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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}

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.

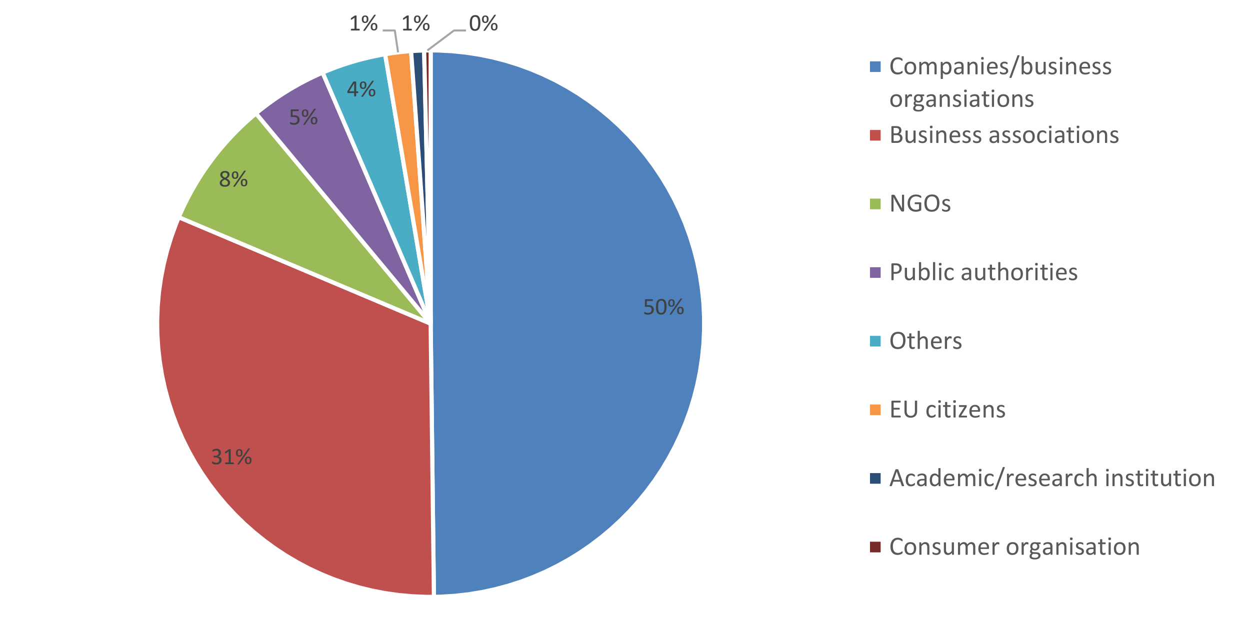
Based on the evaluation of the responses to the public consultation on the Inception Impact Assessment, it was concluded, that the public consultation document (questionnaire), in preparation at that time, covered all relevant topics and aspects for the revision of the gas legislation and for developing 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.

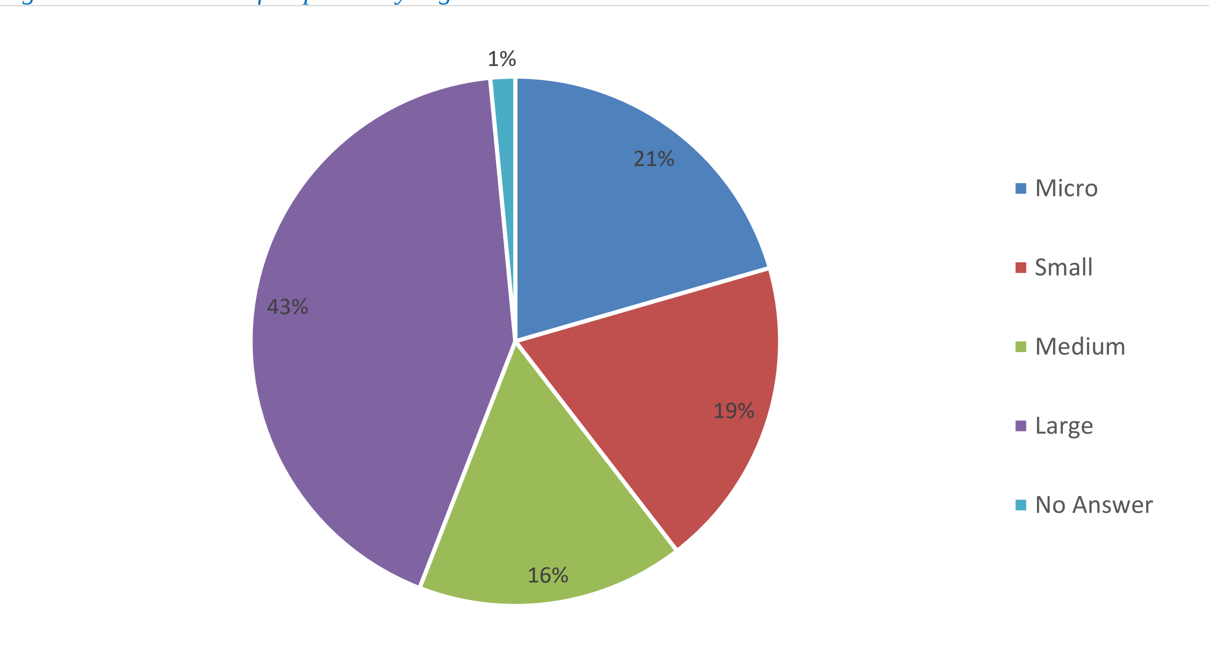
185 Gas networks – revision of EU rules on market access (europa.eu); published in the three working languages of the European Commission with the questions to the public will available in 23 EU official languages (all but Irish), with the option to send responses in any of these languages; with the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

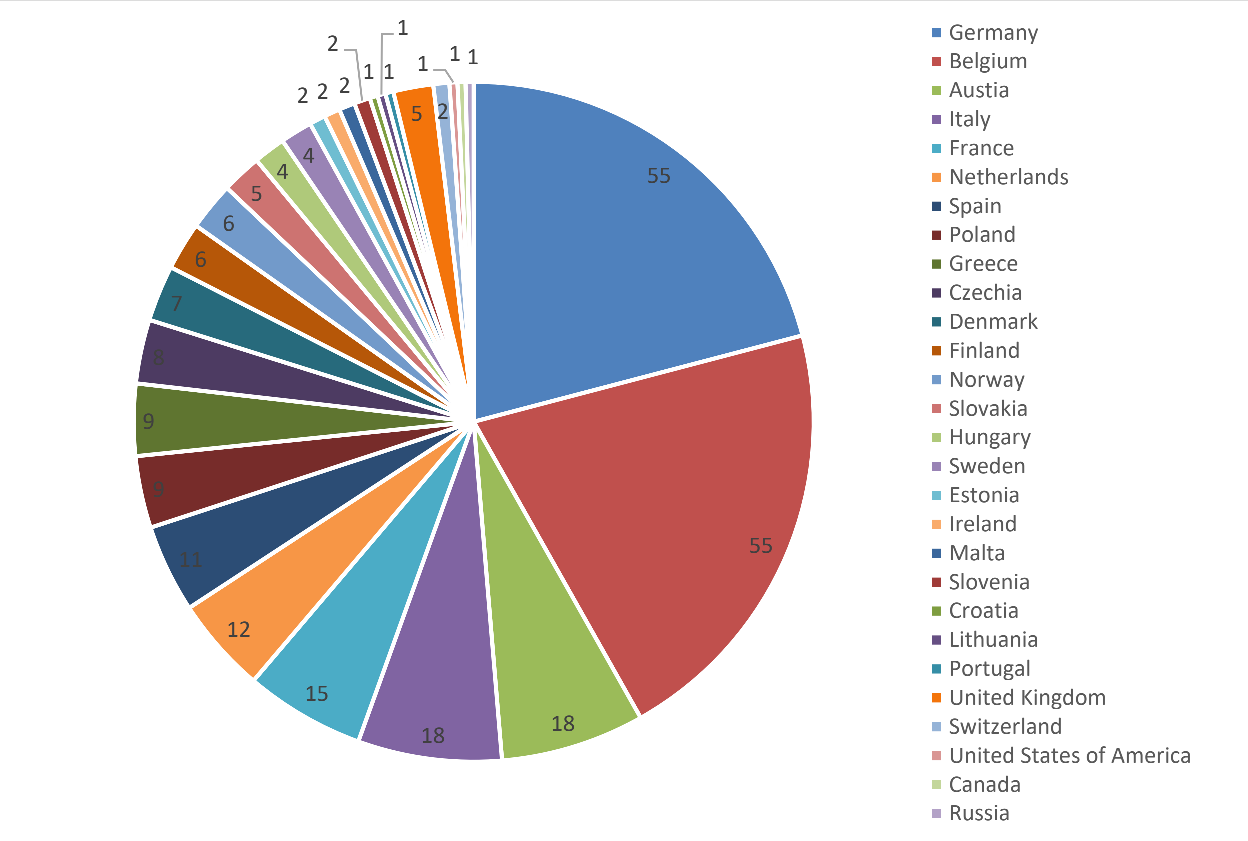
Figure 9: Distribution of responses by organisation size



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

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).

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

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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

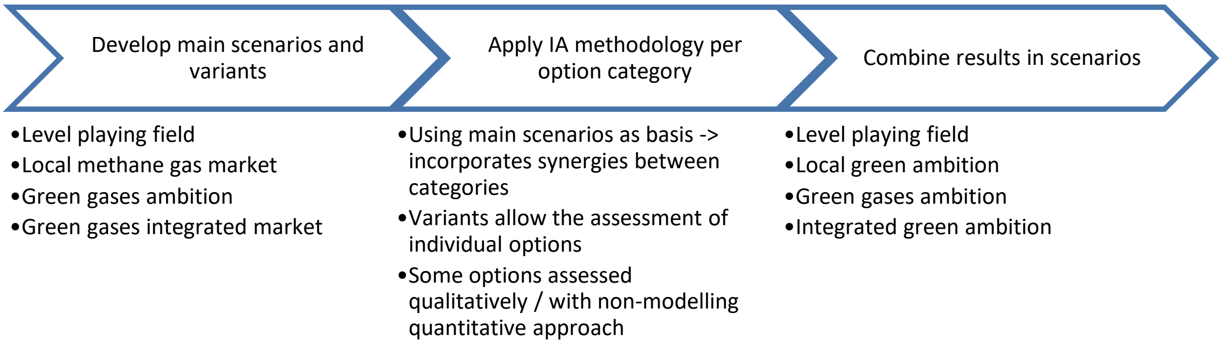
The definition of the number of scenarios and variants for Problem Area II considered the following criteria:

- 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

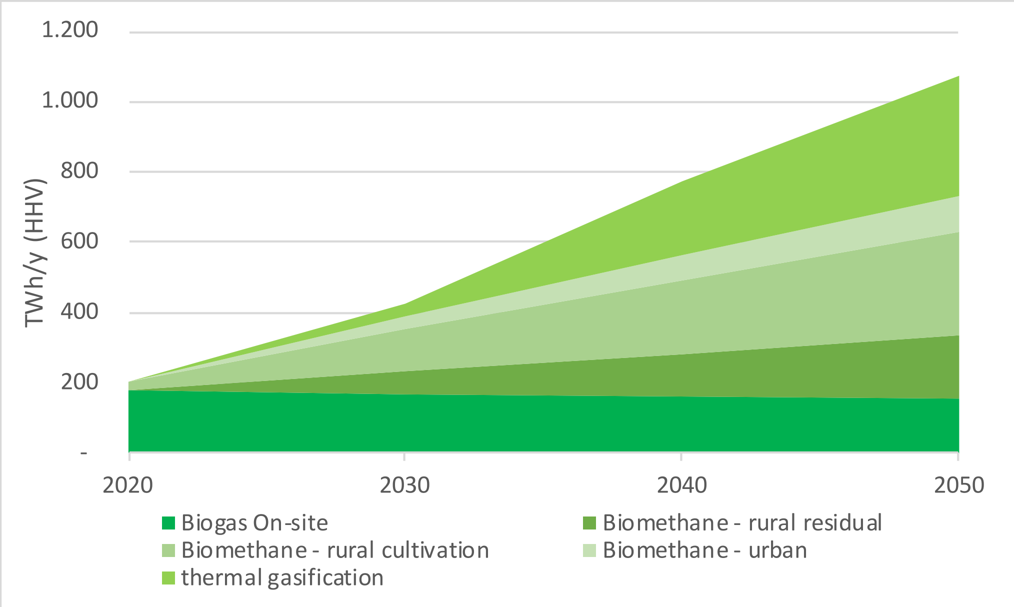
Biomethane Anaerobic digestion - rural residues	- Straw - Grass cuttings abandoned grassland - Animal waste
Biomethane Anaerobic digestion - rural cultivation	- Perennials: grassy - Sequential cropping - Phasing out existing plants: corn
Biomethane Anaerobic digestion - urban	- Common sludge - Sewage 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

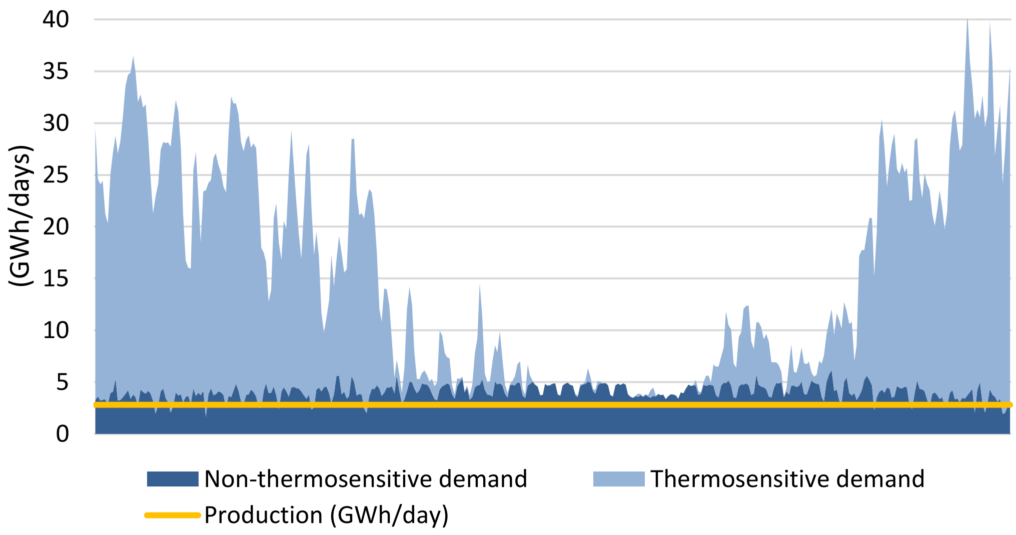
Based on cost-curves, a least-cost potential allocation has be made to meet the biomethane production projected in the MIX-H2 scenario in each Member State. In order to get an upper bound of the seasonal local oversupply, it has been assumed that 100% of the biomethane would be injected at the distribution 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.

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[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.

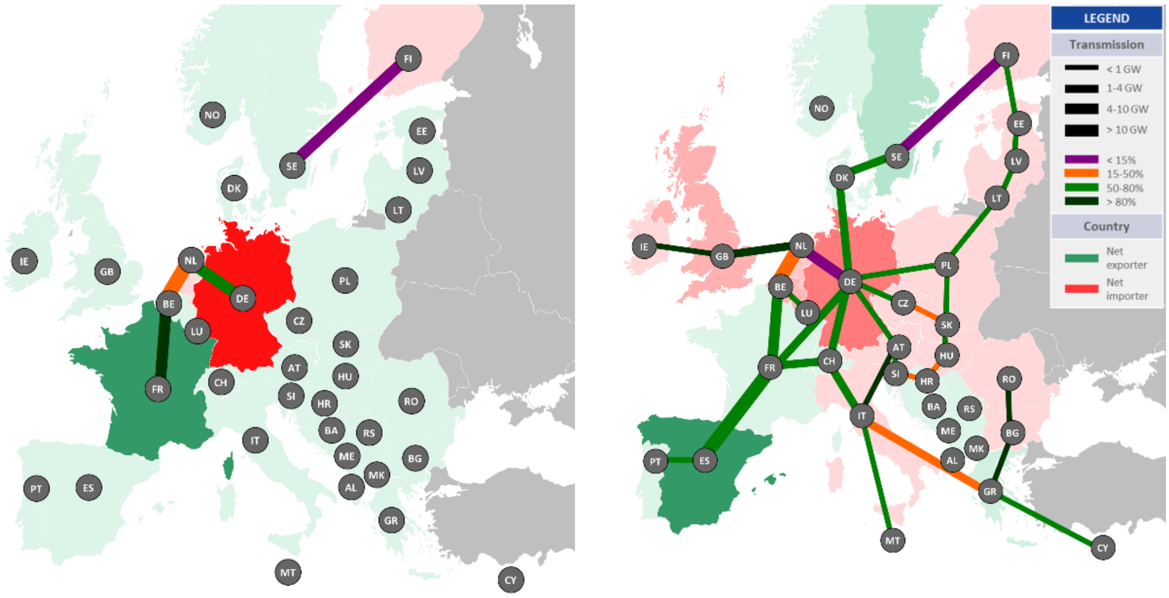
Table 29: Cross-border capacities in main scenarios

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

<table>
<tr><td rowspan="3">Horizontal unbundling</td><td>Objective</td><td colspan="5">Horizontal unbundling has the objective of preventing conflicts of interests arising from the operation of different types of energy networks by a single entity</td></tr>
<tr><td rowspan="2"><u>BAU</u>
No additional measures</td><td rowspan="2"><u>Option 1</u>
Rights for network operation tendered</td><td colspan="2"><u>Option 2</u>
Main regulatory principles</td><td colspan="2"><u>Option 3</u>
Big Bang</td></tr>
<tr><td>2a: Main regulatory principles only</td><td>2b: Main regulatory principles with a vision</td><td>3a: Hydrogen rules by Big Bang</td><td>3b: Hydrogen rules by Big Bang plus</td></tr>
<tr><td>Measures</td><td>No rules</td><td>NA</td><td>Combined hydrogen/CH4 TSO</td><td>Legal + Accounts unbundling</td><td>Legal + Functional</td><td>Accounts unbundling (assets operated by EU TSO (ISO)</td></tr>
<tr><td>Pros</td><td>No administrative burden.</td><td>-</td><td>No additional administrative burden (as BAU for natural gas).
Facilitates repurposing of natural gas network.</td><td>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.</td><td>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.</td><td>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).</td></tr>
<tr><td>Cons</td><td>National rules may prevent combined Hydrogen/CH4 operators in some Member States.</td><td>-</td><td>Risk of conflicts of interest regarding repurposing and de-commissioning of gas network infrastructure.</td><td>Administrative burden and regulatory cost for operation and monitoring, but relatively low.</td><td>Higher administrative burden and regulatory costs for operation and monitoring.</td><td>Higher administrative burden and regulatory costs for operation and monitoring.</td></tr>
<tr><td>Most suitable option</td><td>Option 2b</td><td colspan="5">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.</td></tr>
</table>

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.				
	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	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 BUT: 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

<table>
<tr><th rowspan="3">Hydrogen quality</th><th>Objective</th><td colspan="5">Cross-border market integration; to ensure unhindered cross-border hydrogen flows and required quality for end-users</td></tr>
<tr><th rowspan="2">BAU
No additional measures</th><th rowspan="2">Option 1
Rights for network operation tendered</th><th colspan="2">Option 2
Main regulatory principles</th><th colspan="2">Option 3
Big bang</th></tr>
<tr><td>2a: Main regulatory principles only</td><td>2b: Main regulatory principles with a vision</td><td>3a: Hydrogen rules by Big Bang</td><td>3b: Hydrogen rules by Big Bang plus</td></tr>
<tr><th>Measures</th><td>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).</td><td>MS to ensure that hydrogen quality is addressed in the tendering.</td><td>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.</td><td>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.</td><td>EU-wide acceptable purity level for cross-border points
(like Option 2b)</td><td>EU-wide acceptable purity level for cross-border points
(like Option 2b)</td></tr>
<tr><th>Pros</th><td>Limited administrative burden as no new</td><td>Limits the risk of cross-border flow restriction and market</td><td>Ensures common approach on hydrogen quality for cross-border points across the EU</td><td>Ensures a fully harmonised approach on hydrogen quality at cross-border points.</td><td>Like Option 2b</td><td>Like Option 2b</td></tr>
</table>

	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)

<table>
<tr><th rowspan="3">Regulated asset base (RAB)</th><th>Objective</th><th colspan="5">Rules on regulated asset bases determine whether different types of network assets are financed by joint or separate network tariffs.</th></tr>
<tr><th rowspan="2"><u>BAU</u>
No additional measures</th><th rowspan="2"><u>Option 1</u>
Rights for network operation tendered</th><th colspan="2"><u>Option 2</u>
Main regulatory principles</th><th colspan="2"><u>Option 3</u>
Big bang</th></tr>
<tr><th>2a: Main regulatory principles only</th><th>2b: Main regulatory principles with a vision</th><th>3a: Hydrogen rules by Big Bang</th><th>3b: Hydrogen rules by Big Bang plus</th></tr>
<tr><td>Measures</td><td>Separate RAB (due to current natural gas tariff rules)</td><td>Separate RAB (due to current natural gas rules)</td><td>Joint RAB allowed</td><td>Separate RAB

<u>Sub-option (at MS discretion)</u>: separate RAB but financial flows possible between them (subject to conditions, including financial flows only levied on domestic users and under NRA supervision)</td><td>Separate RAB</td><td>Separate RAB</td></tr>
<tr><td>Pros</td><td>No cross-subsidies between gas and hydrogen possible via gas tariffs.

Competition distortion between private and regulated entities prevented.</td><td>Similar to BAU</td><td>Reduces administrative burden and regulatory costs.
Enables lower network tariffs in hydrogen ramp-up phase.</td><td>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

<u>Sub-option</u>:
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</td><td>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.</td><td>Like Option 3a</td></tr>
</table>

				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%.

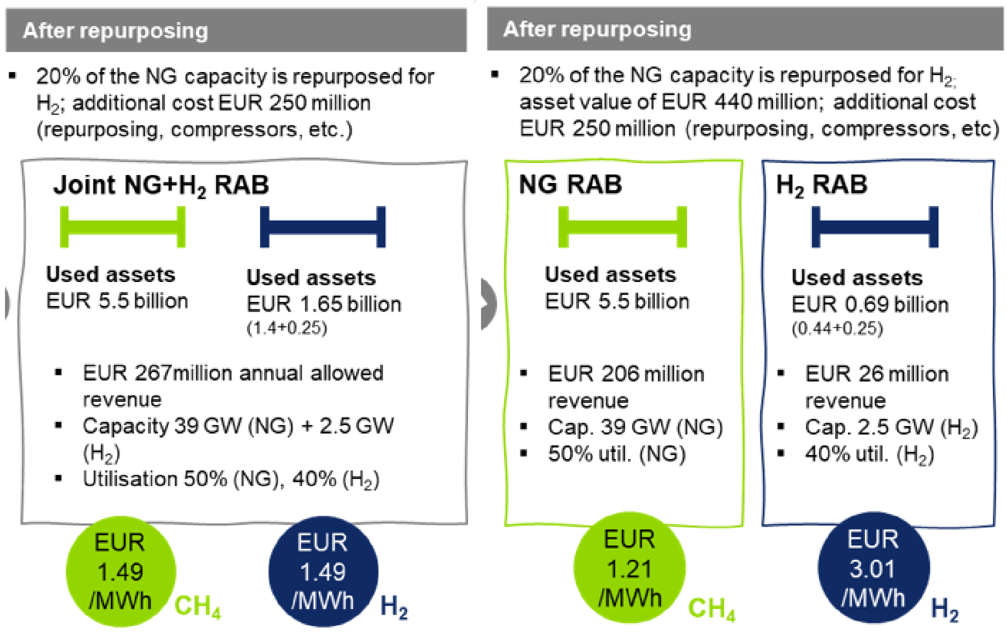
Guidehouse/Frontier Economics sample calculation

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.

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

<table>
<tr><th rowspan="2">Gas Quality</th><th>Objective</th><th colspan="4">Ensure unhindered cross-border flows of gases and interoperability of markets</th></tr>
<tr><th>BAU
No additional measures</th><th>Option 1</th><th>Option 2</th><th>Option 3</th><th>Option 4</th></tr>
<tr><td>**Measures**</td><td>Do nothing.
Stronger enforcement.
Revision of CEN standards to include renewable and low-carbon gases.</td><td>Reinforced cross-border coordination on gas quality management and transparency on national hydrogen blending levels.</td><td colspan="2">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.</td><td>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.</td></tr>
<tr><td>**Pros**</td><td>Limited administrative burden as no new legislation is introduced.</td><td>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.</td><td colspan="2">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.</td><td>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.</td></tr>
</table>

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.

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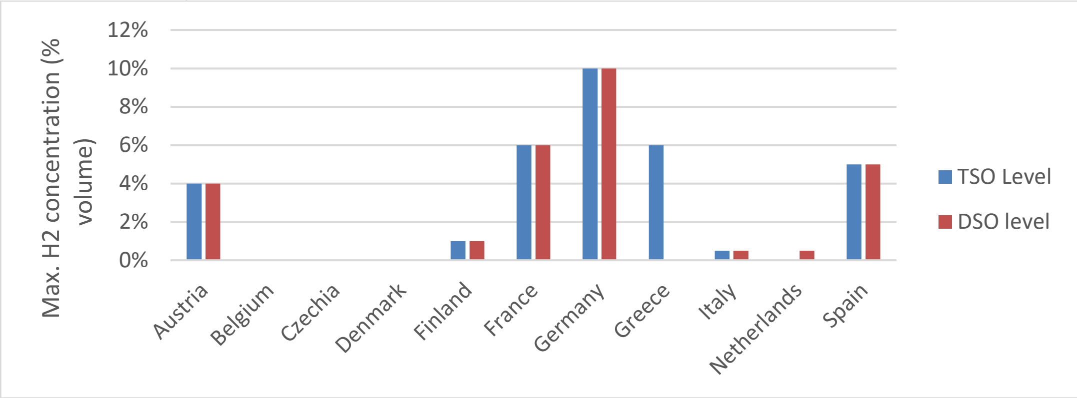
[34] These costs depend also on the extent of integration of hydrogen blended gas. If blended gas is only distributed at the level of some specific grids (with possibly different blending levels per grid), the costs may be limited. If the ambition is to set a national hydrogen blending level at the transmission 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.

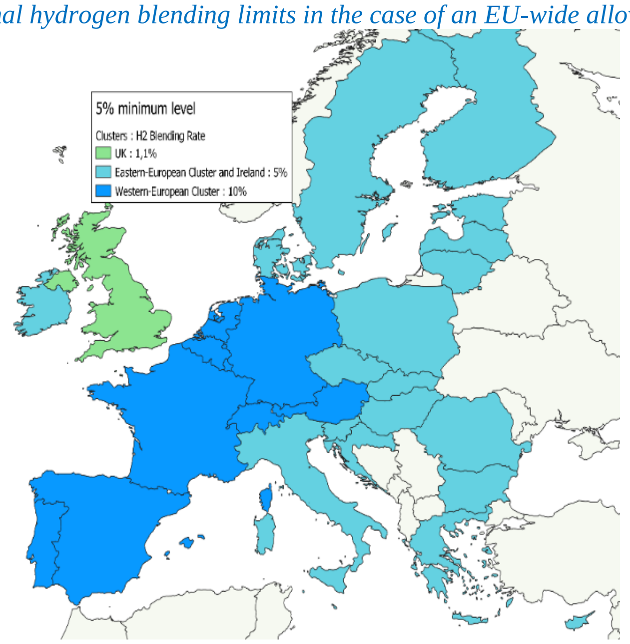
Option 1 introduces strong cross-border coordination leading to the development of three clusters:

- 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

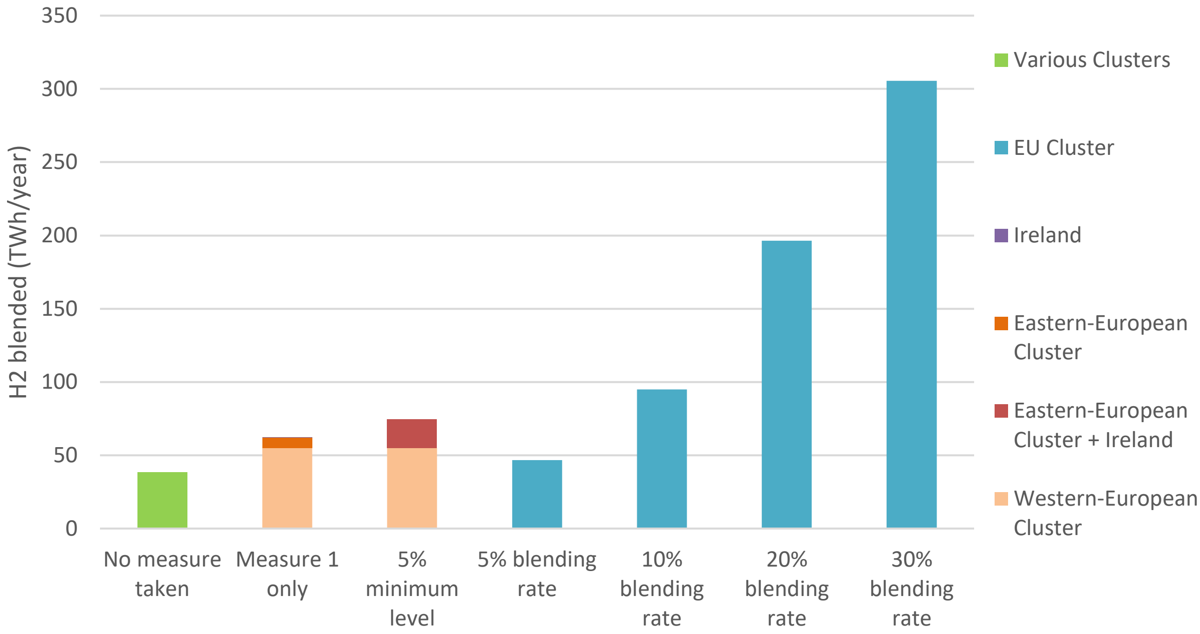
The introduction of a maximum cap at cross-border points in addition to the lower allowed cap for hydrogen blends (Option 4) would lead to one European cluster. The study supporting the Impact Assessment looked into the impact of measures setting the minimum and maximum caps both at the same level (5%, 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

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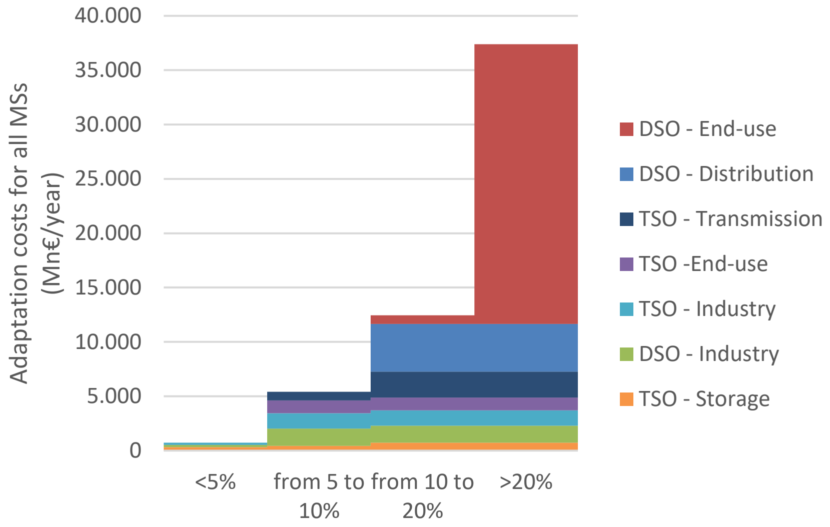
38 The description of the different configurations are available in Table 6-9: Overview of the seven configurations under the different policy measures of the Impact Assessment study, Chapter 6.3.1; (Artelys, 2021).

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

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.			
	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 RE&LC gases**	Option 4 **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

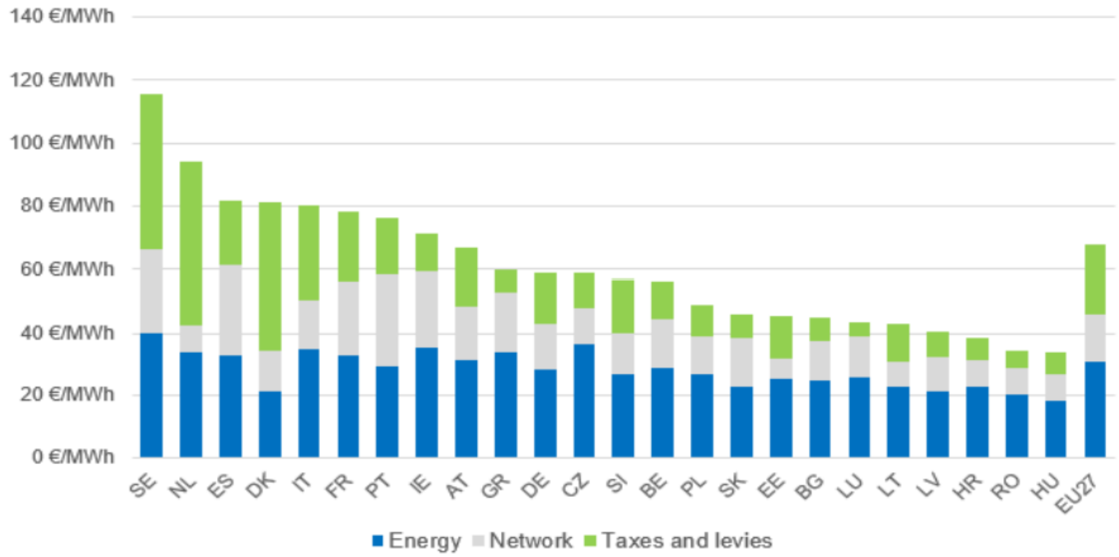
Each option for Problem Area IV considered Section 6.4 of this Impact Assessment comprises (or not) a set of more detailed measures. Please see also the summary table at the end of Section 6.4. in this regard.

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

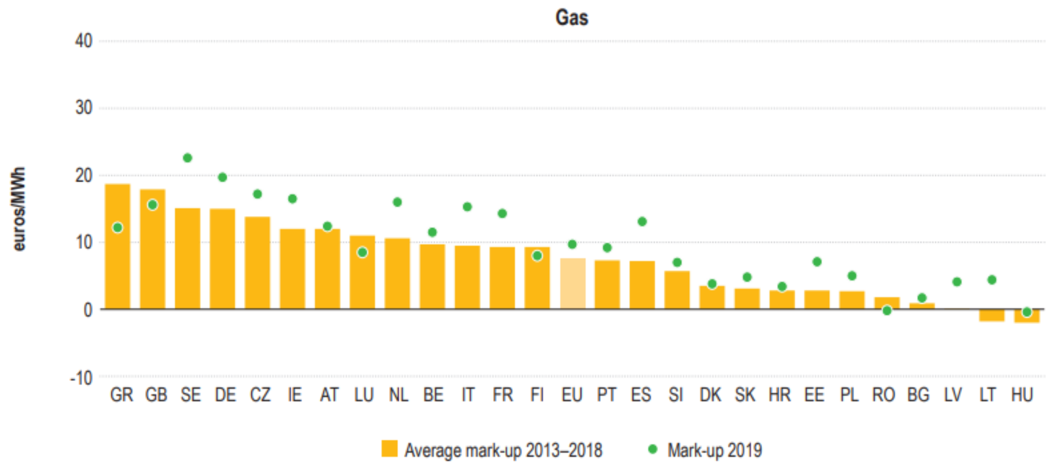
50 2019 ACER Market Monitoring Report – Energy Retail and Consumer Protection Volume, pp. 20-23.

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].

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.

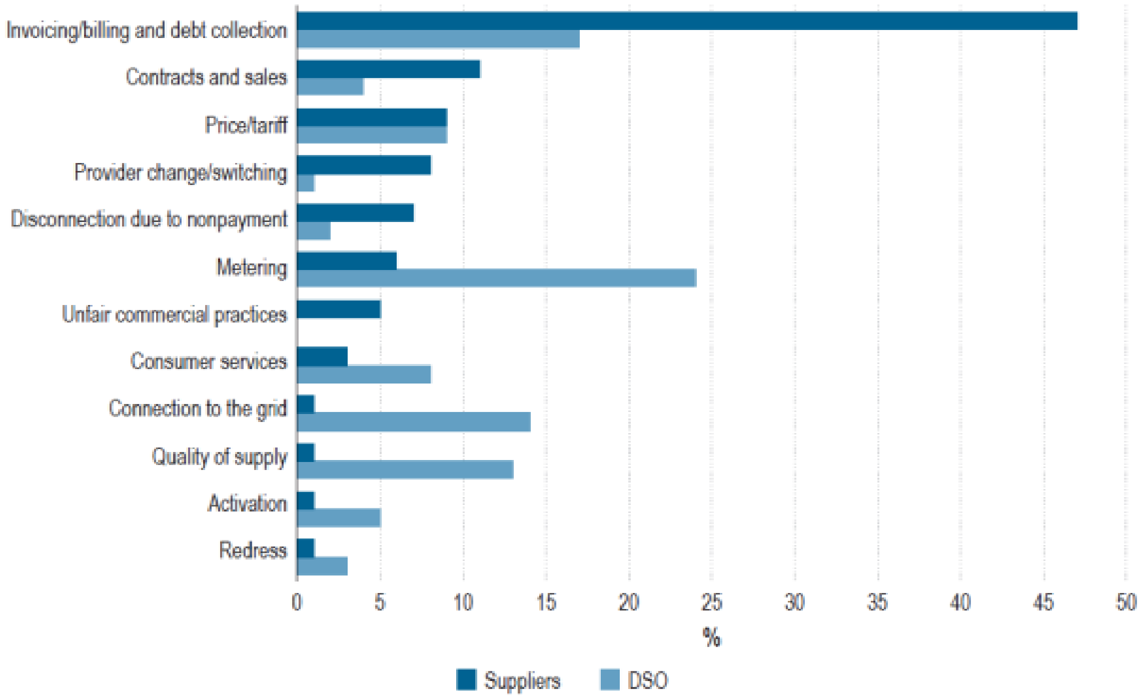
66 ACER Market Monitoring Report 2019 – Energy Retail and Consumer Protection Volume, p. 40.

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].

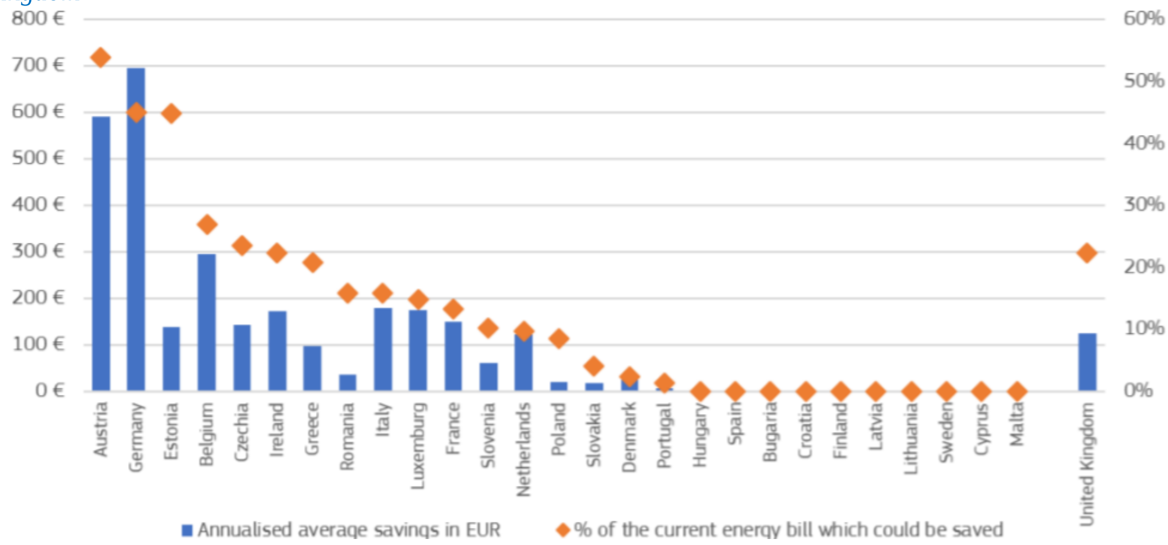
Switching savings potential on gas bills[71]

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.

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.

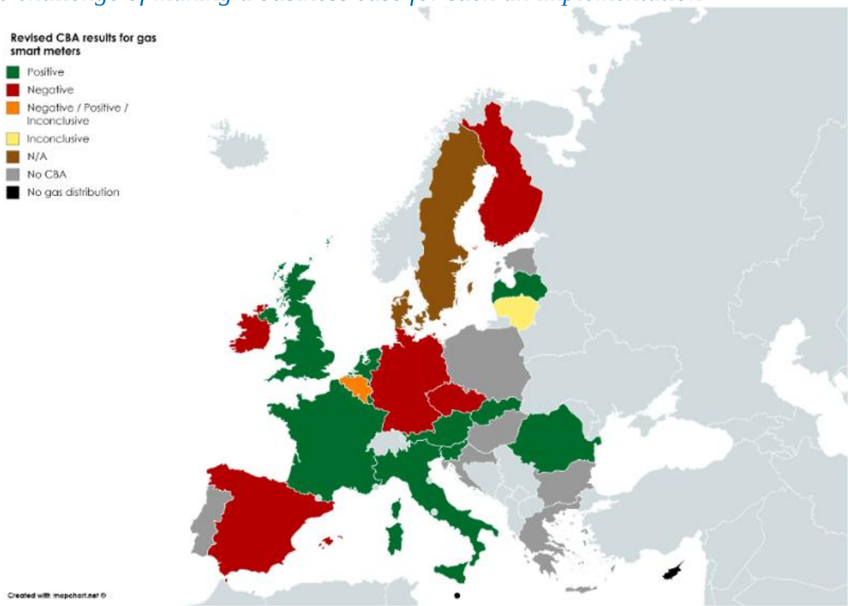
85 The 9th ACER/CEER Market Monitoring Report (2020) – Energy Retail and Consumer Protection Volume, shows that the biggest average share of complaints regarding gas suppliers concerns invoicing/billing and debt collection (40%).

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)).

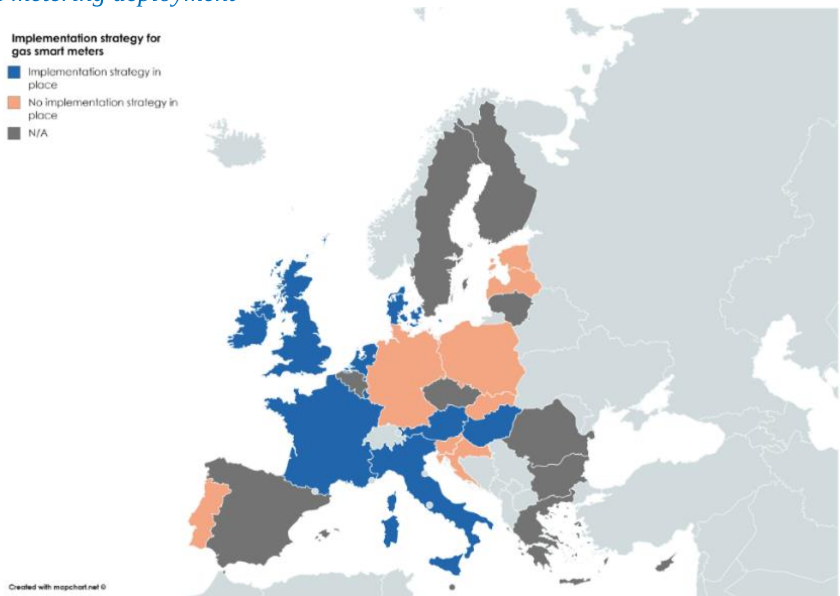
88 These estimations are based on the observed rate of deployment of gas smart meters in 2017 (source: Tractebel report 'Benchmarking smart metering in EU-28' (2019)).

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

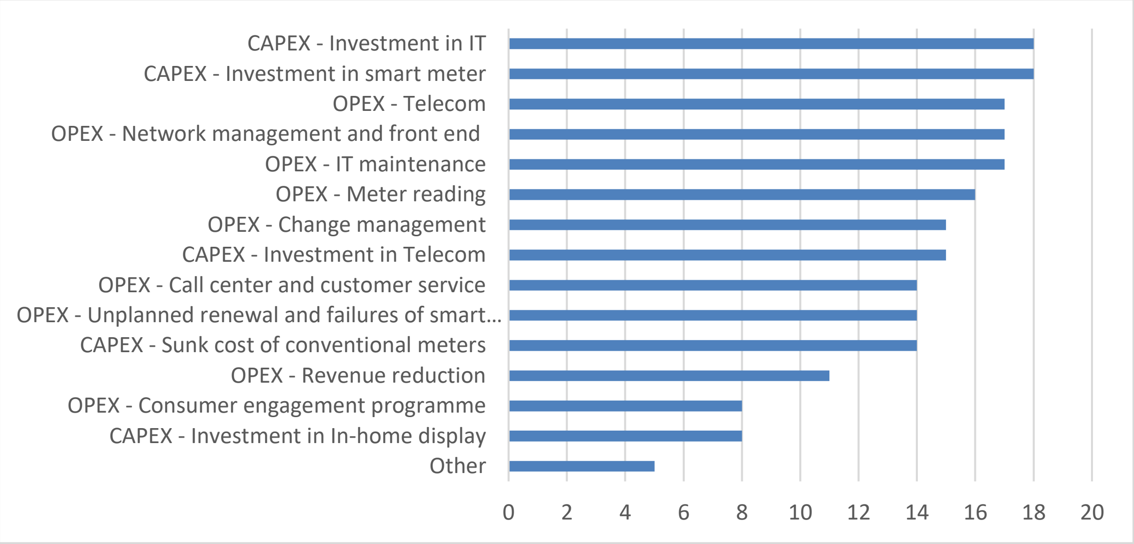
89 Tractebel report 'Benchmarking smart metering in EU-28' (2019).

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

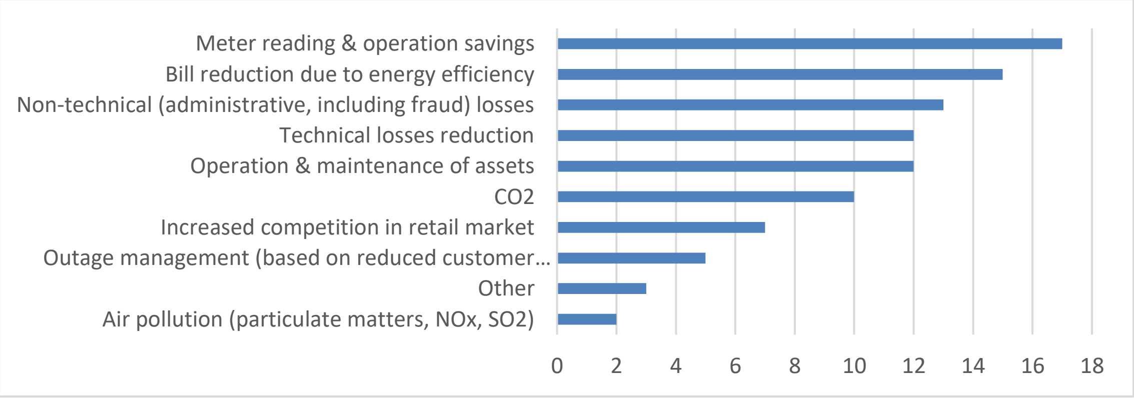
Member States consider in their assessments when they are analysing the cost-effectiveness of such a deployment, and are therefore dictating the outcome of the exercise.

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, paragraphs 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.

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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, CO2 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 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
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).

LIST OF FIGURES

LIST OF TABLES