferred option, since its content fulfils all the necessary pre-conditions to achieve this objective. It will be based on a harmonised certification methodology, integrating all GHG emissions as well as applied in a harmonised way by a system of certification schemes, recognised by the Commission. Including the so certified LCFs in the union database in a mass-balance system would make further support to market integrity by ensuring traceability and efficient transfer of data on GHG emissions footprint along the value chains, which is crucial for intra-EU trade but also for imports of LCFs into the EU. Taking into account that the mandate of the development of the union database is already under RED II not much additional costs or administrative burden can be expected from its extension. The certification process would entail costs at the level of economic operators but it can be expected that they will be largely compensated by the economic opportunities which such certification would give in the context of the energy transition and achieving the decarbonisation targets, specifically at short and medium term. The preferred option is likely to have synergies with other elements of the present proposal, in particular the proposal to extent the entry-exit system to DSO level and the abolition of cross-border tariffs for renewables and low carbon methane gas.

Table 44: H2 inter- connectors with third countries

Regulation of H2 inter-connectors with third countries	**Objective**	Rules on the operation of hydrogen interconnectors with third countries should safeguard competition on the internal energy market and provide legal clarity for investors, operators and market participants.				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	No rules	No rules	Alignment with current rules in Gas Directive Full application of EU-level H2 network operation rules (i.e. unbundling, third-party access and regulated tariffs) to H2 interconnectors between EU Member States and third countries (including possibility of regulatory exemptions for new interconnectors).	Option 2a + Mandatory EU-level IGA As per Option 2a, rules for H2 interconnectors are set out in the Directive. In addition, the detailed operational rules for the entire H2 interconnector shall be enshrined in an intergovernmental agreement (IGA), concluded by the EU and the connected third countries.	Like Option 2b	Like Option 2b
Pros	-	N/A	The full application of EU-level H2 network operation rules (i.e. unbundling, third-party access and regulated tariffs) to H2 interconnectors with third countries would ensure a minimum degree of non-discriminatory third-party use of international hydrogen interconnectors, thereby enabling competition on EU hydrogen markets.	The conclusion of an EU-level IGA would ensure that a single set of rules would apply to the entire H2 interconnector. This in turn would avoid ‘conflict of laws’ situations where divergent sets of rules apply to sections of the interconnector. If required, such EU-level IGAs could diverge from the generally applicable EU law. Coherence across IGAs for different interconnectors would be ensured by their exclusive conclusion at EU level.	Like Option 2b	Like Option 2b

Cons	Lack of legal clarity regarding applicability of H2 network operation rules to international interconnectors may deter investments and could result in legal disputes. Risk of non-competitive market outcomes, limited market access and impediments for interconnection and cross-border trade.	N/A	International hydrogen interconnectors would typically be subject to two or more different legal orders (i.e. EU law and the laws of the third country or countries). This could result in a 'conflict of laws' situation where pipeline operators would have to apply divergent sets of operational rules to different sections of the hydrogen interconnectors.	Failure to agree on operational terms with the connected third countries might create obstacles to the construction and operation of new interconnectors.	Like Option 2b	Like Option 2b
Most suitable option	**Option 2b**	Option 2b builds upon the status quo for natural gas (i.e. application of EU market rules to interconnectors with third countries), but adds an IGA on operational rules prior to starting the operation of hydrogen interconnectors to help ensure the consistent application of the future EU framework on the operation of hydrogen networks to the entire infrastructure.				

Table 45: Measures on regulated asset base (RAB)

Regulated asset base (RAB)	**Objective**	Rules on regulated asset bases determine whether different types of network assets are financed by joint or separate network tariffs.				
	BAU **No additional measures**	Option 1 **Rights for network operation tendered**	Option 2 **Main regulatory principles**		Option 3 **Big bang**	
			2a: Main regulatory principles only	*2b: Main regulatory principles with a vision*	*3a: Hydrogen rules by Big Bang*	*3b: Hydrogen rules by Big Bang plus*
Measures	Separate RAB (due to current natural gas tariff rules)	Separate RAB (due to current natural gas rules)	Joint RAB allowed	Separate RAB Sub-option (at MS discretion): separate RAB but financial flows possible between them (subject to conditions, including financial flows only levied on domestic users and under NRA supervision)	Separate RAB	Separate RAB
Pros	No cross-subsidies between gas and hydrogen possible via gas tariffs. Competition distortion between private and regulated entities prevented.	Similar to BAU	Reduces administrative burden and regulatory costs. Enables lower network tariffs in hydrogen ramp-up phase.	Prevents cross-subsidisation between gas and hydrogen network users. Allows for cost reflective tariff setting for each asset base. Separate RABs from start facilitates valuation transferred assets Sub-option: Enables targeted cross subsidies of hydrogen networks to stabilise tariffs for early hydrogen network users. Cross-subsidies are transparent (as opposed in case of joint RAB) imposition	Prevents cross-subsidisation between gas and hydrogen network users. Allow for cost reflective tariff setting for each asset base. No possibility to support lower network tariffs in hydrogen ramp-up phase (within energy system) Separate RABs from start facilitates valuation transferred assets.	Like Option 3a

				on domestic users avoids cross-subsidies being financed by users in other MS. Provides exit route for phase-out cross-subsidies and avoids combined-RAB lock-in.		
Cons	Repurposing not-enabled.	Incentivising appropriate repurposing investments is challenging in a tendering approach.	Cross-subsidies between gas and hydrogen shippers and users. Competition distortion among incumbent and new network operators. Move to separate RABs later difficult. In view of cross-border tariffs in natural gas, risk that domestic hydrogen network development is financed by consumers in other Member States.	Increased regulatory costs for operation and monitoring. Sub-option: Increased regulatory costs as may require ITC mechanism and NRA supervision. Competition distortion among incumbent and new network operators (but less than under Joint RAB).	Increased regulatory costs. Need for transfer of assets for repurposing may complicate repurposing.	Like Option 3a
Most suitable option	**Option 2b**	Separate RAB for hydrogen prevents uncontrolled and non-transparent cross-subsidies between users of different networks. Sub-option: Targeted levies on domestic network exits allows for temporary cross-subsidisation in ramp-up phase, while avoiding an increase in cross-border tariffs and resulting detrimental impact on cross-border trade. More detailed explanations on the issue of the RAB are provided in text form below.				

Clarification of joint versus separate regulated asset base approach

The present section examines the respective advantages and disadvantages of a joint regulated asset base and a separate regulated asset base for gas and hydrogen networks and complements the above table on detailed measures.

The regulatory asset base (RAB) of a gas transmission system operator (TSO) includes all network assets used for the provision of the regulated service, i.e. the transmission of gas. The combined asset value (as approved by the national regulatory authority) forms the basis for the calculation of the TSO's allowed revenue, i.e. the revenue that has to be recovered from via regulated network tariffs.

If EU and national law would allow for a joint RAB for both gas and hydrogen network infrastructure, the combined value of all gas and hydrogen assets would be used to calculate the allowed revenue of the combined gas & hydrogen operators. A joint RAB should be considered mainly in combination with regulated network tariffs for both natural gas and hydrogen (as opposed to e.g. negotiated network tariffs for hydrogen) as the regulated and non-regulated activities would be difficult to separate and the combination in joint RAB would create moral hazard.

A joint RAB presupposes joint ownership of gas networks and hydrogen networks by a single entity and excludes the possibility of horizontal unbundling requirements (i.e. unbundling between different network activities by a single operator), such as account unbundling, legal/functional unbundling or ownership unbundling between gas network operation and hydrogen network operation.

A joint RAB would enable cross-subsidies between the two types of networks (i.e. gas and hydrogen) that make up the RAB, but does not prescribe them. This possibility could be used to subsidise new dedicated hydrogen networks. However, the introduction of a joint RAB does not *per se* determine the **direction** of these cross-subsidies, nor their **extent**. Additional rules on tariff setting for combined gas/hydrogen operators would be required to regulate these two elements.

Advantages and disadvantages of a joint RAB

This section outlines the pros and cons of a joint RAB model in the abstract. Different implementation options for joint RAB models (and separate RAB models) and their respective pros and cons are set out further below.

Advantages

Enables financing of hydrogen network in the start-up phase via cross-subsidies by methane network users

By including hydrogen assets in the regulated asset base for gas, the currently large number of natural gas users could be paying for an unspecified share of hydrogen infrastructure costs. This holds true particularly in the ramp-up phase of hydrogen, where the number of hydrogen network users is likely to be significantly smaller than for natural gas and hydrogen networks are not (yet) booked to full capacity. The concrete level of cross-subsidisation would depend on tariffication rules. As regards tariff regulation, one option would be to apply the same tariff methodology to both gas assets and hydrogen assets in the combined regulated assets base, thereby equalising tariff levels for both types of infrastructure (see quantification estimates by FNB Gas and Guidehouse/Frontier Economics below which are based on this approach).

A joint RAB can reduce tariff volatility resulting from changing booking behaviour or customers leaving the market, which could be severe for a market with a limited number of customers. It can also reduce the specific tariff in a situation where the infrastructure is designed at a larger capacity than initially required to accommodate an increasing customer base. This holds true particularly in the ramp-up phase of hydrogen, where the number of hydrogen network users is likely to be significantly smaller than for natural gas.

Protects systems with high switching rates from price shocks

In systems with a high share of industrial users, a joint RAB could also prevent sudden increases of methane network tariffs, in a situation where the system operator loses capacity revenues from major customers that switch from methane to hydrogen. The remaining customers would then need to refinance the remaining costs, which may entail sudden tariff rises on the methane side. In a joint RAB, the revenue from those major customers switching to hydrogen would still help to finance the overall network cost and thereby help to keep methane network tariffs stable.

Reduces transaction costs for repurposing of gas pipelines

A joint RAB implies joint ownership of natural gas and hydrogen asset by a single operator, i.e. without horizontal unbundling. The absence of horizontal unbundling would remove the need to transfer gas assets intended for repurposing between different entities (e.g. TSO subsidiaries) or regulatory accounts (in the case of accounts unbundling). This could reduce transaction costs for the respective gas TSOs who own the gas assets and would like to repurpose and operate them for hydrogen transportation. The quantitative impact of this effect is difficult to estimate and would depend on the type of horizontal unbundling in the counter-factual (e.g. higher cost difference for legal/functional unbundling, lower cost difference for accounts unbundling).

Disadvantages

Forces captive gas customers to finance networks primarily used by industry

In a joint RAB model, current household and commercial gas consumers could be forced to pay a share of the costs of the developing hydrogen network (including new investments). In the start-up phase of the EU hydrogen economy, the beneficiaries of this imposed cross-subsidisation would be the initial users of hydrogen, i.e. mainly industrial consumers. The ability of these natural gas users to switch in the short-term from gas to other energy carriers may be limited due the required change of appliances: Whereas the household customer base is expected to decrease (e.g. due to switching to heat pumps), those households which cannot afford a change of their heating system would be captive to the possible price increase for methane. Moreover, once a ‘tipping point’ of hydrogen ramp-up is reached (i.e. where hydrogen use exceeds natural gas use), a joint RAB might lead to a cross-subsidisation of methane users and could then deter switching to other energy sources.

Likely increases cross-border gas tariffs and creates rules fragmentation between Member States

In a joint RAB scenario, for a hydrogen ramp-up period, natural gas tariffs are likely to be higher than in a comparable separate RAB scenario. This possible increase in natural gas tariff levels would also affect tariffs at interconnection points between Member States[29]. Gas transit would thus be more expensive in a joint RAB scenario and these additional costs would be borne particularly by gas-importing Member States with no or insufficient direct import routes. These Member States would thus be contributing to the financing of hydrogen networks in gas-transiting Member States.

Moreover, if Member States were allowed to choose between a joint or separate RAB, this may lead to a fragmentation of market rules within the internal energy market. For instance, in Member States with a joint RAB, hydrogen tariffs would be more likely to be regulated, whereas other Member States might opt for negotiated access tariffs (depending on the EU rules for hydrogen tariff regulation). Such divergence in network access rules could in turn complicate cross-border capacity bookings and thereby impede the integration of national hydrogen markets.

Creates a competitive advantage for existing gas TSOs with risks of conflict of interest regarding network planning

Without any additional checks by the national regulatory authorities, there could be a risk of a conflict of interest on the side of combined hydrogen/methane network operators that leads to a bias in favour of overinvestment into hydrogen networks, since the existing methane customer base could be used to create attractive initial tariffs. Another risk is an over-dimensioning of the hydrogen system on the basis of demand expectations that would not materialise.

Moreover, a joint RAB could distort competition on the market for hydrogen network services: Incumbent gas TSOs would be better placed to develop hydrogen networks under a joint RAB model than other market participants. This competitive advantage of combined operators might also create a bias with regard to decommissioning of natural gas pipelines.

Estimates on tariff impact of a joint RAB

It is difficult to estimate the impact of a joint RAB model compared to a separate RAB model in quantitative terms (i.e. the effect on the level of network tariffs for gas and hydrogen networks) due to the many variables in this equation.

Notably, the effects depends on i) the value of the gas network, ii) the value of gas assets repurposed for hydrogen transport, iii) the cost of additional new-build hydrogen infrastructure, and iv) the changes in demand for gas and hydrogen capacity.

The estimate by FNB Gas and the sample calculation by Guidehouse/Frontier Economics examined below should therefore serve only to describe the manner in which a joint RAB could affect gas tariff levels but do not reflect a likely outcome in absolute terms.

FNB Gas estimate of a joint RAB

FNB Gas, the association of German gas TSOs has published a press release[30] with an estimate as to the impact of a joint RAB on gas tariffs: based on required investments into hydrogen infrastructure of EUR 290 m by 2025, and EUR 600 m by 2030, gas tariffs in Germany would increase by ‘less than 1%’. These calculations are based assuming the same

29 Assuming there is no change to the current entry-exit model of gas tariffs, in which tariffs are charged at entry points and exit points from markets areas which are typically aligned with Member State borders.

30 https://www.fnb-gas.de/fnb-gas/veroeffentlichungen/pressemitteilungen/fernleitungsnetzbetreiber-veroeffentlichen-h2-startnetz-2030/

tariff for both methane and hydrogen points. However, this calculation compares methane network tariffs before repurposing with combined RAB tariffs after repurposing. In a separate RAB scenario, methane network tariffs could be lower due to the expected changes in the active-asset structure. The cost difference to the detriment of methane network users could thus be higher than the estimated 1%.

Guidehouse/Frontier Economics sample calculation

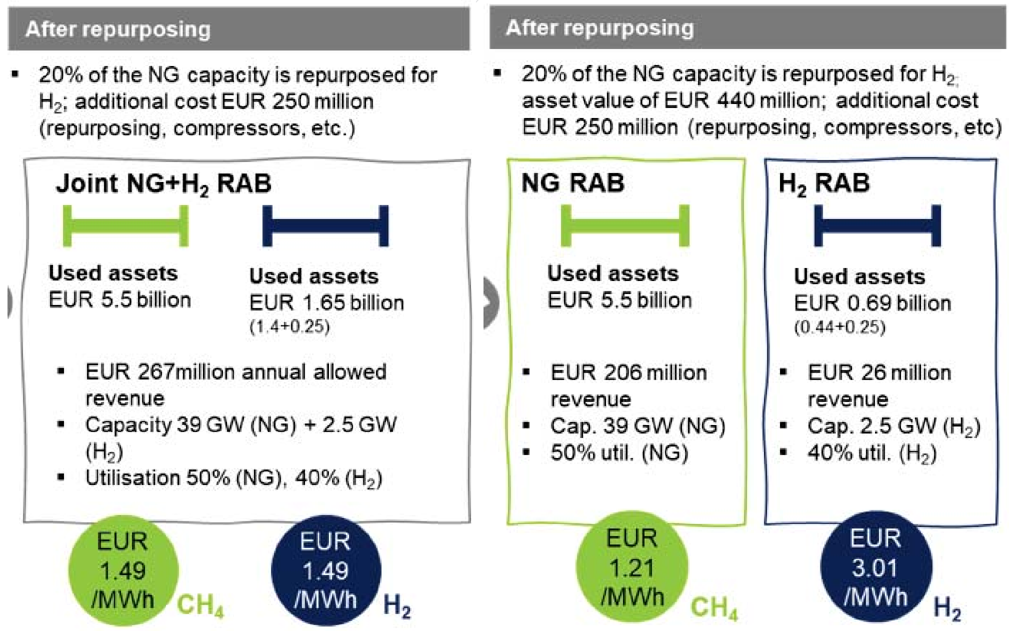
In a study prepared by Guidehouse and Frontier Economics for the Commission, the consultants include a sample calculation for possible changes in tariff levels for stylised joint and separate RAB scenarios, based on the following assumptions: EUR 250 m additional investments into hydrogen infrastructure; constant capacity demand; hydrogen tariffs subsidised to achieve tariff parity for the joint RAB (versus cost-reflective hydrogen tariffs in the separate RAB scenario). Based on these calculations, tariffs could evolve as follows:

- Joint RAB: unitary tariffs of **EUR 1.49/MWh** for **both gas and hydrogen**
- Separate RAB: **gas** tariff of **EUR 1.21/MWh**; **hydrogen** tariff **of EUR 3.01/MWh** (unsubsidised)

- In this sample calculation, gas tariffs are considerably lower in a separate RAB scenario (EUR 1.21/MWh) than the unitary methane/hydrogen network tariff in the joint RAB scenario (EUR 1.49/MWh). This would equate to an **additional financial burden of a 25% increase of network tariffs borne by methane users in the joint RAB scenario** (compared to the corresponding separate RAB scenario).

Figure 16: Estimates for impacts on tariffs of joint versus seperate RAB

Figure below: Joint RAB estimate Guidehouse   Figure below: Separate RAB estimate Guidehouse



Stakeholder opinions

The Commission's public consultation on the hydrogen and gas market decarbonisation package contained two questions on the issue of cross-subsidies between gas and hydrogen network users. 28%[31] of respondents agreed with enabling cross-subsidies in the ramp-up phase, while 34%[32] were in favour of prohibiting cross-subsidies.

- *Stakeholders in favour of a joint RAB*

  Respondents that mainly represent incumbent natural gas TSOs and DSOs or their associated stakeholder organisations and the majority of industrial (mostly German) energy consumers and their associated stakeholder organizations expressed a preference for a joint RAB in order to allow for (partial) cross-subsidisation.

- *Stakeholders against a joint RAB*

  National regulatory authorities, NGO's, consumer associations, research institutions and existing private pipeline operators have indicated to be opposed to the concept of a joint RAB.

Different options for implementation

This section discusses further technical details for the implementation of both joint RAB and separate RAB models.

Joint RAB

As pointed out above, prescribing or allowing a joint RAB would leave open the extent and direction of cross-subsidises. Moreover, in the absence of EU-level tariff rules for hydrogen with corresponding NRA competences in tariff setting, the power of NRAs to safeguard competition and market functioning may be hampered (e.g. if the level of cross-subsidisation is set by Member State governments without NRA involvement). Therefore, the starting point for allowing for a joint RAB approach should be the application of common tariff-setting principles as currently set out in Article 13 of the Gas Regulation and the Network Code on gas transmission tariff structures (TAR NC). This could include a common tariff methodology and a unitary base tariff for the gas and hydrogen pipelines in a given RAB. However, it does not solve the issue of increased cross-border tariffs and resulting detrimental impacts on cross-border trade.

Joint RAB with regulatory safeguards

Additional regulatory safeguards could be envisaged in EU legislation to mitigate the risks of a joint RAB model outlined above. For instance, TSOs could be required to publish a database with the value of repurposed assets (a 'regulatory shadow account'). This would create transparency as regards the level of subsidies and would give regulators more insights in the repurposing of gas assets. Regulators may also have to explicitly agree to repurpose. However, it would not solve the issue of tariff pancaking and resulting detrimental impacts on cross-border trade (barring changes to current Union rules on gas tariffs). Mitigation measures could also increase regulatory costs for national regulatory authorities, e.g. when monitoring additional transparency requirements. Moreover, the effectiveness of these mitigation measures would be dependent on compliance with behavioural requirements (as opposed to structural remedies) and may vary across the Union. Regardless, mitigation measures such as a regulatory 'shadow account' should be considered the regulatory minimum requirement for prescribing or allowing a joint RAB.

31 Out of approx. 260 respondents, including 86 who did not reply to this question.
32 Out of approx. 270 respondents, including 90 who did not reply to this question.

Separate RAB

Prescribing a separate RAB without the possibility of cross-subsidies in EU legislation would avoid the risks associated with a joint RAB as outlined above, notably the increase of pancaking and cross-subsidies by users of methane-importing Member States. It would also prevent a fragmentation of rules between Member States applying a joint or separate RAB. While the financing of hydrogen networks via cost-reflective tariffs could result in higher tariffs during the ramp-up phase[33], other targeted forms of network financing from EU or national facilities could help mitigate this downside (since network tariffs would only have to cover the remaining capital expenses). Other disadvantages of a separate RAB, such as the possible higher transactional costs for repurposing, could be addressed (for example by allowing 'grandfathering' of infrastructure permits and land-use rights for gas pipelines intended for hydrogen use.

Separate RAB with the possibility of temporary financial flows between sectors

If a separate RAB is prescribed in EU legislation, the possibility of temporary financial flows between sectors could be envisaged during the hydrogen ramp-up phase. The level of such financial flows could be left to Member States. The level of financial flows could be fixed or tied to the level of revenues from hydrogen network tariffs, thereby creating a revenue floor for hydrogen network operators. This would allow to keep hydrogen tariffs low in the ramp-up phase, while avoiding the downsides of a joint RAB in the mid- to long-term. In order to avoid a possible adverse effect on cross-border trade, a subsidy mechanism should exclude increases to cross-border tariffs charged at interconnection points of the natural gas grid is excluded (e.g. a transparent temporary levy on domestic exits of the gas grid). As indicated above, other disadvantages of a separate RAB, such as the higher transactional costs for repurposing, could be addressed by EU rules on permitting.

Given the more transparent and direct nature of such a subsidy mechanism, it could also be phased-out more easily after the ramp-up phase for hydrogen networks. Such an exit strategy is more difficult under an initial joint RAB, notably due to asset valuation issues.

Recommended option

In view of the risks of a joint RAB model described above (pancaking, cross-subsidies by gas consumers and gas-importing Member States, conflicts of interest in network planning, distortion of competition, market fragmentation), prescribing the use of separate RABs should be the preferred option. The use of targeted financing options for hydrogen infrastructure should be considered in order to keep hydrogen network tariffs at reasonable levels in the ramp-up phase. Further measures to facilitate repurposing of methane assets could also be considered, e.g. with regard to permitting. The possibility of temporary financial flows between sectors could be envisaged during the hydrogen ramp-up phase, with appropriate regulatory safeguards to ensure transparency and to avoid an adverse effect on cross-border trade.

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33 In absolute terms, but not necessarily in terms of the network tariff's share of total cost of hydrogen, given the higher commodity cost compared to natural gas.

ANNEX 7: DETAILED MEASURES FOR PROBLEM AREA II: RENEWABLE AND LOW CARBON GASES IN THE EXISTING GAS INFRASTRUCTURE AND MARKETS, AND ENERGY SECURITY

Each option for Problem Area II: Renewable and low carbon gases in the existing gas infrastructure and markets, and energy security considered in Section 5.2 of this Impact Assessment comprises (or not) a set of more detailed measures. Please see also the summary table at the end of Section 5.2 in this regard.

This Annex contains an assessment for each of these more detailed measures.

Tables assessing individual measures

Table 46: Measures on access of RES&LC gases to hubs and transmission grids

Access of RES&LC gases to hubs and transmission grids	**Objective**	Enable access of local production of biomethane to the markets			
	BAU **No additional measures**	Option 1	Option 2	Option 3	Option 4
Measures	Access of RES gas is not explicitly dealt with in the current framework. General principle of non-discrimination and the objective for NRAs to help to integrate production of gas from renewable energy sources in both transmission and distribution.	Access of locally produced gases to the hubs and the transmission grid. Enabling physical reverse flows between DSO and TSO.	As Option 1 plus: Connection obligation with firm capacity for new RES&LC gases. Reducing costs of injection for renewable and low carbon gases		
Pros	Limited administrative burden as no new legislation is introduced.	Compliance with the 55% GHG emission reduction target. Improved marketing options.	Biomethane production might be realised at lower total costs as in Option 1. State aid less needed.		
Cons	Patchwork of various provisions in the Member States will persist	Investments costs for reverse flows compressors.	Reducing injection tariff and access tariff is not respecting fully the principle of costs-reflectivity. Connection costs may increase the abatement costs by some €15 to 30/t (from a level of €400/t).		
Most suitable option	**Option 3**	The option contains maximum of measures to support renewable gases. Some elements will be also imported from other options, namely rules on citizens energy communities included from the discarder option and assessed under Problem Area IV. The costs of biomethane production would be lowered (slightly) by a possibility to release producers from injection and connection costs.			

Table 47: Measures on treatment of cross-border tariffs (pancaking)

Treatment of cross-border tariffs (pancaking)	**Objective**	Ensure unhindered cross-border flow and trade of new gases			
	BAU **No additional measures**	Option 1	Option 2	Option 3	Option 4
Measures	Cross-border tariffs for transport of gases are set on interconnection points between MS. No detailed rules to facilitate regional mergers.			Removing cross-border tariffs from interconnection points within EU for RES&LC gases only. Eligibility would be based on presenting the GOs to the TSO. Facilitating voluntary regional gas market mergers (Guidance by the Commission). Measures for transparency of allowed revenues, costs benchmarking.	Removing cross-border and der tariffs from interconnection points within EU for all gases in the methane network.
Pros	Limited administrative burden as no new legislation is introduced. No need to negotiate an ITC mechanism between TSOs and NRAs.			Costs of RES&LC gases reduced. RES&LC gases can move more freely across the borders than natural methane. Assistance for Member States voluntarily engaging in market mergers. Measures on allowed revenues will reduce the outliers on cross-border tariffs. May help tracking RES&LC consumption.	Overall welfare increase for consumers. More gas-to-gas competition Wholesale prices in the S-E EU will fall. Exit tariffs will need to increase in most MSs. Peer review for allowed revenues. Gas market design closer to the electricity market.
Cons	No promotion of regional mergers, no changes to current tariff system. Issue of pancaking is not addressed.			Option to address tariffs removal only on a regional level.	Significant impact on the European gas market. Most TSOs will lose revenues, ITC will be necessary. Administrative costs related to ITC mechanism which will be higher than in electricity. Uncertainty for the gas-consuming industry. Risk of gas to coal switch in power production in PL and NL.
Most suitable option	**Option 3**	The option would contribute to integrate RES&LC as it would allow transporting these gases free of cross-borders tariffs (avoiding pancaking for RES&LC). On top this options aims to introduce, measures for transparency of allowed revenue, and costs benchmarking as well as guidance facilitating voluntary market mergers.			

Table 48: Measures on long-term contracts (LTC)

Long term contracts (LTC)	**Objective**	Ensure long-term clarity for decarbonisation for gas sector and avoid lock-in effects, in line with climate-neutrality objective until 2050.			
	<u>BAU</u> **No additional measures**	<u>Option 1</u> **Allow RES&LC full market access**	<u>Option 2</u> **Allow and promote RES&LC gases full market access**	<u>Option 3</u> **Allow and promote RES&LC gases full market access, tackle issue of long term supply natural gas contracts and remove cross-border tariffs for RES&LC gases**	<u>Option 4</u> **Allow and promote RES&LC gases full market access, tackle issue of long term supply natural gas contracts, EU standards for gas quality and remove cross-border tariffs for all gases**
Measures	No sector specific rules exist as regards gas supply contracts in terms of their duration. Derogations from third party access possible on the take-or-pay obligations concluded in long-term supply contracts (Art. 35 and 48).			As Status Quo plus: Remove privileges (derogations) for new long-term natural gas contracts, signed after [entry into force of the GR], and limit duration of such contracts to 2049.	As Option 3 plus: Introduce time limit for new long-term contracts already before 2050.
Pros	No administrative burden.			Tendency to increase the market price for natural gas. Increase the volume risk of the LTC buyer of natural gas. Clear long-term signal to the industry. Energy security maintained as short-term contracts still possible.	Similar as Option 3 but duration of contracts limited as from near future.
Cons	No clear signal to the industry. New LTC can be signed and can run after 2050, no time limits. Derogations for LTCs are maintained. Negative impact on decarbonisation objectives.			Consumers would see a slight increase of their gas bill on a long term. LTCs can still be signed for a long duration (e.g. 25 years). No full ban of natural gas.	Consumers would see a slight increase of their gas bill on a long term. No full ban of natural gas.
Most suitable option	**Option 3**	Removing the privileges for long term contracts and limiting their duration to 2049 will give a clear long-term signal to the industry towards decarbonisation at the same time maintaining energy security as short-term contracts will be still possible. This option may as well lead to a slight increase of wholesale gas prices with a long-term effect in terms of organising the energy transition.			

Table 49: Measures on gas quality

Gas Quality	Objective	Ensure unhindered cross-border flows of gases and interoperability of markets			
	BAU **No additional measures**	Option 1	Option 2	Option 3	Option 4
Measures	Do nothing. Stronger enforcement. Revision of CEN standards to include renewable and low-carbon gases.	Reinforced cross-border coordination on gas quality management and transparency on national hydrogen blending levels.	EU rules setting principles for processes, roles, responsibilities, cost recovery and allocation, regulatory oversight and reinforced cross-border coordination of gas quality management. Variant: Setting detailed EU rules.		As Option 2/3 plus: EU-level harmonisation of gas quality standard for cross-border interconnection points, based on the quality of natural gas. Variant: Quality standards potentially based on biomethane quality parameters.
Pros	Limited administrative burden as no new legislation is introduced.	Limits the risk of cross-border flow restriction and market segmentation. Supports the integration of renewable and low-carbon hydrogen at the TSO level. Limited intervention; leaves flexibility to the Member States on hydrogen blending. Limited administrative costs.	Harmonised EU approach on gas quality management supports aligned application of gas quality standards. Reinforced cross-border coordination limiting the risk of cross-border flow restriction and market segmentation to a minimum. Leaves flexibility to Member States on application of gas quality standards for the domestic network (i.e. not interfering with the specificities of domestic gas production). EU allowed cap for hydrogen blends for cross-border points supports the integration of renewable and low-carbon hydrogen into the network. Harmonised approach on blending limits the risk of market segmentation. Stakeholder support for EU-level harmonization of gas quality management and reinforced cross-border coordination.		EU gas quality standard provides fully harmonised approach for cross-border IPs, eliminating the risk of cross-border flow restrictions and market segmentation, strongly limiting the risk of cross-border disputes. Supports the integration of biomethane by limiting the cost of adapting biomethane to existing gas quality standards.

Cons	Applicable standards would remain non-binding; risks of cross-border flow restrictions and market segmentation. High potential of cross-border disputes due to differences in gas qualities/blending levels. Gas quality specifications would continue to be mainly defined by the quality parameters of natural gas, limiting the integration of renewable and low-carbon gases in the existing gas network. Stakeholder do not support this option.	Significant costs for TSOs/DSOs and end-users for adapting infrastructure elements and end-use appliances. High abatement cost. Risk of cross-border disputes due to differences in gas quality/blending levels remains very high, which may lead to market segmentation.	Risk of cross-border disputes due to differences in gas quality is limited but still remains. Setting detailed EU rules for gas quality management might be over prescriptive, limiting the flexibility of Member States to reflect national specificities.	Increases cost of gas quality management to comply with the EU gas quality standard. Biomethane quality standard would imply additional quality adaptation cost for other gases in the network. High administrative costs for market participants and authorities.
Most suitable option	**Option 3** (containing Option 2)	Reinforced cross-border coordination on gas quality limits the risk of cross-border flow restriction and market segmentation to a minimum. The harmonised EU approach on gas quality management supports aligned application of gas quality standards. In detail: Under the preferred option gas quality would be governed by a harmonised EU approach for cross-border interconnection points while leaving flexibility to the Member States on the application of gas quality standards in their domestic networks (i.e. without interfering with the specificities of domestic gas production). The preferred option achieves the desired objective of ensuring unhindered cross-border gas flows by strengthening the cross-border regulatory framework and thereby limiting the risk of market segmentation to a minimum. In case Member States (or TSOs) transport cross-border gases, which do not comply with the applicable gas quality and/or blending specifications, the preferred option provides a dispute resolution tool to find agreements. These elements provide an increased clarity and visibility on gas quality and related processes for end-users. In addition, especially the EU-level rules on gas quality management address the risk of negative impacts of different gas qualities for end-users by allocating roles and responsibilities for gas quality handling to market participants, by increasing transparency on actual and forecasted gas quality and the cost of gas quality management, by setting out principles for the recovery of costs incurred by gas quality		

		management and where necessary for the allocation of such costs also cross-border and by ensuring proper regulatory oversight for the improved framework. The preferred option provides a proportionate approach by limiting the intervention to cross-border interconnection points to avoid market segmentation, without imposing gas quality standards or blending obligations at domestic level. In doing so, it leaves flexibility to the Member States to define such standards for the domestic network if they wish so, taking into account the specificities of domestic gas and hydrogen production. In terms of subsidiarity, EU action is needed as, while voluntary standards could in theory lead to an alignment of gas quality specifications and hydrogen blending levels between Member States, they would lead to a convergence across Europe only slowly, or not at all. Further, fostering more efficient and integrated EU markets for gases requires a harmonised and coordinated approach by all Member States, which can only be achieved efficiently by EU action. This option also avoids the distortive effects of uncoordinated, fragmented policy initiatives as many Member States develop national approaches, e.g. with regard to allowed hydrogen blending levels. EU action has significant added-value by ensuring a coherent approach across all Member States. In comparison, Option 1 relies solely on a cross-border dispute settlement tool, risking suboptimal outcomes and increasing the administrative costs for TSOs, NRAs and ACER (especially with an increased number of disputes due to differences in gas qualities and blending levels). As significantly different levels of blending are expected between Member States, this will not resolve cross-border flow constraints. In the absence of clear cross-border rules TSOs would likely reject the flows, or the injection of these gases, which would limit the integration of renewable and low-carbon gases. Voluntary standards could in theory lead to an alignment of gas quality specifications between Member States, if national authorities or network operators adopt them. For example, several interconnected Member States with high ambitions for hydrogen or biomethane integration might have an incentive to align their gas quality standards in order to ensure cross-border flows. In the practice however, the experience with the cross-border application of existing gas standards show, that the voluntary approach would lead to a convergence of gas standards across Europe only slowly, or not at all. Mandatory standards on the other hand (Option 4), could ensure the alignment of standards within the EU but might not reflect the national contexts and lead to unreasonable costs for adapting gas infrastructure and end-user equipment, appliances and processes.

Table 50: Measures on hydrogen blending cross-border framework

Hydrogen blending cross-border framework	**Objective**	Ensure unhindered cross-border flows of gases and interoperability of markets			
	BAU **No additional measures**	Option 1 **Allow RES&LC gases full market access**	Option 2 **Allow and promote RES&LC gases full market access**	Option 3 **Allow and promote RES&LC gases full market access, tackle issue of long term supply natural gas contracts and remove cross-border tariffs for RES&LC gases**	Option 4 **Allow and promote RES&LC gases full market access, tackle issue of long term supply natural gas contracts, EU standards for gas quality and remove cross-border tariffs for all gases**
Measures	Do nothing. As no rules for cross-border flows of hydrogen-gas blends exist, no implementation or enforcement would take place.	Reinforced cross-border coordination and transparency on national hydrogen blending levels.	EU rules setting an allowed cap for hydrogen blends that Member States must accept at cross-border interconnection points and reinforced cross-border coordination.		As Option 2/3 plus: Prohibition against the acceptance of blending levels above maximum cap of hydrogen blends at cross-border IPs.
Pros	Limited administrative burden as no new legislation is introduced.	Limits the risk of cross-border flow restriction and market segmentation. Supports the integration of renewable and low-carbon hydrogen at the TSO level. Limited intervention; leaves flexibility to the Member States on hydrogen blending in the domestic network. Strong stakeholder support for blending and for setting allowed blending thresholds at national level with EU cross-border framework. Limited administrative costs.	EU allowed cap for hydrogen blends for cross-border points supports the integration of renewable and low-carbon hydrogen into the network. Harmonised approach on blending limits the risk of market segmentation. Leaves flexibility to Member States on application of gas quality standards for the domestic network (i.e. not interfering with the specificities of domestic gas production). Reinforced cross-border coordination limiting the risk of cross-border flow restriction and market segmentation to a minimum.		Maximum cap of hydrogen blends limits the adaptation costs.

Cons	Applicable rules on hydrogen blends would continue to be set at national level; their application cross-border would not be aligned risking cross-border flow restrictions and market segmentation. High potential of cross-border disputes due to differences in blending levels. Stakeholder do not support this option.	Significant costs for TSOs/DSOs and end-users for adapting infrastructure elements and end-use appliances. High abatement cost. Risk of cross-border disputes due to differences in blending levels remains very high, which may lead to market segmentation.	Increasing adaptation and CO2 abatement costs (depending on the actual blending level chosen). Divided views among stakeholders on the role of blending hydrogen. Limited support for EU-level allowed cap for hydrogen blends for cross-border points. Only limited support by stakeholders in the public consultation for setting binding EU-level allowed cap for hydrogen blends at cross-border points.	Maximum cap of hydrogen blends might limit blending in a few Member States (depending on the actual threshold chosen). High administrative costs for market participants and authorities.
Most suitable option	**Option 3** (containing Option 2)	5% allowed cap for hydrogen blends at cross-border points, which TSOs must accept (but without setting a blending obligation). An EU allowed cap for hydrogen blends for cross-border points supports the integration of renewable and low-carbon hydrogen into the network and limits the risk of market segmentation, without imposing a blending obligation, i.e. leaving choice to the Member States. Setting this EU allowed cap at 5% would enable the integration of 70 TWh hydrogen per year at an adaptation cost of €3 bn/year. A higher cap would increase the adaptation costs drastically (€5 bn/year for 10% or €12 bn/year for 20%). See further details below.		

Gas quality: Hydrogen blending cross-border framework

The variety of sources of gases transported through the EU's methane gas networks represents a variety of gas qualities, with different physical and chemical characteristics. In practice, the injection of growing volumes of renewable and low-carbon gases is changing the parameters of gas transported and consumed in the EU. Therefore, the Impact Assessment looks at the consequences of blending hydrogen into the existing gas grid on gas quality. These quality changes can have negative impacts on the cross-border gas flow and can cause problems and additional costs, especially for system operators and end-users. Significant differences in the quality of gases can make gas quality management more complex and costly for all involved market participants.

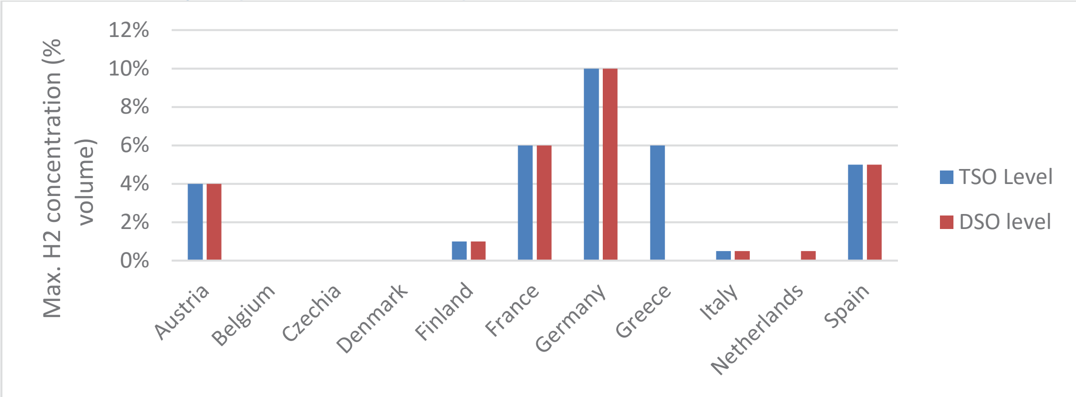
This is in particular relevant for hydrogen, where blending of already limited volumes affects the design of gas infrastructure, end-user applications, and cross-border system interoperability. Hydrogen has a lower specific energy content which reduces the calorific value of the gas mix and the methane number (important for gas engines), and can affect combustion properties. Not all gas infrastructure components and gas consumers are able to cope with blended gases. If hydrogen blending into gas grids exceeds specific thresholds, this implies substantial additional investments to upgrade the existing grid infrastructure (e.g. distribution and transmission pipelines, gas metering and monitoring) and end-user equipment (e.g. power generation plants gas engines, residential appliances, industrial equipment)[34].

Heterogeneous hydrogen blending levels in the EU

Currently, allowed hydrogen blending rates are determined in some Member State and vary significantly (see *Figure 17*). The highest allowed hydrogen admixture rates are in Germany (10%), France (6%), Greece (6%) and Spain (5%). Allowed hydrogen admixture rates are lower in Finland (1%), Ireland (0.1%mol), Italy (0.5%), Lithuania (0.1%mol) and the Netherlands (0.02%). Belgium, the Czech Republic and Denmark do not allow hydrogen blending while in all other 15 Member States no regulation exists. Thus, national hydrogen admixture regulation highly varies and raises a need for closer cooperation and alignment between Member States as it otherwise entails the risk of trade restrictions and a fragmented EU gas market.

34 These costs depend also on the extent of integration of hydrogen blended gas. If blended gas is only distributed at the level of some specific grids (with possibly different blending levels per grid), the costs may be limited. If the ambition is to set a national hydrogen blending level at the transmission level (resulting into the acceptance of this level for all distribution grids) the costs may be higher. For a level of maximum X % hydrogen blended, the whole transport network must be refurbished to support between 0 and X % hydrogen at any time to cope with the local variations of hydrogen and natural gas injected, with significant adaptation costs.

Figure 17: Maximum hydrogen concentration regulation or objective



Source: (ACER, 2020), (FCHJU, 2021)

Main impacts of the policy options

Chapter 6.3 of the study supporting the Impact Assessment[35] is focusing on the impacts of establishing a regulatory framework for hydrogen blending, especially a cross-border framework ensuring unhindered cross-border flows and avoiding market segmentation. It analyses the impacts of four situations with regard to blending hydrogen into the existing gas network:

1. No measure taken (option BAU);
2. Measures ensuring cross-border coordination between Member States (Option 1);
3. Implementation of an allowed cap for hydrogen blends at cross-border points (Option 2/3); and,
4. Implementation of a maximum cap at cross-border points in addition to the lower allowed cap for hydrogen blends (Option 4).

For this assessment, the study estimates national hydrogen blending thresholds in the transmission networks and based on this clusters of cooperating Member States. It constructs different 'cluster configurations' depending on the policy options chosen and their associated minimum and maximum allowed caps for hydrogen blends. The minimum and the maximum allowed caps considered in the analysis are 5%, 10%, 20% and 30%[36,37].

The clusters, which are used to assess the different impacts of the policy options, were determined according to the following rules:

- If a Member State cooperates with another, they coordinate regarding the establishment of a joint allowed threshold. In this analysis, the highest national blending threshold of the cluster was chosen as the joint allowed threshold for each cluster. The gas flows between countries cooperating are not constrained.
- Gas systems are supposed to cope with dynamic blending thresholds between 0% and the allowed threshold at any point in time.

[35] Assistance to assessing options improving market conditions for bio-methane and gas market rules (Artelys, 2021).

[36] The blending levels (in %) are expressed in volumetric terms and represent the hydrogen blending rates at the transmission grid level. 10% blending rate means in this analysis that 10% of the volume is constituted by hydrogen, which represent approximately 3% of the energy content of the gas mixture (HHV).

[37] The methodology is described in more detail in Chapter 6.3.1 of the supporting study (Artelys, 2021).

- Gas flows from a country with a lower blending level to a country with a higher one are feasible. However, gas flows from a country with a higher blending level to a country with a lower one are not feasible. It would be technically possible thanks to deblending stations at interconnection points, but the associated costs would be significant, thus this solution was discarded in the analysis.

Under option BAU no EU-level measure is taken and Member States continue to define the allowed blending limits at national level (including the possibility to set them at zero). These individual choices would lead to 23 different clusters in the EU.

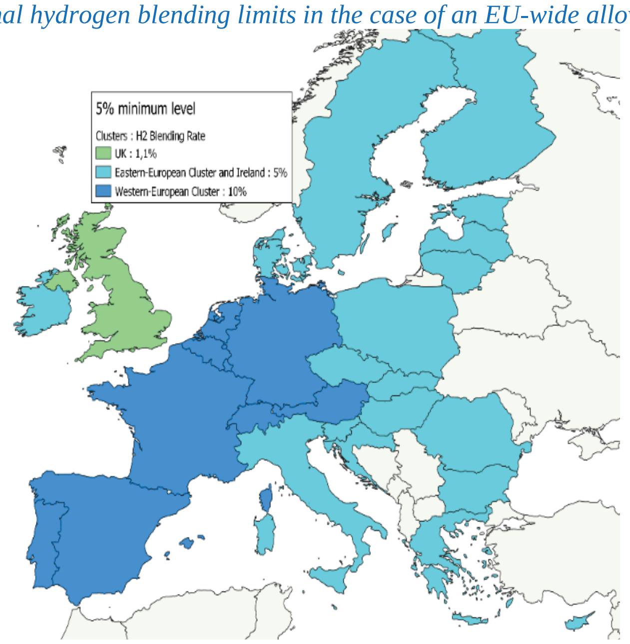
Option 1 introduces strong cross-border coordination leading to the development of three clusters:

- a Western-European with higher hydrogen blending ambition, with 10% as the joint allowed blending threshold (aligned with the highest blending threshold in the cluster, i.e. Germany);
- an Eastern-European, with 1.9% blending threshold (aligned with the highest blending threshold in the cluster); and
- a UK-Ireland cluster with 1.1% blending threshold (the UK's national blending threshold).

The impact of an EU-level harmonised allowed cap for hydrogen blends will strongly depend on the actual blending threshold chosen. Below a value of 10% the allowed level would impact only the Member States in the Eastern cluster, and above a value of 10% it would impact all Member States, giving rise to one unique European cluster.

Option 2 with a 5% allowed hydrogen blending cap at cross-border interconnection points would lead to two blending clusters where Ireland and the Eastern-European cluster feature the same blending limit (though they are not connected) and Western Europe represents still one cluster. *Figure 18* below displays a configuration with a 5% acceptance cap.

Figure 18: Estimated national hydrogen blending limits in the case of an EU-wide allowed cap of 5%



Source: Artelys, Trinomics, Frauenhofer, JRC, 2021

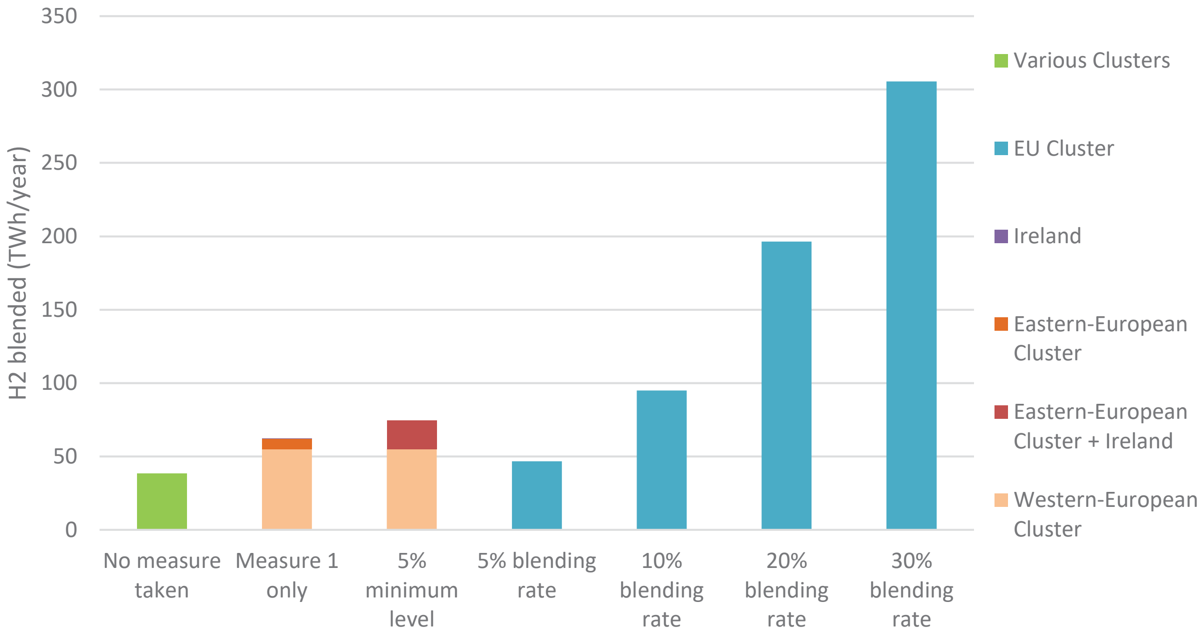
The introduction of a maximum cap at cross-border points in addition to the lower allowed cap for hydrogen blends (Option 4) would lead to one European cluster. The study supporting the Impact Assessment looked into the impact of measures setting the minimum and maximum caps both at the same level (5%, 10%, 20% or 30% 'blending rates')[38].

Economic impacts

The study focuses on the effect of the measures on the development of the hydrogen sector (i.e. how much hydrogen is expected to be injected into the network due to the measures under the different options), on adaptation costs, on administrative costs, on the impact on gas flows and supply sources as well as the impact on security of supply.

As regards the development of the hydrogen market, the option establishing an EU-wide allowed cap for hydrogen blends at 5% for interconnection points would allow the integration of 75 TWh/year hydrogen. Strong cross-border coordination measures do not offer the same level of harmonisation across borders and would therefore lead to the integration of a lower volume with 60 TWh/year. Setting both the allowed blending cap and the maximum cross-border blending cap at a high level could integrate a higher volume of up to 305 TWh/year (see *Figure 19*), however, at a significantly higher cost[39].

Figure 19: Volume of hydrogen blended into gas networks depending on the cluster configuration



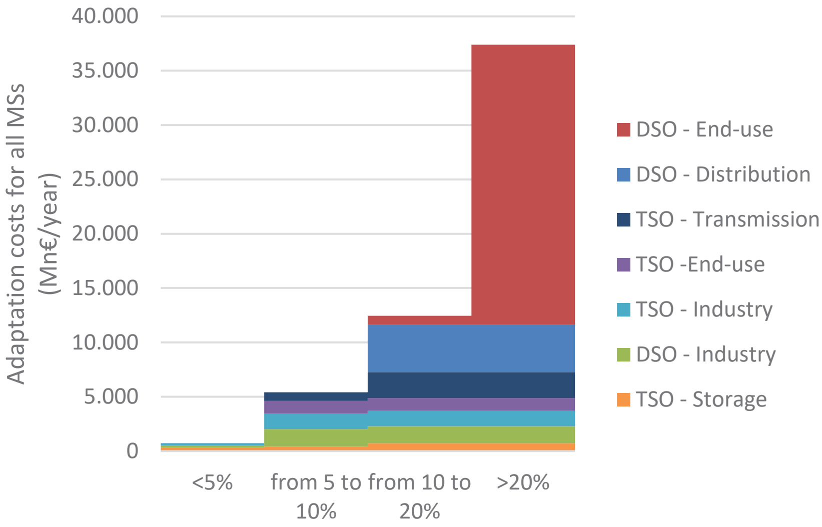
Source: Artelys, Trinomics, Frauenhofer, JRC, 2021

38 The description of the different configurations are available in Table 6-9: Overview of the seven configurations under the different policy measures of the Impact Assessment study, Chapter 6.3.1; (Artelys, 2021).

39 The figures represent an upper estimate of what the volumes of blended hydrogen could be, corresponding to the maximum levels that could be accepted in the national networks. The actual blending level in the network will range between 0 and this maximum accepted level. To achieve the hydrogen volumes shown in *Figure 19*, blending would also need to be at the maximum rate. In practice, fluctuations in blending rates in national networks may result in lower volumes of blended hydrogen. See in more detail in point 6.3.2.1 of the Impact Assessment study (Artelys, 2021).

The supporting study considers adaptation costs of the integration of blended hydrogen into the transmission networks, impacting the transmission and distribution network equipment, storages, industry and household end-use appliances[40]. The level of adaptation costs is expected to increase drastically with the acceptance level, from EUR 3,6 bn/year for 5% cap (with some countries being already at 10%), EUR 5,4 bn/year for 10%, EUR 12,5 bn/year for 20% and to EUR 37,4 bn/year for 30% (as shown in *Figure 20*).

Figure 20: Total adaptation costs needed to make EU equipment suitable for a certain threshold of blending



Source: Artelys, Trinomics, Frauenhofer, JRC, 2021

In addition to the adaptation costs, the measures introducing EU-level allowed caps for hydrogen blends would lead to administrative costs, most notably for:

- NRAs as they need to ensure the implement of the new regulatory framework.
- ACER, ENTSOG, NRAs and TSOs to monitor the implementation of the measures. However, if these tasks are incorporated within current monitoring obligations in the Interoperability Network Code, these costs would be limited[41].
- TSOs, regarding information publication and (real-time) gas quality monitoring[42].
- Businesses will have to ensure that their equipment can operate with the level of blending (system operators and end-users).

Gas flows in Europe are expected to change due to blending different volumes of hydrogen in the absence of a cross-border regulatory framework. To assess the changes to the flows and their impact on security of supply, the supporting study assumes that gas flows from Member States with higher hydrogen blending rates to Member States with lower blending rates are constrained. In the modelling, gas flows are expected to change depending on the cluster

[40] The detail of the required adaptations is shown in **Error! Reference source not found.** and further detailed in Section 10.2.4 of the Annex of the supporting study (Artelys, 2021).

[41] Further details on the administrative costs are available in Chapter 6.3.2.3 of the supporting study, (Artelys, 2021).

[42] TSOs may need to publish additional information on gas quality, due to the increase in blending in the networks, in order to inform sensitive users that may adapt the behaviour of their equipment to the gas quality. However, this will cause very limited additional administrative costs as provisions already exist regarding data publication of the Wobbe-Index and gross calorific value on an hourly basis.

configuration[43]. The introduction of an EU-level allowed cap at 5% could limit the flows from the Western-European cluster both to the Eastern-European cluster and to the UK[44]. In practice, however, such a situation is unlikely to occur, as coordination between Member States would arise before taking the risk of the fragmentation of the internal gas market. In comparison, when no EU-level measures are taken and no cross-border coordination takes place, the flows change considerably compared to a situation without blending. This even implies relevant volumes of energy not served in selected Member States. In case of Option 1, flows from the Western-European cluster would likely not be feasible, neither to the UK, nor to the Eastern-European cluster.

Would Member States not cooperate at cross-border interconnection points, the flow constraints would have an effect on the security of gas supplies[45]. Under option BAU, the assumption that there is no coordination implies that the energy not served reaches 7% of the total natural gas demand of the EU[46]. This is an upper estimate, as Member States would be inclined to coordinate or refrain from blending before such a serious issue would emerge. The energy not served decreases significantly with the implementation of Options 1 and 2, representing less than 0.2% of total EU gas consumptions.

To eliminate the risks from the lack of cross-border coordination between Member States, all options in the gas quality and hydrogen blending policy area feature measures to strengthen cross-border coordination and dispute settlement, with strong involvement of the NRAs and where necessary ACER (except option BAU).

Environmental impacts

One of the main advantages of blending hydrogen into the gas network consists of lowering the CO2 content of the transported gas[47]. Introducing a 5% allowed hydrogen blending cap at cross-border points would lead to lower emission (8 Mt CO2/y avoided emissions) compared to Options 1 and 4 (6 Mt CO2/y and 5 Mt CO2/y), as the supporting study assumes that such a measure enables higher blending rates in the Western-European cluster (tending towards 10%), leading to higher blended hydrogen volumes, hence the lower emissions.

Administrative impacts and affected parties

All assessed options facilitate to different degrees an unconstrained gas flow and cross-border coordination compared to a situation where all Member States would establish their own

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43 The analysis focuses more specifically on the impacts of different levels of EU coordination/harmonisation on blending, notably on gas flows and the potential risk of a gas market fragmentation. A detailed analysis on the impact of the measures on the gas supply sources and gas flows is available in the supporting study under Chapter 6.3.2.4 (Artelys, 2021).

44 As described above, the study assumes that the Western-European cluster would merge towards a 10% blending level, the Eastern-European cluster towards a blending level of 1,9%, while the UK would keep its national blending level of 1,1%.

45 See Chapter 6.3.2.5 (Artelys, 2021).

46 Projected to equal 3500 TWh/year by 2030 under the MIX-H2 scenario.

47 In the analysis of the supporting study, avoided CO2 emissions were calculated by removing the emissions of natural gas and replacing it by the indirect emissions of the corresponding hydrogen energy. The CO2 content of natural gas used is the one published by ADEME for combustion only and is equal to 185 gCO2/kWh HHV. The CO2 content of hydrogen used for the analysis comes from the EU Taxonomy (3 kgCO2/kgH2), and is thus set at 76 gCO2/kWh HHV. In more detailed please see Chapter 6.3.3. (Artelys, 2021).

blending levels. With the homogenisation of blending rates at cross-border points, the decrease in the number of clusters leads to enhanced network interoperability and scale effects on equipment purchase[48]. Option 4 would also have a positive impact as a maximum blending level set at the EU-level would avoid that a single Member State's initiative on blending would harm its neighbours in terms of gas supply. At the same time, the establishment of EU-wide allowed caps imply a significant coordination and negotiation effort in order to define thresholds that comply with the ambitions and strategies of all individual Member States.

In the absence of an EU framework (option BAU), TSOs and NRAs would need to coordinate to ensure unrestricted cross-border gas exchange via bilateral or multilateral agreements. In case of a fragmentation of the EU gas market related to a non-coordinated introduction of hydrogen blending in EU transmission grids, gas consumers would have to face supply disruptions and significant additional costs related to occasional gas shortcomings. As the injection of growing volumes of renewable and low-carbon hydrogen will lead to greater differences in gas qualities and more frequent quality fluctuations, cross-border disputes can arise more often. This would require from TSOs and NRAs active cooperation to reach joint solutions and take joint decisions, based on the rules of the existing Interoperability Network Code. In case NRAs cannot take joint decisions, ACER's involvement would become necessary, i.e. the Agency would have to take an individual decision.

Three blending clusters would form under the cross-border measures of Option 1, meaning, that TSOs and DSOs would have to adapt most of their equipment to accept the hydrogen share present in natural gas (the magnitude of the adaptation depending on the blending level chosen for the cluster). TSOs would have to manage, and potentially avoid, flows form Member States with a higher blending level to those with a lower one. TSOs and NRAs (and where NRAs cannot find agreements, ACER) would need to ensure cross-border coordination between Member States, especially to maintain interoperability between the different clusters. Depending on the hydrogen blending levels of their countries, end users will need to adapt their equipment. They will most likely also bear some of the grid adaptation costs linked to the deployment of hydrogen blending.

Under Option 2/3, all TSOs and DSOs would need to comply with the applicable allowed blending cap defined by EU rules that would represent adaptation costs for any threshold chosen. NRAs would have to ensure that TSOs (and possibly DSOs) comply with the allowed cap. The allowed blending cap would also affect an increasing number of grid end-users. The harmonised rules limit the administrative impact of cross-border disputes. Depending on the actual level of the allowed cap for hydrogen blends, most of the infrastructure and end-user equipment will need to be adapted and certified to demonstrate it complies with the applicable standards, increasing the administrative complexity in this market.

Under Option 4 all TSOs and DSOs would need to comply with the (lower) allowed hydrogen blending cap and the maximum allowed cap which would represent important adaptation costs for any threshold chosen. The two allowed blending caps would affect all grid end-users. For a low blending threshold (5%) this may be of low impact, but for a high threshold (e.g. 20%) almost all end-users will need to adapt their equipment. However, the

[48] See in detail in Chapter 6.3.4 in the study supporting the Impact Assessment.

adoption of a maximum hydrogen blending cap should reduce the administrative work for market operators in the gas system by increasing the homogenisation of European gas market characteristics and reduce the need for interaction with different TSOs.

Stakeholders' views on hydrogen blending cross-border framework

Respondents to the public consultation are divided on the role of blending hydrogen into the existing gas network, with a majority agreeing that hydrogen blending provides a cost efficient and fast first step to energy system decarbonisation. However, a quarter of respondents underline that blending prevents the direct use of pure hydrogen in applications where its value in terms of GHG-emission reductions is higher (such as industry and transport) and that it creates technical constraints and additional costs at injection and end-users points. This view is supported by all the responding NGOs and by some representatives of the hydrogen industry (while NRAs did not provide a response).

While the number of responses to the questions on the specific policy options were limited (e.g. only five Member States replied to these questions) there is a division among the stakeholders. Most responses support harmonisation in the form of national hydrogen blending levels set by Member States in a standardised and transparent way, based on EU rules. A third of the respondents support setting a harmonised EU-wide allowed cap for hydrogen blends, which TSOs must accept at cross-border interconnection points. Some respondents however argue that hydrogen blending levels should not be introduced at all.

In dedicated meetings with Member States, a clear majority supported the blending of hydrogen into the existing gas network. Especially Western European Member States urged for setting an allowed cap to support blending and the development of hydrogen markets, while a group of Eastern European Member States called for a minimum allowed cap as an option for decarbonisation. A smaller group of delegations expressed prefer avoiding blending while two Member States clearly refused this option as blending is diminishing the value of hydrogen and risk of prolonging the use of natural gas (lock-in effect).

Description of the preferred option: Option 3 (containing Option 2)

Under the preferred option gas quality would be governed by a harmonised EU approach for cross-border interconnection points while leaving flexibility to the Member States on the application of gas quality standards in their domestic networks (i.e. without interfering with the specificities of domestic gas production). The allowed cap for hydrogen blends would be set at 5% for all EU cross-border points. This would mean that TSOs would be obliged to accept blending levels below this cap at cross-border points and might accept higher blends on a voluntary basis. In any case, the rules would not propose mandatory blending.

The consideration is to set the allowed blending cap at an optimal level, i.e. if set too low, it does not avoid quality-related issues impacting cross-border flows whereas if set too high, it can lead to high adaptation costs for Member States with low expected blending rates. It could also be possible to evaluate and gradually increase the minimum allowed blending rate. However, a gradual increase of the minimum rate can lead to higher adaptation costs and uncertainty for Member States and market participants. Therefore, it is important to provide visibility on a minimum allowed cap that strikes a balance between these aspects.

The 5% EU allowed cap for hydrogen blends for cross-border points represents a level that is cost-efficient in terms of adaptation and abatement costs. It supports the integration of 70 TWh/year renewable and low-carbon hydrogen into the network at an adaptation cost of EUR 3.6 bn/year, leading to 8 Mt CO2/year avoided emissions at an abatement cost of EUR 433/tCO2 (see *Table 1*). In comparison, a higher cap would increase the adaptation costs drastically (EUR 5,4 bn/year for 10% or EUR 12,5 bn/year for 20%), while Option 1, i.e. relying on national blending rules with cross-border coordination, would integrate a lower volume of hydrogen (50TWh/year) at the same adaptation cost.

Table 51: Summary of the results

Blending level	No measure	Measure 1 only	5% min level	5% min & max	10%	20%	30%
Adaptation costs (€bn/year)	2.6	3.6	3.6	0.7	5.4	12.5	37.4
Avoided emissions (Mt CO2/year)	4	6	8	5	10	21	33
Abatement costs (€/tCO2)	612	532	445	144	524	582	1124

Source: Artelys, Trinomics, Frauenhofer, JRC, 2021

The preferred option achieves the desired objective of ensuring unhindered cross-border gas flows by setting a harmonised allowed cap for every interconnection point within the EU and thereby limiting the risk of market segmentation to a minimum. In case Member States (or their TSOs) transport cross-border a blend which is not compliant with this specification, the reinforced cross-border coordination mechanism provides a dispute resolution tool to find agreements. These elements provide an increased clarity and visibility on gas quality and related processes also for end-users. In addition, especially the EU-level rules on gas quality management address the risk of negative impacts of different gas qualities for end-users by allocating roles and responsibilities for gas quality handling, by increasing transparency on actual and forecasted gas quality and the cost of gas quality management, by setting out principles for the recovery of costs incurred by gas quality management and where necessary for the allocation of such costs also cross-border and by ensuring proper regulatory oversight for the improved framework.

At the same time, the preferred option provides a proportionate approach by limiting the intervention to cross-border interconnection points to avoid market segmentation, without imposing a blending obligation. In doing so, it leaves flexibility to the Member States to define blending levels for the domestic network if they wish so, taking into account the specificities of domestic hydrogen production. In terms of subsidiarity, EU action is needed as, while voluntary standards could in theory lead to an alignment of gas quality specifications and hydrogen blending levels between Member States, they would lead to a convergence across Europe only slowly, or not at all. Further, fostering more efficient and integrated EU markets for gases requires a harmonised and coordinated approach by all Member States, which can only be achieved efficiently by EU action (not by individual Member States). This option also avoids the distortive effects of uncoordinated, fragmented policy initiatives as many Member States develop national approaches. EU action has significant added-value by ensuring a coherent approach across all Member States.

In comparison, Option 1 relies solely on a cross-border dispute settlement tool, risking suboptimal outcomes and increasing the administrative cost for TSOs, NRAs and ACER as an increased number of disputes is expected to occur due to differences in blending levels. If significantly different blending levels occur between Member States, this will not resolve cross-border flow constraints. In the absence of clear rules, TSOs would likely reject cross-border flows, or the injection of hydrogen in their domestic networks, limiting the integration of renewable and low-carbon hydrogen. Voluntary standards could in theory lead to an alignment of hydrogen blending levels between Member States, if national authorities or network operators adopt them. However, based on the experience with the voluntary cross-border application of gas quality standards to date, voluntary adoption of blending levels would lead to a convergence of gas standards across Europe only slowly, or not at all. Option 4 on the other hand sets both a minimum and a maximum allowed cap for hydrogen blends at cross-border points thereby excluding the possibility of voluntary agreements between Member States on higher blending levels. While this measure avoids that the adaptation costs generated by one Member State's blending pathway have to be covered by adjacent Member States, it can limit the level of renewable and low-carbon hydrogen integrated into the system depending on the exact blending level.

Table 52: Measures on LNG

LNG terminals	**Objective**	Ensure transparent access to LNG terminals for imported RES gases, including liquid hydrogen.			
	<u>BAU</u> **No additional measures**	<u>Option 1</u> **Allow RES&LC gases full market access**	<u>Option 2</u> **Allow and promote RES&LC gases full market access**	<u>Option 3</u> **Allow and promote RES&LC gases full market access, tackle issue of long term supply natural gas contracts and remove cross-border tariffs for RE&LC gases**	<u>Option 4</u> **Allow and promote full RES gases market access, tackle issue of long term supply natural gas contracts, EU standards for gas quality and remove crossborder tariffs for all gases**
Measures	LNG terminals are regulated with third party access (exemptions are possible). No clear rules on capacity allocation and congestion management. Tariff discounts may be granted. Underutilization of capacities in some cases.	Principles concerning transparency, voluntary (e.g. led by industry) initiatives and supported by EU guidance.	Binding legal framework at EU level for transparency, congestion and access rules (secondary trading).	As Option 2 plus: Mandatory market test/screening and development plans for LNG terminals (and gas storage) to receive RES&LC gases.	As Option 3 plus: Removing the entry tariff discount in favour of LNG natural gas or extending existing discount also to RES&LC gases.
Pros	Small administrative cost	No need for a regulatory intervention, just legally non-binding action as guidelines by the EC. Transparency may be improved (voluntarily).	Improvement of transparency, market access and congestion management – more efficient utilization of the terminals + additional available capacities for RES&LC gases	Obligation to consider the RES&LC gases imports. Matching supply and demand (exporters and importers) by market tests. More transparency which capacities are available for RES&LC gases.	If discount for RES&LC gases added, imports of these gases are incentivised.
Cons	Underutilization may remain. Congestion may occur due to high volumes to be imported. Mainly imports of natural gas.	Only transparency would be improved, only limited impact on RES&LC gases. As it is voluntary action, the effects are less certain.	Need to adjust current regulatory framework - some burden for LSOs – 'cost to adjust'.	Need to adjust current regulatory framework - some burden for LSOs 'cost to adjust'.	If discount is removed, it can negatively impact energy supply of some MS. Risks of cross-subsidization.

Most suitable option	**Option 3**	A mandatory market test/screening mechanism and development plans bring incentive to prepare for the imports of RES&LC gases. These mechanisms will contribute to match supply and demand and increase transparency on which capacities are available for RES&LC gases.

ANNEX 8: DETAILED MEASURES FOR PROBLEM AREA III: NETWORK PLANNING

Table 53: Measures on network planning

Network Planning	**Objective**	Ensure transparent and inclusive infrastructure planning		
	BAU **No additional measures**	Option 1 **National Planning**[49]	Option 2 **National Planning based on European Scenarios**	Option 3 **European Planning**
Measures	Baseline: Do nothing Note: Inclusion of hydrogen in the EU-wide network development plan (TYNDP) as proposed in the TEN-E	One single network plan (NDP) (including also storages, LNG and production) per Member State irrespective of the unbundling model chosen and the number of gas TSOs in the country. Instead of providing a national plan, Member States can also opt to come up with a regional plan instead. The NDP needs to be drawn up every two years (now: every year). The network plan remains binding only for ISO and ITO certified TSOs to the extent valid today. National regulatory authorities are empowered and required to ensure a transparent process. The NDP includes information to what extent and from what point in time certain methane pipelines are not required anymore and could be used for other purposes (e.g. hydrogen-transport). Introduction of a sustainability indicator.	Integrated planning on national level by requiring joint scenario building between gas and electricity. The joint scenario needs to be aligned with the at least one scenario used for the TYNDP. This can also be ensured linking it to the relevant NECP, which is required to be in line with the climate goals. Creation of a competence for NRA to assess the actual need for a hydrogen pipeline network. Distribution system operators as well as LNG and storages need to be involved in the scenario building. NRAs may take decisions for setting a framework for the involvement (de-minimis rules, national DSO association). Other energy carriers (e.g. hydrogen, district heating) as well as CO2 need to be taken into account in the scenarios, but not in the plan itself. Provisions for national electricity plans needs to be amended to require joint scenario building.	Drawing up a system wide network development plan (i.e. going beyond joint scenario development), including gas, hydrogen and electricity on European level only. Unregulated infrastructure investments and investment plans are taken into account when elaborating the national network development plan.

49 Note: Options build up on each other. All elements included in Option 1 are included in Options 2, all elements in Option 2 are included in Option 3.

Pros	No additional burden on NRAs/TSOs that do not have a national plan.	Requiring a single, consolidated NDP avoids potential incoherencies between the visions of different gas TSOs operating in the same country (e.g. in France), leading to a more coherent, cost-efficient network planning procedure, lowering the risks of over-dimensioning the system or stranded assets. Having plans in each MS ensures that PCIs are included with highest priority and ACER can provide an opinion on the consistency between the NDP and TYNDP.	Same as Option 1, plus: Ensures that indirect interlinkages between gas and electricity are treated in a consistent way in subsequent processes. Eliminating risks that electricity and gas TSOs plan the evolution of their systems based on incompatible assumptions (e.g. electricity TSOs assuming a strong deployment of heat pumps in the residential sector while the gas TSO assumes a deployment of gas boilers). The transparency obligation (repurposing potential) and the performance of market test facilitates the evaluation of potential hydrogen-PCI projects under the revised TEN-E regulation, while reducing the risk of initial over dimensioning of the hydrogen-network.	Joint planning ensures that the efficiency of investments in the gas sector (incl. hydrogen) is compared to alternatives such as electricity networks, and that the most economically, environmentally sound and secure option is identified and selected.
Cons	Does not ensure consistency of European and national plans.	Higher planning costs/administrative burden.	Higher coordination/transaction costs between involved parties.	Risks that planning undermines individual sector performance and liability. No available objective model to identify and optimise investment needs across different energy carriers → risk that implementation can only be done on low(er) level of sophistication not being suited for individual system planning. The current TYNDP is not based on hydraulic modelling. TSOs would need to provide all detailed network information to ENTSOG. This may create confidentiality conflicts and increases the risk for critical infrastructure and could be better achieved on national or regional level.

Most suitable opion	**Option 2**	This option provides the best balance in terms of achieving the objective of more inclusive planning allowing for a conceptual system plan, but leaving the required level of detail sector specific. It also enables the identification and actual use of pipelines that for repurposing based on the market demand for hydrogen and informing about locations based on avoiding network costs.

ANNEX 9: DETAILED MEASURES FOR PROBLEM AREA IV: LOW LEVEL OF CUSTOMER ENGAGEMENT AND PROTECTION IN THE GREEN GAS RETAIL MARKET

Each option for Problem Area IV: Low level of customer engagement and protection in the green gas retail market in Section 5.4 of this Impact Assessment compromises a set of more detailed set of more detailed measures. Please see also the summary table at the end of Section 5.4 in this regard.

This Annex contains an assessment for each of these more detailed measures.

Table 54: Measure on retail market, consumer protection and engagement

Retail markets, consumer protection and engagement	**Objective**	Ensure adequate levels of customer empowerment and protection in the decarbonised market			
	Option 0 **No additional measures**	Option 1 **Enforcement and soft implementation measures**	Option 2 **strengthened enforcement, enhanced implementation measures and intense consultations with stakeholders**	Option 3 **Flexible legislation**	Option 4 **Harmonization and extensive consumer safeguards**
Measures	Baseline: Do nothing.	No new legislation is adopted. The problem drivers are addressed by strengthening enforcement, i.e. reinforced administrative cooperation, information campaigns, exchange of good practices without resorting to new legislation. In addition, Commission issues interpretative and guidance documents on **switching** and **bills.**	The same enforcement non regulatory measures as in Option 1 are complemented by bilateral consultations with Member States to try to progressively phase out **price regulation.** Soft legislation (COM Recommendation/Guidance on price regulation, billing, switching and price comparison tools). **Renewable energy communities** are supported by an interpretative note and enhanced through existing initiatives, such as the Energy Community Repository. All relevant **smart metering** provisions are consolidated in a single legislative act (no extra regulatory requirements are introduced) and use is made of the	New legislation mostly mirroring the electricity provisions provides Member States leeway to adapt their laws to the conditions in national markets. Member States phase out blanket **price regulation.** Exemptions for households, micro-enterprises as well as vulnerable and energy poor households are defined at the EU level. The use of **contract termination fees** is **restricted**. Provisions on billing and **switching** are aligned with those in the Electricity Directive, The right to access objective and certified **price comparison tools** is granted to customers. An improved, principle-based EU legal framework to support Member	New EU harmonised legislation going beyond the levels of customer empowerment and protection currently in force in electricity market is proposed. Member States phase out blanket **price regulation.** Exemptions for vulnerable and energy poor households are defined at the EU level. All **switching**-related fees are banned, including contract termination fees. NRAs offer (or fund) **price comparison tools**. Format and content of **energy bills** is partially harmonised. A uniform EU framework to monitor **energy poverty** and reduce disconnections is set up. The concept of '**citizen energy**

			existing acquis and of further promotion of best practices. **Data management** arrangements are primarily left with Member States. Support to the **EU Energy Poverty Advisory Hub** is enhanced.	State action on **vulnerable and energy poor consumers** is put in place. The concept and enabling framework for '**citizen energy communities'** is mirrored into EU gas legislation. EU **data management** rules are set up, along with measures for transparent and non-discriminatory access to data irrespectively of the data management model used. While the decision for **smart metering** remains with Member States, additional requirements are adopted for an enhanced deployment. That includes a set functionalities, a rollout target, and the right to a smart meter as well as regular revision of negative assessments, and a strong recommendation to carefully consider the benefits for selective, targeted rollouts.	**communities**' is made more citizen-centred and coupled to an enabling framework with support measures. A standard EU **data management** model (data hub) is enforced throughout the EU, along with standardised formats for exchange of data. A mandatory throughout the EU **smart metering** rollout is legislated, irrespectively of the national cost-benefit assessment, with fixed functionalities that are mirroring those for electricity.
Pros		Little additional administrative burden resulting from enhanced enforcement, however, it would be limited as no new legislation is introduced. Low cost of implementation. More flexibility to Member States and NRAs to accommodate their national specificities in the measures.	Still relatively limited additional efforts needed by Member States, though increased (in comparison to Option 1), due to cooperation on phasing out regulated prices and implementing soft legislation, in addition to reinforced enforcement foreseen already in Option 1. Soft legislation will provide further guidance to MS and once implemented, benefits to customers. Some progress towards the phasing	Higher levels of non-household customer satisfaction as a result of the better service levels consumers receive in the non-regulated market. Increase energy efficient consumption of gas caused by artificially low prices in non-household markets. Better engagement of customers in transition and strengthened customer rights and satisfaction. Positive environmental impact thanks to improved customer awareness of consumption and energy origin as well	Significantly increased market opening, effective retail market competition. Increase energy efficient consumption of gas caused by artificially low prices in all markets. Strengthened rights for customers and improved customer satisfaction. Possible improvement in consumer engagement to some

			out of regulated prices may be achieved. Low cost of implementation, though slightly higher than in Option 1. More flexibility to Member States and NRAs to accommodate their national specificities in the measures.	as increased public acceptance of renewable gas and private capital mobilisation through energy communities. Transparent and non-discriminatory data access from eligible market parties resulting in a high net benefit for service providers and consumers and in increased competition in the retail market.	extent. Positive social impact due to the enhanced citizen focus of the energy community concept. Easier enforcement of standardised, harmonised rules.
Cons		Does not ensure consistency of European and national frameworks. No significant improvements of the status quo realistically expected. Does not align with EU policy targets and decarbonisation plans. Consumer engagement and protection are only limitedly addressed. Low consumer satisfaction persists due to limited availability of innovative offers (including green) and high value services. Maintain a fragmented, not updated to reflect market and technology developments regulatory framework across the EU which translates into administrative costs for	Higher planning costs/administrative burden (compared to Option 1). Non-regulatory measures are unlikely to consistently and adequately address current issues, as they would rely on Member States' proactive attitude without binding rules, with high risks of fragmented landscape throughout Europe in terms of customer empowerment and protection. Does not align with EU policy targets and decarbonisation plans. Low consumer satisfaction persists due to limited availability of innovative offers (including green) and high value services. A fragmented regulatory framework across the EU also not reflecting of the latest market and technology developments.	Higher coordination/transaction costs between involved parties. Increased costs and administrative burden for suppliers and increase in margins for suppliers. Household customer satisfaction and availability of innovative offers (including green) increases but in 15 household markets it will depend on the speed of opening and competition paths of national gas retail markets.	Risks that planning undermines individual sector performance and liability. No available objective model to identify and optimise investment needs across different energy carriers. Uncertain effectiveness of measures to address current issues (e.g., suitability of NRA developed PCTs). Expected political resistance to full harmonisation of certain consumer protection measures. Increased administrative costs for public authorities to implement support measures for energy communities and high adaptation, divergently within the EU disproportionate costs by enforcing smart metering and data management solutions that do not fit all.

		entering new markets.			
Most suitable option		**Option 3**	This option is based on proposing flexible legislation mirroring the electricity market with regard to customer protection and where relevant the empowerment provisions. It is likely to be the most effective, efficient, and consistent with other problem areas.		

ANNEX 10: ADDITIONAL ANALYSIS FOR PROBLEM AREA IV: LOW LEVELS OF CUSTOMER PROTECTION AND ENGAGEMENT

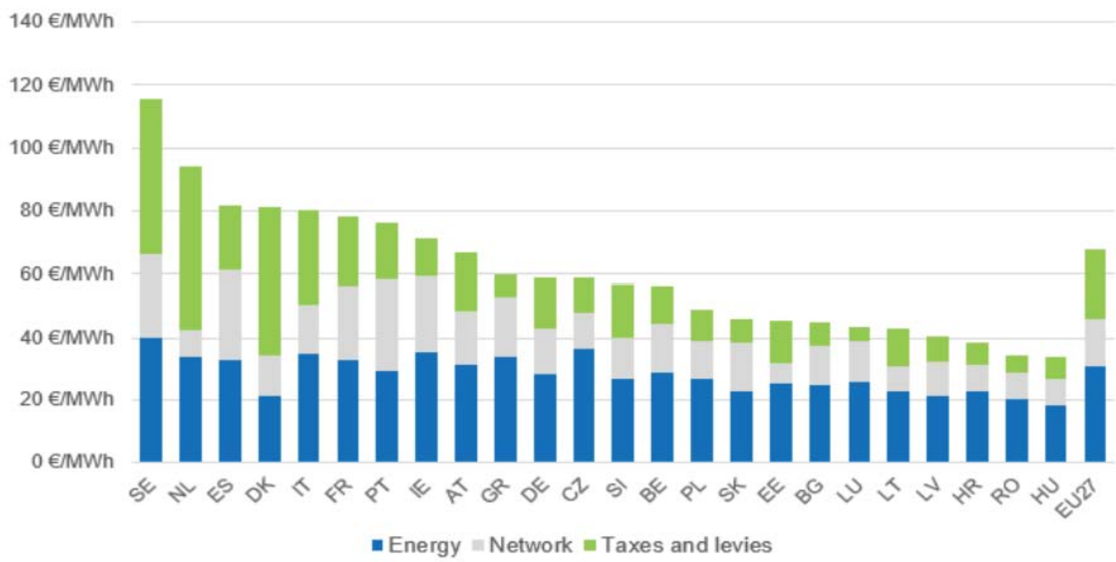
Each option for Problem Area IV considered Section 6.4 of this Impact Assessment comprises (or not) a set of more detailed measures. Please see also the summary table at the end of Section 6.4. in this regard.

This Annex contains a more detailed analysis of the problem drivers and an overview the contemplated measures under each of the policy options.

Driver 1: Untapped competition potential in retail markets

Household gas prices vary significantly between different Member States. Household gas prices in 2019 remained lowest in Romania (3.4 euro cents/kWh post-tax), and highest in Sweden (11.8 euro cents/kWh), where considerably higher taxes and charges are levied. A wide range of factors contribute to this including the kinds of energy consumed, the level of regulatory intervention in price setting, differing levels of competition and the different taxes and levies applied (*Figure 21*)[50].

Figure 21: Household prices in the EU in 2019[51]



Source: 2020 Report on Energy Prices and Costs

Moreover, in spite of falling prices on wholesale markets, **overall retail gas prices for household consumers rose steadily between 2010 and 2019**. This trend was largely driven by increased non-contestable charges (including network charges, taxes and levies) in recent years. The composition of gas prices changed from 2010 until 2019. The energy component increased at an annual rate of 0.8% and reached EUR 30/MWh in 2019, whilst the network

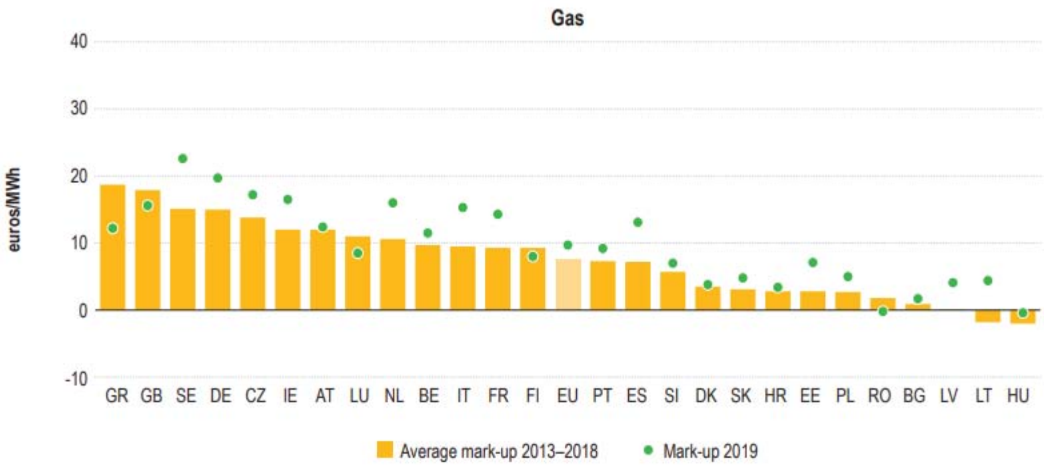
[50] 2019 ACER Market Monitoring Report – Energy Retail and Consumer Protection Volume, pp. 20-23.

[51] Report on Energy Prices and Costs, 2020, p. 6; https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0951&from=EN. See footnote 58.

charges and taxes increased annually for household gas customers by 2.6% and 3.6%, respectively[52].

In addition, the **average retail mark-ups**[53] in the retail gas markets for households increased significantly across the EU in 2019 compared to the average observed between 2013 and 2018. In 2019, the mark-ups on the energy component of the household customer gas bills in several Member States, including Czech Republic, Germany and Sweden also seem to be higher than could be expected, posing questions about the extent of retail price competition[54].

Figure 22: Average annual mark-up in retail gas markets for household consumers in MSs, Great Britain and Norway from 2013–2018 and annual mark-up in 2019 (EUR/MWh)[55]



Source: ACER, 2019

Abnormally low or negative mark-ups are equally problematic as they make it difficult or impossible for a new supplier (of green gases) to compete against an incumbent supplier (of natural gas). Such mark-ups can be observed in countries with regulated prices for households, such as Romania, Bulgaria, Slovakia, Cyprus, Hungary and Lithuania. Negative mark-ups were observed in Hungary[56] and Lithuania[57] where the energy component of the retail prices was set at a level below wholesale energy costs.

As regards non-price competition, a positive trend can be observed in terms of **gas offer types** available between 2018 and 2019, with ten offer types available in more Member States. In particular, social offers, which are available in eight Member States in 2019 in comparison to two Member States in 2018, were subject to a steep increase. Other new offer types include offers with monetary gains or additional service and different pricing options[58].

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52 Ibid 2, p. 65.

53 The mark-up is an indicator of the level of difference between prices charged to consumers and the estimated costs to supply them with energy as well as an indicator of the level of responsiveness of retail energy prices to changes in prices on wholesale markets. Mark-ups include profits, and additional operating costs (e.g. marketing, sales, consumer services, overhead, etc.). See 2019 ACER market monitoring report, Energy Retail and Consumer Protection Volume, p. 28.

54 2019 ACER market monitoring report, Energy Retail and Consumer Protection Volume, pp. 26-27.

55 See footnote 63.

56 On average, for the period 2013-2019.

57 On average, for the period 2013-2018.

58 ACER Market Monitoring Report 2019, Energy Retail and Consumer Protection Volume, p. 55.

However, the number of types of gas offers, which are **manly fixed offers**, remains generally lower than in the electricity products. Nevertheless, data shows the number of types of gas offers increased in 13 out of 23 Member States in 2019. In addition, in 16 out of 25 Member States, five or more different types of offers were available in 2019 in comparison to 2018[59].

By the end of 2014, green gas offers continued to make strides in the market with in total almost one quarter of gas offers marketed as green. Dual-fuel offers (electricity and gas), comprised more than 35% of all offers on price comparison tools in Amsterdam, Brussels, Dublin, Lisbon, London and Paris – capitals with traditionally higher consumption of gas. And at the end of 2014, 12% of all gas offers presented in the price comparison tools across Europe included an additional service, up from 4% and 7% respectively from just the previous year.

Figure 23: Overview of the selection of differentiating elements in gas offers depending on the number of years since market liberalisation in Europe – 2013–2015[60]

Gas

MS	Number of countries	Years since liberalisation	Year	Average number of offers	Average number of offers per supplier	Percentage of spot-based offers	Percentage of green offers	Percentage of offers with additional services	Average switching rates
Group I	4	≤5	2015	↑4	↑1.4	0%	0%	↑5%	↑6.0%
			2013	3	1.3	0%	0%	0%	0.0%
Group II	15	5≤10	2015	↑21	↑1.9	↑1%	↑7%	↑7%	↑5.2%
			2014	14	1.7	1%	3%	2%	4.4%
			2013	10	1.6	0%	5%	0%	4.9%
Group III	7	>10	2015	↑73	↑2.9	↑4%	↑19%	↑21%	↑9.5%
			2014	63	2.6	2%	20%	20%	10.4%
			2013	59	2.7	0%	6%	11%	8.8%

Source: ACER, 2015

The figure above illustrates a positive correlation between the duration of the liberalisation process and the average number of offers, percentage of green offers and average switching rates.

With the cumulative market shares of the three largest gas suppliers for households more than 70% in most countries in 2016, including those with a large number of nationwide suppliers, **gas retail markets remain largely concentrated**[61]. As a result, the retail household market for small competitors is above 30% in only 5 out of 25 countries in gas, while the rest of the market is held by three dominant suppliers.

In 2019, 71% of the Member States reported HHI levels above 2 000 in household gas markets and 40% in non-household gas markets, indicating the high degree of gas markets concentration that still exists and potential for further competition to be obtained in the respective gas markets[62].

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59 ACER Market Monitoring Report 2019, Energy Retail and Consumer Protection Volume, p. 55.

60 ACER Market Monitoring Report 2015 - ELECTRICITY AND GAS RETAIL MARKETS.pdf (europa.eu), p. 21. See footnote 134.

61 See footnote 64.

ACER Market Monitoring Report 2019 - Energy Retail and Consumer Protection Volume.pdf (europa.eu).

High levels of retail market concentration also suggest that competition could be improved. Whereas there is a positive evolution for the non-household[63] gas market, with an increased number of Member States reporting Herfindahl-Hirschman Index levels below 2 000[64], household gas markets continue to be more concentrated[65]. In nine countries, the amount of nation-wide supplier in the gas market was below or equal to 20 in 2019[66]. The latter may indicate the existence of high entry barriers for new suppliers to enter the market and offer innovative, high quality services and products (such as green offers) to consumers[67].

Driver 2: Insufficient customer empowerment in terms of switching, price comparison tools, billing information, energy communities, and access to data

Billing and switching

Energy bills are a crucial tool for enabling consumers to participate in the energy market by assessing their energy consumption and select the best, and possibly greenest, offers. Billing remains the largest concern for consumers. For example, according to statistics collected within the European Consumer Complaints Registration System, the majority of complaints reported between 2011 and 2016 concerned billing[68]. The following graph compiled by ACER shows that, overall, 2.4 million complaints related to gas were filed in 2019, whereas a relatively large share of complaints concerned invoicing and billing (45%)[69].

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63 Consisting out of industrial and commercial players.

64 The Herfindahl-Hirschman Index is a commonly used indicator to measure the degree of market concentration. Based on the guidance from the European Commission, a HHI above 2 000 signifies a highly concentrated market. In general, a high number of suppliers and low market concentration are viewed as indicators of a competitive market structure.

65 In 2019, 71% of the Member States reported HHI levels above 2 000 in household gas markets and 40% in non-household gas markets, indicating the high degree of gas markets concentration that still exists and potential for further competition to be obtained in the respective gas markets[65]. ACER Market Monitoring Report 2019 - Energy Retail and Consumer Protection Volume.pdf (europa.eu). See 2019 ACER Market Monitoring Report – Energy Retail and Consumer Protection Volume, pp. 20-23.

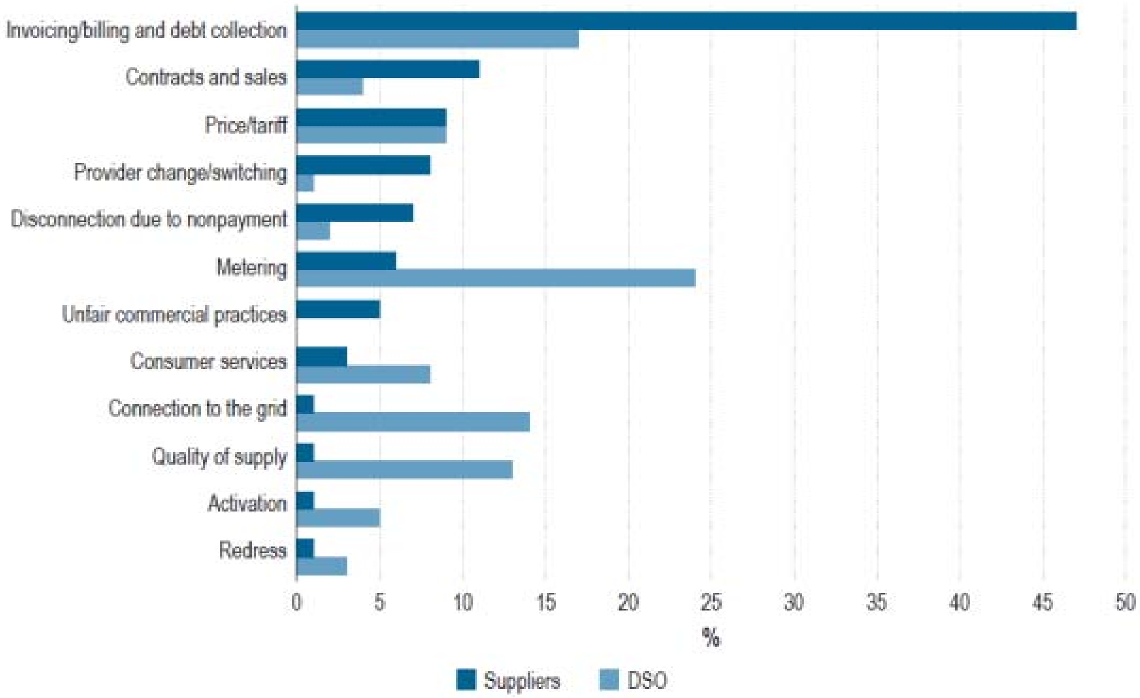
66 ACER Market Monitoring Report 2019 – Energy Retail and Consumer Protection Volume, p. 40.

67 ACER Market Monitoring Report 2019 – Energy Retail and Consumer Protection Volume, p. 42.

68 Available at: https://ec.europa.eu/info/policies/consumers/consumer-protection/evidence-based-consumer-policy/consumer-complaints-statistics_en

69 ACER and CEER, 2020, Annual report on the results of Monitoring the internal electricity and natural gas markets in 2019, energy retail and consumer protection volume.

Figure 24: Consumer protection – Complaints and ADR



Source: ACER-CEER's 2020 Market Monitoring Report

In a survey conducted as part of the study *Investigating the benefits of aligning EU consumer protection and information rules in the gas and electricity sectors*, 70% of respondents indicated that they would see it as relevant to a large extent to mirror provisions on bills and billing from the Electricity Directive to the Gas Directive. Similar results were found for mirroring provisions contractual rights (66%) and switching (63.5%)[70].

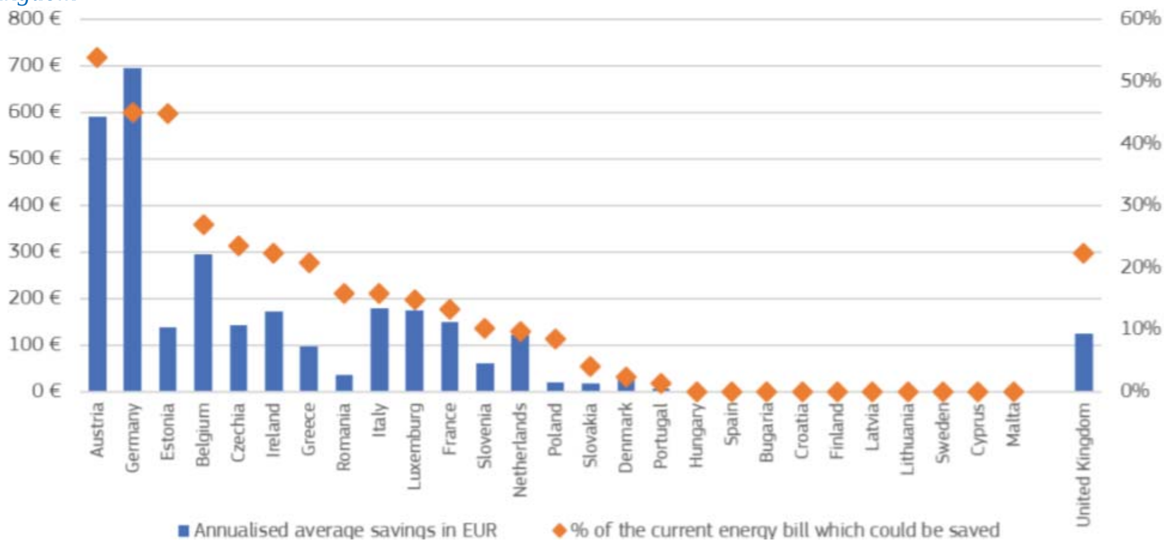
Switching savings potential on gas bills[71]

The following graph shows the potential annualised gas bill savings in Europe and percentage of the current energy bill that could be saved. Whilst data vary across countries, the highest possible annualised savings were identified for Germany, where households could save up to EUR 694, or 45%, in 2020 if they had switched to the most advantageous offer. In percentage terms, the highest savings could be achieved in Austria, where households could have saved around 50%.

[70] European Commission Study Investigating the benefits of aligning EU consumer protection and information rules in the gas and electricity sectors, Draft Final Report, June 2021, p. 147

[71] See footnote 135.

Figure 25: Annualised gas bill saving potential in December 2020 in the EU Member States and the United Kingdom[72]



Source: VaasaETT data collection. Saving potential is reported to be zero for Spain and Hungary, for Bulgaria, Croatia, Finland, Latvia, Lithuania, Sweden, Cyprus and Malta no data are available

Energy communities[73]

Energy communities still struggle to emerge on the renewable and low-carbon gas market. Whilst the Renewable Energy Directive 2018/2001/EU covers local renewable gas based communities through the concept of REC[74], it does not cover all types of community initiatives, most notably renewable gas based communities-of-interest[75].

[72] *Quarterly report on European Gas Markets with focus on the European barriers in retail gas markets, Market Observatory for DG ENERGY,* Volume 13, issue 4, fourth quarter of 2020, p. 37

[73] See footnote 85.

[74] Local energy communities can be equated with the concept of renewable energy communities considering the members or shareholders in effective control need to be located in proximity of the production installations.

[75] Citizen energy communities can be considered communities-of-interest, they are not bound by a common geographical area but rather a purpose.

Figure 26: Major differences between citizen energy communities (CEC) in the Electricity Market Directive and renewable energy communities (REC) in the Renewable Energy Directive[76]

	CEC	REC
Energy	**Electricity**	**Renewable energy**
Membership	**Any entity**	**Natural persons, local authorities, SMEs**
Control	Effective control by natural persons, local authorities, small enterprises	Effective control by natural persons, local authorities, SMEs located in proximity of the projects
Purpose	Primary purpose to provide environmental, economic or social community benefits for members or the local area	
Activities	Generation, storage, selling, sharing, aggregation or other energy services, distribution (optional)	

In turn, the more restrictive governance approach to REC may limit the potential of energy communities in terms of consumer engagement (i.e. enabling consumers to collectively purchase renewable and low-carbon gas, irrespective of their geographical location) and the uptake of renewable and low-carbon gas through the mobilisation of private investment in renewable and low-carbon gas production installations.

One governance criteria is especially of interest in this regard; the geographical limitation for members or shareholders in effective control of the REC (i.e. they need to be located in 'proximity' of the production installations owned by the community). Introducing CEC in the Gas Directive would complement the local renewable gas production by facilitating the collective purchase of renewable and low-carbon gases, irrespective of the geographical location of the consumer. CEC would be conducive to such purpose due to the absence of a geographical restriction for the members or shareholders in effective control of the community. To illustrate, one can imagine a cooperative of farmers situated in a remote rural area (e.g. Agrinio Union in Greece[77]) producing biogas and injecting this into the wider gas grid to supply their members/shareholders in a distant city.

Mirroring the concept of CEC would open up energy communities to larger actors, including large gas companies. Whilst this may be conducive to their development considering the safety risks[78] associated with and technology readiness level of biomethane plants[79], this would also increase the risk of corporate capture (either directly or indirectly through linked entities or subsidiaries) of citizen led initiatives for the purpose of greenwashing or benefiting from the enabling framework. The requirement of effective control for smaller actors and the exclusion of decision-making power for large gas companies would mitigate such a risk, but may require further clarification and regulatory oversight.

To summarise, introducing a regulatory framework[80] for communities-of-interest (i.e. CEC) could contribute to the decarbonisation gas supply in a cost-effective way, by enabling

76 Artelys study (2021).
77 Union of Agrinio – A.C. "Union of Agrinio" (e-ea.gr).
78 Katarzyna Stolecka and Andrzej Rusin, 'Potential hazards posed by biogas plants' (2021).
79 Kathrin Bienert et al., 'Multi-Indicator Assessment of Innovative Small-Scale Biomethane Technologies in Europe' (2019).
80 Such a framework may help overcome a series of institutional barriers, including unfavourable legislation, support mechanisms, information and administrative barriers, grid access, access to finance,

collective purchase of renewable gas and as such incentivising injection of locally produced green or low-carbon gases into the wider system. This would be a welcome development considering a net-zero emissions economy by 2050 will require increasing amounts of biogas/biomethane compared to today's consumption[81].

Smart metering and access to data[82]

The Gas Directive 2009/72/EC includes provisions promoting smart metering[83] and easy access to data[84] to facilitate consumers' active participation in the market. Access to smart metering, is a prerequisite first for making accurate metering information quickly and readily available to consumers and suppliers. As such, it can largely help resolve issues like unjustified or incorrect invoices that are one of the largest sources of consumer complaints as reported by the regulators[85]. In addition, smart metering can provide final customers with the right tools to manage their energy behaviour, exercise their choices, and get access to improved and new energy services. It also presents an opportunity for new product developers or new entrants to come in and promote their exciting new offers that rely on frequent meter readings. However, smart meters, whose deployment is encouraged by current legislation in those situations where it is economically reasonable, cost-effective and beneficial, and therefore appropriate[86], are not yet installed in most Member States, usually as a result of negative or inconclusive cost-benefit assessments (see *Figure 27*). At the current slow pace and limited deployment range[87], it is expected that by 2024[88] 34 million gas meters will be installed in the EU-27 representing just a 37% penetration rate. As data shows the business case for gas smart metering is not yet overwhelming across the EU (*Figure 27*) and few Member States have an implementation strategy in place (*Figure 28*); this links to the cost-effectiveness issues described in the main part of this Impact Assessment.

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high investment costs, and the existence of oligopolies (due to large economies of scale). The importance of such a regulatory framework cannot be underestimated. Those countries that had a framework in place have the highest numbers of energy communities today. For example, in 2016, there were 650 energy communities in Denmark, supporting policies have been in place since 2008. Furthermore, it appears EU level reforms have coincided with an increase of 1 321 energy communities between 2016 and 2019. See Frontiers, 'Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer', p. 9.

81 Trinomics, 'Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure', p. 11.

82 See footnote 87.

83 Articles 3(8) and Annex I.2 of the Gas Directive 2009/73/EC; also complementing provisions can be found in Articles 9(2); 10(2); 12(2b) of the Energy Efficiency Directive (EED) 2012/27/EU.

84 Article 41(1)(q), Article 45(first paragraph), and Annex I (1h) of the Gas Directive 2009/73/EC.

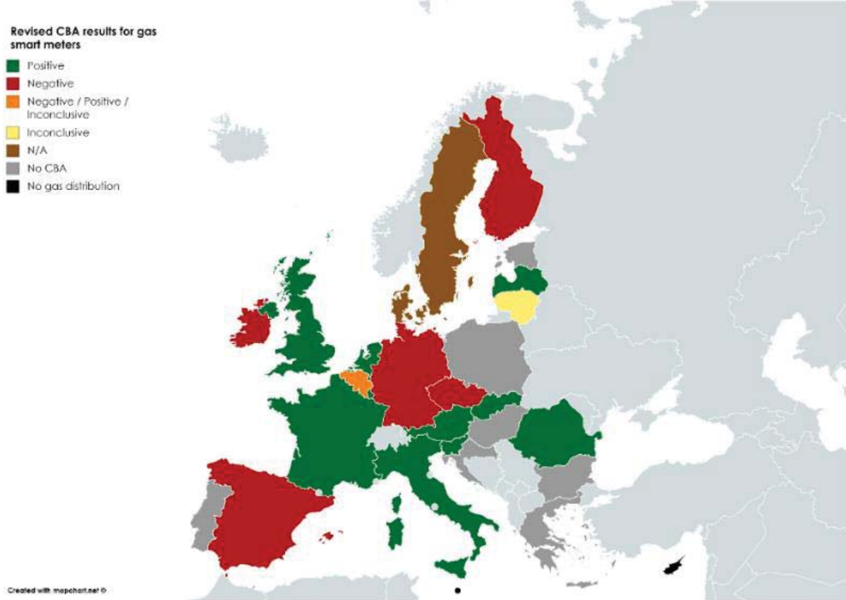
85 The 9th ACER/CEER Market Monitoring Report (2020) – Energy Retail and Consumer Protection Volume, shows that the biggest average share of complaints regarding gas suppliers concerns invoicing/billing and debt collection (40%).

86 Recital (52) of the Gas Directive 2009/73/EC.

87 Only France, Italy, Luxembourg and the Netherlands in the EU-27 are currently proceeding with large-scale rollouts. Installations of gas smart meters have also started in other countries, but at different speed and level of ambition; namely in Germany, Estonia, Ireland and Poland. The rest of the Member States concluded for now that the costs outweigh the benefits; others intend to install gas smart metering systems only under certain conditions or have reached no decision yet (source: Tractebel report 'Benchmarking smart metering in EU-28' (2019)).

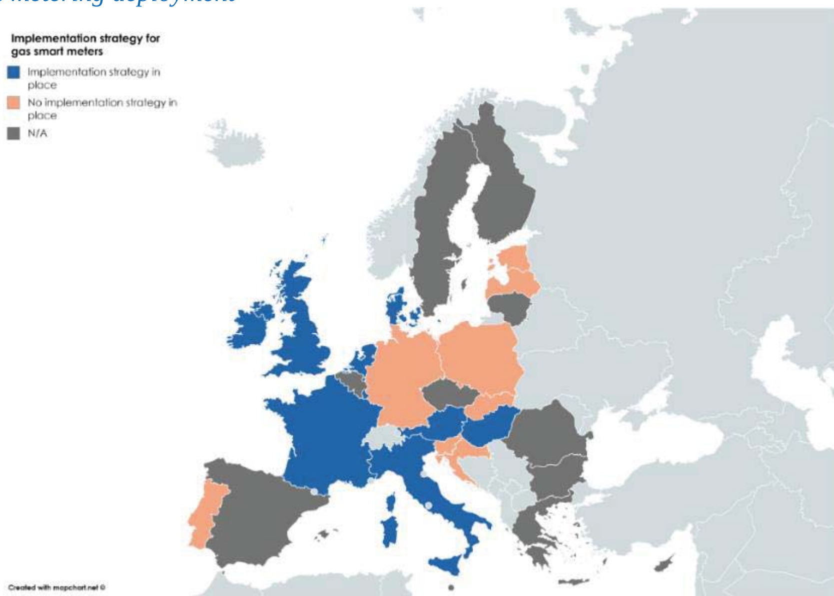
88 These estimations are based on the observed rate of deployment of gas smart meters in 2017 (source: Tractebel report 'Benchmarking smart metering in EU-28' (2019)).

Figure 27: Cost-Benefit-Analyses (CBA) results in the EU-28 for a large-scale rollout of gas smart meters demonstrating the challenge of making a business case for such an implementation



Source: Tractebel study, 2019[89]

Figure 28: Overview of EU-28 States that have an implementation strategy in place with specific legal provisions for gas metering deployment[90]



Source: Tractebel study, 2019

The main costs associated with a gas smart meter roll-out, regardless of the entity carrying it out, are the associated investment and operational costs (see *Figure 29(a)*), and the main benefits link to savings and energy efficiency gains (*Figure 29(b)*). These are elements that

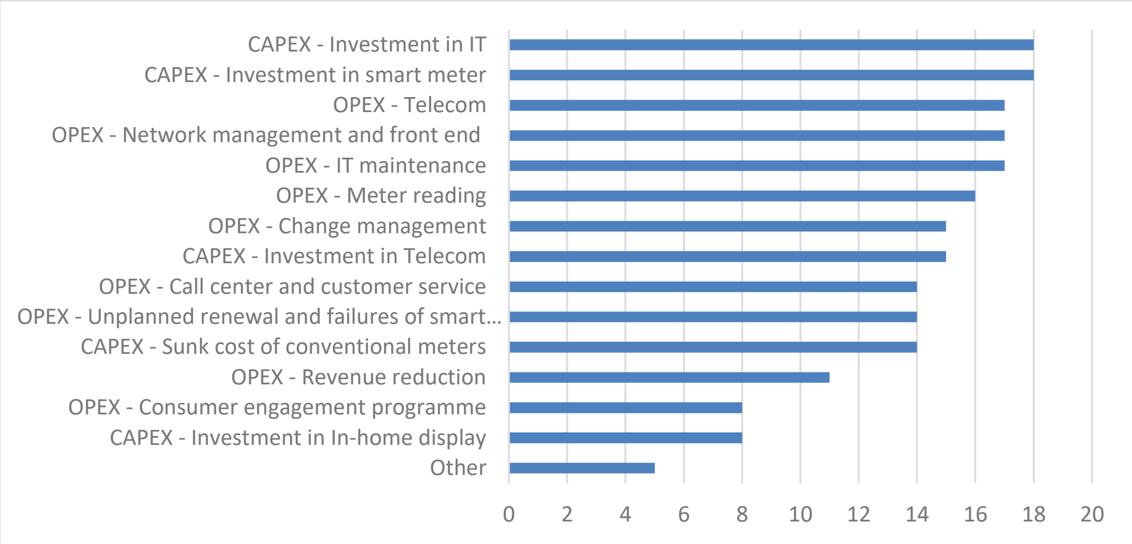
89 Tractebel report 'Benchmarking smart metering in EU-28' (2019).

90 Flanders is planning a segmented rollout of gas smart meters simultaneously with the segmented rollout of electricity smart meters; N/A in the legend stands for data not made available in the course of the project by the relevant national authorities

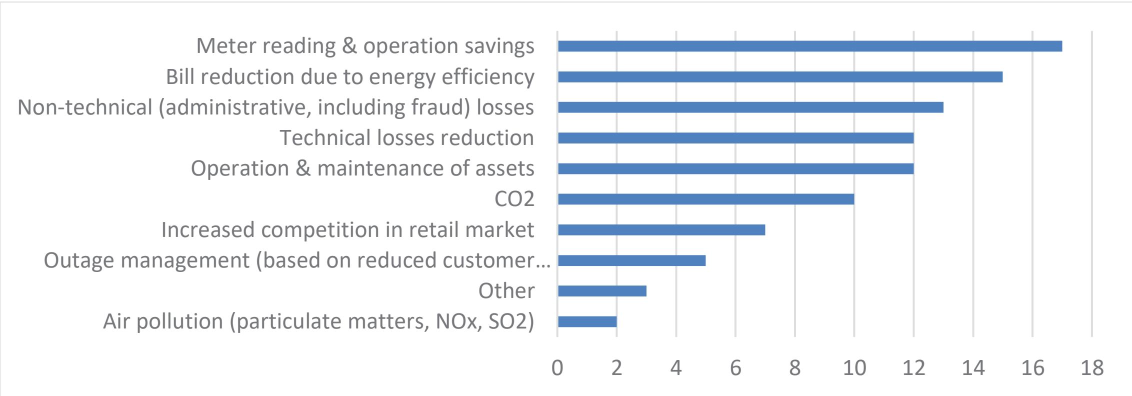
Member States consider in their assessments when they are analysing the cost-effectiveness of such a deployment, and are therefore dictating the outcome of the exercise.

Figure 29: Ranking of the considered (a) Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) costs, and (b) benefits in the gas CBAs vs. number of Member States that conducted at least one gas CBA

(a) Costs



(b) Benefits



Source: Tractebel study, 2019

As of 2018, estimates across all Member States indicated that there remained large differences in per metering point costs across the EU, with the highest price per metering point at EUR 826 in the Czech Republic and the lowest at EUR 38 in Latvia[91]. These cost differences could be explained by a number of factors such as the type of meter considered, the cost of living, the economies of scale that could be achieved etc. Wide and unexplained disparities in cost estimates between countries make it difficult to draw conclusions on an

[91] Source: Tractebel report (2019) – estimates cited here are based on data provided by Member States through their individual cost-benefit-analyses (CBA). For the most part therefore, these are given in Net Present Value for the year in which the CBA was carried out. As such, the specific estimates are not meant to be compared like-for-like but instead serve as both a rough estimate of actual smart meter costs and benefits at the time of their estimation and as internally consistent estimates of costs and benefits within each individual CBA.

average cost for a ‘typical’ meter from these cost-benefit-assessments. Although more recent evidence[92] from countries that are actually rolling out gas smart meters suggests **costs in the range of EUR 100-350** per metering point, and on **average: cost close to EUR 247** and **benefit of EUR 225 per metering point.**

This benefit/cost ratio is improved when selective rollouts are considered involving use cases that can fast return energy savings and overall benefits coming from the availability of more granular information as enabled by gas smart metering. This is the underlying consideration when under Option 3 selective rollouts involving beneficial use cases and no-regret scenarios are promoted (see *Table 49* related options).

It is also notable that estimated costs and benefits (where they have been reassessed by Member States) can change significantly over time. This is true as new evidence and promising use cases come to light and as views on how the gas system will evolve are updated. This highlights the importance of periodically revisiting the analysis which is proposed under Option 3 (see *Table 49*).

So far, the primary market drivers for the deployment of gas smart metering in Europe, according to available field data, have been the digitalisation of the distribution grids (for the optimisation of network operations) and of the retail market (to foster innovation and new energy services)[93], as well as actions for energy efficiency and for tackling poverty – elements that have also been incorporated to a certain extent also in the countries’ cost-benefit assessments. Yet, there were not enough to realise the desired levels of implementation. Nevertheless, no specific target was set by the gas legislation in the first place. It was though anticipated that market drivers and regulatory environments as well as parallel rollouts for electricity smart meters and the possibility to share the telecommunication infrastructure and associated costs, could have triggered a more decisive move towards deployment in a number of Member States. Since this has not been the case so far, Option 3 considers a target for implementation.

Moreover, even when smart meters are rolled out, they might not always be supported by arrangements, such as data management set-ups, that are necessary, for consumers and service providers of their choice, to get easy and timely access to data and accordingly control their consumption behaviour or get actively involved in the market.

The current legislation stays silent on the specifics regarding access to data and data management arrangements as well as on the respective responsibilities, which in many cases are undertaken by network operators. This could place incumbents in a privileged position regarding access to consumer data – especially smart metering data – and could create asymmetry of information between them and potential new entrants, and even result in higher transaction costs.

To prevent this, safeguards need to be in place. These safeguards exist but they are not fully developed in the current gas legislation. Moreover, the diverse interests of market actors who may be involved in data handling mean that they are unlikely to emerge without regulatory intervention. As a result, and given the value of data, it is necessary to ensure that it is managed in a non-discriminatory and transparent way. This way, the right information will be

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92 Source: Frontier study ‘Assessment of policies for gas distribution networks, gas DSOs and the participation of consumer’ (2021).

93 See Figure 33 and Table 27 in the Tractebel report ‘Benchmarking smart metering in EU-28’ (2019).

available to all those eligible, as and when requested, including to final customers and third parties of their choice, while at the same time ensuring a high level of data protection. This is the underlying rationale for proposing the data management measures under the preferred Option 3 (see Problem Area IV Options of this Impact Assessment).

These very principles are already spelled out in the new Electricity Directive (EU) 2019/944 (Article 23) which also authorises the Commission to adopt through implementing acts interoperability requirements and transparent and non-discriminatory procedures for access to data (Article 24), and are proposed (under Option 3 of Problem Area IV, and *Table 49*) to be mirrored in the case of gas. This is in order to facilitate the delivery of data-driven services and products and in turn boost competition across the EU. At the same time, such a measure will constitute a concrete step forward supporting the creation of the energy data space and data sharing within the EU and even across sectors. Regarding the protection of personal data, the Electricity Directive recalls that the Regulation (EU) 2016/679 (GDPR) remains the relevant umbrella legislation, also for the energy sector, providing a comprehensive framework and overarching principles for the identification and handling of such data. This should be accordingly recalled in new gas provisions when easy, safe and secure access to data by those eligible is promoted.

Equipped with the right tools, such a smart meters, and with access to timely and accurate data, consumers can get actively involved in the gas market if they wish so. Prior to that though they need to trust and feel at ease with such a perspective.

Consumer acceptance of smart metering is a prerequisite for this, and a key element for the success of a rollout. The messages that come out from pilot installations, and ongoing deployments, reinforce the fact that consumers should be properly informed of their rights and also be made aware from the very beginning of the opportunities opened up with smart metering (Energy Efficiency Directive, Article 9(2c)). At the moment, very few Member States are setting up such communication campaigns with targeted messages[94] or intend to systematically monitor the extent of consumer engagement and overall satisfaction. This is another variable that is currently missing and could be accordingly incorporated in all rollouts as it is proposed under the preferred Option 3 (see Problem Area IV in main Impact Assessment) to enhance the effectiveness of the respective smart metering provisions.

To summarise, evidence to date[95] suggests that the smart metering provisions currently in place have been less effective than intended. At the same time, it confirms that the business case for gas smart metering remains more challenging to make in most national settings compared to electricity, but could be enhanced by promoting those use cases that can fast deliver benefits. Moreover, given the value of data, it becomes more apparent that measures for access to data might need to be further enhanced following also the example of electricity. To this respect, principles for the non-discriminatory and transparent access to (smart meter) data, independently of the Member States' data management model, could be explicitly set also for gas. This is to ensure the easy, safe and secure access to data by those eligible, and support the delivery and creation of novel (energy) services and products that benefit consumers and businesses alike.

94 ASSET study on consumer satisfaction KPIs for the roll-out of smart metering in the EU Member States – external study launched by the Commission (2018); ANEC position paper 'Monitoring the success of smart metering deployment from a consumer perspective' (2015).

95 See also Evaluation Report.

As aforementioned, the preferred scenario is that captured under Option 3 that foresees a partial mirroring of the **smart metering** provisions for electricity. Accordingly, Member States still decide on deployment based on a cost-benefit analysis (as in Article 19(2) in the Electricity Directive). Furthermore, Member States are strongly encouraged to carefully consider potential synergies with an already rolled out electricity smart metering infrastructure (i.e. supporting communications) as well as selective rollouts to cases that can quickly return net benefits (e.g. connection of gas heat pumps) in order to keep costs in check. Moreover, a requirement for regular reviewing of negative assessments is introduced (mirroring Article 19(5)) as well as for a careful monitoring of the delivery of consumer benefits in case of a rollout. Smart metering provisions apply only to new rollouts, as it is the case also for electricity (Article 19(6) of Electricity Directive), and include a deployment target (similar to Annex II for electricity) and a right to a smart meter at own expense (i.e. Article 21 of Electricity Directive), while functionalities that reflect gas specificities (e.g. no need for dynamic response and near-real time measurements) are incorporated in the measures (partial mirroring of Article 20 of Electricity Directive). As far as **data** is concerned, under the preferred Option 3, provisions are set mirroring those for electricity (in Articles 23 and 24) laying down key principles on data management and a mandate for the Commission to develop in implementing acts interoperability requirements and transparent and non-discriminatory procedures for access to data.

ANNEX 11: EVALUATION AND IMPACT ASSESSMENT

Table 55: Table of synergies between Evaluation and Impact Assessment as well as relevant connected legal acts which require revision

Areas	Articles in existing acts	Where covered in the evaluation	Where covered in the Impact Assessment	Relevant legal act to be revised
Subject matter, scope and definitions	**Directive 2009/73/EC** Article 1: Scope – Include new gases Article 2: Definitions **Regulation 715/2009** Article 1: Scope Article 2: Definitions	Chapter 1, paragraph 1.2 Chapter 7, paragraphs 7.3.1, 7.3.3	Chapter 1, paragraphs 1.2,1.4,1.5 Chapter 4, paragraphs 4.1, 4.2 Chapter 7, paragraph 7.5	Gas Directive and Gas Regulation
Promotion of market integration for renewable and low carbon gases	**Directive 2009/73/EC** Article 13: review the tasks of transmission, storage and/or LNG system operators Article 25: review tasks of DSOs Articles 47 and 48: level playing field, PSOs, take-or-pay delete **Regulation 715/2009** Articles 4 , 5 , 8: review ENTSOG- DSOs tasks Article 13: tariffs for access to network, cross-subsidisation	Chapter 1, paragraph 1.2 Chapter 7, paragraphs 7.3.1, 7.3.4	Problem Area II Chapter 2, paragraphs 2.1, 2.2 Chapter5, paragraphs 5.1, 5.2 Chapter 6, paragraphs 6.1, 6.2, 6.7 Chapter 7, paragraphs 7.1, 7.2, 7.7 Chapter 8, paragraphs 8.1, 8.2, 8.5 Chapter 9, paragraphs 9.1, 9.2	Gas Directive and Gas Regulation TEN-E Regulation Renewables Energy Directive Energy Effiency Directive
Security of supply and risk preparedness	**Directive 2009/73/EC** Article 3: PSOs (links to SOS, regulated prices and RES PSOs) Articles 5 and 6: Alignment with SOS Regulation Article 41 (1)t: Duties and powers of the regulatory authority – monitoring the implementation of safeguard measures Article 46: Safeguard measures **Regulation 715/2009** Article 8: review tasks of ENTSO-G on cybersecurity	Chapter 1, paragraph 1.2 Chapter 3, paragraph 3.2.1; Chapter 7, paragraphs 7.3.4, 7.4.2	Problem Area III Chapter 2, paragraphs 2.2, 2.3 Chapter 5, paragrapghs 5.2.1, 5.3 Chapter 6, paragraphs 6.2 Chapter 7,-paragraph 7.5.1 Chapter 8, paragraph 8.2	Gas Directive and Gas Regulation Security of Supply Regulation Renewables Energy Directive
Regional cooperation and market mergers	**Directive 2009/73/EC** Article 7.4: unbundling and market mergers, NRAs oversight and certification in merged markets **Regulation 715/2009** Article 12: regional cooperation of TSOs	Chapter 7, paragraphs 7.1.1, 7.3.2	Problem Area III Chapter 2, paragraph 2.2.1.2 Chapter 6, paragraph 6.7	Gas Directive and Gas Regulation Electricity Directive
Gas quality	**Directive 2009/73/EC**	Chapter 1, paragraph 1.2	Problem Area I, II	Gas Directive and

Areas	Articles in existing acts	Where covered in the evaluation	Where covered in the Impact Assessment	Relevant legal act to be revised
	Article 8: technical rules – gas quality Article 13: review tasks of TSOs Article 25: review tasks of DSOs Article 41: review duties and powers of the regulatory authority **Regulation 715/2009** Article 8: review tasks of ENTSOG and areas for Network Codes Article 18: review TSO level transparency requirements and include DSO level transparency related to gas quality	Chapter 7, paragraph 7.3.2	Chapter 6, paragraphs 6.1.2, 6.2	Gas Regulation
LNG	**Directive 2009/73/EC** Article 13: review tasks of system operators Article 36: include new criteria for LNG new infrastructure **Regulation 715/2009** Article 15: TPA for Storage and LNGs Articles 18, 19: transparency of LNG and storages DSOs – include transparency platforms	Chapter 7, paragraph 7.3.2	Problem Area II Chapter 2, paragraph 2.2.1.5 Chapter 5, paragraph 5.2	Gas Directive and Gas Regulation Renewables Energy Directive
Network Planning	**Directive 2009/73/EC** Articles 14, 18, 20, 21, 22, 23, 35 and 41: Network planning of ISO and ITO amend and expand to other TSOs, connection rules, refusal of access	Chapter 1, paragraph 1.2 Chapter 7, paragraph 7.3.3	Problem Area III Chapter 2, paragraph 2.3 Chapter 5, paragraphs 5.1, 5.3 Chapter 6, paragraph 6.3 Chapter 7, paragraph 7.3 Chapter 8, paragraph 8.3	Gas Directive and Gas Regulation TEN-E Regulation Renewables Energy Directive Electricity Directive
Consumer empowerment and protection	**Directive 2009/73/EC** Article 3: PSO Article 45: consumers, energy poverty Article 28: closed networks, energy communities Annex I: consumer protection	Chapter 7, paragraphs 7.1.2, 7.3.5	Problem Area IV Chapter 2, paragraph 2.4 Chapter 5, paragraph 5.4 Chapter 6, paragraph 6.4 Chapter 7, paragraph 7.4 Chapter 8, paragraph 8.4	Gas Directive and Gas Regulation Electricity Directive
Regulatory oversight ('mirroring')	**Directive 2009/73/EC** Articles: 40, 41, 42, 43, 44: powers of NRAs Gas Directive **Regulation 715/2009** Article 9: ACER monitoring	Chapter 2, paragraph 2.1 Chapter 7, paragraph 7.5.1	Chapter 4, paragraphs 3.2, 3.3 Chapter 9, paragraph 9.5	Gas Directive, Gas Regulation and ACER Regulation

ANNEX 12: DETAILED ANNEX ON COHERENCE WITH THE PRESENT PROPOSALS WITH OTHER FIT FOR 55 PROPOSALS AS WELL AS OTHER LEGISLATIVE ACTS

This Annex explains the coherence with the legislative proposals brought forward in the context of the Fit for 55 package and other relevant initiatives as outlined in Section 1.4.

The proposed initiative focusses on enabling markets to decarbonise gas consumption. It is strongly linked and complementary to the legislative proposals brought forward in the context of the Fit for 55 package and other relevant initiatives to implement the European Green Deal including:

The revised Renewable Energy Directive (RED II)

RED II is the main EU instrument dealing with **the promotion** of energy from renewable sources. It aims to incentivise the penetration of renewable energy including renewable gases.

It was adopted in 2018 and has to be fully implemented by Member States on 1 July 2021. This Directive was calibrated in the Clean Energy for All Package with other energy, climate, environmental but also consumer legislation.

The EGD and its follow-up initiatives have increased the ambition of the Union climate and energy policies. This new ambition can only be achieved with considerably increased volumes of renewable energy in the system in addition to a strong improvement in energy efficiency. RED II is therefore being revised in the context of the Fit for 55 package with the aim:

- to increase the renewables share in final energy consumption in line with the Climate Target Plan conclusions;
- to increase energy system integration by promoting electrification based on renewable electricity, to create a level playing field for all innovative renewable fuels and to specifically promote innovative renewable fuels (such as hydrogen and its derivatives produced from renewable electricity); and
- to ensure that renewables, in particular produced from forest biomass, are sustainable.

The Renewable Energy Directive and its review incentivise the penetration of renewable energy including gaseous ones. The present initiative seeks to ensure that competitive markets exist for renewable and low carbon gases.

Certain interactions exist between these initiatives that are elaborated upon below:

- Other low-carbon fuels (including low-carbon gases) have been left outside the scope of RED II since not being of renewables nature and hence not fitting well in the context of a directive which main goal is the promotion of the use of energy from renewable sources. However, low-carbon fuels such as low-carbon hydrogen may also play a role in the transition, particularly in the short and medium term to rapidly reduce emissions of existing fuels, and support the uptake of renewable fuels such as renewable hydrogen. This is the reason why the EU Energy System Integration strategy highlighted the need to define and certify low carbon fuels (LCFs). In order to fill in this gap and enable low-carbon fuels to be a viable solution for Member States in a transitional period, this Impact Assessment explores the options of deploying a comprehensive system of terminology and certification of non-renewable low-carbon fuels.
- The RED *inter alia* includes the right for renewable self-consumers and renewable energy communities to generate, store and sell renewable energy, including renewable

gases, without being subject to disproportionate procedures. Furthermore, it includes measures to simplify and speed up administrative and permitting procedures to ease the administrative burden for renewable projects developers. The Directive also develops general principles for the design of support schemes. It also sets up a framework for guarantees of origin and certification of sustainability for renewable and low-carbon gases. This element is of particular importance with regard to ensuring market participation for such gases.

The RED and the present initiative are hence complementary.

The Energy Efficiency Directive (EED)

In general, energy efficiency measures interact with the present initiative as they affect the level and structure of gas demand. In addition, energy efficiency measures can alleviate energy poverty and reduce consumer vulnerability. Besides consumer income and energy prices, energy efficiency is one of the major drivers of, and at the same time solutions for energy poverty. Revision of EED will set a more ambitious binding annual target for reducing energy use at EU level. It will guide how national contributions are established and almost double the annual energy saving obligation for Member States. The public sector will be required to renovate 3% of its buildings each year to drive the renovation wave, create jobs and bring down energy use and costs to the taxpayer.

As gaseous fuels are currently dominating in European heating and cooling supply and in the cogeneration plants, their efficient use stays at the core of the energy efficiency measures. The provisions in the EED set the criteria for the high-efficiency cogeneration, including for the plants using gaseous fuels. High-efficiency cogeneration plants are important contributors to achieve efficient heat supply in district heating systems. The definitions of the EE on high-efficiency cogeneration and efficient district heating and cooling are widely accepted concepts on quality in EU legislation applicable to state aid, energy taxation and financial support programmes.

The present initiative is coherent with the energy efficiency first principle. The present initiative seeks to ensure efficient markets. An open and competitive EU market with prices that reflect energy carriers' production costs, carbon costs, and external costs and benefits would efficiently provide clean and safe hydrogen to end users who value it most. Efficient markets result in efficient relative prices. Solid relative price signals not only allow energy users to make informed decisions about what energy carrier to use where, it also means that they can make efficient decisions between consuming energy or not, i.e. to make an optimal trade-off when investing in energy efficiency measures[96]. Similarly, operational decisions to convert one energy carriers into another will only be taken if economically attractive in its own right and if not other, more efficient and lower cost alternatives exist. Robust price signals and efficient markets are thus coherent with the energy efficiency first principle.

Energy Performance of Buildings Directive and the Renovation Wave initiative

Heating and cooling constitutes around half of the EU's final energy consumption and is the biggest energy end-use sector, ahead of transport and electricity, covering a wide range of end-use applications and technologies in buildings, industry and district heating and cooling.

[96] A hydrogen strategy for a climate-neutral Europe, COM(2020) 301 final.

Space heating and water heating in buildings (households, services, industry) accounts for 30.9% of final energy demand in the EU.

In the EU, heating, cooling and domestic hot water account for around 80% of energy consumed in residential buildings.

The shifting of buildings' heating and cooling systems away from fossil fuels to more renewable based systems is key to achieve the higher ambitions of the Green Deal and the 2030 CTP and for the decarbonisation of buildings. According to the 2030 Climate Target Plan, in order to achieve the 55% emission reduction target by 2030, the EU should reduce buildings' GHG emissions by 60%, their final energy consumption by 14% and energy consumption for heating and cooling by 18% (compared to 2015 levels).

This initiative and the present initiative are complementary.

The Regulation on trans-European energy networks (TEN-E)

TEN-E lays down rules for the timely development and interoperability of trans-European energy networks. The TEN-E is a policy that is focused on linking the energy infrastructure – electricity, natural and biogas, oil, CO2 – of EU countries. The TEN-E Regulation puts in place a framework for Member States and relevant stakeholders to work together in a regional setting to identify and implement projects of common interest to connect energy networks, connect regions currently isolated from European energy markets, strengthen existing cross-border interconnections, and help integrate renewable energy. As such, the TEN-E is a central instrument in the development of an internal energy market and necessary to achieve the European Green Deal objectives.

In December 2020, the Commission presented a legislative proposal to revise the TEN-E Regulation[97] in order to better support the modernisation of Europe's cross-border energy infrastructure and achieve the objectives of the European Green Deal. Among others, the Commission's proposal includes:

- an obligation for all projects to meet mandatory sustainability criteria and to follow the 'do no harm' principle as set out in the Green Deal;
- an update of the infrastructure categories eligible for support through the TEN-E policy, ending support for oil and natural gas infrastructure;
- a new focus on hydrogen infrastructure including transport and certain types of electrolysers;
- new provisions on smart grid investments for integrating clean gases (like biogas and renewable hydrogen) into the existing networks;
- continued attention to the modernisation of electricity grids and storage and carbon transportation networks;
- a revised governance framework to enhance the infrastructure planning process and ensure it is aligned with our climate goals and energy system integration principles, through increased stakeholder involvement throughout the process, a reinforced role of the EU Agency for the Cooperation of Energy Regulators (ACER) and improved oversight by the Commission.

The TEN-E Regulation and the present initiative are complementary.

97 COM(2020) 824 final EUR-Lex - 52020PC0824 - EN - EUR-Lex (europa.eu)

Emission Trading Scheme (ETS)/Innovation Fund and Effort Sharing Regulation

The Emission Trading Scheme (ETS) increase the price of using fossil fuels relative to renewable and low-carbon gases and, thus, fosters the use of such gases and investments in related production technology. The Commission has already proposed strengthening, including reinforcements in and extensions to the aviation sector, maritime and road transport, and buildings.

The Effort Sharing Regulation assigns strengthened emissions reduction targets to each Member State for buildings, road and domestic maritime transport, agriculture, waste and small industries. Recognising the different starting points and capacities of each Member State, these targets are based on their GDP per capita with adjustments made to take cost efficiency into account.

The Innovation Fund, which was established by the EU Emission Trading System (EU ETS) Directive for the period 2021 to 2030, is one of the funding instruments supporting the transition to a climate neutral Europe by 2050. It supports the demonstration of low-carbon technologies and processes in energy intensive industries (including products substituting carbon intensive ones), environmentally safe carbon capture and utilisation and storage of carbon dioxide (CCU and CCS), innovative renewable energy and energy storage technologies. Funds originate from the auctioning of 450 million allowances in the EU Emission Trading System and the remaining funds of a previous programme on innovation (NER300). For the period 2020 to 2030, the Innovation Fund will provide more than EUR 11 bn (depending on the carbon price) for investments in breakthrough low-carbon technologies close to the market.

These initiatives and the present initiative are hence complementary.

Energy Taxation Directive (ETD)

The Energy Taxation Directive 2003/96 (ETD) lays down the EU rules for the taxation of energy products used as motor fuel or heating fuel and of electricity[98].

The Revision of the ETD pursued as part of the Fit for 55 package aims to improve price signals thereby reinforcing green innovation and investment in all these sectors. The new rules aim at addressing the harmful effects of energy tax competition, helping secure revenues for Member States from green taxes less detrimental to growth than taxes on labour. They will remove outdated exemptions and incentives for the use of fossil fuels, for example in EU aviation and maritime transport, while promoting clean technologies. The revision will also help foster investment in new and innovative green industry by making rules clearer so that investors and innovators can plan their long-term investment in green technology and renewables more securely. Moreover, the updated rules will help facilitate the transition away from fossil fuels towards clean fuels and support the EU's delivery of its ambitious targets on the reduction of greenhouse gas emissions and energy savings.

Thus, whilst the ETD review seeks to align the tax component of energy prices with Green Deal Objectives, the present initiative seeks to foster efficient markets for gaseous energy carriers in which market participants can take investment and operational decisions based on the price signals at hand.

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98 Council Directive 2003/96/EC of 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity. *OJ L 283, 31.10.2003, p. 51–70.*

The ETD and the present initiative are hence complementary.

Methane leakage

Under the umbrella of the European Green Deal and as called for by Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action[99], the Commission adopted an EU strategy to reduce methane emissions[100] in October 2020 which announces that the Commission will propose legislation to reduce methane emissions in the energy sector.

The specific objectives of the forthcoming policy proposal are two-fold: i) to improve the availability and accuracy of information on the specific sources of methane emissions associated with energy consumed in the EU, and ii) to put in place EU obligations on companies to mitigate those emissions across different segments of the energy supply chain.

Specifically of relevance to the gas industry, point i) on improving information relates to the actions outlined in the Communication on the methane strategy on compulsory measurement, reporting, and verification (MRV) for all energy-related methane emissions at company-level, building on the methodology of the existing global voluntary initiative called the Oil and Gas Methane Partnership (OGMP[101]). Point ii) on mitigation relates to the action in the Communication on the methane strategy on an obligation to improve leak detection and repair of leaks (LDAR) on all natural gas infrastructure as well as any other production, transport or use of natural gas, including as a feedstock; and to the action on eliminating routine venting and flaring in the energy sector covering the full supply chain, up to the point of production.

Reducing methane emissions from the energy system is a prerequisite of any decarbonisation pathway that continues to foresee methane as an energy carrier or feedstock. The present initiative seeks to facilitate the penetration of renewable and low-carbon gases, including methane based gases.

CCS directive

Hydrogen can be produced by different means and processes. One of these processes (and actually currently the most commonly used) is based on producing hydrogen from natural gas. The CO2 produced by this process can be captured and transported to a storage site for CO2. Article 21 of Directive 2009/31/EC[102] already obliges Member States to take the necessary measures to ensure that potential users are able to obtain access to transport

99 Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action, http://data.europa.eu/eli/reg/2018/1999/oj

100 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on an EU strategy to reduce methane emissions (COM(2020) 663 final) https://ec.europa.eu/energy/sites/ener/files/eu_methane_strategy.pdf

101 The Climate and Clean Air Coalition created a voluntary initiative to help companies reduce methane emissions in the oil and gas sector. The Oil & Gas Methane Partnership was launched at the UN Secretary General's Climate Summit in New York in September 2014. https://www.ccacoalition.org/en/activity/ccac-oil-gas-methane-partnership

102 Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006OJ L 140, 5.6.2009, p. 114–135

networks and to storage sites for the purposes of geological storage of the produced and captured CO2 and lays down the principles of transparent, non-discriminatory fair and open access.

The Alternative Fuel Infrastructure Regulation

On July 2021, the European Commission adopted a package of proposals to deliver on the targets agreed in the European Climate Law enabling enable the necessary acceleration of greenhouse gas emission reductions in the next decade. Among these initiatives, the revised Alternative Fuels Infrastructure Regulation will repeal Directive 2014/94/EU of the European Parliament and of the Council on the deployment of alternative fuels infrastructure.

All new cars registered as of 2035 will be zero-emission. To ensure that drivers are able to charge or fuel their vehicles at a reliable network across Europe, the revised Alternative Fuels Infrastructure Regulation will require Member States to expand charging capacity in line with zero-emission car sales. On top of this, Directive 2014/94/EU requires Member States to set up national policy frameworks to establish markets for alternative fuels and ensure that an appropriate number of publicly accessible recharging and refuelling points is put in place.

Whilst interdependencies exist, the Alternative Fuel Infrastructure Directive is aiming at infrastructure investments in publicly available refuelling and recharging points for alternative fuel vehicles and vessels. From the perspective of the present initiative, these are not part of the infrastructure operated by a transmission or distribution system operator but an investment by energy system users. The present Impact Assessment thus aims at different types of infrastructure.

The FuelEU Maritime and REFuel EU Aviation proposals

The FuelEU Maritime proposal allows renewable and low-carbon fuels, including hydrogen-derived fuels like methanol and ammonia, to be used to meet the greenhouse gas intensity limit of the energy used on-board a ship. The REFuel EU Aviation proposal: Sets out a minimum share of 0.7% of ‘synthetic aviation fuels’ in the aviation fuels supplied to aircraft operators (art. 4).

These two initiatives imply an increased demand for hydrogen and hydrogen derivatives. These demand effects of these initiatives have been considered in the base-line of the present initiatives. It should be added that in the REFuel EU Aviation proposal ‘Synthetic aviation fuels’ are renewable fuels of non-biological origin as defined in the Renewable Energy Directive.

The present initiative is thus complementary with the The FuelEU Maritime and REFuel EU Aviation proposals in that it will provide the infrastructure to meet the demand created by the The FuelEU Maritime and REFuel EU Aviation and is also coherent in its use of concepts.

GLOSSARY

Term or acronym	*Meaning or definition*
ACER	Agency for the Cooperation of Energy Regulators
ADR	Alternative dispute resolution
AFID	Alternative Fuels Infrastructure Directive, Directive 2014/94/EU of the European Parliament and the Council of 22 October 2014 on the deployment of alternative fuels infrastructure EUR-Lex - 32014L0094 - EN - EUR-Lex (europa.eu)
BAU	Business as usual
BEUC	The European Consumer Organisation
Biogas	A mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion; its precise composition depends on the type of feedstock and the production pathway.
Biomethane	A near-pure source of methane produced either by 'upgrading' biogas (a process that removes any CO_2 and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation. Biomethane, subject to fulfilling specific gas quality standards, can be directly injected into the gas grid
CAPEX	Capital expenditure
CBA	Cost-benefit-analyses
CCUS	Carbon capture usage and storages
CEAP	Circular Economy Action Plan
CEC	Citizen energy community as defined in Article 2 (11) Electricity Directive (EU) 2019/944
CEER	Council of European Energy Regulators
CEN	European Committee for Standardization
CH4	CH_4 is the chemical formula for methane, a greenhouse gas. CH_4 is used as shorthand to refer to methane.
Clean Energy Package	The Package, adopted during the course of 2019, consists of eight legislative acts as well as other

	initiatives and measures aimed at facilitating the clean energy transition. The Clean Energy Package lays the ground for establishing a new electricity market design by introducing an updated Electricity Directive and Regulation, a new Regulation on Risk Preparedness and a revised ACER Regulation.
DSO	Distribution system operator; an undertaking that manages, develops and maintains the electricity or natural gas distribution network in a given area and, where applicable, its interconnections with other systems.
EEA	European Environment Agency
EED	Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency EUR-Lex - 32018L2002 - EN - EUR-Lex (europa.eu)
EGD	European Green Deal; COM/2019/640 final
EHB	European Hydrogen Backbone
EIB	European Investment Bank
Electricity Directive	Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU EUR-Lex - 32019L0944 - EN - EUR-Lex (europa.eu)
Energy communities	Used as an umbrella term to denote community energy initiatives as a social phenomenon. The term covers both communities-of-interest and communities-of-location.
Electricity Regulation	Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity EUR-Lex - 32019R0943 - EN - EUR-Lex (europa.eu)
Energy System Integration strategy	Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions Powering a climate-neutral economy: An EU Strategy for Energy System Integration, COM/2020/299 final

	EUR-Lex - 52020DC0299 - EN - EUR-Lex (europa.eu)
ENTSOG	European Network of Transmission System Operators for Gas
EPBD	Energy performance of buildings directive: Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings EUR-Lex - 32010L0031 - EN - EUR-Lex (europa.eu) and amending Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity EUR-Lex - 32019L0944 - EN - EUR-Lex (europa.eu)
ETD	Council Directive 2003/96/EC of 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity EUR-Lex - 32003L0096 - EN - EUR-Lex (europa.eu)
ETS	Emissions Trading Scheme EU Emissions Trading System (EU ETS) (europa.eu)
EU Hydrogen Strategy	A hydrogen strategy for a climate-neutral Europe. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, COM(2020) 301 final EUR-Lex - 52020DC0301 - EN - EUR-Lex (europa.eu); EU_Hydrogen_Strategy.pdf.pdf
EUCJ	Court of Justice of the European Union
FCH JU	Fuel cells & hydrogen joint undertaking
Fit for 55 package	Set of proposals forming part of the European Green Deal to revise and update EU legislation and to put in place new initiatives with the aim of ensuring that EU policies are in line with the climate goals agreed by the Council and the European Parliament resource.html (europa.eu)
Gas Directive	Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC EUR-Lex - 32009L0073 - EN - EUR-Lex (europa.eu)

Gas Regulation	Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 EUR-Lex - 32009R0715 - EN - EUR-Lex (europa.eu)
GCG	Gas Coordination Group
GDPR	General Data Protection Regulation
GHG	Greenhouse gas
GOs	Guarantees of Origin
Governance Regulation	Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action, amending Regulations (EC) No 663/2009 and (EC) No 715/2009 of the European Parliament and of the Council, Directives 94/22/EC, 98/70/EC, 2009/31/EC, 2009/73/EC, 2010/31/EU, 2012/27/EU and 2013/30/EU of the European Parliament and of the Council, Council Directives 2009/119/EC and (EU) 2015/652 and repealing Regulation (EU) No 525/2013 of the European Parliament and of the Council EUR-Lex - 32018R1999 - EN - EUR-Lex (europa.eu)
GW	Gigawatt
HHV	Higher heating value
Horizontal unbundling	Separation between network-based energy transport activities for different energy carriers, e.g. separation between the operation of hydrogen network operation and electricity grid operation.
Hydrogen	A feedstock for industrial processes and energy carrier that can be produced through a variety of processes from fossil fuels or electricity via electrolysis. Hydrogen can be used as a feedstock, a fuel or an energy carrier and storage, and has many possible applications across industry, transport, power and buildings sectors.
Hydrogen infrastructure	Term encompassing hydrogen pipelines, large-scale hydrogen storage and hydrogen terminals

Hydrogen quality	Includes hydrogen purity and contaminants
H2	Hydrogen
IEA	International Energy Agency
IGA	Intergovernmental Agreement
Hydrogen Terminals	An installation used for the transformation of liquid hydrogen or liquid ammonia into gaseous hydrogen for injection into the hydrogen network
Interoperability NC	Network Code on interoperability and data exchange rules Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules (Text with EEA relevance) EUR-Lex - 32015R0703 - EN - EUR-Lex (europa.eu)
IPs	(Cross-border) Interconnection points
IRENA	International Renewable Energy Agency
ISO	The ‘Independent System Operator’ is an entity entirely separated from a vertical integrated company. As per Art. 14 of the Directive 2009/73 (Gas Directive), vertically integrated companies retain the ownership of their network assets in this unbundling model whereas an ISO performs all the functions of network operators.
ITC	Inter-TSO Compensation
ITO	The ‘Independent Transmission Operator’ performs all the functions related to network operation while remaining part of the integrated untertaking that owns the network. To ensure independence, detailed rules are provided on its managerial and operational indipendence (Art. 17-23 Gas Directive).
JRC	Joint Research Centre of the European Commission
LCF	Low-carbon fuel are recycled carbon fuels as defined in article 2 of Directive (EU) 2018/2001, low-carbon hydrogen and synthetic gaseous and liquid fuels the energy content of which is derived from low-carbon hydrogen, which meet a greenhouse gas emission reduction threshold.

LCH	Low-carbon hydrogen means hydrogen the energy content of which is derived from non-renewable sources, which meets a certain greenhouse gas emission reduction threshold.
LCOE	Levelised cost of energy
LDAR	Leak detection and repair
LNG	Liquified natural gas
LSO	LNG system operator
LTC	Long term contract
LTS	2050 long-term strategy, A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy COM(2018) 773 EUR-Lex - 52018DC0773 - EN - EUR-Lex (europa.eu)
MBS	Mass-balance system
METIS (model)	Mathematical model providing analysis of the European energy system for electricity, gas and heat, see Annex 4
MRV	Monitoring reporting and verification
MS	Member State
Mt	Megatonne
Mtoe	Million tonnes of oil equivalent
MWh	Megawatt hour
Natural Gas	Methane of fossil origin
NC TAR	Network code on harmonised transmission tariff structures for gas, Comission Regulation (EU) 2017/460 EUR-Lex - 32017R0460 - EN - EUR-Lex (europa.eu)
NDP	National network development plans
NECP	National Energy and Climate Plan

NER 300	Funding programme for innovative low-carbon technology, focusing on the demonstration of environmentally safe carbon capture and storage
NRA	National regulatory authority
NS2	Nord Stream 2
OGMP	Oil and Gas Methane Partnership
OPEX	Operating expense
PC	Public consultation
PCT	Price comparison tool
PRIMES (model)	Price-Induced Market Equilibrium System: an energy system model for the European Union.
RAB	Regulatory Asset Base, which means all network assets of a network operator used for the provision of regulated network services that are taken into account when calculating network related services revenue
RCF	Recycled Carbon Fuels, are produced using the residual fossil energy in certain types of wastes and by-products, such as non- recyclable waste plastics and unavoidable industrial off-gases
REC	Renewable Energy Community as defined in Article 2 (16) Renewable Energy Directive (EU) 2018/2001
RED II	Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources EUR-Lex - 32018L2001 - EN - EUR-Lex (europa.eu)
RES gas	Renewable gas, which means biogas as defined in Article 2, point (28) of Directive 2018/2001, including biomethane, and renewable gaseous fuels part of fuels of non-biological origins (‘RFNBOs’) as defined in Article 2, point (36) of that Directive’‘renewable gases’ means biogas as defined in Article 2, point (28) of Directive 2018/2001, including biomethane, and renewable fuels of non-biological origins (‘RFNBOs’) as defined in Article 2, point (36) of that Directive.

RES&LC gases	Renewable and low-carbon gases
RFNBO	Renewable fuels of non-biological origins, which are fuels produced from renewable energy sources other than biomass, primarily renewable power
SMEs	Small and medium-sized enterprises
Sector Integration Strategy	Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions powering a climate-neutral economy: An EU Strategy for Energy System Integration COM/2020/301 final EUR-Lex - 52020DC0301 - EN - EUR-Lex (europa.eu)
SoS Regulation	Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 EUR-Lex - 32017R1938 - EN - EUR-Lex (europa.eu)
SSO	Storage system operator
Synthetic methane	Methane produced from hydrogen and CO2, such as CO2 captured from air.
Take-or-pay	A payment obligation that exists irrespective of requesting the delivery of the contracted commodity
TEN-E Regulation	Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009 EUR-Lex - 32013R0347 - EN - EUR-Lex (europa.eu)
TFEU	Treaty on the Functioning of the European Union
TPA	Third-party access
TSO	Transmission system operator, which is the entity that an undertaking that manages, develops and maintains the network for the transport of natural gas, which mainly contains high-pressure pipelines, and, where applicable, its interconnections with other systems

TWh	Terawatt-hour
TYNDP	Ten-Year Network Development Plan
Vertical unbundling	Separation of energy transport activities using energy networks from energy supply and energy production activities
VTP	Virtual trading point, a means a non-physical commercial point within an entry-exit system where gases are exchanged between a seller and a buyer without the need to book transmission or distribution capacity
WACC	Weighted average cost of capital
Wobbe-Index	Indicator of the interchangeability of natural gas. Frequently defined in the gas quality specifications for e.g. injection or transportation of natural gas and used to compare the combustion energy output of different composition gases used in an appliance (e.g. turbine, boiler).

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