European Commission

Potentials of sector coupling for decarbonisation - Assessing regulatory barriers in linking the gas and electricity sectors in the EU

- Final report

frontier economics

CE Delft Committed to the Environment

THEMA Consulting Group

COWI

This study was carried out for the European Commission by Frontier Economics, together with CE Delft and THEMA Consulting Group, as part of the COWI Consortium.

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1 EXECUTIVE SUMMARY

STUDY OBJECTIVE

Frontier Economics ('Frontier'), together with CE Delft and THEMA Consulting Group ('THEMA'), as part of the COWI Consortium (hereafter "the consortium") have been appointed by the European Commission to carry out a study on the integration of the EU gas and electricity sectors - assessing regulatory barriers (ENER/B2/2018-260).

This report presents the results of the consortium's assessment[1] 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.

The main objectives of this study are:

- to provide a vision of the future energy system for the EU (in 2030 and in 2050) in which full decarbonisation of the energy system is achieved;
- to discuss the future role of gases in this system;
- to identify the potential technologies necessary for these developments;
- to identify regulatory barriers and gaps for the effective and efficient deployment of these technologies; and
- to discuss possible solutions and policy recommendations.

THE FUTURE EU ENERGY SYSTEM, THE ROLE OF GASES AND THE CONCEPT OF SECTOR COUPLING

In the coming decades, the EU energy system needs to change dramatically to make the transition to a decarbonised energy system. This transition is necessary to achieve the EU's 2030 climate targets as well as the EU's commitments under the Paris Agreement, which aim to limit the average global temperature rise to well below 2°C. While it is difficult to project with certainty exactly what this means for the EU energy system by 2050, some key themes emerge from recent studies.

One insight from these studies is that decarbonisation of the energy system is expected to be associated with an increasing level of integration of different energy carriers, in particular gases, electricity and heat. For the purpose of this study, we understand sector coupling as linking the EU electricity and gas sectors, both in terms of their markets and infrastructure.[2]

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[1] We note that this study is based on qualitative research. In particular, and as described further in the main body of the report, the analysis is based on a review of existing quantitative and qualitative evidence in relation to the current and future energy system.

[2] There are other ways in which the electricity and gas sectors could be increasingly integrated in the future. These include, for example, the use of biomethane in power generation and the flexible ('smart') use of electricity and gas heating depending on price, whether in individual buildings (in 'hybrid' heat pumps) or in district heating networks.

A key driver behind this is the reduction in the cost of producing electricity from renewable sources in recent years. Continued cost reductions could provide a business case for using this electricity to produce gases such as hydrogen or methane in a carbon neutral way.

Another key driver of sector coupling, and the deployment of renewable and low-carbon gases more generally (including biogas and biomethane), is the potential cost saving to be realised from their use in a decarbonised energy system. While overall final energy demand is expected to decrease due to energy efficiency, consumption of electricity is expected to increase. This demand is expected to be met by increasing shares of renewable electricity.

However, much of the new renewable electricity generation capacity will be from intermittent sources (such as solar and wind) and may not typically be located close to either load centres or existing network connections. It will therefore be important to find cost-effective storage and transport solutions for this renewable energy.

The case for renewable and low-carbon gases arises from the fact that they could be transported and stored at lower cost than electricity, by making use of existing storage and transport infrastructure. Their use may also avoid potentially costly and distruptive changes to end-use appliances.

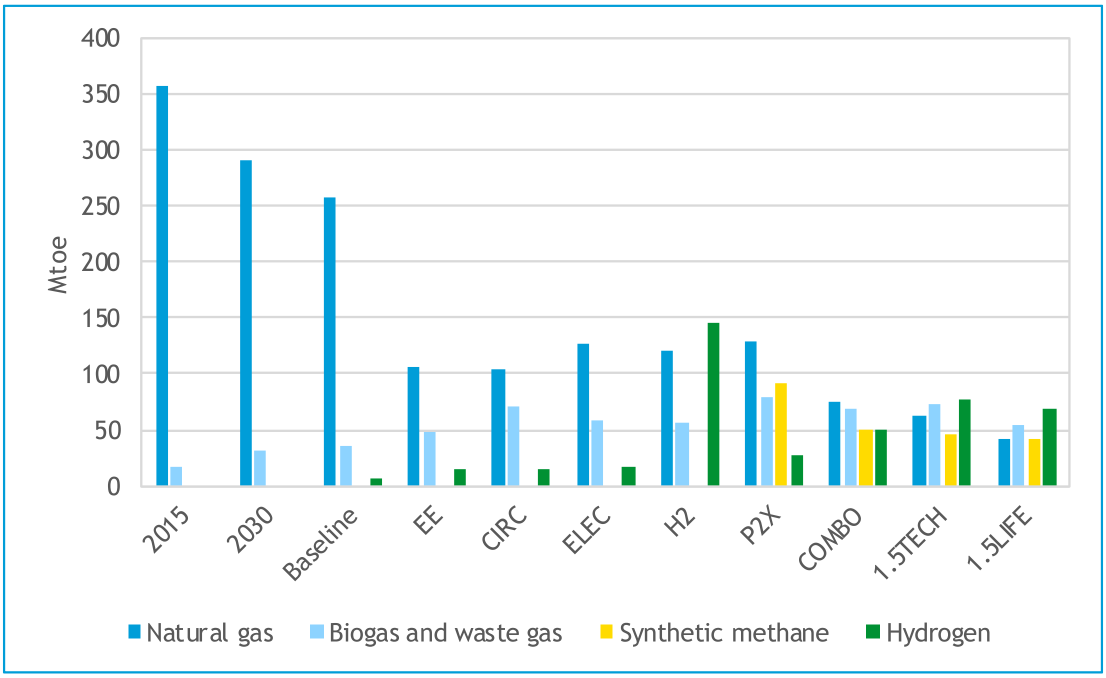
The extent to which gases will be used in the future is uncertain. It will depend on a range of factors, including:

- The availability of alternative flexibility options in the energy system – in particular, considering the role the gas system currently plays in the energy system in helping to meet seasonal fluctuations in energy demand, other sources of seasonal flexibility such as generation with carbon capture and storage or seasonal heat storage;
- Developments in the relative costs of gas and electricity end-use appliances; and
- The role of policy in steering outcomes.

Exactly which gases will be used in the future is also uncertain.[3] The use of natural gas may potentially increase in the transition to replace more polluting fuels (i.e. to 2030) but should eventually largely be phased out by 2050. However, different renewable and low-carbon gases (for example biomethane, hydrogen and synthetic methane) could all play a role in the future. This uncertainty is exposed by the varying roles that different scenarios foresee for different types of gases (summarised in Figure 1 below). It is also possible that some gases may feature more strongly in some Member States than others.

[3] This study mentions a wide range of gases that are likely to play a role in the decarbonisation of the EU energy supply of the coming decades. A list of relevant definitions has been developed (adhering to the definitions included in Article 2 of the Renewable Energy Directive recast (RED II)), and is set out in section 3.4 of this report.

Figure 1 EU demand for gaseous fuels, in 2015, forecast for 2030, baseline for 2050 and different decarbonisation scenarios for 2050 developed for the EU 2050 strategy



Source: European Commission (2018) "A Clean Planet for all, A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy", COM(2018) 773 final.

As well as increased gas and electricity sector coupling, large-scale deployment of the technologies that are part of the hydrogen and methane supply chains will also result in linkages between natural gas, hydrogen and methane. This is illustrated in Figure 2.

Figure 2 High-level overview of linkages between gases for energy use in 2050: Natural gas, hydrogen and methane

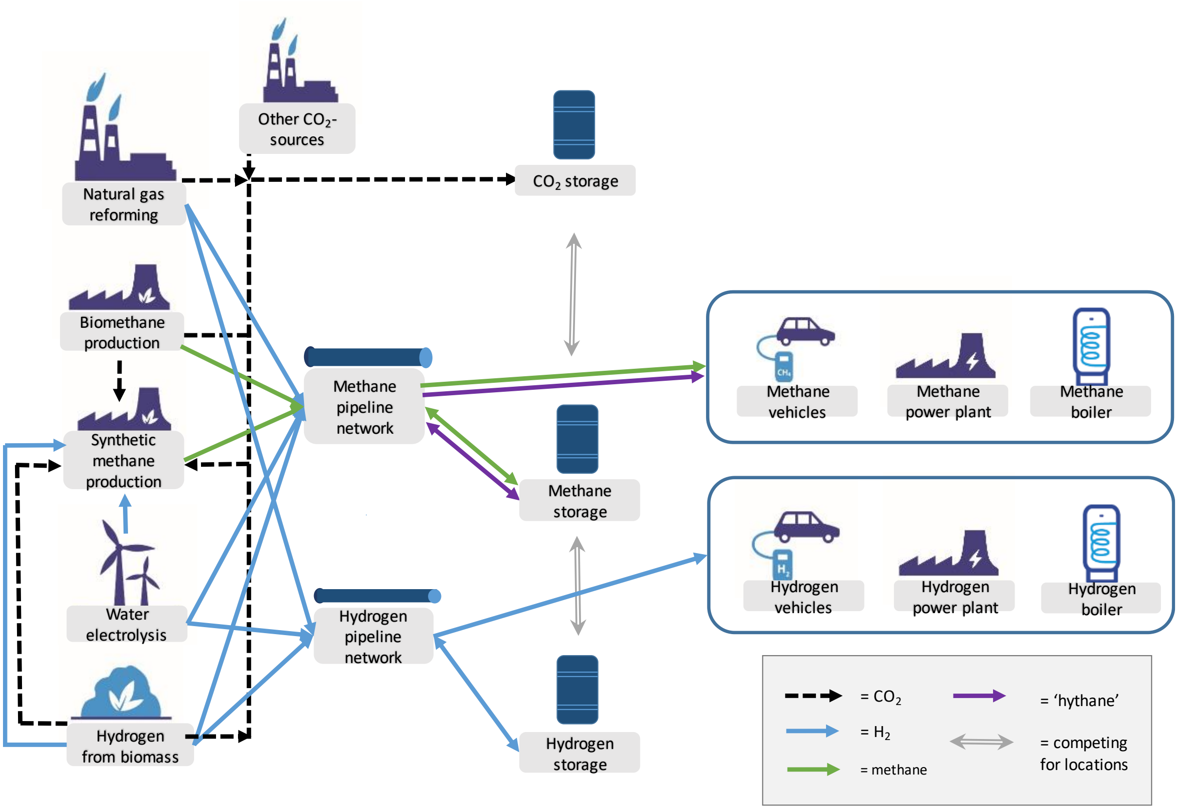


Figure 2 shows, for example, that:

- Methane and hydrogen supply chains might be linked either via reforming of natural gas, by conversion of hydrogen into synthetic methane or through blending in the gas network;
- A common feedstock (biomass) could link hydrogen production and biomethane production; and
- Hydrogen, methane and CO_2 supply chains could be linked through possible competition for gas storage capacity.

The findings from our literature review have a range of implications for gas infrastructure and storage needs and policy. While the precise impacts differ significantly between scenarios applied in recent literature, a number of themes emerge:

- The first is the importance of continued innovation and learning in technologies that are currently less mature.
- The second is the variety of technological approaches to renewable and low-carbon gases and sector coupling technologies, highlighting the importance of a level playing field for gases (compared to other energy carriers) and between different gases (especially once such technologies are no longer in the transition phase), as well as openness to potential new technologies.
- The third is that, while the use of natural gas is expected to be largely phased out by 2050, new gases will begin to flow in increasing quantities in existing infrastructure. As a result, the focus of infrastructure regulation will need to shift from natural gas to a variety of different (low-carbon and renewable) gases.
- The fourth is that growing interlinkages between energy carriers and between transmission and distribution systems mean that co-ordination in system planning and operation will become increasingly important.

- The fifth is that different countries or regions may adopt different technological approaches. This suggests that attention needs to be paid to how to ensure that different gases can co-exist both within and between countries and regions and that interoperability and functioning markets are enabled.

REGULATORY BARRIERS AND GAPS

For the purposes of this study, regulation is defined as encompassing the legal framework at the EU or Member State level, acts of regulatory bodies and agencies as well as administrative practice. Regulation (or the absence thereof) is considered to contribute to potential barriers to sector coupling and renewable and low-carbon gas technologies if it threatens either a level playing field between technologies or the development of innovative technologies. Based on this definition, the absence of regulation may also constitute a barrier. The study therefore also covers regulatory gaps.

To identify possible barriers and gaps, we drew on a range of sources, including country-based research into regulatory framework in a sample of Member States and input from stakeholders. The result was a 'long list' of potential barriers which is presented in this report. From this 'long list', we developed a 'short list' of barriers for which recommendations are provided.

Figure 3 provides an overview of the barriers and gaps identified. These are grouped into five categories:

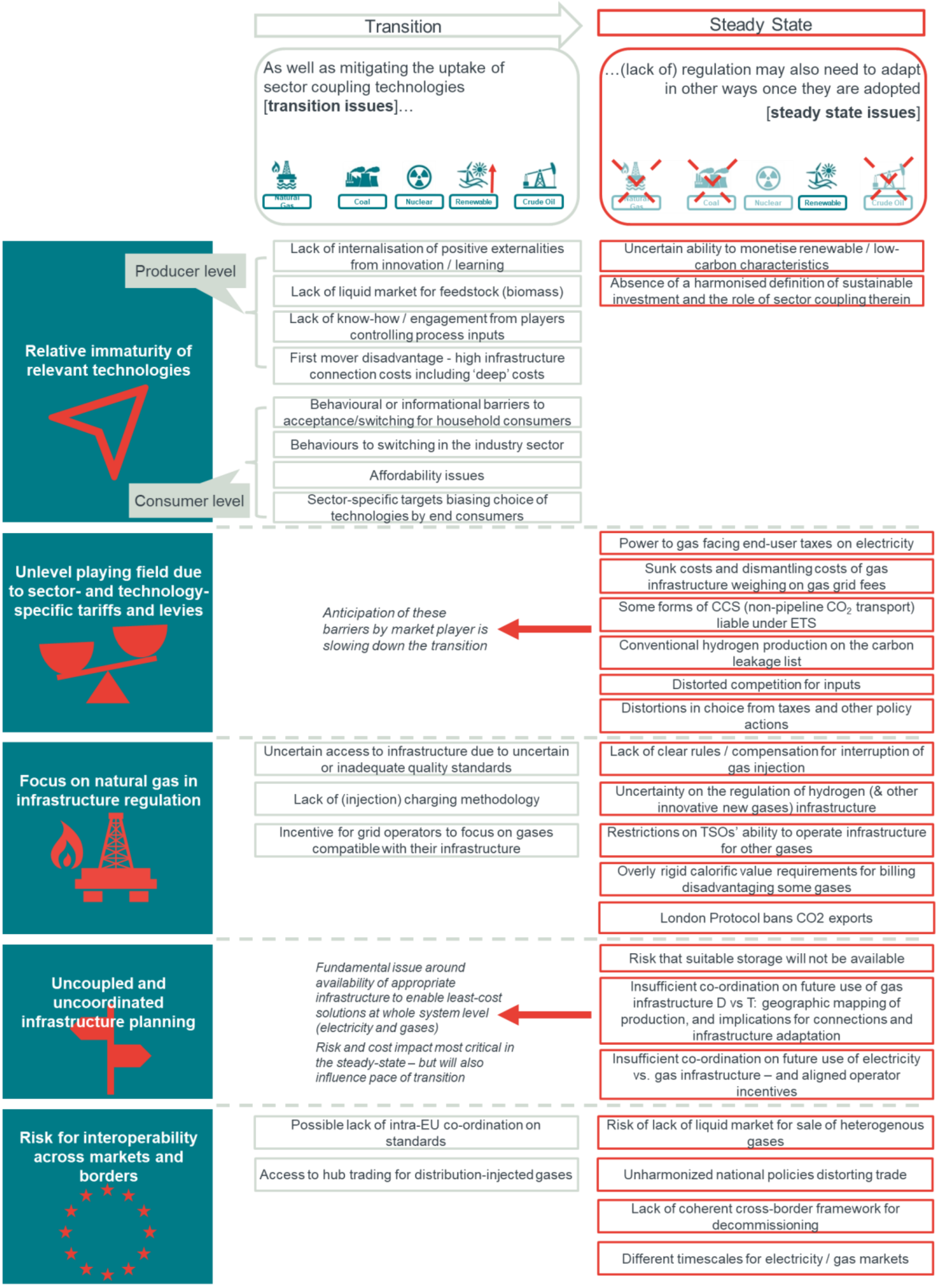
- A first group includes barriers related to the **immaturity of the relevant technologies**.
- A second group encompasses issues arising from **technology- and sector-specific regulations** which may be inadequate in the emerging sector-coupled energy market.
- The third and fourth barrier groups focus on infrastructure.
    - Barriers in group three arise from the transition of **infrastructure** from being used for natural gas to being potentially **used by a multitude of gas types**.
    - Group four focusses on issues linked to the increasing need of **interlinkage between the electricity and gas sectors** deploying sector-coupling technologies.
- A fifth group concerns the **interoperability** between different markets.

Within each group, we find that barriers and gaps pertain either to:

- The **transition phase**, during which the costs of relevant technologies are expected to continue to reduce as their uptake increases; or
- The **steady state**, i.e. the barriers and gaps are expected to prevail even when the relevant technologies have reached maturity.

The full list of barriers and gaps identified as part of this study, organised in the five categories described above, is displayed in Figure 3 below.

Figure 3 Overview of barriers and gaps preventing closer co-ordination ('sector coupling') between the EU gas and electricity sectors and hindering the deployment of renewable and low-carbon gases



Source: Frontier Economics

Below we summarise the short-listed barriers in each category. Further detail, including on the barriers not on the short list, is included in the main body of the report.

Relative immaturity of relevant technologies

Two barriers from this category have been retained in the short list.

- ***Lack of internalisation of positive externalities from innovation / learning:*** Knowledge and learning from early stage R&D and deployment will not only benefit the stakeholders undertaking and financing the investment but will spread more widely. As a result, although the costs borne by the developer may be lower than the benefit to society (and thus an innovation in the public interest), they could be higher than the benefit the individual developer can retrieve. This may cause underinvestment in renewable and low-carbon gas technologies.

- ***First mover disadvantage – high infrastructure connection costs including 'deep' costs:*** Depending on connection charging rules for low-carbon and renewable gases production sites, the first connecting site in a region could bear high connection costs, including a share of the cost of required infrastructure reinforcement that will then go on to serve to transport gases produced at other sites that connect subsequently. This can deter the first site from connecting in the first place. This may in turn cause underinvestment in renewable and low-carbon gas technologies.

Unlevel playing field due to sector- and technology-specific tariffs and levies

Two barriers from this category have been retained on the short list.

- ***Power-to-gas facing end-user taxes on electricity:*** Power-to-gas facilities may be treated as end consumers and face electricity input costs that include end-user taxes and levies. This includes cases where these taxes and levies are not reflecting forward-looking costs incurred on the system due to the presence of these facilities (i.e. that are not 'cost-reflective'), but instead are intended purely to recover costs, such as the cost of supporting renewable energy sources. There is a risk that the recovery of taxes and levies from power-to-gas facilities curbs investment in this technology relative to the level of investment that would have prevailed if those facilities only faced forward-looking costs. This would therefore preclude the system from benefiting from this technology. In particular, there is a risk of distortion of the level playing field between synthetic gases (that rely on electricity from the public system) and other renewable gases such as biomethane, as the latter's input costs are not significantly increased by end-consumer taxes and levies.

- ***Sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees:*** With the expectation of declining volumes of (natural) gas transported, average infrastructure tariffs could be expected to increase to ensure recovery of sunk investment costs. The risk is that this incentivises switching away from gas to other energy carriers to a degree that might not be cost effective from a societal perspective (because the increase in tariffs would not reflect cost causation, but the recovery of legacy costs). Additionally, any dismantling costs may be borne by low-carbon and renewable gases consumers because of the common energy carrier, despite the fact that the infrastructure being dismantled (or at least underutilised) was not built for them.

Focus on natural gas in infrastructure regulation

Five barriers from this category have been retained on the short list.

- ***Uncertain access to infrastructure due to uncertain or inadequate quality standards:*** Many technologies may only be viable for developers if the produced gases can be transported and stored. But quality standards, developed in a context where the only broadly established gas type was natural gas, currently impose restrictive conditions or limits. The market and investors face uncertainty on the extent to which injection will be possible for various types of low-carbon and renewable gas. While norms have been adopted in relation to biomethane in several countries, we find ongoing widespread uncertainty, e.g. on the allowed hydrogen blend. This is in part due to a lack of evidence regarding technical feasibilities (though investigations are underway) and creates uncertainty for developers.

- ***Lack of (injection) charging methodology:*** Injection of renewable and low-carbon gases at the distribution level is not covered by the existing EU-level network charging methodology. Uncertainty on the charging methodology makes it difficult for potential technology developers and network operators to anticipate future costs.

- ***Incentive for grid operators to focus on gases compatible with their existing infrastructure:*** Grid operators face a number of incentives that may bias them to facilitate access to the network for those gases that are compatible with their current infrastructure. This may manifest itself in a number of ways, for example in the framework for connections. This may hinder the level playing field between different renewable and low-carbon gases. Existing provisions in 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 ('RED II') and 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 ('the Gas Directive') may provide some degree of reassurance for developers of renewable gases that Member States will take actions to facilitate their access to the gas system. However, it is not clear how the provisions of the Gas Directive would apply to (non-renewable) low-carbon gases. And they do not specifically address issues related to network operator incentives.

- ***Lack of clear rules / compensation for gas interruption/ curtailment:***, In contrast to the electricity system, physical congestion has been relatively rare in the gas system. However, this may change in the energy transition due to the increasing role of low-carbon and renewable gases located at distribution grid level, where fewer flexibility options may exist. This may be mitigated by making investments that enable flows from distribution to transmission level, where there is more flexibility. However, this may not always be efficient and some congestion management may be required at distribution level. Given the importance of a high utilisation rate for typically capital-intensive technologies, developers of renewable and low-carbon gases will want to have clarity on how congestion will be managed.

- ***Uncertainty on the regulation of hydrogen (& other innovative new gases) infrastructure:*** While the Gas Directive sets out clear rules for unbundling, third-party access and tarification, it is not clear how these provisions might apply to gases other than natural gas, biogas and gas produced from biomass. This uncertainty may cause investors to abstain from investments into hydrogen or other innovative gases.

Uncoupled and uncoordinated infrastructure planning

Three barriers from this category have been retained on the short list.

- ***Risk that suitable storage will not be available:*** Gas storage operators may be unable to predict to what extent there will be a technical or commercial requirement for gas storage in the future energy system. Future gas demand is uncertain and storage facilities or the pipelines connecting the facility may not be technically suitable for different types of future gases. Storage operators may therefore decide to stop operating, which risks inefficiency from a societal perspective if the flexibility from storage is needed.

- ***Insufficient co-ordination on future use of transmission and distribution infrastructure (geographic mapping of production, and implications for connections and infrastructure adaptation):*** In the long run, the optimal design of the gas system will depend on the least cost options to facilitate injection and transport of gases produced from least cost technologies. This may involve significant changes in the infrastructure design, such as enabling reverse flows or investment into additional capacity of the network itself to store gas. Optimising the long run design of the gas system would require coordination between distribution and transmission level planning.

- ***Insufficient co-ordination on future use of electricity and gas transmission infrastructure – and aligned operator incentives:*** In a world of growing interlinkages between infrastructure for electricity and gases, the least cost network infrastructure may only be designed and built if it is planned jointly by electricity and gas infrastructure operators (at both transmission and distribution level).

Risk for interoperability across markets and borders

Two barriers from this category have been retained on the short list.

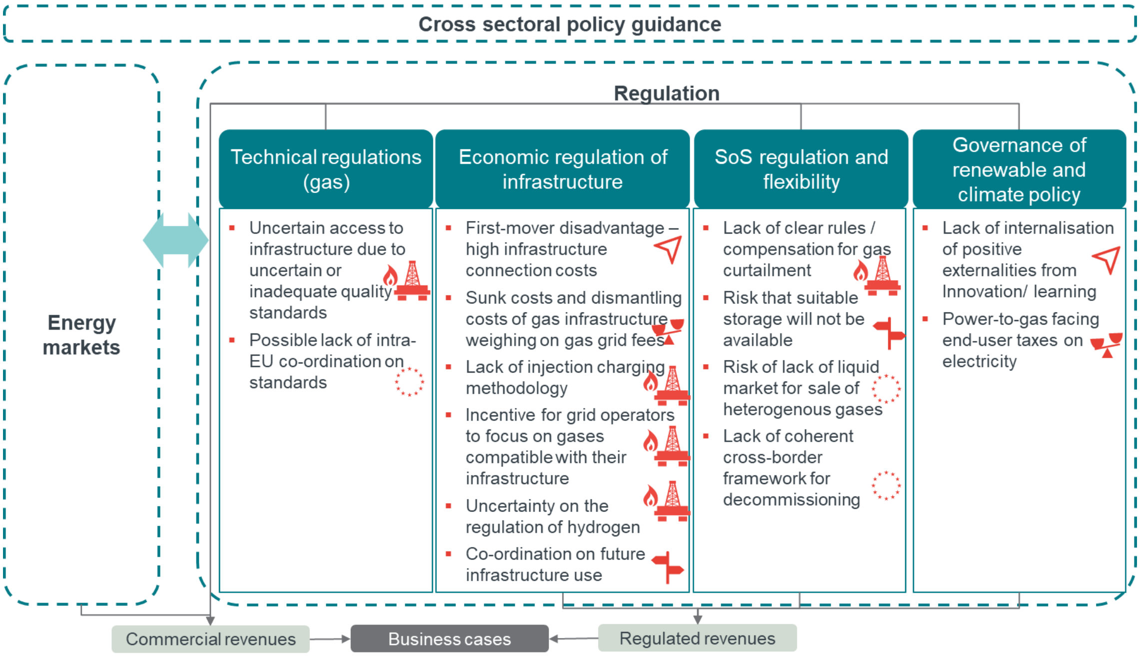
- ***Risk of lack of liquid market for sale of heterogenous gases:*** Given the heterogeneity in technologies and gases that may be deployed to achieve the decarbonisation of the energy sector, there is a risk of fragmentation of the gas market into different products and different regions. This may jeopardise the (generally strong) liquidity in the gas market, resulting in increasing transaction costs for market participants.

- ***Lack of coherent cross-border investment framework decommissioning:*** As set out above, falling (natural) gas demand may lead to TSOs decommissioning some gas infrastructure. There is a risk that, while perhaps cost-effective from an individual Member State perspective, such decommissioning may be inefficient from an EU-wide perspective if infrastructure (interconnectors or other pipelines) benefits multiple Member States. A separate but related issue is that if Member States bear the entire cost of decommissioning assets within their territory (and these costs are recovered from gas users), the resulting tariffs may incentivise an inefficient switch away from gas (as described above under the barrier 'sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees').

Summary

Figure 4 below summarises how the short-listed barriers and gaps described above map to different aspects of the energy policy and regulatory framework.

Figure 4 Summary of regulatory barriers and gaps identified



Source: Frontier Economics

POLICY RECOMMENDATIONS

We have identified and assessed a range of potential options to address the barriers described above. The potential solutions identified drew on stakeholder input and 'best practice' identified when surveying country-based evidence. While we provide some high level design considerations for our recommendations in the main body of the report, further work will be needed on policy design and the assessment of different options.

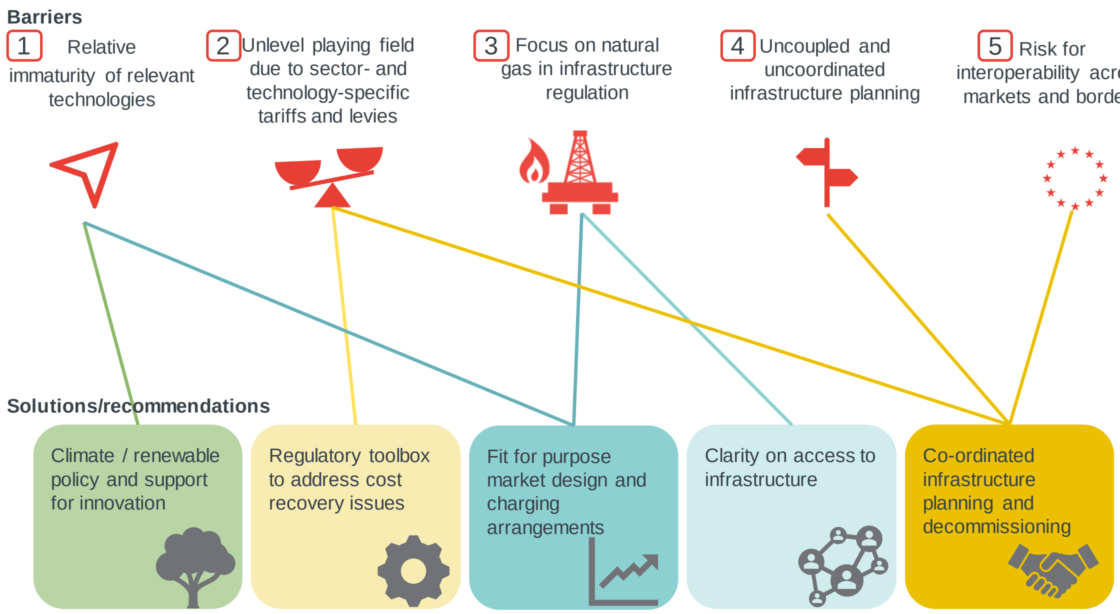
We find that, overall, our recommendations can be grouped into five categories:

- **Interventions via climate and renewable policy, and support for innovation**: this group of solutions is designed to address barriers and gaps related to the relative immaturity of sector coupling and low-carbon and renewable gas technologies;
- **A regulatory toolbox to address cost recovery issues:** this group would serve to address barriers and gaps from group 2, i.e. issues contributing to an unlevel playing field across technologies;
- **A number of changes to market design and charging arrangements to make them more fit-for-purpose in the face of the expected changes in the sector:** these would address issues stemming both from the relative immaturity of relevant technologies, and the historic focus on natural gas in infrastructure regulation;
- **The provision of increased clarity on access to infrastructure** would also aim to overcome barriers and gaps stemming from the historic focus on natural gas in infrastructure regulation; and
- **The facilitation of co-ordinated infrastructure planning and decommissioning**, which would be expected to help achieve a level playing field across technologies, avoid the risks of uncoupled and uncoordinated

infrastructure planning, as well as the risks related to interoperability across markets and borders.

This is summarised in Figure 5 below. We then present proposed solutions in further detail.

Figure 5 Overview of barrier categories and solution categories



Source: Frontier Economics

Climate and renewable policy and support for innovation

Support for innovation is key to addressing some of the barriers particularly relevant in the transition phase for renewable and low-carbon gas technologies.

Indeed, **(financial) support for Research and Development (R&D), pilots or demonstration projects** and, potentially, beyond that, **ongoing support for further deployment following the demonstration phase**[4] would be a direct way to address positive externalities related to innovation. State aid rules and/or internal energy market legislation would need to ensure that any ongoing support is granted in a way that promotes competition and market integration.

We see a case for **allowing network operator ownership (or involvement in) research-stage or pilot power-to-gas projects** in specific circumstances to address co-ordination barriers. Network operator involvement would need to be targeted in scope (e.g. limited to understanding technical impacts on the networks) and subject to conditions (such as time limits and knowledge sharing) to avoid potential longer-term

[4] R&D refers to fundamental research (typically led by academia) and the application of this research to the development of new concepts and processes (typically led by industry). Demonstration refers to the testing of new applications in a commercial setting. At the research, development and demonstration phases, the focus is typically learning about the feasibility and costs of different approaches. During the deployment phase, the focus is on large-scale roll-out of a technology and achieving cost reductions as supply chains and expertise develop. R&D may continue during the deployment (and demonstration) phases, for example with the aim of helping to identify incremental improvements to production processes and/or achieving cost reductions.

negative effects on competitive and market-based investments. NRAs would need to play an important role in minimising potential negative consequences.

Power-to-gas ownership by network operators could also be relevant once the transition phase has ended, in situations where it is difficult (or disproportionate) to ensure market signals convey system benefits (e.g. the benefits of the specific location of a facility) well enough. Again, NRAs would play an important role in ensuring that such projects would indeed be beneficial for the system and in verifying that it is not possible to secure market-based investment.

Regulatory toolbox to address cost recovery issues

As highlighted in the description of barriers above, the ways in which policy costs (such as RES support costs) and the costs of gas infrastructure are recovered matter for the uptake of renewable and low-carbon gases.

A direct solution to the issue of power-to-gas facing end-user taxes on electricity would be to ensure that **only final electricity consumption faces (cost-recovery) taxes and levies**.

Dealing with issues related to sunk and decommisisoning costs requires a suite of regulatory solutions.

To reduce the risk of over-investment in gas infrastructure**, leaving asset stranded risk with network operators** may be an option. However, this may only have limited scope of application: **for forward-looking investments over which network operators exercise a degree of discretion** (and provided such investments can be easily identified). For other types of costs, more frequent (regulatory) **reviews of whether prospective investments are necessary** may be beneficial.

Regarding the distribution of the costs of legacy investment (and of decommissioning costs):

- To minimise distortions between consumer choices between energy carriers, **sunk infrastructure costs could be distributed away from infrastructure users and towards taxpayers** instead.
- If this is not feasible (or not acceptable), ensuring **an equitable distribution of sunk costs between different energy carriers** (i.e. electricity, gas and heat) could be an alternative to investigate.
- **Allowing for faster recovery of costs** (e.g. accelerated regulatory depreciation) may also be part of the toolkit, although the benefit in terms of avoiding distortions to choices between energy carriers is less clear.

Fit for purpose market design and charging arrangements

Given the historical focus on natural gas, gas market design needs to evolve to efficiently accommodate renewable and low-carbon gases into the market. This is particularly the case given that much of the new capacity is expected to be connected at the distribution level.

There are **a variety of connection charging approaches that avoid the first-mover disadvantage while still preserving locational signals** (to varying degrees). While there may be complexities in their implementation, such options have the potential to encourage the development of low-carbon and renewable gases while minimising the risk of incentivising uptake of expensive connections. Consistency between the frameworks for connection charging and for dealing with connection requests (see "Clarity on access to infrastructure" below) would be important.

The creation of **harmonised injection charging rules** (at distribution level) would increase certainty for developers regarding how they might be charged for use of the gas grid, in turn reducing the costs across the EU of deploying renewable and low-carbon gases.

Successful integration of renewable and low-carbon gases into the market also **requires that the framework for managing physical congestion is complete** (in particular at distribution level).

- **Competitively tendered voluntary agreements** between network operators and participants to limit injections may be a relatively straightforward measure to implement.
- **More sophisticated market-based systems** allowing for real-time adjustment of bids may offer greater efficiency, but may not be a proportionate solution if congestion issues remain limited.
- **Obliging participants to limit injections** may be appropriate in situations where there may be a limited number of options to address localised congestion issues, leading to possible market power concerns.

Clarity on access to infrastructure

Many of the barriers stemming from the historic focus of regulation on natural gas could be addressed through greater clarity on the access for new gases to infrastructure.

To reduce the risks to developers stemming from uncertainty regarding quality standards, it would first be important to **provide improved visibility on gas quality for gas producers**. **Clear rules on how quality is managed on an ongoing basis** (such as the potential impacts on connection requests or on interruption of production and possible compensation) would help to further reduce risks.

The first step in addressing TSOs' incentives to focus on gases compatible with their infrastructure would be **a review of regulatory frameworks to identify such biases**. An additional specific (but partial) solution might be **an obligation for network operators to connect** renewable and low-carbon gas sources to the gas system, provided certain conditions (specified in advance, such as regarding gas quality) are met.

Finally, **clarifying whether (and under what conditions) the provisions of the Gas Directive apply to hydrogen (and other gases)** is likely to provide increased clarity for developers regarding their ability to secure access to infrastructure, reducing the risks to investment.

Co-ordinated infrastructure planning and decommissioning

Improved co-ordination in planning and decommissioning decisions can help to improve the efficiency with which infrastructure is used. It could also help to improve interoperability across markets and sectors.

An assessment of the implications of the expected change in the role of gas as well as the mix of technologies on the likely optimal level of gas storage capacity would be a first step in addressing some of the uncertainty related to storage, and could provide a basis for assessing whether further intervention is needed.

Co-ordinated infrastructure planning (between transmission and distribution level, and between electricity and gas networks) would allow operators to arrive at a shared view on possible developments in demand and supply and identify and evaluate investment possibilities in different parts of the system. This would be an important enabler of lower costs. **Regulatory incentives on individual operators to**

achieve cost savings at system level may provide the mechanism for ensuring any potential cost savings identified are actually achieved.

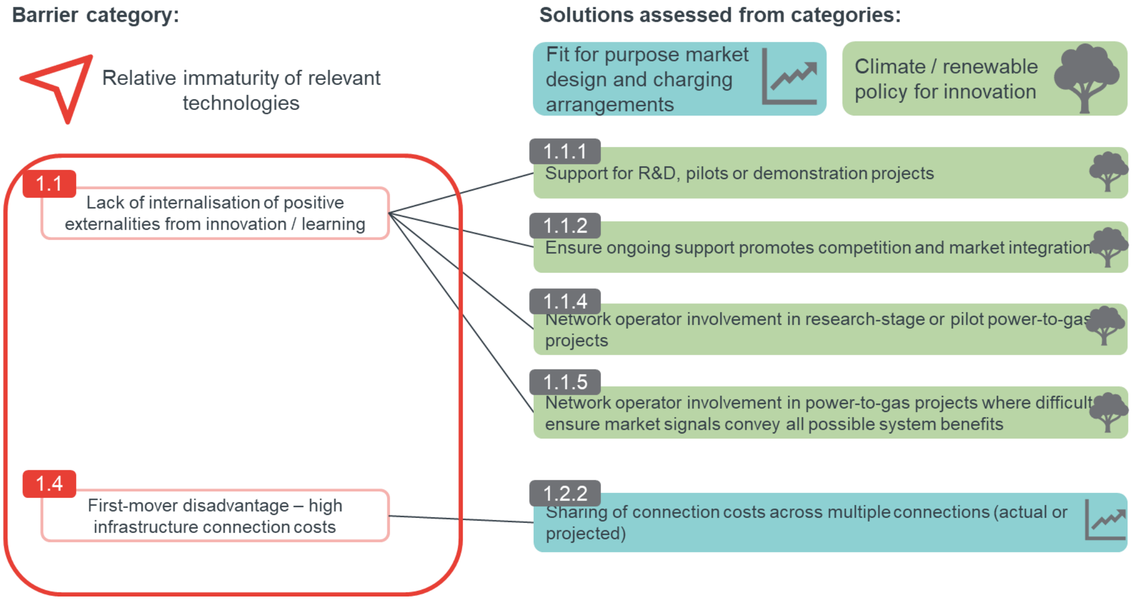
Ensuring a more systematic consideration of the potential impacts on liquidity in energy system planning, in particular for infrastructure investment and decommissioning decisions, would allow liquidity impacts to be traded off against other costs and benefits.[5] This should therefore promote 'least cost' infrastructure planning decisions in a wider sense.

A framework for cross-border decommissioning decisions could provide a route to avoiding or delaying the decommissioning of assets that might deliver benefits outside of the Member State in which they are located. By providing for more equitable sharing of decommissioning costs across borders, it may also help to reduce issues related to dismantling costs weighing on gas grid fees.

Overview

Figure 6 to Figure 10 provide an overview of how the recommendations set out above address individual short-listed barriers. Solutions are mapped to the categories described above through colour-coding, with the corresponding groups identified in the top right corner of each figure.

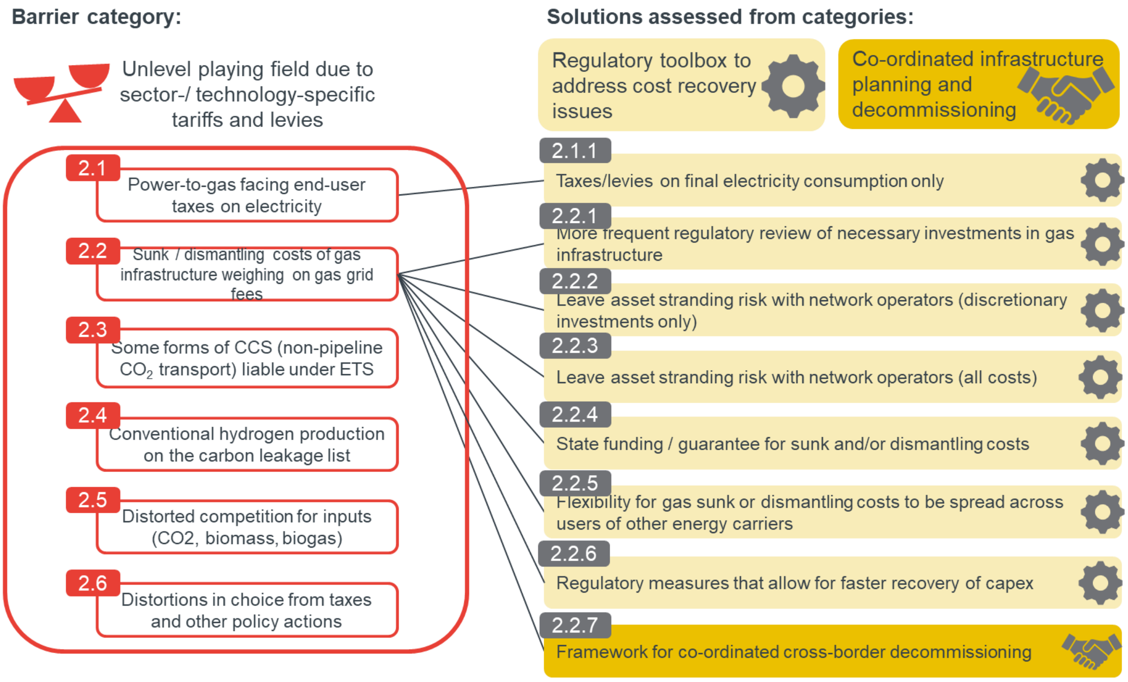
Figure 6 Recommendations to deal with the relative immaturity of relevant technologies



Source: Frontier Economics

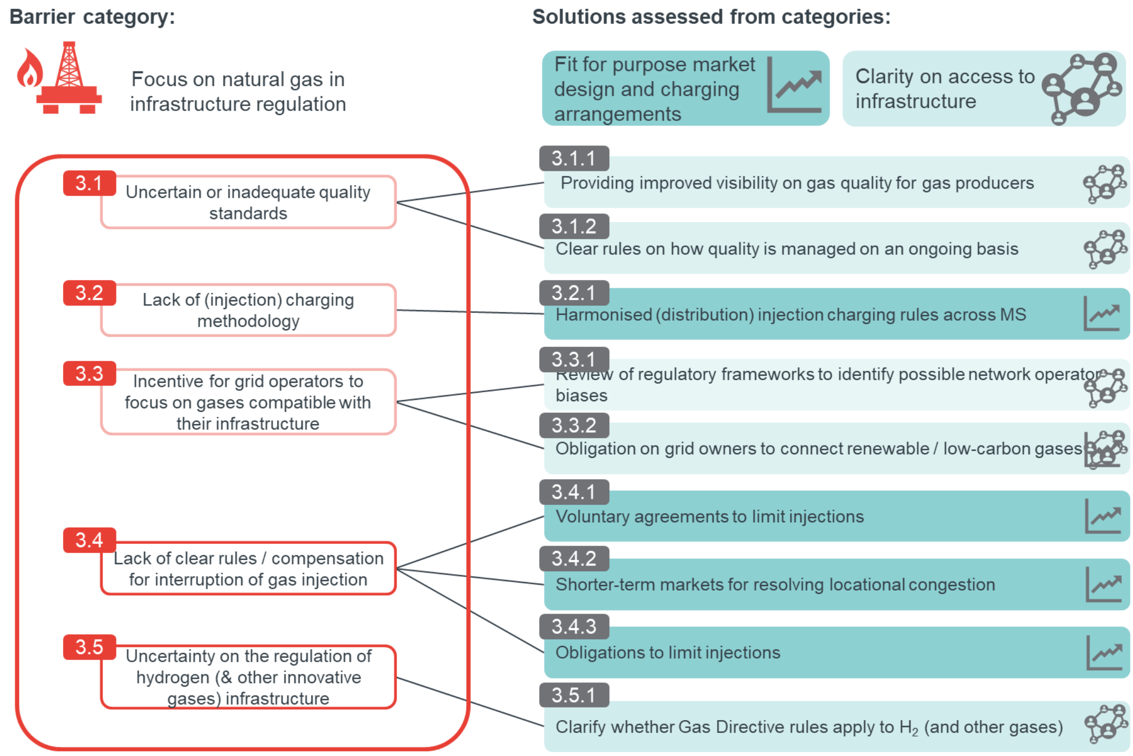
[5] For example, conversion of an existing pipeline to use hydrogen may bring benefits in terms of decarbonisation, but there may be a risk that it contributes to a fragmenting of the gas market.

Figure 7 Recommendations to deal with the unlevel playing field due to sector-/technology-specific tariffs and levies



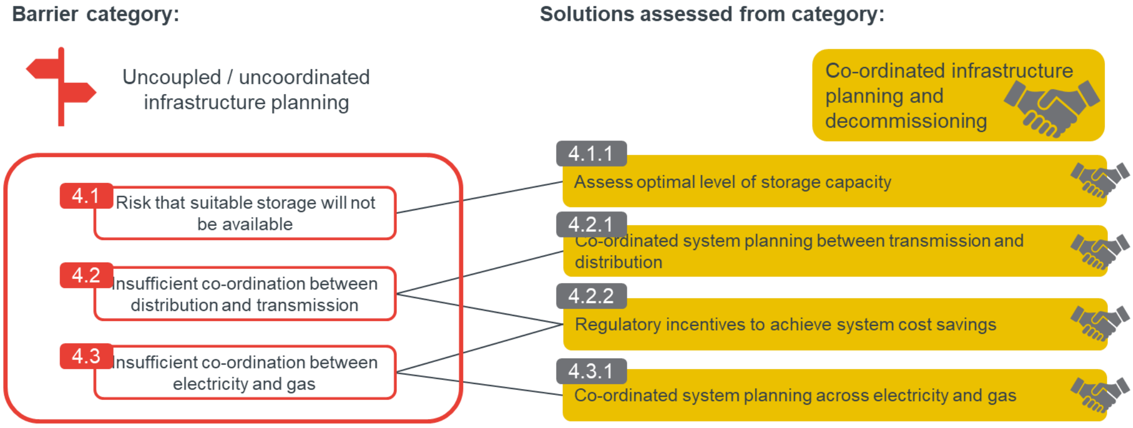
Source: Frontier Economics

Figure 8 Recommendations to deal with the focus on natural gas in infrastructure regulation



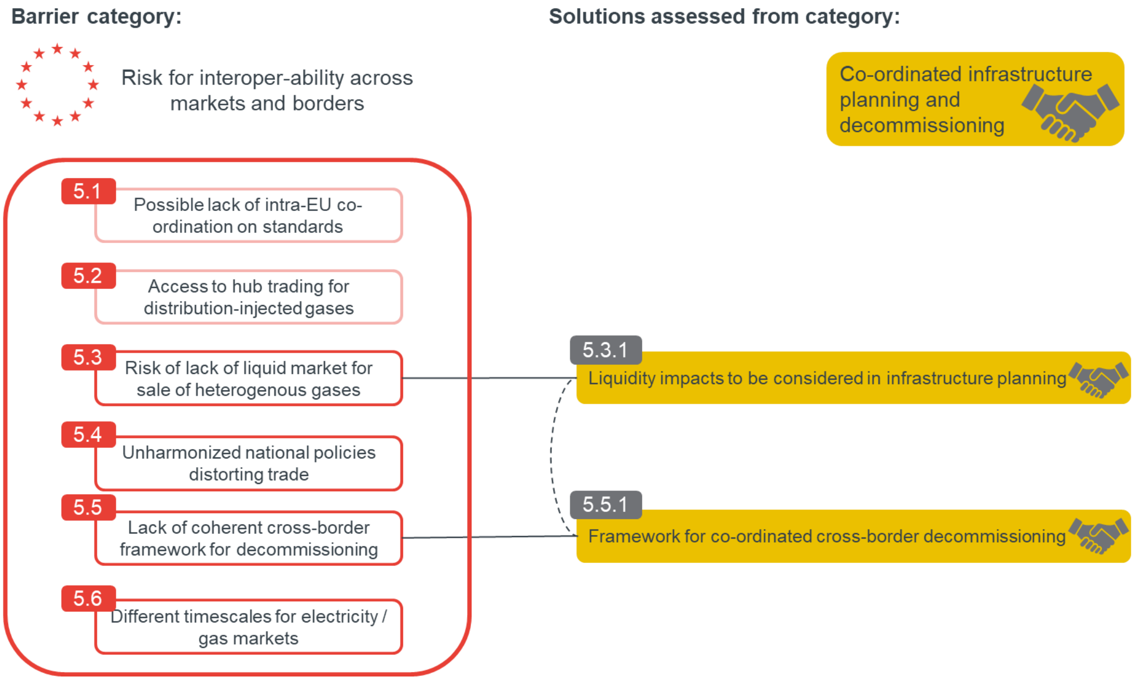
Source: Frontier Economics

Figure 9 Recommendations to deal with uncoupled / uncoordinated infrastructure planning



Source: Frontier Economics

Figure 10 Recommendations to deal with the risk for interoperability across markets and borders



Source: Frontier Economics

2 ACRONYMS

AE[R]	Advanced Energy [R]evolution scenario developed by Greenpeace
CBA	Cost-benefit analysis
CEER	Council of European Energy Regulators
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Use
CHP	Combined Heat and Power
CMP	Congestion Management Procedure
DAC	Direct Air Capture
DSM/DSR	Demand-side management/response
DSO	Distribution System Operator
E[R]	Energy [R]evolution scenario developed by Greenpeace
EC	European Commission
EU	European Union
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
(EU) ETS	(European Union) Emissions Trading System
GHG	Greenhouse gases
GoO	Guarantee of Origin
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LNG	Liquified natural gas
NRA	National Regulatory Authority
OECD	Organisation for Economic Co-operation and Development
OECD Europe	all European members of the OECD: Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.
OPEX	Operational Expenditures
PtG	Power-to-Gas
PCI	Project of Common Interest
PV	Photovoltaic
R&D	Research and development
RED	Renewable Energy Directive (2009/28/EC)
RED II	Renewable Energy Directive (recast) (2018/2001/EC)
SoS	Security of Supply
TSO	Transmission System Operator
TYNDP	Ten-year Network Development Plan

3 INTRODUCTION

In this chapter we state the objectives of the study, including definitions and scope for the technologies analysed, we set out the structure of the report and we summarise the key findings of our analysis on the outlook for the EU energy system and the role of gases within it.

3.1 OBJECTIVE

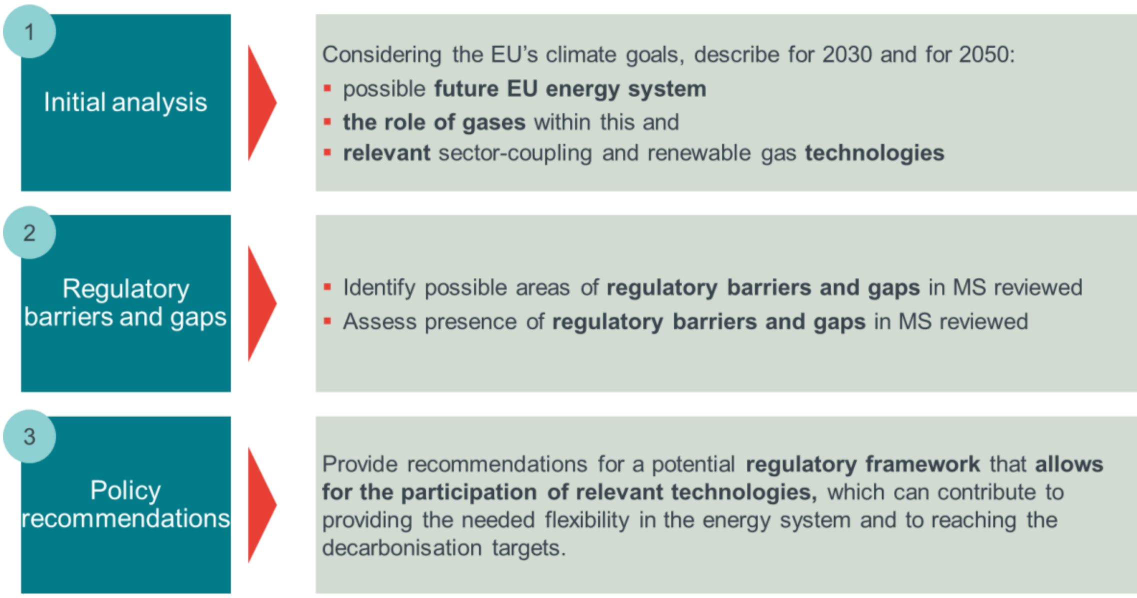
This final report presents the results of the project. The main objectives have been as follows:

Objective 1 – The initial analysis provides the context by describing a possible future EU energy system, the role of gases within the system, and relevant sector-coupling and renewable and low-carbon gas technologies.

Objective 2 – The core part of this study deals with identified regulatory barriers and gaps in Member States as well as inconsistencies across Member States.

Objective 3 – Based on the barriers and gaps identified under Objective 2, policy recommendations are provided.

Figure 11 Summary of analytical steps required



Source: Frontier Economics, CE Delft

3.2 STRUCTURE OF THIS REPORT

This study is structured as follows:

- Section 3.3 gives an overview of the insights from the analysis under Objective 1, the initial analysis, while section 3.4 clarifies technical definitions and the scope.
- Chapter 4 sets out the methodology followed to:
  - identify regulatory barriers and gaps (4.1); and
  - identify and assess solutions for barriers and gaps (4.2).
- Chapter 5 presents:
  - the list of barriers and gaps, allocated to a long and a short list; and
  - the solutions for each short-listed barrier and gap.
- Chapter 6 summarises the policy recommendations.

- Appendix A provides more detail on the approach to barrier identification.
- Appendix B gives an overview of the major findings of the country-based research.
- Appendix C includes the detailed assessment of solutions envisaged to overcome regulatory barriers and gaps.

3.3 OVERVIEW OF THE FUTURE ENERGY SYSTEM AND THE ROLE OF GAS

This section summarises the key findings of our analysis on the outlook for the EU energy system and the role of gases within it. The underlying detail is set out in a separate report (the 'Intermediate Report').

This section is structured as follows:

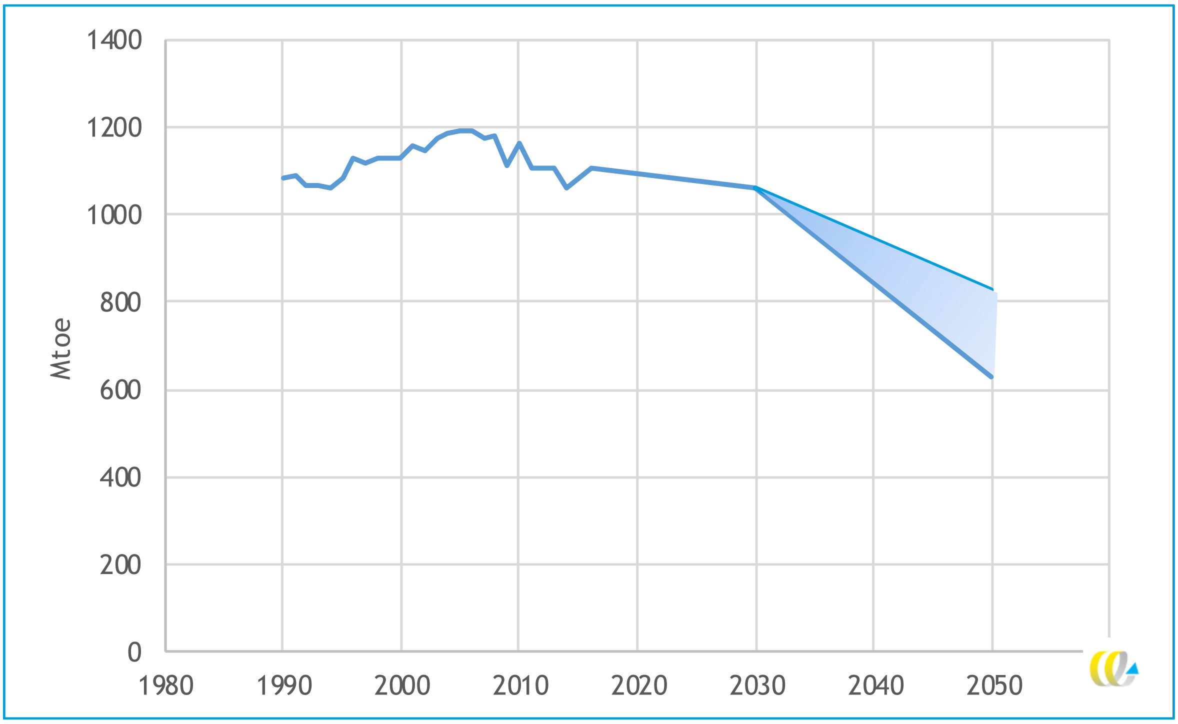
- We first describe the outlook for the future EU energy system.
- We describe the role of gases within this, and the implications for infrastructure.
- We outline how linkages between energy carriers could evolve.
- Finally, we set out the high-level policy implications of the findings of the Intermediate Report. These have guided our thinking on regulatory barriers and gaps to renewable gases and sector coupling technologies.

3.3.1 THE FUTURE EU ENERGY SYSTEM

In the coming decades, the EU energy system needs to change dramatically to make the transition to a decarbonised energy system. This transition is necessary to achieve the EU's 2030 climate targets as well as the EU's commitments under the Paris Agreement, which aims to limit the average global temperature rise to well below 2°C. An assessment of recent literature leads to the conclusion that despite significant uncertainties, a number of likely key elements of the EU's future decarbonised energy system to 2050 can be identified.

The first is that total final energy demand is expected to reduce significantly through energy efficiency measures in all end-use sectors. Key drivers include a large reduction in heat demand, but also an increase in energy efficiency in industry and transport (including a shift from more to less energy-intensive modes of transport, such as public transport). This is illustrated in Figure 12.

Figure 12 EU final energy demand: historic data, forecast for 2030 and average for the decarbonisation scenarios for 2050 developed for the Commission's 'Long Term Strategy'

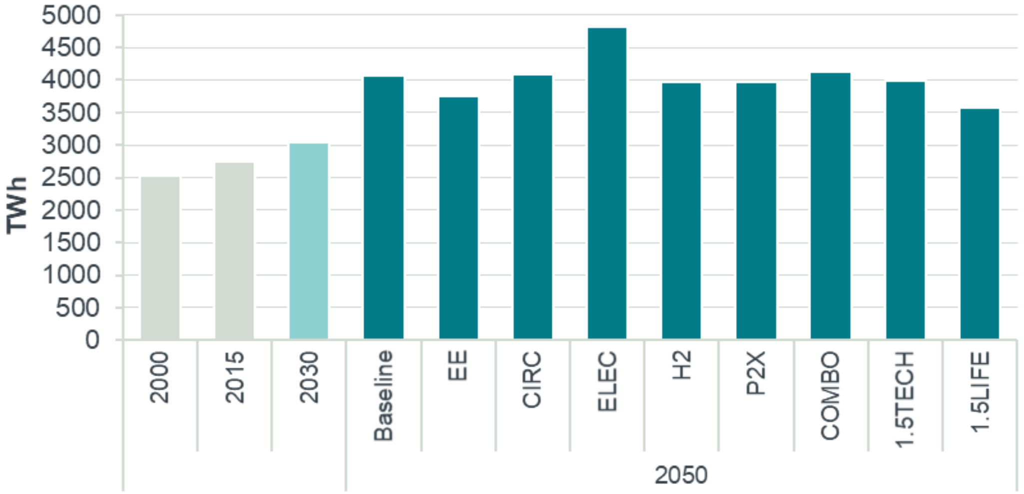


Source: European Commission (2018) "A Clean Planet for all, A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy", COM(2018) 773 final.

While overall final energy demand is expected to decrease, final demand for electricity will increase, due to increased electrification of heating and transport. This is illustrated by the Commission's Long-Term Strategy[6], which sees electricity demand rise in all analysed pathways in Figure 13.

[6] European Commission (2018) "A Clean Planet for all, A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy", COM(2018) 773 final.

Figure 13 EU final electricity consumption (historical and projected)

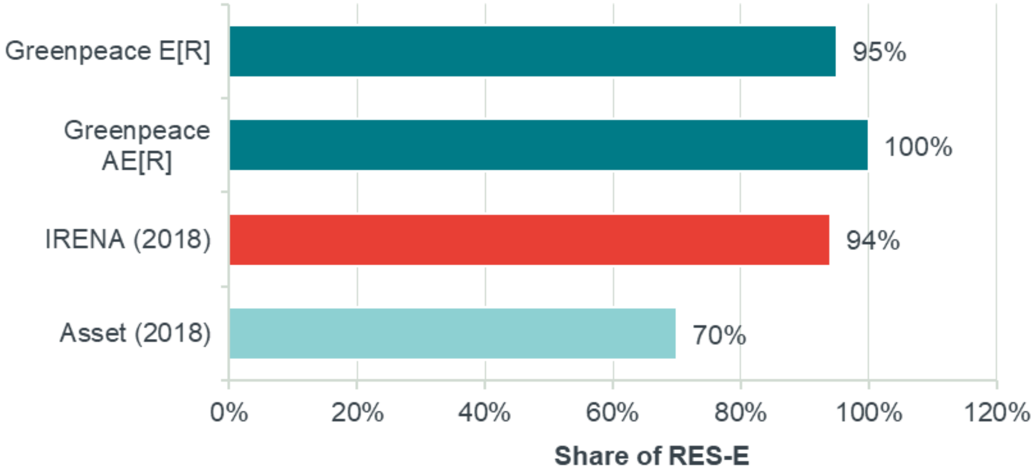


Source: European Commission (2018) "A Clean Planet for all, A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy", COM(2018) 773 final.

Demand for electricity will be further increased by demand for Power-to-X production (amplified by the conversion efficiency losses involved with Power-to-X production).

In power production, the most carbon intensive fossil fuels (coal, lignite, oil) are expected to be phased out, with use of natural gas potentially increasing in the transition (i.e. to 2030) but eventually largely being phased out by 2050. Renewable power production is generally expected to increase (as illustrated in Figure 14).

Figure 14 Projected share of RES-E in 2050 in EU / OECD Europe



Sources: ASSET, 2018, "Sectoral integration: long-term perspective in the EU Energy System, final report". Greenpeace, 2015, "Energy [r]evolution: A sustainable world energy outlook 2015, 100% renewable energy for all". IRENA, 2018, "Global energy Tranformation: a Roadmap to 2050".

Note: IRENA (2018) figures relate to the 2050 REmap scenario. Greenpeace (2015) figures relate to the 'Energy Revolution' (E[R]) and 'Advanced Energy Revolution' (AE[R]) scenarios and cover OECD Europe (including Israel and Switzerland).

The growth in renewables (much of which will be from intermittent sources, such as solar PV and wind) means that additional flexibility will be required on the electricity system. The long-term role of nuclear power is a key uncertainty, as is the deployment of fossil fuel generation with CCS (cf. definition in chapter 3.4).

Hence, the flexibility requirement of the electricity grid is expected to be achieved by a combination of demand side management/response (DSM/DSR), energy storage (for example in batteries, heat storage, or in hydrogen, synthetic methane or other chemical energy carriers) and peak gas power plants. The latter can be run on natural gas, with increasing shares over time of renewable or low-carbon gases (biomethane, hydrogen and/or methane from renewable electricity or from natural gas with CCS).

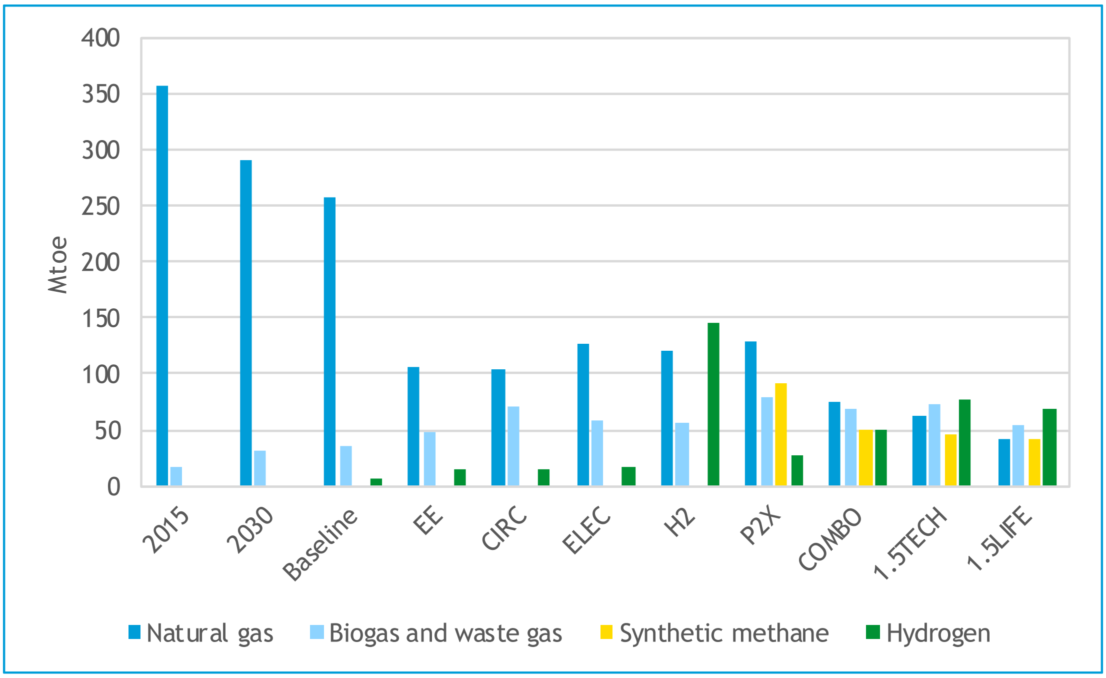
3.3.2 THE ROLE OF GASES AND SECTOR COUPLING AND IMPLICATIONS FOR INFRASTRUCTURE

It is, in principle, possible to use all the different renewable and low-carbon gases (including hydrogen) in all applications for which natural gas is used today (such as heat and power production), as well as others for which natural gas is not significantly used at the moment (such as transport). This would, however, require the gases to meet the current quality standards, or alternatively, an adaptation of the quality standards themselves and/or end-use equipment and infrastructure. Overall, the continued use of gases could help to reduce the costs of decarbonisation through a combination of limiting the costs of changing end-user appliances and avoiding the need for reinforcements and upgrades to the electricity grid (by making use of the existing gas grid to transmit energy).

However, the respective roles of different types of gases in the future energy mix are still uncertain. Natural gas might play a minor enduring role in industry and power generation. The extent of this role may be partly dependent on whether CCS can be deployed commercially, which is itself uncertain. Many scenarios also feature significant use of renewable and low-carbon gases. Precisely which gases are used is a further uncertainty, with hydrogen, synthetic methane and biomethane all featuring in varying quantities in the different studies by 2050.

This uncertainty is illustrated in Figure 15 below.

Figure 15 EU demand for gaseous fuels, in 2015, forecast for 2030, baseline for 2050 and different decarbonisation scenarios for 2050 developed for the EU 2050 strategy



Source: European Commission (2018) "A Clean Planet for all, A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy", COM(2018) 773 final.

Clearly, developments in cost will be an important driver of the extent to which gases are used in the future and, if so, which gases are predominantly used. But policy will also play a role. In particular, given the co-ordination that would be required (e.g. appliance switchovers, infrastructure upgrades), any future in which hydrogen is transported or used in significant quantities within the EU requires strategic decisionmaking by policymakers (whether at national or at EU-level).

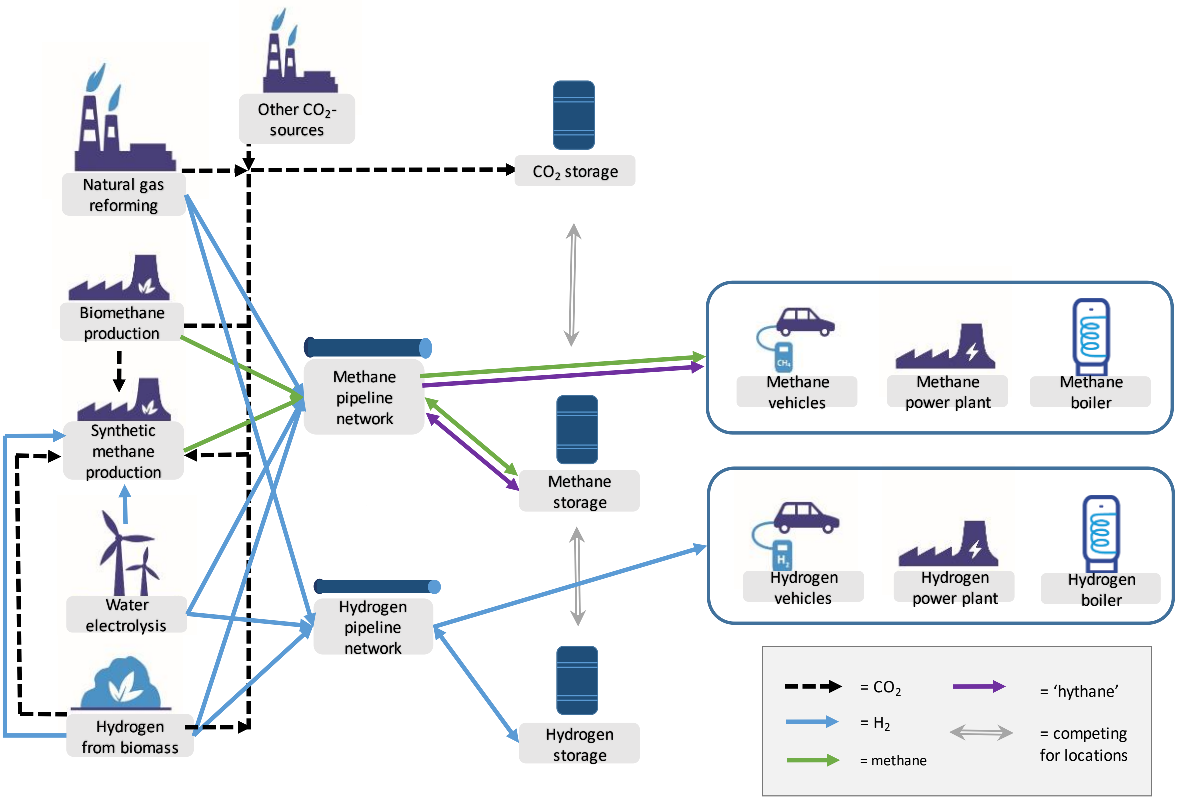
These developments have a range of possible impacts on gas infrastructure and storage needs. These impacts differ significantly between scenarios presented in recent literature, but include the following:

- Since natural gas demand is expected to decrease in the coming decades, the (average) utilization level of the transmission grid, LNG import terminals and import pipelines is also likely to decline, mitigated by the extent to which these convert to using increasing shares of renewable or low-carbon gases.
- The impacts on the transmission grid, the distribution grid and storage facilities are likely to differ from location to location. Some existing grids might be used for renewable methane or biomethane, or transformed to (local) hydrogen grids, and others may become obsolete.
- Any large-scale use of hydrogen might also require conversion of existing gas storage or new hydrogen storage locations. New fuelling infrastructure may need to be developed for the transport sector.
- Existing gas storage facilities might need to be adjusted to allow the storage of renewable gases.
- Synthetic methane production is likely to require dedicated CO_2 transport infrastructure to transport CO_2 captured from industrial processes to methanation plants, or further development of CO_2-capture from air technologies.
- Given that much of renewable and low-carbon gas production is expected to be located at distribution level, flows on the distribution grid (and flows between the distribution and transmission level) will require increased active management.
- Greater substitutability of gas and power for final energy consumption (e.g. in heating) is likely to require closer co-ordination between gas and power system operation, both at transmission and distribution level.

3.3.3 Linkages between energy carriers

As well as increased gas and electricity sector coupling, large-scale deployment of the technologies that are part of the hydrogen and methane supply chains will also result in linkages between natural gas, hydrogen and methane. This is illustrated in Figure 16.

Figure 16 High-level overview of linkages between gases for energy use in 2050: Natural gas, hydrogen and methane



- Natural gas reforming and CCS provide the possibility to convert natural gas upstream in the supply chain to low-carbon hydrogen.

- Hydrogen production from biomass competes with biomethane production from biomass. The CO_2 produced in both processes can be captured and stored; it could also be used to produce synthetic methane.

- Similarly, hydrogen could either be used directly or in synthetic methane production. This could lead to competition between synthetic methane and hydrogen, with the cost of the CO_2 used in the synthetic methane process (see point above) becoming an important factor in determining the effectiveness of this competition.

- As discussed earlier, hydrogen could be injected into the methane (natural gas) pipeline network up to a blending level of 2-20% by volume (with the maximum blending level still uncertain) without needing substantial additional investments in the gas network.

- Parts of the natural gas network could be adapted to transport 100% hydrogen. This also likely requires the replacement of end-use appliances and turbines. Although such adaptation could lead to a situation in which natural gas networks and hydrogen networks exist in parallel, it could provide the best match with local/regional production capacities in certain areas. Hydrogen and methane could be produced, transported and consumed more locally than is the case for natural gas today. In such a scenario, links between the hydrogen and methane supply chains would be broken at the level of injection to the grid (as they would no longer be blended together). However, links would remain elsewhere in the value chain (e.g. in production), as set out in the second and third bullets above.

- Hydrogen, methane and CO_2 could all be stored in underground locations or in available gas storage vessels. These are further discussed in the relevant sections of the Appendices to the Intermediate Report. Some of the underground locations may be suitable for storing either gas, but this is still a topic of research. Also, natural gas (LNG) transport vessels could perhaps be modified to transport hydrogen or CO_2. In such cases these gases would be competing for the same storage capacity.

In short, the simultaneous development of low-carbon and renewable hydrogen and methane supply chains would create several supply chain linkages, some of which are complementary and synergetic, and some of which are substitutional. Further linkages might be developed in the future if other chemical energy carriers (such as ammonia) are deployed in significant quantities.

3.3.4 IMPLICATIONS FOR POLICY

The findings from our literature review have a range of implications on gas infrastructure and storage needs and policy. While the precise impacts differ significantly between scenarios applied in recent literature, five themes emerge.

The first is the importance of continued innovation and learning in technologies that are currently less mature. Any large-scale market uptake of renewable and low-carbon gas technologies will require innovations and R&D efforts in all aspects of the value chains, to further develop the necessary technologies, to create and preserve options for the future, and to reduce cost and improve efficiencies. This is expected to require significant investments over the coming decades, for example in renewable energy production, production plants for the gases, upgrading of existing infrastructure and storage, new infrastructure and storage, and new end-use applications.

The second is the variety of technological approaches to renewable and low-carbon gases and sector coupling technologies. This highlights the importance of a level playing field for gases (compared to other energy carriers) and between different gases. In the transition phase there may need to be an element of support prioritising those technologies that are potentially more promising. However, as support is phased out, it is important that the market can send efficient signals regarding technology choices to ensure that the energy transition can happen at least cost to society. It will also be important to maintain a sufficient degree of technology openness to facilitate the market entry of energy carriers that might grow in relevance over time (e.g. ammonia).

The third is that, while the use of natural gas is expected to be largely phased out by 2050, new gases will begin to flow in increasing quantities in existing infrastructure. Some infrastructure may be switched over entirely to new gases (such as hydrogen). New infrastructure may also be focussed on new gases. As a result, the focus of infrastructure regulation will need to shift from natural gas to a variety of different (low-carbon and renewable) gases.

The fourth is that interlikages and substitutability between the electricity, gas and heat sectors in all areas of the value chain are likely to grow going forward. As a result, planning the required investments efficiently will likely require an integrated development of the gas and electricity systems. Given much of the new gas production may be located at distribution level, co-ordination in system planning and operation between transmission and distribution levels is also likely to be important.

The fifth is that different countries or regions may adopt different technological approaches. This suggests that attention needs to be paid on how to ensure that different gases can co-exist both within and between countries and regions.

These themes have influenced how we have framed the analysis of potential regulatory barriers and gaps. We consider each of these areas in turn in the chapters that follow.

3.4 DEFINITIONS AND SCOPE

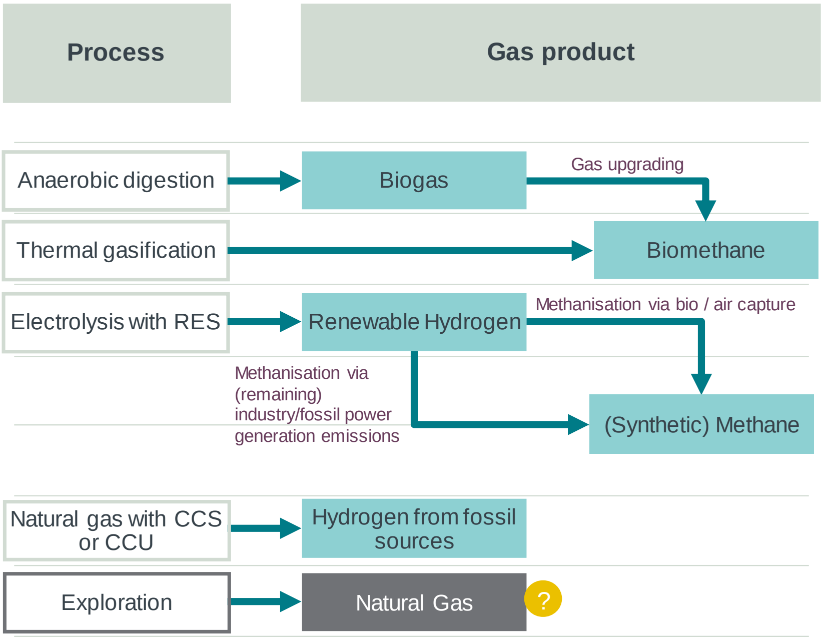
This study mentions a wide range of gases that are likely to play a role in the decarbonisation of the EU energy supply of the coming decades. To prevent misunderstandings and ensure a uniform terminology throughout this project, a comprehensive list of relevant definitions has been developed. This adheres to the definitions included in Article 2 of the Renewable Energy Directive recast (RED II) , with additional terminology specific to this report defined only where necessary.

A selection of key definitions from the RED II and additional definitions that are relevant for this study are provided in the following table.

Term	**Meaning**
Selected definitions from RED II	
Energy from renewable sources Or Renewable energy	Energy from renewable non-fossil sources, namely wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogas
Renewable liquid and gaseous transport fuels of non-biological origin	Liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass.
Biofuels	Liquid fuel for transport produced from biomass
Biogas	Gaseous fuels produced from biomass
Additional terminology relevant for this study	
Gases	All types of gaseous fuels, including natural gas, hydrogen, renewable gas, biomethane, decarbonised gas, etc.
Renewable gases/ Gases from renewable sources	Gaseous fuels produced from renewable non-fossil sources, namely wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogas
Natural gas	Naturally occurring gas of fossil origin, consisting primarily of methane
Biomethane	Gaseous fuels with a quality that allows injection into the natural gas grid produced either from biogas through upgrading, or by thermal gasification of biomass.
Power-to-Gas, PtG	Technology to transform electricity into a gaseous energy carrier (notably hydrogen or methane)
Renewable hydrogen	Hydrogen produced from renewable energy sources
Hydrogen from fossil sources	Hydrogen derived from either gasification of solid fuels (e.g. coal) or from reforming of natural gas.
Hydrogen from fossil sources using Carbon Capture and Storage	Hydrogen derived from either gasification of solid fuels (e.g. coal) or from reforming of natural gas. In this report, we use the term to primarily refer to hydrogen produced from natural gas where the CO_2 has been to a high extent captured (sometimes referred to as blue hydrogen)
Synthetic methane	Methane produced from hydrogen.

A schematic overview of the main categories of gases covered in this study is depicted in the figure below. We note that these different gases may be transported in separate infrastructures or blended in a single infrastructure.

Figure 17 An overview of the gases included in this report: illustrative definitions



Source: Frontier Economics, CE Delft

4 Methodology for Identifying Regulatory Barriers and Solutions

This chapter describes the methodology followed to complete Objectives 2 and 3 of the assignment, and is structured as follows:

- We first explain our methodology for identifing regulatory barriers and gaps.
- We then explain our methodology for identifying and assessing possible solutions, and for translating this assessment into recommendations.

It is important to note that, due to the timings of the study, neither the identification of barriers nor the assessment of solutions takes full account of recently EU energy market legislation that has recently come into effect, originally forming part of the Commission's Clean energy for all Europeans package of proposals.[7]

4.1 Methodology of regulatory barriers and gaps analysis

This section is structured as follows:

- We first explain how we define the concept of a 'regulatory barrier or gap'.
- We then set out our methodology for identifying potential regulatory barriers and gaps to sector coupling technologies and renewable and low-carbon gases.

4.1.1 Definition of Barriers

As illustrated in Figure 18, for the purposes of this study, regulation is defined as encompassing the legal framework at the EU or Member State level, acts of regulatory bodies and agencies as well as administrative practice. Regulation (or the absence thereof) is found to possibly risk constituting a barrier to sector coupling and renewable and low-carbon gas technologies if it threatens either a level playing field between technologies or the development of innovative technologies.

Such a threat to the level playing field may be rooted in distortions in relation to:

- the most efficient use of existing infrastructure (pipelines, storages, etc.)
- the most efficient new investment into traditional technologies (pipelines, storages, etc.) or new technologies (e.g. power-to-gas facilities, carbon capture and storage technologies, etc.).

As a result, the identified barriers may both threaten the achievement of climate policy targets and/or contribute to inefficiently high costs of the energy transition.

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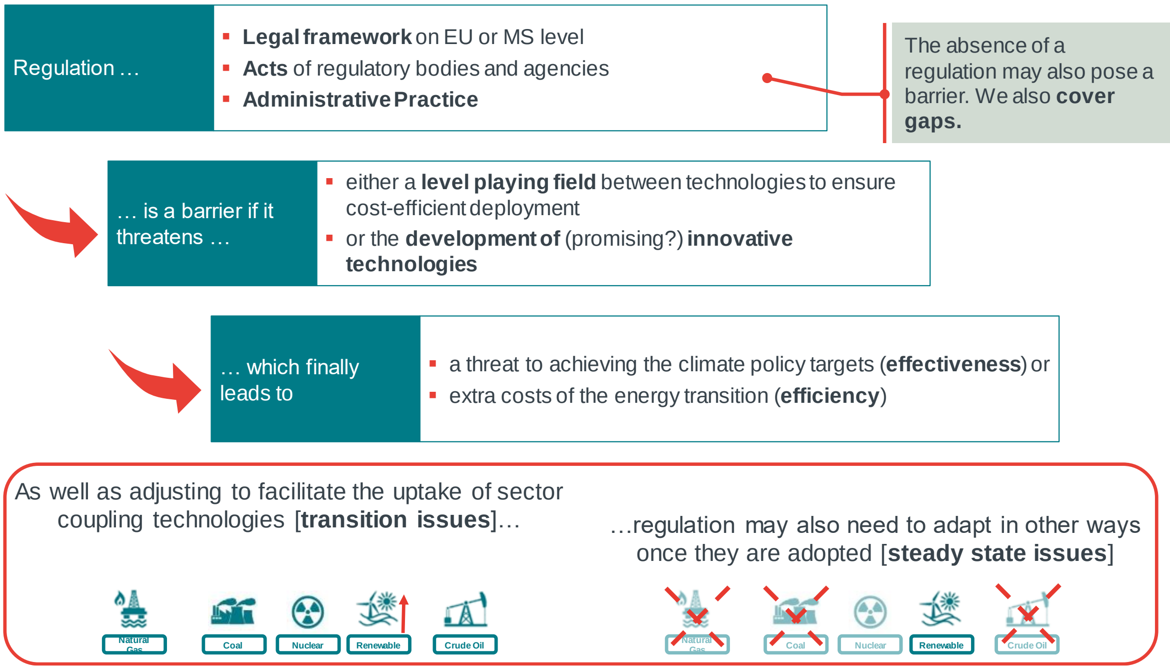
7 https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans

Figure 18 Definition of barriers and gaps



Source: Frontier Economics

It is important to note the following:

- **Barriers and gaps**: Based on the retained definition, the absence of regulation may also constitute a barrier. This study therefore also covers regulatory gaps.
- **Scope of barriers for sector-coupling and related technologies**: While barriers to electrification may be viewed as a barrier to sector coupling between the electricity and gas sectors, the scope of this study does not include barriers to electrification.

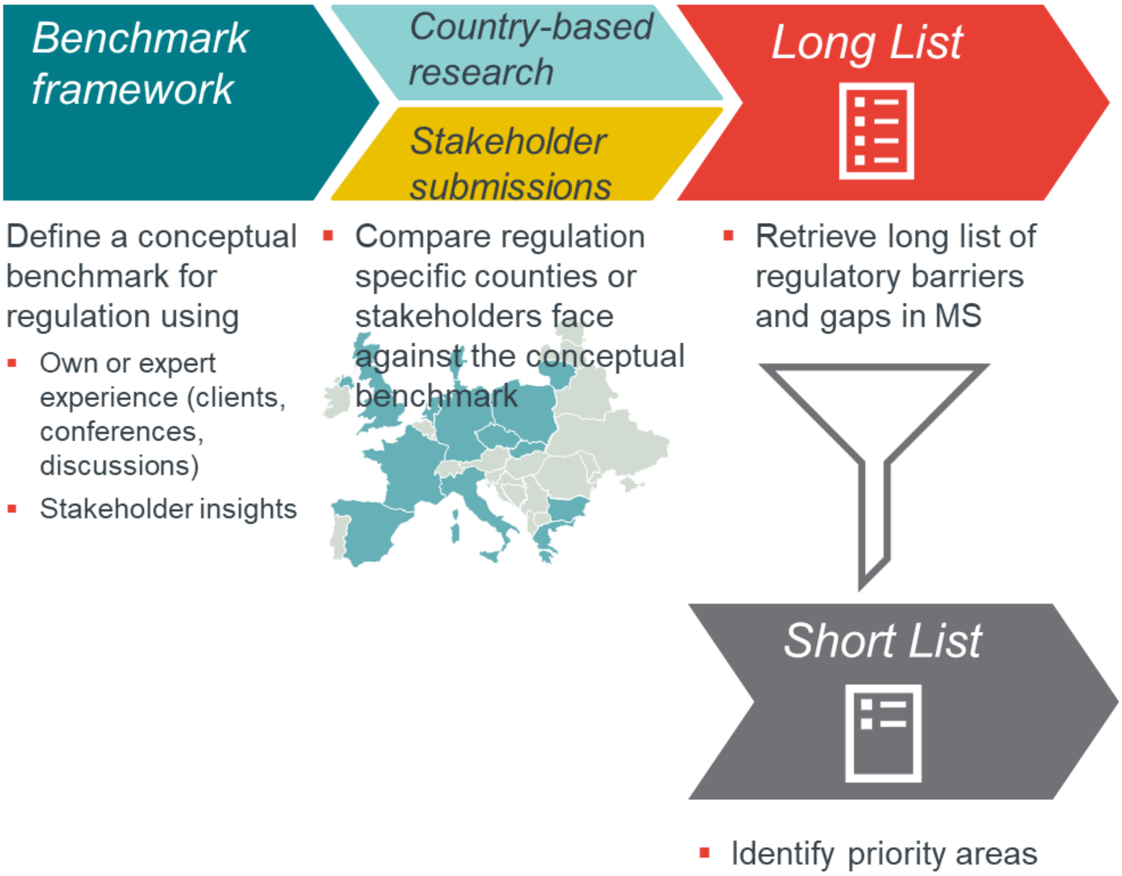
4.1.2 Methodological approach for identifying barriers

To identify regulatory barriers and gaps the following methodological steps were implemented, as described in Figure 19:

- **A conceptual benchmark for regulation** was developed to capture the scope of regulation(s) assessed as part of the study, in line with the definition provided in section 4.1.1;
- **Research** was carried out to collect qualitative evidence and feedback on barriers encountered by pilot projects in a selection of countries (**country-based research)**;
- **Submissions from stakeholders** were invited and reviewed;
- **A long list of barriers** was established based on the above; and
- Within this list, **a short list of barriers** was agreed that would then be assessed with a view to provide recommendations (see section 5).

Each step is described further below.

Figure 19 Overview of methodology for the identification of regulatory barriers and gaps

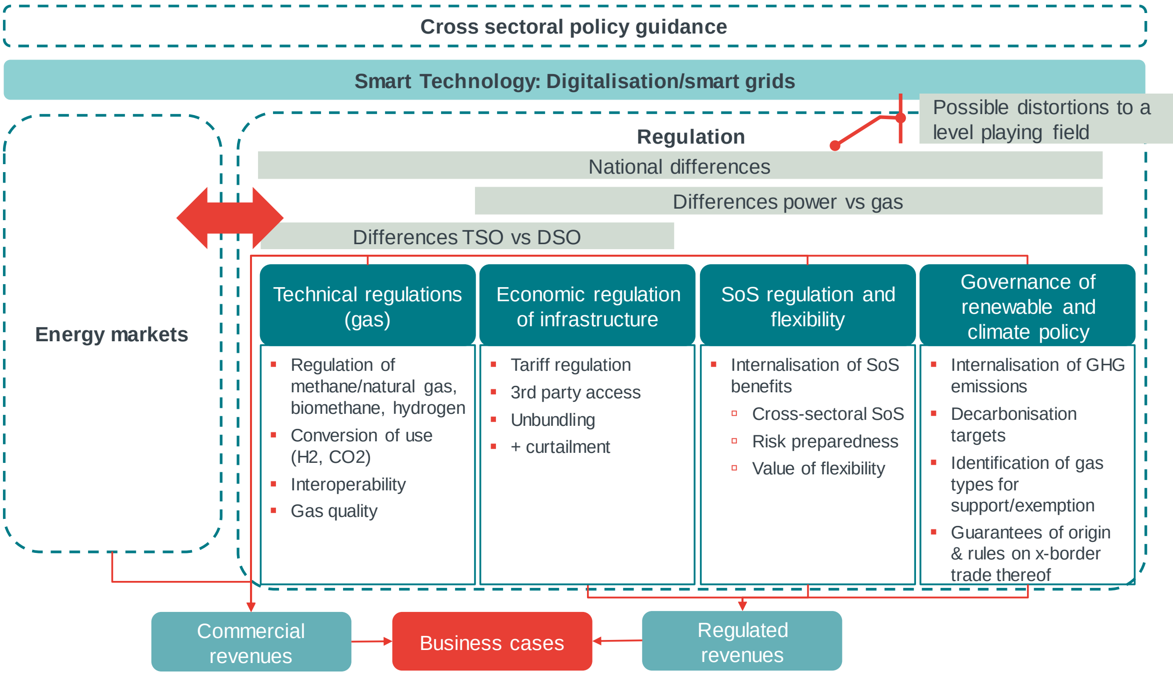


Source: Frontier Economics

The conceptual benchmark for regulation (see Figure 20) was used to map the regulations to be assessed with a view to identifying barriers and gaps. The benchmark included a detailed list of the regulatory areas under analysis, as well as an an initial view on the regulatory arrangements that might be considered efficient in each area. The benchmark effectively provided a detailed structure for the analysis, in particular for the country-based research (see below).

The benchmark also highlighted that barriers could stem from within each type of regulation, from national differences in those regulations, from differences in the treatment of energy carriers, or from differences in regulation at TSO- and DSO-level.

Figure 20 The conceptual benchmark for regulation illustrates the coverage of barriers in the whole system



Source: Frontier Economics

The conceptual benchmark captures the essential consideration that in an efficient situation the operator (of existing facilities) or investor of (new) infrastructure will need to tap into all potentially available sources of revenue:

- Commercial revenues that may be for instance achieved through some merchant operation, e.g. by contracting a facility to an energy trader;
- Regulated revenues – these may relate to capped revenues of monopoly infrastructure, revenues that reward certain wider system benefits of a facility or additional revenues that reward the environmental/climate benefit of a facility.

System benefits could for instance relate to avoiding the need to invest in alternative infrastructure. For instance, a power-to-gas facility may help avoid investment in power grids, if renewable electricity can be converted to gas and the energy then transported in an existing pipeline system, instead of reinforcing the electricity grid to transport the additional power. This also implies that some of the system benefits will inevitably depend on the precise location where a facility is situated within a given electricity and gas network topology.

The regulatory environment needs to be able to facilitate the monetisation of all systemic (and climate) benefits of a facility by the operator or owner (i.e. the financial rewards ultimately need to be bundled in the hands of the operator/investor). In some cases, this may only be achieved by generating multiple revenue streams, which ultimately benefit the operator or investor. It will not necessarily require that the operator/investor is the direct beneficiary of the primary revenue streams.[8]

[8] For example, the owner of a power-to-gas facility may benefit from merchant revenues of arbitrage trades between gas and power, if the actual trades are carried out by an energy trader, but the traders book (and pay to the benefit of the operator/investor) capacity in the power-to-gas facility.

If this is not achieved, there can be a barrier or a gap that will keep operators or investors from deploying the facility that is most beneficial from an overall economic perspective.

Based on this benchmark, a number of potential barriers and gaps were identified, drawing on three main types of input:

- Expert insights: the energy transition and the consequential need for regulatory adjustment are currently much discussed topics. We used the experience of our project work, clients and insights from conferences for the establishment of the long list.
- Expert group meeting on 21st November 2018 in Brussels: In our meeting with the expert group[9], we gained insights from the experience of relevant stakeholders that contributed further to the list of barriers and gaps.
- Stakeholder workshop in Brussels on 6th of March 2019: We received further comments from a larger group of stakeholders during and after the presentation of our intermediate findings at a workshop held on March 6th 2019.

More detailed information on the research methodology can be found in Appendix A.

Country-based research into representative Member States enabled us to compare the conceptual benchmark against current practice in those Member States.

Thirteen Member States (Belgium, Bulgaria, Denmark, France, Germany, Greece, Italy, Lithuania, Poland, Slovakia, Spain, The Netherlands and the United Kingdom (UK)), were the subject of research. The selection of Member States was agreed with the Commission and designed to cover a wide and representative range of Member States and to ensure a range of possible low-carbon gas and/or sector coupling applications are covered. More information on the country selection and the key barriers per country can be found in Appendix A.

The conceptual benchmark for regulation fed directly into the approach for conducting the country-based research. Figure 48 in Appendix B gives an overview of the information collected as part of this exercise. It is important to note that the country-based research was based on a desktop review of regulations and on interviews with country stakeholders. The stakeholders included a mix of energy producers, vendors, network operators or industry players, in particular those involved in pilot projects for sector coupling and low-carbon and renewable gases technologies. We note that the research methodology was targetted at gaining insights, in particular feedback from local developments, and was not designed as a systematic survey. Due to the different interview partners, but also due to the differences in status and national plans in relation to the energy transition across the countries, the findings are not all-encompassing. While the research for each country focuses on the current barriers and gaps faced in their current situation, and in some cases anticipated in the future, it does not necessarily mean that these are the exhaustive list of barriers that may arise in this country in the future (absent intervention). Where this helps understand the nature of barriers, references to country-specific examples are included in section 5; by construction those examples are not exhaustive.

Stakeholders (including EU sector associations, Member States and NRAs) added to the country-based analysis of barriers by providing their assessments of the most pressing barriers. A workshop was held on March 6th 2019 and provided the opportunity for stakeholders to participate to the discussion. A presentation of the barriers and gaps

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[9] Participating parties were ACER, CEER, CEDEC, European Biogas Association, ECF, ENTSO-E, ENTSOG, Eurogas, Eurelectric, E3G, GEODE, Hydrogen Europe

identified at that point in the study was shared with participants ahead of the workshop. The stakeholders had the chance to share additional comments with the consortium in form of a written response. Input from stakeholders was used to substantiate and/or ensure the completeness of the list of barriers identified. We also note that several stakeholders opted to provide views on solutions to address barriers and gaps. The consortium used this input in the subsequent step of the study.

The Long List of barriers brings together the information from the conceptual framework, the country-level analysis and the stakeholder perspectives. The Long List includes some Member State specific barriers as well as barriers stemming from inconsistencies across regulatory regimes in different Member States. The explanation of the barriers on the long list focuses on setting out clearly why and how each factor might act as a barrier or gap - i.e. explain which market or regulatory failure is occurring and the impact on the level playing field in terms of development of renewable and low-carbon gases and sector coupling technologies.

The Short List corresponds to those areas for which a set of recommendations has been elaborated in further stages of the study, as agreed by the Commission and the consortium.

4.2 METHODOLOGY TO IDENTIFY AND ASSESS SOLUTIONS

In this sub-section, we:

- Explain how we have identified potential solutions for short list barriers;
- Set out our criteria for qualitatively assessing potential solutions; and
- Set out how we translate the qualitative assessment of potential solutions into a recommendation.

4.2.1 IDENTIFICATION OF SOLUTIONS

In identifying potential solutions for assessment, we have drawn on the following sources:

- **Country-based research**: In some cases, individual countries have taken, or are considering taking, action to address some of the barriers identified.
- **Stakeholder feedback**: Stakeholders have suggested a number of potential policy options to promote sector coupling technologies. We have included those potential solutions that are linked to the short-listed barriers.
- **Own analysis**: We have considered (from first principles) potential solutions that could directly address some of the barriers raised, also drawing on work carried out to develop the 'conceptual benchmark for regulation'.

4.2.2 ASSESSMENT CRITERIA

We use the following criteria to qualitatively assess potential solutions:

1. **Net societal costs and benefits:** What is the expected balance of overall costs and benefits to (EU) society as a whole?

    a. In assessing this criterion, we make the simplifying assumption that delivery against EU environmental objectives is held constant. In other words, we assume that individual policy options do not affect whether binding EU renewable energy and climate targets are met, but only affect how targets are met. As a result, different solutions might still have different effects on the costs of achieving targets. We also consider security of supply impacts within this criterion.

b. Solutions are likely to deliver net benefits to society if they improve productive and allocative efficiency[10], at both Member State and EU level and if they result in the right conditions for promoting innovation.

2. **Investment environment:** Do the proposed structures give rise to investible propositions? That is, can they attract capital to support material investment in long lived assets (by matching risk allocations with investor appetites, delivering reasonable returns over appropriate time horizons, providing clarity on long-term regulatory treatment and addressing risks associated with stranding)?

3. **Consumer protection:** How might any impact on net societal costs translate into an impact on consumer bills? To what extent do impacts differ by timescale (short vs. long run) or by energy carrier (electricity vs. gas)? Are there any impacts on fairness and choice?

4. **Complexity and timelines:** How radical are the institutional changes required over today's market and regulatory framework? What is the risk of unintended consequences?

5. **EU value-added:** Is co-ordinated action at EU level likely to be key to delivering the benefits identified?

We assess each potential solution qualitatively against each of the criteria above, using a 'traffic light' rating system to indicate performance against each criterion. Figure 21 below sets out how we assign ratings to each assessment criterion.

[10] Productive efficiency occurs when production happens at the lowest possible cost. Allocative efficiency refers to the optimal distribution of resources across the economy. It occurs where every good or service is supplied until the point where price is equal to the marginal social cost of production (i.e. the incremental cost to society of producing an additional unit).

Figure 21 Evaluation of performance against individual assessment criteria

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Positive	*Benefits outweigh costs. Indicates lower magnitude of impacts.*	*Positive for all investors; reduces risk*	*Reduces bills unambiguously; positive for fairness and choice*	*Low risk of unintended consequences; implementation time ≤1 year*	*Clear case for co-ordinated EU action*
Mixed / Neutral	*Balance of costs and benefits neutral or uncertain.*	*Mixed or neutral impacts on investors*	*Mixed or neutral impacts*	*Medium risk of unintended consequences OR 2-4 years for implementation*	*Uncertain / limited gain to co-ordinated EU action*
Negative	*Costs outweigh benefits. Indicates lower magnitude of impacts.*	*Negative for investors; increases risk*	*Bills increased; negative for fairness and choice*	*High risk of unintended consequences OR ≥5 years for implementation*	*No gain to co-ordinated EU action*

Source: Frontier Economics

4.2.3 TRANSLATING ASSESSMENT CRITERIA INTO RECOMMENDATIONS

To be included in our list of recommendations, potential solutions must have a positive overall balance of societal costs and benefits. This is likely to be the case for solutions that directly address an identified market or regulatory failure, to the extent that costs of implementation remain manageable. Where several potential solutions are possible but are mutually exclusive, we also aim to make clear which solutions might deliver the highest net benefit to society.

In practice, however, policymakers' decisions on which solutions to adopt will be more complicated and will need to consider a wider range of potentially relevant impacts than just the overall net benefit to society. The final policy decision will be a complex trade-off of several factors.

- To that end, the assessment criteria do include other impacts relevant from an economic and policy perspective, such as the impact on consumers. We therefore provide information to allow policy-makers to arrive at an alternative evaluation based on a possible trade-off between net societal benefits and other relevant impacts.
- However, our criteria do not include other considerations that might be relevant to a final policy decision. These include, for example, the impacts of potential solutions on fundamental rights or a more detailed analysis of compliance with the 'subsidiarity' principle.

In addition, given the scope of this study, neither detailed work on design of individual policy options nor a robust quantitative assessment of costs, benefits and distributional impacts of all options have been carried out. Further work will be needed on these aspects.

5 LIST OF BARRIERS AND SOLUTIONS FOR SHORT-LISTED BARRIERS

In this section we:

- discuss the barriers and gaps identified as part of this study, grouped by high-level barrier category, and note which are on the long list and which are on the short list; and
- for short-listed barriers and gaps, we provide policy recommendations on how to address them.

We focus on setting out clearly why and how each factor might act as a barrier or gap (i.e. explain which market or regulatory failure is occurring and the impact on the level playing field in terms of development of renewable and low-carbon gases and sector coupling technologies). After the description of each barrier we indicate whether it was retained on the short list. In describing barriers, we sometimes use examples from countries reviewed to illustrate the nature of the barrier. However, this is not intended to be a complete list of all the countries in which a barrier may be present.

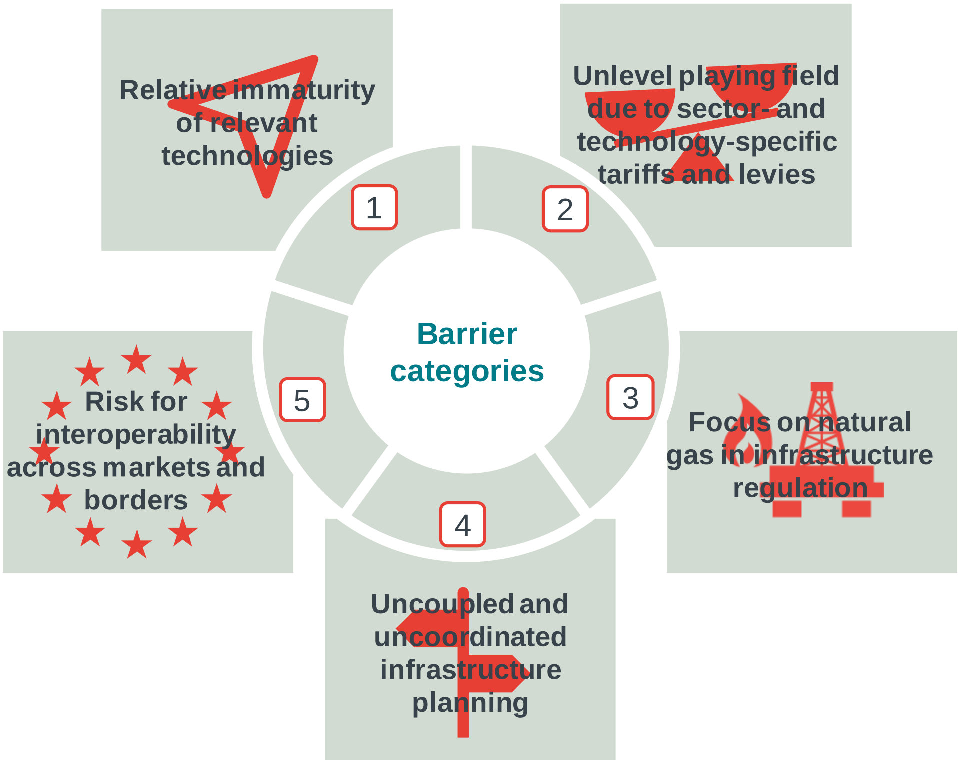
For some of the barriers remaining only in the long list we give high level recommendations to feed into further work to overcome these barriers on the European or Member State levels. For barriers retained in the short list we discuss recommendations in further detail.

As apparent in Figure 22, barriers and gaps identified as part of this study may be categorised within five groups, corresponding to the themes set out in section 3.3.4.

The first two groups include barriers faced by project developers as well as consumers of relevant renewable and low-carbon gas and sector-coupling technologies.

- The first group of barriers focuses on issues related to the immaturity of the relevant technologies.
- The second group encompasses issues arising from technology- and sector-specific regulations which may be inadequate to the emerging sector-coupled energy market.
- The third and fourth barrier groups focus on infrastructure. Barriers in group three arise from the transition from natural gas to a multitude of gas types.
- Group four focusses on issues linked to the increasing need of interlinkage between the electricity and gas sectors deploying sector-coupling technologies.
- Group five deals specifically with the interoperability between different markets.

Figure 22 Barrier categories



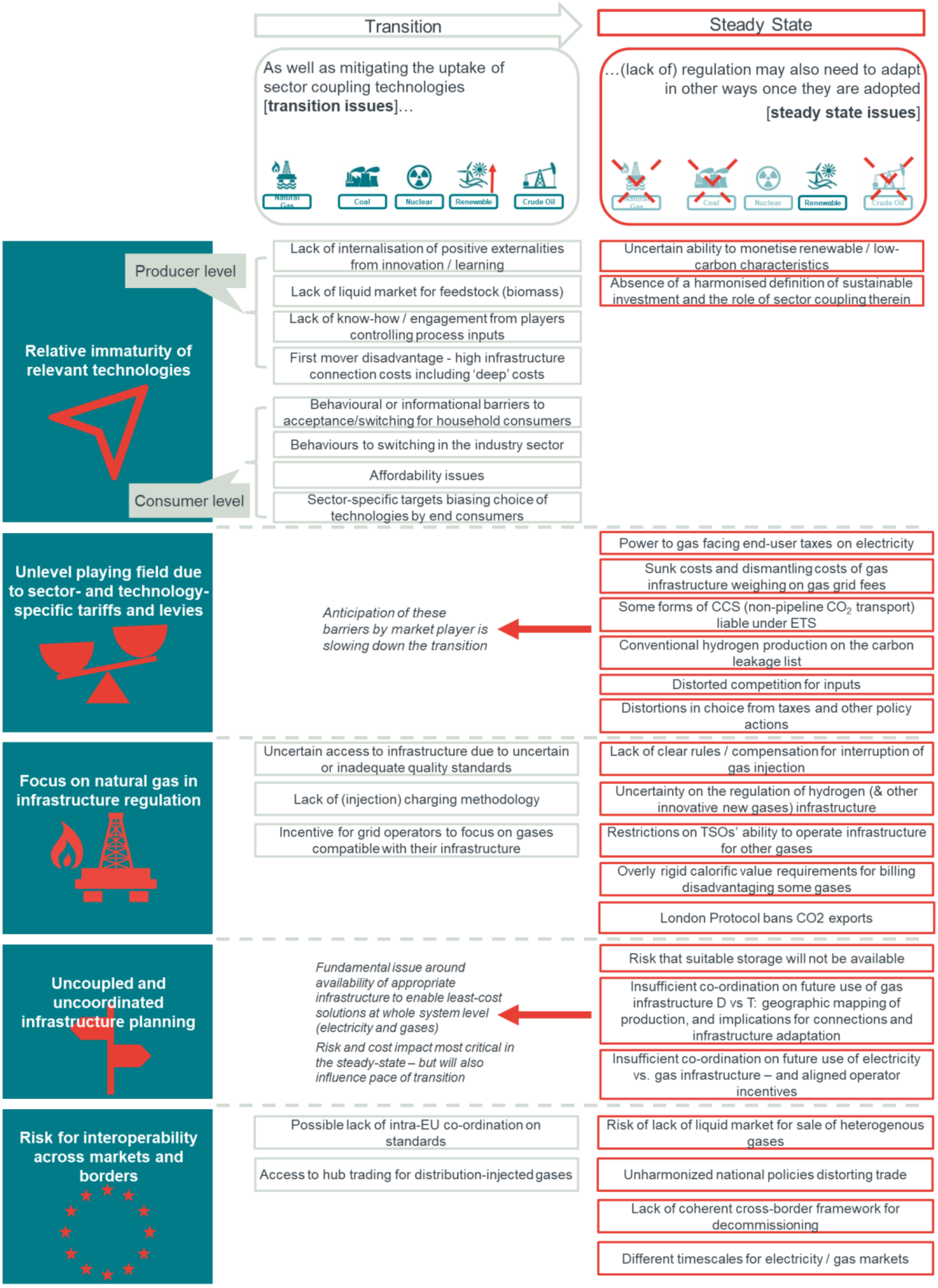
Source: Frontier Economics

The analysis has shown that barriers and gaps include both transitional issues as well as steady state issues.

- Transitional issues are those barriers and gaps that are expected to apply when renewable and low-carbon gases and sector-coupling technologies are still in early technology readiness levels and in a phase during which the costs are expected to continue to reduce as the technologies' uptake increases. These are issues that would be expected to be resolved, either spontaneously or through intervention, by the end of the transition – but their prevalence in the transition phase may mean that efficiency is not achieved.
- Steady state issues are those barriers and gaps that are expected to prevail even when the relevant technologies have reached maturity.

The full list of barriers and gaps identified as part of this study is displayed in Figure 23 below.

Figure 23 Long list of low-carbon renewables gases and sector coupling technologies barriers and gaps



Source: Frontier Economics

For each of the short-listed barriers, we also present our recommended solutions, together with the overview of our qualitative assessment of their relevance. The solutions we assess can also be grouped into five categories:

- **Interventions via climate and renewable policy, and support for innovation**: this group of solutions is designed to address barriers and gaps related to the relative immaturity of sector coupling and low-carbon and renewable gases technologies;

- **A regulatory toolbox to address cost recovery issues:** this group would serve to address barriers and gaps from group 2, that is to say issues contributing to an unlevel playing field across technologies;

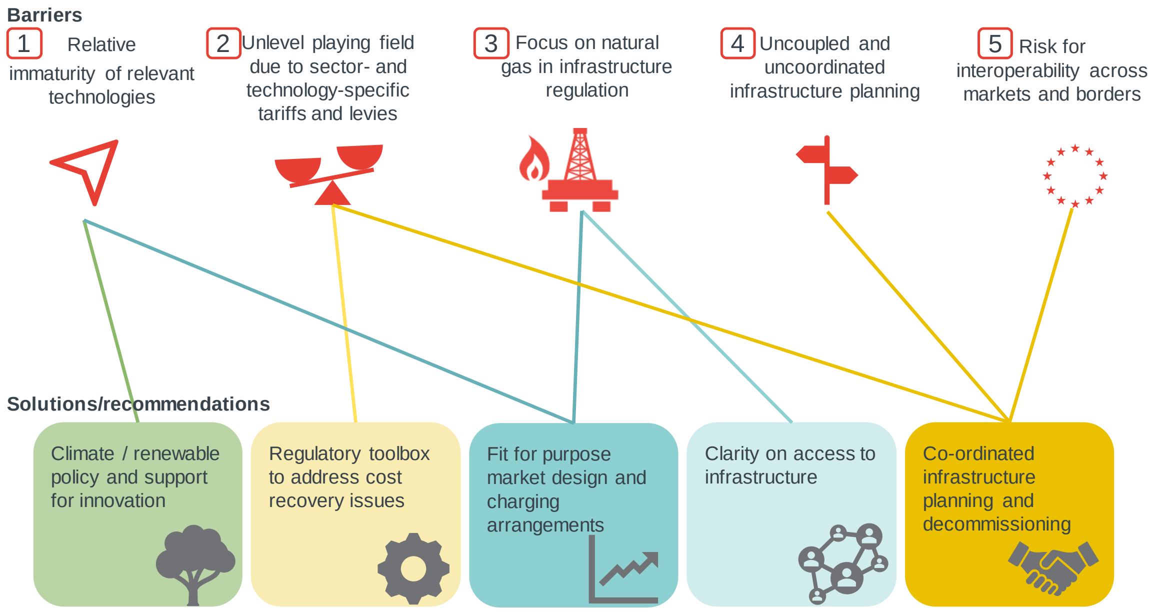
- **A number of changes to market design and charging arrangements to make them more fit-for-purpose in the face of the expected changes in the sector:** these would address issues stemming both from the relative immaturity of relevant technologies, and the historic focus on natural gas in infrastructure regulation;

- **The provision of increased clarity on access to infrastructure** would also aim to overcome barriers and gaps stemming from the historic focus on natural gas in infrastructure regulation; and

- **The facilitation of co-ordinated infrastructure planning and decommissioning**, which would be expected to help achieve a level playing field across technologies, avoid the risks of uncoupled and uncoordinated infrastructure planning, as well as the risks related to interoperability across markets and borders.

Figure 24 below provides an overview of how the categories of solutions described above map to the high-level categories of barriers.

Figure 24 Overview of barrier categories and solution categories



Source: Frontier Economics

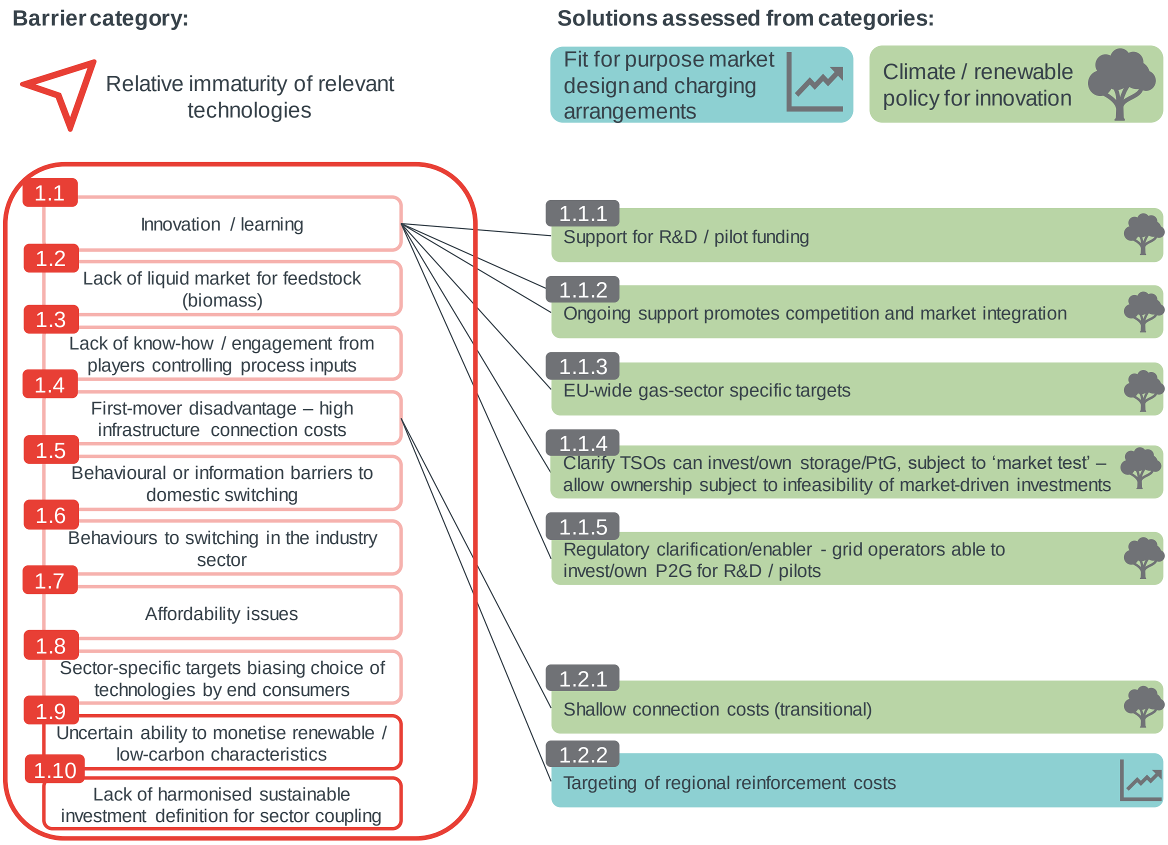
In the following sub-sections, we describe the individual barriers identified and solutions assessed in more detail.

5.1 Relative immaturity of sector coupling and renewable and low-carbon gases technologies

The first category of barriers relates to the immaturity of the relevant technologies. By construction, most of these barriers are expected to be problematic in the transition period. In the steady state, i.e. as we approach 2050, a number of technologies are expected to have reached maturity and may have overcome some of the barriers[11].

Figure 25 gives an overview of the barriers identified in this category, as well as the potential solutions assessed for the short-listed barriers.

Figure 25 Overview of short and long list barriers in category 1 and the solutions assessed for short list barriers



Source: Frontier Economics
Note: Barriers outlined light red belong to the transition, barriers outlined red are steady state barriers.

Transition - Producer level

The following issues have been identified which may be reducing appetite from project developers in the transition phase.

5.1.1 Lack of internalisation of positive externalities from innovation / learning

The development of immature technologies will benefit not only the developer or investor but also other developers and overall society. Knowledge and learning from innovation will not only benefit the stakeholders undertaking and financing the investment but will spread more widely, i.e. will have a positive externality. This applies at different stages of the technology development process:

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[11] We note that new technologies may arise on an ongoing basis and face transitional issues later than those technologies that are already envisaged to be at play.

- Fundamental research is used to acquire new knowledge of underlying foundations of phenomena and observable facts, without any direct commer cial application or use in view.

- The results of this research need then to be applied to the development of new concepts and processes (in the context of this report, the development of new sector coupling technologies, or new ways of producing renewable and low-carbon gases).

- At the demonstration phase, new technologies are tested in a commercial setting. The objective may be to evaluate how the technology performs or to see how it interacts with the environment or system in which it operates (for example testing hydrogen injection in existing gas infrastructure).

- During the deployment phase, the focus is on large-scale roll-out of a technology and achieving cost reductions as supply chains and expertise develop. Research and development (R&D) may continue during the deployment (and demonstration) phases, for example with the aim of helping to identify incremental improvements to production processes.

As a result of the above, although the costs borne by the developer[12] may be lower than the benefit to society, they are likely to be higher than the benefit the individual developer can retrieve. This may lead to underinvestment in some of these technologies. This is a market failure common to all countries and technologies.

This barrier or gap has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for lack of internalisation of positive externalities from innovation / learning

The direct way of addressing this market failure would be **support for Research and Development (R&D), pilots or demonstration projects** and, potentially, beyond that, **support for further deployment following the demonstration phase** to help achieve potential 'learning-by-doing' benefits (cost reductions driven by increased deployment). Public financial support can help boosting the innovative activity carried out by the market, in instances where there are positive spillovers which are not considered by private investors and where this results in the market under-investing compared to the socially optimal level. Support for R&D, pilots and deployment of low-carbon gases comes at a cost in the near term but can help to deliver reduced costs associated with decarbonisation over the longer-term.

- In deciding on an approach to technology support, there will be a trade-off to be evaluated between ensuring that funding is directed towards technologies that have greater promise (for example, in terms of future cost and ability to be deployed at scale) and avoiding closing off other technology options for the future by denying them support or otherwise discriminating against them. Robust policy design can mitigate the risk that too much support is granted to technologies with limited promise.
- Support could come from individual Member State budgets, subject to State aid rules. Support at Member State level could help promote a diversity of options, since it is possible that certain technologies may be more relevant in some Member States than in others. .

[12] The study did not develop own cost analysis. Existing evidence in this area was reviewed as part of the work for Objectives 1 and 2, and is presented in the Intermediate Report.

- In addition, support could come from EU-wide funding mechanisms (such as the Innovation Fund under the EU ETS). Support at EU level could be desirable to the extent Member States have incentives to free-ride on the efforts of others. This may be the case where the benefits of technology development extend beyond the Member State (to other regions in the EU) and where individual Member States may find it too risky to invest by themselves or where their finances are significantly constrained.

Another intervention to accompany the development of innovative sector coupling and low-carbon and renewable gases technologies is **ongoing support**. How ongoing support is granted to power-to-gas projects is an important consideration. The benefits of ongoing support to immature technologies will be enhanced if **support is granted in ways that promote competition and market integration**. This is particularly the case where support is not through central EU funding mechanisms, but instead granted by individual Member States.

- EU rules for support for renewable electricity[13] promote competitive tendering of support, technology-neutrality (striking a balance between the benefits of competition and the need to promote emerging technologies) and cross-border participation in support schemes. Similar rules for gases would help to promote the uptake of lower-cost solutions. Potential risks to investors from increased competition in the allocation of support can be mitigated if the award of financial support happens at a sufficiently early stage of project development
- EU rules also promote balancing responsibility and market integration of renewable electricity installations. Provided that players can manage the risks associated with balancing responsibility (for example through short-term trading), this represents an efficient allocation of risk, as parties would be incentivised to reduce the costs they impose on the wider system. Similar rules for gases would help to reduce the costs of operating the system, though the benefits may be lower compared to electricity, given that flexibility within the gas system helps to limit balancing costs (due to the ability to vary linepack, the amount of gas stored within the system). The corollary of this, on the other hand, is that the risks to market participants of balance responsibility would be lower in gas than in electricity. Participants are typically only required to balance their portfolios over daily timescales, making the presence of very short-term markets (e.g. hourly) less important. Clear rules around congestion management for (gas) injection (see section 5.3.4) may also be a pre-requisite for balance responsibility.
- Exemptions from competitive tendering and full market integration are possible for small installations. Similar rules could be adopted for support for renewable and low-carbon gas technologies.

Several stakeholders have also called for **(binding) EU-wide (gas-sector specific) targets, for renewable and/or low-carbon gases**. While such targets would not directly address the innovation market failure, they could be a driver for policies (such as financial support) that might address it. Hence, we assess this potential solution under the 'innovation' barrier. In our assessment, we consider that, assuming the

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[13] Including the Commission's Guidelines on State aid for environmental protection and energy ('EEAG 2014')[13], Directive 2018/2001 on the promotion of the use of energy from renewable sources ('RED II')[13] and the revised Electricity Regulation (Regulation 2019/943 on the internal market for electricity, OJ L 158, 14.6.2019, p. 54–124).

existing governance and climate policy framework is strong enough to spur Member States towards meeting long-term climate and renewable energy targets, then gas sector-specific targets risk simply increase the costs of meeting the broader targets[14] by reducing EU and Member State flexibility. A sector-specific target is only likely to be efficient if:

- it addresses a barrier to political engagement that can otherwise not be solved through existing (or potential reforms to) Energy Union governance arrangements; or
- there were to be a specific political objective to further the development of renewable and low-carbon gases.

The solutions above address issues related to financing but not necessarily the question of who is best-placed to carry out the required innovative activity. In that respect, several stakeholders have called for grid operators being able to own, operate or otherwise participate in power-to-gas projects. This could be a signal that stakeholders do not perceive that there is sufficient clarity on whether network operators would be able to operate or participate in research-stage or pilot power-to-gas projects, or that they believe exemptions to the usual EU rules on 'unbundling' are justified for such projects. We have assessed the relevance of **allowing network operator ownership (or involvement in) research-stage or pilot power-to-gas projects in specific circumstances**. By 'pilot', we refer to demonstration-stage power-to-gas projects with the primary objective of studying the impacts of power-to-gas facilities on the electricity and gas systems. Such projects are likely to be limited in size and number.

This may necessitate clarifying EU legislation in relation to unbundling rules but would not be expected to reopen the principles of unbundling (as network operator involvement would be tied to specific circumstances and types of projects). To strike the right balance in this regard, we would recommend that the following considerations should be taken into account:

- The involvement of network operators in such projects may be particularly important to the extent that understanding technical impacts on the networks themselves (for example, in terms of gas quality or in terms of the potential system cost savings delivered) may be an important subject of study.
- Such 'experimental' projects would not be expected to have a commercial purpose. Assuming projects remain limited in size, it may be difficult (or disproportionate) to devise and agree on commercial arrangements that would allow other parties to own and operate power-to-gas facilities while allowing network operators (potentially both on the electricity and gas side) to keep a central role in the technical feasibility studies. Addressing this co-ordination barrier could (in conjunction with ensuring sufficient financing of innovative activity) therefore also help to ensure an optimal level of innovation takes place.
- Ownership could, in these special circumstances be allowed by either electricity or gas network operators. However, given power-to-gas projects would have effects on both systems, an affected network operator should have the opportunity to provide feedback to the operator leading the project on its design (and location), before it goes ahead.

[14] This will be the case irrespective of how the sector-specific target is defined (e.g. in terms of production or in terms of consumption).

- It would be important to ensure that the projects remain targeted in scope (i.e. limited to research and pilot projects) and that solutions are found (such as time limits for TSO ownership[15]) to avoid potential longer-term negative effects on the functioning of competitive and market-based investments.
- Review and approval of such projects by the NRA would play an important role in minimising the potential negative consequences on commercial investment activity and maximising the potential benefits to the wider market.
- It would also be important to ensure that any learning from such projects (funded publicly or through regulated network tariffs) is made available to market participants. This would further contribute to reducing the risk that market participants are deterred from engaging in the market by the presence of regulated competitors.

We consider the relevance of **ownership of power-to-gas projects by grid operators may, even in the steady state,** contribute to addressing potential co-ordination barriers preventing potential investors from fully capturing wider system benefits in addition to commercial benefits:

- As explained above (section 4.1.2) investment will reach efficient levels if investors can monetise not just commercial benefits, but also any benefits they bring for the wider system (and which may relate to regulated revenues, e.g. for the provision of certain ancillary and system services).
- It may in principle be possible to design arrangements (such as locational network signals or complete markets for flexibility) that allow investors to capture such wider benefits. Such arrangements may even already exist in many jurisdictions (for example, market-based re-dispatch in electricity or differential network charging based on location).
- However, the task of ensuring a fully comprehensive and efficient set of locational signals across both electricity and gas networks to ensure market-driven investment may (depending on the likely scale of investment required) be complicated.
- While there is therefore a risk of 'policy failure' in any administrative assessment of the extent to which power-to-gas projects may bring system benefits, there is equally a risk that locational signals are not perfectly designed and that this may preclude certain power-to-gas investments that would be desirable from a system perspective.
- Ownership of power-to-gas facilities may therefore allow investment in power-to-gas facilities that the market may not deliver (if such projects are economically desirable but would not go ahead on a merchant basis).

However, ownership of power-to-gas projects by grid operators in the steady state would not be without risks and it is important these are effectively managed:

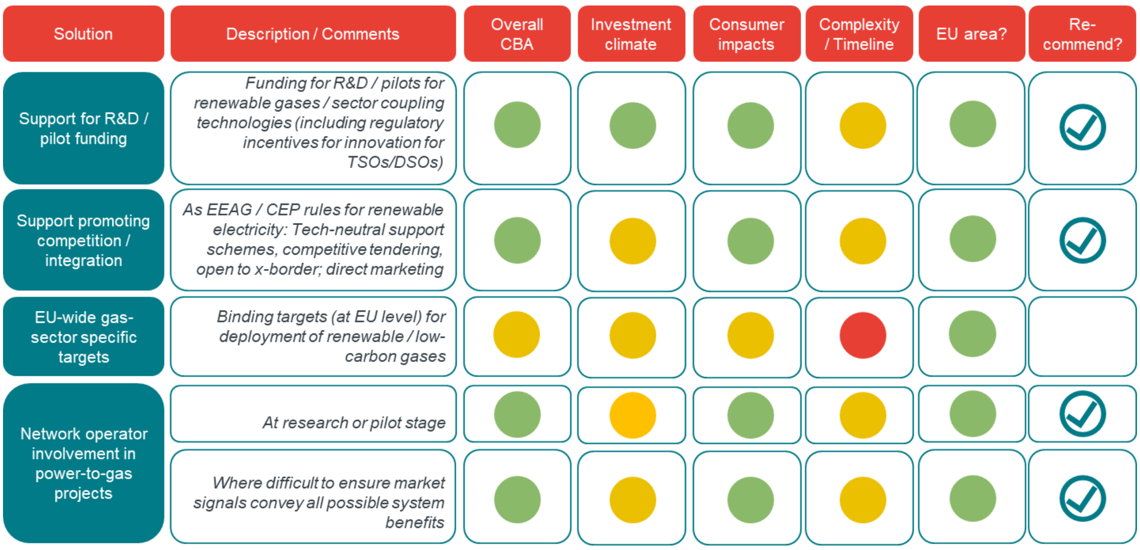
- First, merely allowing network operators to own or operate power-to-gas facilities may not be sufficient to ensure efficient levels of investment: network operators would need to face incentives (see sections 5.4.2 and 5.4.3) to achieve cost savings that drive them to carry out such investments.
- Depending on network operators' incentives, the location proposed for any project may not be optimised across both electricity and gas systems. Co-ordination and communication between electricity and gas network operators

[15] We note that, by construction, the expectation would be that in most cases the technology used in pilot projects would become obsolete.

(see section 5.4.3) would be important to ensure benefits are maximised. This may need to be incentivised through regulatory arrangements.
- To result in efficient levels of investment, projects would need to be able to capture commercial benefits as well as system benefits. Given this, there may be concerns from market players that network operators may distort or even dominate the power-to-gas sector entirely, deterring market based investment. As above for investment in pilot projects, NRAs may play an important role in ensuring that network operators are only allowed to carry out investments only in situations in which pilot projects are desirable and where changes to market design are not feasible or proportionate and in which market players cannot be attracted to invest (for example by applying a 'market test').

Figure 26 below summarises our assessment of the options set out above. In summary, we would recommend taking forward the following solutions (for more detailed assessment and policy design work):
- support R&D, pilots or demonstration projects and, potentially, beyond that, support for further deployment following the demonstration phase;
- ensuring that any ongoing support is granted in ways that promote competition and market integration;
- allowing network operator ownership (or involvement in) research-stage or pilot power-to-gas projects but only in specific circumstances; and
- allowing network operator ownership of power-to-gas only in situations where it is difficult (or disproportionate) to ensure market signals convey all possible system benefits (e.g. the benefits of the specific location of a facility) well enough.

Figure 26 Assessment of potential solutions to address lack of internalisation of positive externalities from innovation and learning



Source: See Appendix C for further detail on the assessment.

5.1.2 Lack of liquid market for feedstock (biomass)

A number of renewable and low-carbon gases technologies rely on biomass inputs. Biomass is typically produced in decentral locations such as farms. Sources of biomass may not be part of a liquid market, where inputs can be traded at minimal transaction costs. Therefore, developers run the risk of default of input source, as in an illiquid market it may be difficult to find another source of the input. This issue has been raised in France[16].

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.1.3 Lack of know-how / engagement from players controlling process inputs

Some players have historically only engaged as energy consumers but hold the potential input for the production of renewable energy, such as biomass, CO_2, wind or solar potential. Lack of know-how or engagement from the stakeholders hinder the effective use of inputs and the effective realisation of potentials. This barrier has been raised in France.

Further, this barrier is a consequence of the one above, as an illiquid market will hamper:

- access to banking funds; and
- access to equity, especially for players like biomass farmers that have historically not been very engaged in the energy market.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.1.4 First mover disadvantage - high infrastructure connection costs including 'deep' costs

Developers of renewable and low-carbon gases and sector coupling technologies typically face connection costs, charged by network operators to establish a physical connection between the site and the existing gas network.

There is no harmonised practice for connection charging in gas across the EU, but rather a range of practices. Schematically, these practices are typically articulated around a sequence of considerations:

- First, gross connection costs are calculated. These are costs that would need to be incurred by the infrastructure operator in order to connect and accommodate load served to the site and/or production injected from the site. These costs can be calculated as only the costs of those assets required to establish the physical connection from the site to the existing grid – hereafter 'shallow' costs. Gross connection costs may also be calculated to include any other incremental, often labelled 'reinforcement' costs to be incurred on the existing infrastructure to accommodate the presence of the site on an ongoing basis. In those instances gross connection costs are said to be 'deep'.

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[16] As mentioned above in Figure 26 Assessment of potential solutions to address lack of internalisation of positive externalities from innovation and learning we give non-exhaustive country examples were a barrier has been raised in interviews with country stakeholders. This, however, does not necessarily mean that this barrier does or will not occur in other countries.

- Second, the share of gross connection costs to be borne by the site is set. In several Member States, an "economic test" is applied whereby the proportion of the resulting investment costs to charge to the site will reflect gross connection costs net of expected future tariff revenue from the site. This test may be performed on a site-by-site basis. In other instances, a fixed share of gross connection costs may be applied standardly across sites.

It may be the case that reinforcements are triggered by one site and then allow accommodating additional sites (e.g. where grid capacity is incremented). Where gross connection costs include deep costs, and where sites are required to bear a non-null share of gross connection costs, then there is a risk that the first connecting site will bear the majority of these costs, even if then further sites go on to connect. This can deter the first move from happening.

The optimal configuration of reinforcement will also often depend on volume and location of connections in the medium term. It will therefore not be efficient to deal with an incremental connection request with piecemeal reinforcement. However it would equally not be efficient for the first connecting site to bear the full cost of reinforcements designed to be optimal given expected further connections.

This barrier materialises in those Member States where a methodology exists today to set connection costs for low-carbon and renewable gases sites. In those countries where no such methodology exists, lack of clarity around the connection charging approach to be applied in the future may also be an issue (it would leave project developers hypothetising around costs to be borne for future projects, undermining confidence in business plans).

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for first mover disadvantage high infrastructure connection costs including 'deep' costs

By construction, addressing this barrier would require amending the approach to determining connection costs to be borne by project developers, with a view to reducing (or even eliminating) the first mover disadvantage, compared to subsequent connections. **There is a spectrum of potential solutions to achieve this. For instance, the share of gross connection costs to be borne by the site may be set by taking into account:**

- expected tariff income from a group of connections (as opposed to a single connection); or
- expected tariff income from projected future connections in the same area (as opposed to focussing only on a single connection)

A a result, connections might be made if:

- tariff income exceeds a certain percentage (not necessarily 100%) of reinforcement costs;
- tariff income from a group of connections (as opposed to a single connection) exceeds reinforcement costs; or
- expected tariff income (from projected future connections in the same area) exceeds reinforcement costs (as opposed to focussing only on a single connection).

Each of the above options would result in the first connecting site in a given area having to bear less than 100% of the reinforcement costs it might generate, thereby reducing (or even eliminating) the first mover disadvantage, compared to subsequent connections.

At the same time, they all still include locational signals (to varying degrees) – at the level corresponding to the geographical reach of the group of connections taken into account in the calculations. Overall, therefore, such options have the potential to encourage the development of low-carbon and renewable gases while minimising the risk of incentivising uptake of expensive connections.

There may however be some complexities:

- There may still be a question as to the degree to which reinforcement costs specific to a particular connection should be socialised or targeted to the individual connection in question.
- Some models may not guarantee that infrastructure operators recover their expenditure. Outstanding costs would be expected to be socialised within allowed revenue, with a distortion in the distribution of costs amongst network users.
- Models based on projections of potential gas connections in a given region could end up becoming a 'self-fulfilling prophecy' (since, other things equal, charges will tend to be lower in regions with higher estimated connections). This may lead to inefficiency if alternative projections might have led to more connections taking place in regions with lower reinforcement costs.

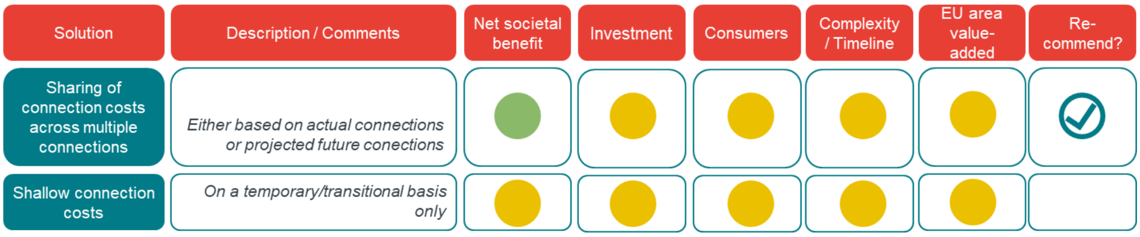
While **considering only shallow costs when assessing gross connection costs** (potentially on a transitional basis) would also address the first-mover disadvantage barrier it may not be the most appropriate solution. The main risk is that it would encourage developers to connect in locations with high reinforcement requirements, increasing the overall costs associated with decarbonisation.

Regardless of the precise approach taken, it will be important to ensure that decisions on connection charging and handling connection requests are co-ordinated across energy carriers (to avoid potentially creating new distortions between them) and levels of the network (this is discussed further below in sections 5.4.2 and 5.4.3). For example, if electricity connection charges reflected 'deep' costs but gas connection charges reflected 'shallow' gross connection costs, power-to-gas facilities might have incentives to connect predominantly to areas where electricity connection charges were cheap, but which could require significant gas network reinforcement costs.

In addition, to the extent that cross-border participation in support schemes becomes a reality (see section 5.1.1 above), a degree of regional co-ordination on connection charging approaches may also be appropriate to ensure efficiency.

Figure 27 below summarises our assessment of the options set out above. In summary, we would recommend taking forward connection charging approaches that avoid the first-mover disadvantage while still preserving locational signals (for more detailed assessment and policy design work).

Figure 27 Assessment of potential solutions to address a possible 'first mover disadvantage' with deep connection charging



Source: See Appendix C for further detail on the assessment.

Transition - Consumer level

The achievement of the transition may also face barriers on the energy consumers' side.

5.1.5 Behavioural or informational barriers to acceptance/switching for household consumers

Household consumers' investment and consumption preferences and decisions are based on costs and softer factors such as safety standards and sustainability characteristics. The following issues are relevant in several of the countries reviewed:

- Regarding cost information, it is key that consumers are able to correctly compare the costs of different technology options. For instance, there is an information barrier if the principles / structure / cost components making up the bill of the different energy carriers are not comparable.
- Softer technology characteristics such as perception of safety and sustainability may have the potential to increase consumers' readiness to accept and switch to climate neutral technologies. However, this information is often only incompletely available for consumers. One example is that, in some countries, energy in gaseous form, especially hydrogen, is perceived as more dangerous than other energy carriers. However, this may be due to a relative lack of awareness of ensured safety levels. Another example is that consumers might make a more conscious decision regarding which gases to use if they were more aware of the different climate implications of different gases.

Further, even when all relevant information is available, behavioural barriers may arise that prevent switching decisions for cost optimisation.

- Household consumers will likely not constantly incur search costs looking for information to decide whether to switch to a technology or not. Typically, consumers will only look for alternatives to currently-installed technology at the end of its lifetime, for instance when a heating appliance needs to be renewed. However, sometimes it may be important for society that consumers make a switch away from a technology before the end of the lifetime of existing appliances, for example to avoid harmful emissions. This may be the case for instance when switching from a less efficient heating appliance like a normal heating boiler to a more efficient condensing boiler or switching from a natural gas supplier to a renewable and low-carbon gas supplier. However, consumers may need to be pointed to these advantages, as they will not necessarily themselves look for them.
- Consumers may abstain from switching even when it is economically beneficial because they prefer to stick to what they currently have and what they already know. Another reason why households may stick with current technologies is, that they may weigh the short run costs they have from switching to the new technology more than the long run benefits.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.1.6 Barriers to switching in the industry sector

For industrial consumers the barriers to switching may be different than for households. Barriers may be less behavioural in nature to the extent that industrial sites will be managed with a view to optimising costs on an ongoing basis, and will not shy away from incuring time/information search costs in order to optimise the technology portfolio even within the lifetime of current installations.

However, technical barriers may arise. While the energy transition is a continuous development towards the climate targets in 2050, for industrial players the decision to switch to renewable or low-carbon gases may be a binary, i.e. all or nothing, decision. This is for example the case if an industry site decides to switch from natural gas as an energy source to renewable or low-carbon hydrogen. One barrier may be the perceived risk that the necessary amount of renewable or low-carbon gas will not be available. This scarcity risk may arise due to the mere volume required for industrial processes. This barrier has been raised in Germany.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.1.7 Affordability issues

Some technologies are expensive for (certain groups of) consumers – either because of their upfront investment costs or their ongoing costs – which may be a barrier to reaching efficient levels of their deployment.

Regulation may exacerbate affordability issues. For example, in 2010, in Baden-Würtemberg, Germany, the regional government introduced an obligation on homeowners to source 15% of heat requirements from renewable sources such as solar thermal energy, heat pumps or biofuels, whenever replacing existing heating equipment. Homes heated by gas could fulfil the criteria by using a certain share of renewable gas. However, that share was given credit only if combined with a micro-CHP facility rather than for example the possibility to use a cheaper gas condensing boiler. Many homeowners, perceiving high up-front costs micro-CHP, switched to new (less expensive) conventional boilers just before the law was introduced. Others have not switched the heater since the law became effective. As a result, the number rate of heating equipment replacements decreased significantly since the introduction of the law. Thus, the policy fell short in its ambition to boost renewable heating.

Further, there is a first-mover disadvantage for consumers in the transition as cost reduction with increasing scale of the production or network coverage can be expected. Therefore, it may be difficult to find early adopters of technologies. For instance,

- the Bulgarian government aims at 30% of households having access to natural gas by 2020[17] to decrease the high share of coal and solid fuels use (34% compared to a 16% EU average). However, it is down to prospective retail customers to pay for equipment and connection costs from the nearest gas point, which – especially in view of the low network density[18] - is a financial barrier. Grants are in place to help households pay for gas connection and some equipment costs[19], but take up of the programme remains low.
- the roll out of hydrogen may be an option in the future. Incremental roll out by region affects consumers differently depending on the geography and time. Early in the transition, hydrogen will cost more than later on, once technology matures. These differences in costs will result in both regional and temporal inequalities in the costs faced by consumers.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.1.8 Sector- and technology-specific targets biasing choice of technologies by end consumers

Policies may bias consumers' choice between technologies, if they are designed in a way that favours some technologies. An example of a technology specific policy with potentially strong impact on end-user choices is renewable and low-carbon gas as a factor in building codes. Currently building codes often treat electricity-based heating devices as climate-neutral, even when electricity is generated from fossil sources. Conversely, gas appliances like gas boilers are not regarded as climate neutral, even if renewable and low-carbon gas is used[20].

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

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[17] Ministry of Economy, Energy and Tourism, 2011, The Energy Strategy of the Republic of Bulgaria till 2020, page 27. Available at https://www.me.government.bg/files/useruploads/files/epsp/23_energy_strategy2020%D0%95ng_.pdf

[18] EWRC, 2018, Annual Report to the European Commission, page 47. Available at https://www.ceer.eu/documents/104400/6319351/C18_NR_Bulgaria-EN.pdf/62db8c49-4510-b6f0-224c-03794b1bb304

[19] Through the programme DESIREE Gas, co-funded by the EU. See https://desireegas.bg/en/about-the-project

[20] Another example is renewable gases as an option to achieve car fleet targets: Fleet targets (Directive 2009/33/EC) incentivise efforts to tackle carbon emissions in the transport sector. However, as it stands, they adopt only a "tank-to-wheel" perspective and fail to examine the whole value chain from "well-to-wheel". In other words, fleet targets may fail to account for the differing carbon intensities of the fuels used, triggering the following regulatory failure: On the one hand, an electric vehicle counts as climate-neutral within a fleet, even if the electricity was generated from 100% coal and generated CO_2 emissions. On the other hand, a car with a gas combustion engine driven by 100% renewable gas, e.g. synthetic methane, counts as one emitting CO_2 emissions of natural gas, despite the fact the CO_2 emitted from the engine was extracted from the environment beforehand to generate a climate-neutral gas.

Steady state – producer level

While most of the barriers in this group are of transitional nature, a barrier has been identified that may persist even after technologies have reached scale and maturity.

5.1.9 UNCERTAIN ABILITY TO MONETISE RENEWABLE / LOW-CARBON CHARACTERISTICS

Producers may face uncertainty on the extent to which they will be able to monetise and trade renewable and low carbon characteristics in the long run. This would be expected to impede their willingness to incur investment costs. The barrier persists even after

- **on the production side,** the technology is produced at a large scale and cost reductions have been realised.
- **on the consumption side,** the technology is deployed and consumers are willing to pay for the renewable and low-carbon characteristic.

The uncertainty to monetise and trade in the steady state context may stem from **technical factors** as the differences in technical standards which may hamper the ability to trade across regions; and **policy factors** such as the following.

To seek a higher price for renewable or low-carbon gases, their producers need to be able to certify the renewable (or low-carbon) characteristic of the gas produced. Guaratees of Origin (GoO) are required to enable them to do so.

The revised Renewable Energy Directive (RED II) reflects some crucial points. Recital 55 reflects the need for GoO[21]. Also recital 59 of the RED II reflects that GoO should not only be in place for renewable electricity but also for other energy forms, such as hydrogen produced from renewable electricity[22].

However, RED II is seen to leave scope for interpretation. While it makes important suggestions, there is the perceived risk that the way in which Member States will implement GoO schemes will not always adequately reflect the contribution of various technologies to environmental goals. For instance, for stakeholders producing renewable gas via electrolysis, it is important whether renewable electricity from the grid can count as being renewable or not.

Some stakeholders believe that Article 27, paragraph 3 of RED II should in principle allow this provided certain conditions are met:

> *"Electricity that has been taken from the grid may be counted as fully renewable provided that it is produced exclusively from renewable sources and the renewable*

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[21] "Guarantees of origin issued for the purposes of this Directive have the sole function of showing to a final customer that a given share or quantity of energy was produced from renewable sources. A guarantee of origin can be transferred, independently of the energy to which it relates, from one holder to another. However, with a view to ensuring that a unit of renewable energy is disclosed to a customer only once, double counting and double disclosure of guarantees of origin should be avoided."

[22] "Guarantees of Origin currently in place for renewable electricity should be extended to cover renewable gas. Extending the guarantees of origin system to energy from non-renewable sources should be an option for Member States. This would provide a consistent means of proving to final customers the origin of renewable gases such as biomethane and would facilitate greater cross-border trade in such gases. It would also enable the creation of guarantees of origin for other renewable gases such as hydrogen."

properties and other appropriate criteria have been demonstrated, ensuring that the renewable properties of that electricity are claimed only once and only in one end-use sector."

However, many stakeholders face uncertainties regarding:

- the ways in which the renewable character of electricity consumed may be demonstrated, for example whether a Power Purchasing Agreement between a renewable electricity generation facility and an electrolyser would be sufficient (as opposed toa direct connection through an exclusive power cable to allow the electrolyser) to count all its power as renewable; and
- the circumstances under which gases can count as being renewable. There are some doubts as to whether the renewable property of gases can only be claimed when used outside of transport since Article 27 refers to transport only.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.1.10 ABSENCE OF A HARMONIZED DEFINITION OF SUSTAINABLE INVESTMENT AND THE ROLE OF SECTOR COUPLING THEREIN

There is a lack of a harmonized understanding of what sustainable investments are. This may hinder the flow of capital to projects that serve decarbonisation objectives. A classification system for sustainable investments is currently being built by the EU institutions and a dedicated technical expert group. Sector coupling technologies should be considered and appropriately reflected in the classification system for their benefits to climate change mitigation and to environmental objectives. For conceptual certainty, EU-level, national and corporate policies should also clarify the relevance of sector coupling – one publicly accessible effort is the revision of the EIB's energy lending criteria[23], which already features references to sector coupling. As noted above, there should be clarity on the relevant technologies and the statement of their benefits to decarbonisation.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.2 UNLEVEL PLAYING FIELD DUE TO SECTOR- AND TECHNOLOGY-SPECIFIC TARIFFS AND LEVIES

The second group of barriers and gaps encompasses issues arising from technology- and sector-specific regulation that may become less fit-for-purpose in the emerging sector-coupled energy market.

Barriers in this category are expected to persist in the steady state even after transitional issues have been resolved. However, the anticipation of the barriers in the steady state may be a barrier for market players to implement the transition.

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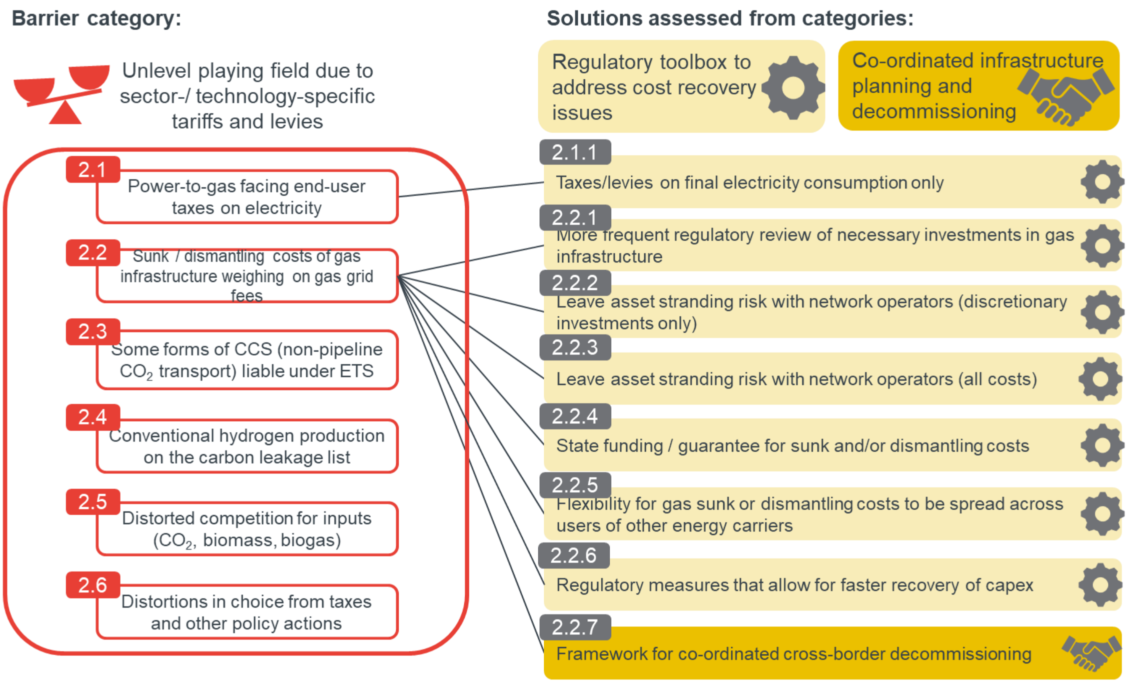
23 https://www.eib.org/en/about/partners/cso/consultations/item/public-consultation-on-eibs-energy-lending-policy.htm

Figure 28 gives an overview of the barriers identified in this category, as well as the potential solutions assessed for the short-listed barriers.

Figure 28 Overview of short and long list barriers in category 2 and the solutions assessed for short list barriers



Source: Frontier Economics
Note: Barriers outlined light red belong to the transition, barriers outlined red are steady state barriers.

Steady state

5.2.1 POWER-TO-GAS FACING END-USER TAXES ON ELECTRICITY

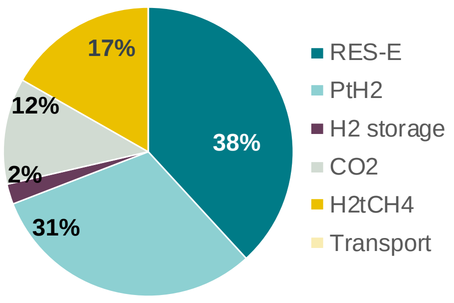
At present, taxes and levies, i.e. non-generation and non-grid components, constitute 2/3 of the average EU retail electricity bill.[24]

Electricity costs are the main cost driver for power-to-methane, amounting to almost 40% for synthetic methane (see Figure 29). The share is even higher for synthetic hydrogen as power is here the only cost-relevant ingredient.

Figure 29 Electricity is the main cost driver for power-to-methane

[24] Cf. Eurelectric (2017).

Where current regulations dictate that power-to-gas facilities are treated as end consumers, electricity costs include end-user taxes and levies, further increasing costs for power-to-gas facilities (this is the case in many countries for instance Germany, the Netherlands and Spain).



Source: Agora and Frontier Economics (2018)[25]

A concern arises where these taxes and levies are not 'cost-reflective' and intended to drive a specific behaviour (as is the case, for example, with carbon taxes), but instead are intended to recover costs, such as those of supporting RES. As with any cost-recovery charges, there is a risk that taxes and levies distort the efficiency of the system. In addition, there is a risk that the recovery of taxes and levies from power-to-gas curbs investment, and therefore precludes the system from benefiting from this technology (e.g. via reduced electricity network expansion requirements, or reduced curtailment of RES). In particular, there is a risk of distortion of the level playing field between synthetic gases[26] and other renewable gases as biomethane, as the latter's input costs are not significantly increased by end-consumer taxes and levies.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for power-to-gas facing end-user taxes on electricity

A solution to this barrier would be to ensure that **only final energy consumption in electricity faces taxes and levies**. Energy storage or power-to-gas facilities would therefore not face taxes and levies on electricity inputs.

This would be expected to help to reduce the costs of decarbonisation, by ensuring that renewable and low-carbon gas production technology choices are driven by the underlying costs to society (as opposed to being distorted by cost recovery taxes and levies). This will become even more relevant as any financial support for renewable and low-carbon gases is phased out. However, in the short run, (final) electricity consumers might pay more if levies previously paid by existing power-to-gas facilities are redistributed.

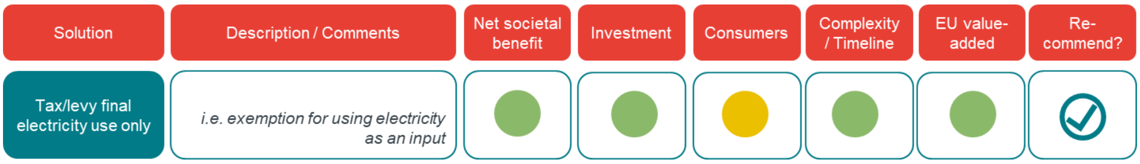
We note that another potential solution, suggested by some stakeholders, would be to remove all taxes and levies (those that are not intended to be 'cost-reflective', such as carbon taxes, but instead are intended to recover costs, such as those of supporting RES) from energy consumption. The burden of such taxes and levies could instead be shifted to general taxation. In theory, using the full flexibility of the tax system to recover policy-related costs could lead to the least distortive outcome from an economy-

[25] All cost shares (in %) and absolute figures (ct/kWh) are rounded and associated with the following scenario: North and Baltic Sea, reference scenario 2030, Wind-offshore, CO_2 from DAC, 6% weighted average cost of capital, no taxes and levies.
[26] Similar arguments may apply to hydrogen produced by methane reforming (in combination with CCS).

wide perspective. However, given that the sums involved would be significant, it is uncertain in practice whether taxing energy use could be avoided completely.

Figure 30 below summarises our assessment of the option set out above. In summary, we would recommend more detailed assessment and policy design work into ways of ensuring that only final electricity consumption faces (cost-recovery) taxes and levies.

Figure 30 Assessment of potential solution to address power-to-gas facing end-user taxes on electricity



Source: Frontier Economics

5.2.2 SUNK COSTS AND DISMANTLING COSTS OF GAS INFRASTRUCTURE WEIGHING ON GAS GRID FEES

As the initial analysis (see section 3.3) showed, total final energy demand is expected to reduce significantly through energy efficiency measures. Fossil fuels will phase out with an uncertain, minor role of natural gas. Since natural gas demand is expected to decrease, the (average) utilisation level of the transmission grid, LNG import terminals and import pipelines is also likely to decline. This decline may be partly mitigated by the extent to which infrastructure can be converted to using increasing shares of renewable or low-carbon gases.

Against this background there are two main risks:

- First, the risk, on a *forward-looking basis*, of (inefficient) over-investment (or of keeping existing infrastructure online longer than would be efficient).
- Second, the risk that, with declining volumes of gas transported, unit tariffs would need to increase to ensure recovery of sunk costs (i.e. those costs associated with legacy investments that have been irreversibly incurred and which do not vary with consumption).

The second risk above might in the medium and long term undermine the affordability and competitiveness of gas. It may incentivise switching away from gas to other energy carriers, to an extent that might not be cost effective from a societal perspective (because the increase in tariffs would not be cost reflective).

Additionally, the geographical distribution of low-carbon and renewable gases production may differ from that of natural gas, leading to high dismantling costs in the future. These costs may be socialised via infrastructure tariffs, conditional on the relevant NRA allowing them as part of the operator's recoverable cost base (e.g. assuming that the NRA finds these costs to correspond to those of an efficient operator). As such, dismantling costs will be borne by low-carbon and renewable gases consumers because of the common energy carrier, and even though the infrastructure being dismantled was not built for them. The corresponding increase in tariffs would not be cost-reflective.

We note that this can be a very relevant situation in the context of power-to-gas investment. The case for a continued role of the gas sector in a decarbonising economy stems in large part from the ability to re-use existing gas infrastructure. However, private investors may only engage in related activity if they face just the incremental cost of their infrastructure usage. If they are burdened with extensive legacy cost of an otherwise underutilised gas infrastructure, they may not engage in new and efficient investments in the first place.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees

To the extent the issue is related to the risk of prospective over-investment, it may be desirable to introduce measures that allow for **more frequent (regulatory) review of necessary investments in gas infrastructure** in light of demand and production uncertainty. This could take the form of a reduced duration of price control periods or uncertainty / re-opener mechanisms. Such measures are likely to be a 'limited regret' way of reducing costs of prospective investments), by reducing the risk of unnecessary investments being carried out in the first place.

One question is whether network operators might be well-placed to bear the costs themselves, in which case a solution may be to **leave asset stranded risk with network operators**. In principle, network operators bearing this risk could lead to them being more cautious regarding prospective investments, thereby avoiding making investments that could be potentially stranded in the future (i.e. avoiding a potential "moral hazard" problem). Alternatively, they might be more innovative regarding the potential for repurposing infrastructure for a different, more profitable, use. This would only be an appropriate solution, however, for forward-looking investments over which network operators are able to exercise a degree of discretion (that is, investments undertaken on their own initiative), as only in such cases would the network operator be well-placed to manage such risks. That said:

- In practice, a share of investment is likely to be mandated (e.g. out of conformity with ongoing security requirements). Identifying the extent to which investments are discretionary is not a straightforward exercise.
- Network operators are likely to require a higher rate of return if they are required to bear asset stranding risk than is currently the case in the current regulatory framework. This may feed through to higher tariffs, offsetting some of the cost savings from more cautious investment decisions.

Leaving asset stranded risk entirely with network operators would therefore not be expected to be appropriate for the majority of costs. Some share of investment may be viewed as mandatory, and another part may have been agreed jointly with the regulator. For past investments, it would be difficult to identify retrospectively the extent to which this was driven by regulators or public policy goals (such as security of supply), as opposed to by network operators themselves. This is likely to be highly subjective and depend on local circumstances. Depending on the implicit or explicit regulatory contract, placing stranding risk for existing investment on network operators today may constitute a breach of this contract. This has the potential to undermine the investment environment in infrastructure going forward more generally, increasing risk and, in turn, costs of developing new infrastructure.

Other solutions are therefore needed to address the distribution of costs associated with legacy investment (which cannot be reversed) and whatever future investment is still deemed necessary despite the possibility of more frequent regulatory reviews (such as investment required to ensure infrastructure that remains used meets security standards). As explained above, by construction the recovery of these sunk costs will not be reflective of forward-looking costs incurred on the system. Therefore, cost-recovery solutions need to be designed to mitigate the risk of distorting decisions to invest in technologies (at producer or consumer level) relative to the decisions that would have been made based on purely cost-relfective tariffs. In other words, solutions are needed to mitigate the risk that increasing unit tariffs for gases lead to inefficient switching away from gas to other energy carriers.

In order to distribute costs away from gas infrastructure users and gas consumers, the **State could instead guarantee to cover sunk costs, dismantling costs or both**, or a taxpayer fund could be set up to cover such costs. This approach may in certain circumstances lead to the most efficient outcome from society's perspective. This would be the case if it helps minimise distortions in investor or consumer choices (in particular those between different energy carriers) and the resulting welfare losses. Using the full flexibility of the tax system also potentially allows for better management of potential equity concerns (though at the risk of reducing efficiency).

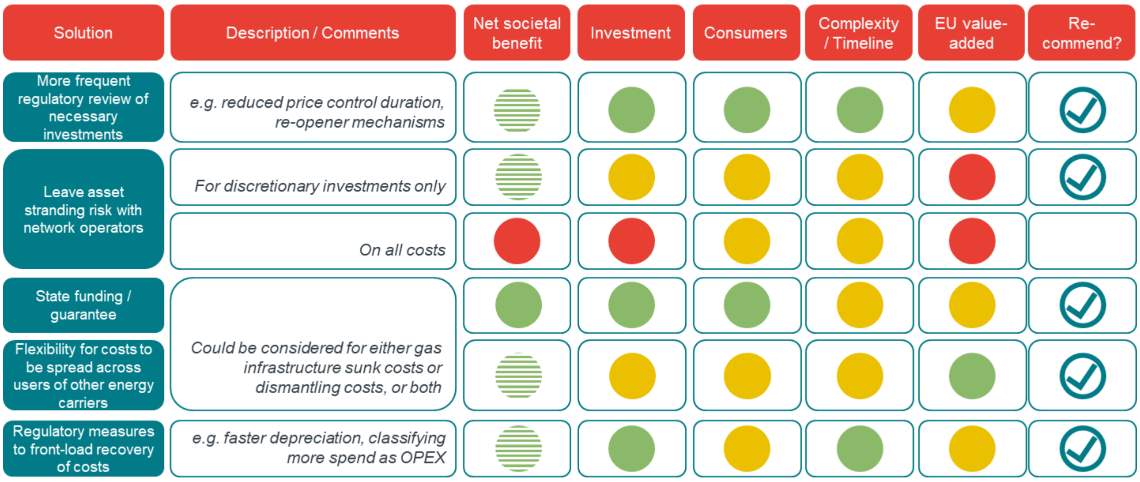
However, we appreciate that taxpayer funding may not be an acceptable option in all Member States. All (or some) costs may still need to be recovered from infrastructure users and energy consumers. To the extent this is the case, **allowing flexibility for gas sunk or dismantling costs to be spread across users of other energy carriers** (such as electricity or heat) could still lead to net benefits to society through avoiding excessively disincentivising gas use compared to other energy carriers. However, realising benefits relies on being able to spread costs without creating new distortions (or worsening existing ones) between energy carriers. In practice, this may be difficult to achieve.

Measures that allow for increased recovery of costs today (vs tomorrow), such as accelerated regulatory depreciation or classifying more spend as OPEX (as opposed to CAPEX) may also be a part of the regulatory toolkit. Their use could help to ensure a closer match between the expected pattern of use of gas infrastructure over time and the recovery of costs by network operators. They may also be positive for investment (by increasing certainty of cost recovery). However, given they entail simply a redistribution of costs from future to present consumers, the benefit in terms of avoiding distortions to choices between energy carriers is unclear. There is a risk that, taken too far, redistribution could result in (current) gas consumption being inefficiently discouraged. To mitigate this risk therefore, careful assessment of the room for redistribution is likely to be needed. It may be helpful to combine such measures with others that seek to shift the burden of sunk cost recovery away from gas consumers to other sources (such as those discussed above).

Figure 31 below summarises our assessment of the options set out above. In summary, we would recommend taking forward the following solutions (for more detailed assessment and policy design work):

- more frequent (regulatory) reviews of whether prospective investments are necessary;
- leaving asset stranded risk with network operators (for forward-looking investments over which network operators exercise a degree of discretion);
- distributing sunk infrastructure costs away from infrastructure users and towards taxpayers instead;
- if redistributing to taxpayers is not feasible (or not acceptable), ensuring an equitable distribution of sunk costs between different energy carriers; and
- allowing for faster recovery of infrastructure expenditure.

Figure 31 Assessment of potential solutions to address sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees



Source: See Appendix C for further detail on the assessment.

5.2.3 Some forms of CCS (non-pipeline CO_2 transport) liable under ETS

CO_2 emissions that are captured and permanently stored do not, under Article 12 of the ETS Directive, result in a liability to surrender allowances, for facilities holding a permit under Directive 2009/31/EC (on geological storage of carbon dioxide)[27]. However, some stakeholders are concerned that stored GHG emissions might still be liable if transported to geological storage via means other than pipeline infrastructure. The basis for such a concern is unclear, but may stem from the definition of 'transport network' under Directive 2009/31/EC, which refers only to pipelines. If the concern were valid, it would result in a distortion between different types of transport infrastructure for CO_2. It might hinder applications of CCS (such as production of low-carbon hydrogen), in particular in circumstances where pipeline transport of GHG emissions is not feasible or cost-effective.[28]

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.2.4 Conventional hydrogen production on the carbon leakage list

Some sectors are exposed to a significant risk that the costs related to climate policies such as the EU ETS make them decide to transfer their business to another country with no (or less stringent) constraints on greenhouse gas emissions. This could lead to an increase in total global emissions and is therefore referred to as carbon leakage[29]. As a response to the risk of carbon leakage, certain sectors receive freely-allocated EU ETS

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[27] OJ L 140, 5.6.2009, p. 114–135.
[28] That said, this barrier may be less relevant to CCS technologies that result in carbon in solid form as a by-product.
[29] Cf. https://ec.europa.eu/clima/sites/clima/files/factsheet_ets_en.pdf

allowances, to safeguard their competitiveness and thereby prevent carbon leakage. The manufacture of industrial gases (which includes hydrogen production) is on the list of eligible sectors[30].

The amount of freely-allocated allowances is calculated based on the direct emissions associated with hydrogen production. This means that hydrogen produced from steam methane reforming (without CCS), for example, would be granted free allowances due to the direct emissons in the production process. However, any production process without direct emissions – such as hydrogen produced from electrolysis – would not[31]. This reduces incentives to switch to alternative, potentially lower emission, production methods[32].

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

DISTORTED COMPETITION FOR INPUTS

There are three examples for distorted competition for inputs:

Subsidies or legal restrictions attached to specific end usage can be a barrier. This may hinder the efficient use of these inputs such as biomass or biogas. If subsidies only apply to specific uses they may steer the system away from using inputs where they are most valuable. For instance a given gas could be eligible for Feed-in-Tariffs when used for electricity generation but not when used in industry processes[33]. If a renewable or low-carbon gas is not used where it is most valuable to the energy system as a whole, this is a barrier to its most efficient use and risks increasing total costs.

Another example of distorted competition arises if **energy production inputs are burdened with different taxes**. The input with lower taxes will have a (potentially unjustified) advantage. In the case of electricity production from gas, electricity producers would prefer the lower taxed gas to save costs. For instance, in Italy only biogas is exempted from taxes for electricity and heat self-production but not biomethane.

Competition for inputs is also distorted if **CO_2-heavy inputs** are **favoured:** In the context of the energy transition it is essential that there is a market for renewable characteristics of inputs (and outputs). This can be threatened where energy policy tends to treat renewable energies and fossil energies alike or even positively

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[30] Cf. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32014D0746&from=EN

[31] Cf. Guidance Document n°9 on the harmonised free allocation methodology for the EU-ETS post 2020 - Sector-specific guidance (2019), p. 169 f. https://ec.europa.eu/clima/sites/clima/files/ets/allowances/docs/p4_gd9_sector_specific_guidance_en.pdf

[32] The extent of the distortion depends on the degree to which installations receiving freely-allocated allowances still bear some costs of purchasing allowances. In principle, the amount of free allocation is based on a benchmark emissions intensity, meaning that those installations less efficient than the benchmark can expect to still bear some costs of purchasing allowances.

[33] For instance, in Slovakia, while there are no targeted support schemes for the production of hydrogen or e-gases from renewable sources, electricity produced from biogas of different origins is eligible for feed-in-tariffs.

discriminate fossil energy carriers. In the Czech Republic for example, coal and coke are exempted from taxes when used for electricity production while other fossil (though less CO2-heavy) fuels like natural gas are not..

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.2.5 DISTORTIONS IN CHOICE FROM TAXES AND OTHER POLICY ACTIONS

Heterogeneous taxes and s**ubsidies or legal restrictions** may also arise as a barrier to effective decion making for end consumers. They may distort end-consumer choice by shifting the preferences away from the most effective and cost-efficient deployment of a given renewable or low-carbon gas.When sector policy reduces the costs of an energy carrier it leads to two types of distortions.

- Firstly, it hinders the level playing field between energy carriers **within a specific sector**. Namely, tax adjustments hinder the most cost-efficient (renewable) energy supply of a given sector, because the choice is influenced by the different tax burdens rather than by the true costs. For instance, in Greece, there is no distinction between fossil and renewable energy carriers, but natural (or synthetic) gas used for transport purposes is untaxed, while (fossil or renewable) diesel and petrol have different taxes.
- Secondly, this distorts the cost-efficient usage of energy carriers and therefore renewable and low-carbon gases **across sectors**. E.g. in France renewable gases get a different tax discount if used as a driving fuel than as a heating fuel. Similarly, in Spain renewable gases are only on the political agenda and receive support in the transport sector.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

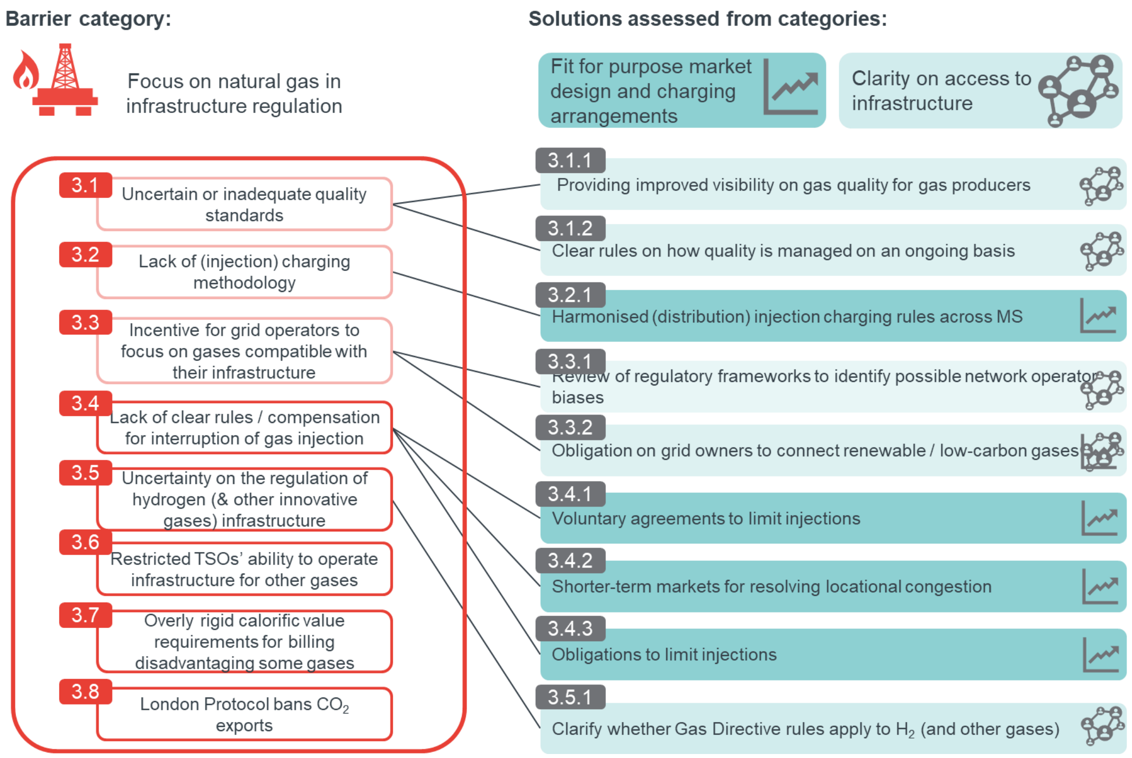
5.3 FOCUS ON NATURAL GAS IN INFRASTRUCTURE REGULATION

The third and fourth barrier categories relate to infrastructure. Barriers in this section are both threats to the take-up of technologies or to a level playing field between them, i.e. barriers faced mainly by project developers, and barriers for infrastructure operators that may hinder their ability to play the role required of them to achieve the energy transition.

In the third category, we focus on barriers that arise from the fact that much of the regulation and market has been designed with a natural gas focus. As the initial analysis has found, in the future energy system, natural gas will largely phase out by 2050, possibly first increasing in the transition. Potentially large-scale use of hydrogen requires conversion of existing gas storage or new hydrogen storage locations, and new fuelling infrastructure may need to be developed for the transport sector. Also, existing gas storages might need to be adjusted to allow more dynamic operation to store renewable and low-carbon gases.

Thus, the barriers in this group arise from the transition of one natural gas to a multitude of gas types. Figure 32 gives an overview of the barriers identified in this category, as well as the potential solutions assessed for the short-listed barriers.

Figure 32 Overview of short and long list barriers in category 3 and the solutions assessed for short list barriers



Source: Frontier Economics
Note: Barriers outlined light red belong to the transition, barriers outlined red are steady state barriers.

Transition

5.3.1 UNCERTAIN ACCESS TO INFRASTRUCTURE DUE TO UNCERTAIN OR INADEQUATE QUALITY STANDARDS

Many technologies may only be viable for developers if they can be transported and stored. Producers will monetise the value this creates at a systemic level in the long run. However, for this to be the case, developers need to be confident that they will be able to inject into the grid and storage facilities. But quality standards, developed in a context where the only gas type was natural gas, currently impose conditions or limits and the market is facing uncertainty on the extent to which injection will be possible for various types of low-carbon and renewable gas types.

While norms have been adopted in relation to biomethane in several countries[34], we find ongoing and widespread uncertainty on the allowed hydrogen blend (for instance in the Czech Republic and France). Sometimes estimates exist but there may still be inconsistencies across sources on the allowed hydrogen share for a given Member State. The compatibility of existing underground storages with hydrogen is still a topic requiring further research in much of the EU.[35] The uncertain or inconsistent estimates

[34] And indeed EU-wide standards also exist (EN 16723-1:2016 for the injection of biomethane in the natural gas grid and EN 16723-2:2017 on natural gas and biomethane for use in transport).
[35] We are aware of assessments of the potential for hydrogen storage in UK salt caverns (see ETI, 2018, "Salt Cavern Appraisal for Hydrogen and Gas Storage"), but not of any EU-wide assessment of hydrogen storage potential.

of the allowed hydrogen blend raise the question of whether the restrictions to the blend of hydrogen are of a technical or rather regulatory nature.

Further, uncertainty on the limit for the blend of hydrogen leads to uncertainty on the necessary future effort to adjust the infrastructure to be compatible with higher blends of hydrogen.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for uncertain access to infrastructure due to uncertain or inadequate quality standards

As discussed in section 5.3.1 above, an important first step in addressing this are consistent quality standards across the EU. Several Member States (such as the UK) are reviewing their standards. CEN is working on the inclusion of the Wobbe Index in the H-gas standard. Resolving issues created by quality differences between Member States (see section 5.5.1) will also be important.

But even once this has been achieved, further action may still be necessary to fully address the barrier.

One area for improvement relates to **providing improved visibility on gas quality for gas producers.** The Interoperability network code requires ENTSOG to publish a long-term gas quality outlook and allows TSOs to provide information on gas quality variation in the shorter term to consumers, DSOs and storage operators. However, it does not explicitly require TSOs to do so, nor is the provision of information to gas producers mentioned.

Such information would provide those seeking to inject renewable and low-carbon gases into the grid greater clarity on their ability to do so, reducing the uncertainties they face. For example, if the proportion of hydrogen in the grid is already at the maximum acceptable level, there is no scope for additional hydrogen injection to the grid. Knowing this could allow investors to pause existing investments, avoiding costs that may later prove to be unnecessary.

Risks to developers are particularly likely to be reduced if information provision is implemented in conjunction with **clear rules on how quality is managed on an ongoing basis**. The Gas Directive requires Member States to ensure non-discriminatory access for biogas and gas from biomass to the gas system "…*provided that such access is compatible with the relevant technical rules and safety standards on an ongoing basis*".[36]However, this leaves a number of questions unanswered. Developers may still benefit from greater clarity on the rules for managing gas quality and on exactly what they might mean for synthetic gases. For example:

- Ex-ante, once limits are close to being reached, should new connections be refused (or limited in size) until possible investments to manage quality issues can be made?
- How can an efficient trade-off be struck between managing gas quality at network level, as opposed to requiring the producer to make improvements to quality before injection to the system?
- In real time, what rules might govern possible interruption to production to ensure quality standards are met? What (if any) compensation should be available if this happens?

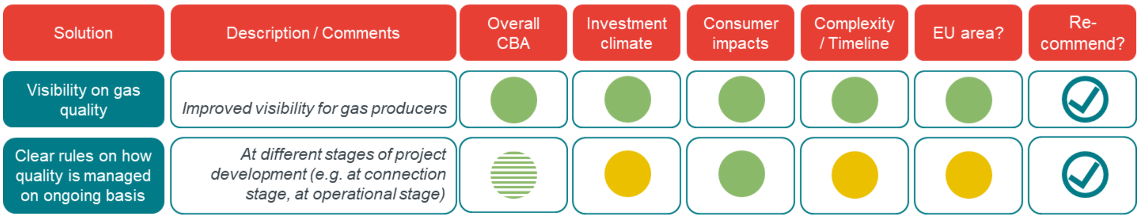
[36] Recital 26.

- What transparency is required regarding the rules, and what recourse should developers have in case of disputes with grid operators regarding how rules for managing quality have been applied?

Figure 27 below summarises our assessment of the options set out above. In summary, we would recommend taking forward the following solutions (for more detailed assessment and policy design work):

- Providing improved visibility on gas quality for gas producers; and
- Clear rules on how quality is managed on an ongoing basis.

Figure 33 Assessment of potential solutions to address uncertain access to infrastructure due to uncertain or inadequate quality standards



Source: See Appendix C for further detail on the assessment.

5.3.2 Lack of (injection) charging methodology

Commission Regulation (EU) 2017/460 ("NC TAR")[37] establishes harmonised transmission tariff structures for gas. However, with increasingly decentrally generated renewable and low-carbon gases, the fundamental inflow characteristic of the gas infrastructure may change, because inflow into the gas infrastructure may occur anywhere in the transmission grid and in the distribution grid. In view of this, some gaps may remain in the charging framework:

- **Transmission grid**: Many Member States do not produce natural gas themselves but import it. This means that gas flows into the national system only occurr via international transmission pipelines or LNG terminals. With national production of low-carbon and renewable gases, entry points and associated tariffs need to be determined for local injection into the different pressure levels of the different transmission levels.

- **Distribution grid**: Tariffs at the distribution level have historically only covered the off-take from the grid and not injection into it, as the inflow came directly from the higher-pressure level transmission grid. Currently the injection of decentrally produced renewable and low-carbon gases is not part of the charging methodology in several Member States.

The resulting uncertainty on ongoing injection charges that may be incurred by low-carbon and renewable gas production sites makes it difficult for potential technology developers and network operators to anticipate future costs.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

[37] OJ L 72, 17.3.2017, p. 29–56.

Recommendation for lack of (injection) charging methodology

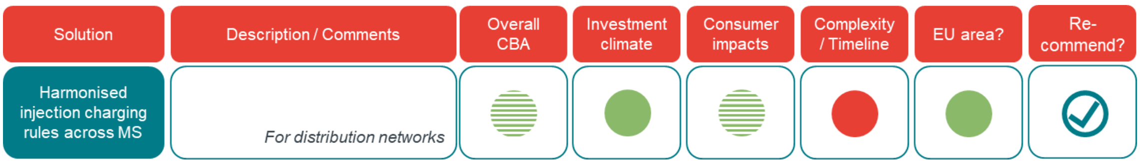
As a solution to this barrier, we consider the option of **harmonising injection charging rules across Member States**, particularly covering distribution-injected gases (since NC TAR already addresses transmission network entry/exit tariffs for gas). An important feature of such rules would be to avoid the creation of 'new' distortions, such as (temporary) exemptions from injection tariffs for renewable and low-carbon gases which are currently not foreseen under NC TAR.[38]

The creation of harmonised rules would increase certainty for developers regarding how they might be charged for use of the gas grid, in turn reducing the costs across the EU of deploying renewable and low-carbon gases, to the extent it reduces the associated risks to developers.

Harmonisation across Member States could also, in principle, make it more likely that deployment of low-carbon and renewable gases happens where it is most cost-effective, helping to reduce the costs of their deployment across the EU. However, this depends on the extent to which resulting tariffs are cost reflective. In addition, we note that previous experience on the network code development process suggests that the process to harmonise charging rules could be complex and time-consuming.

Figure 34 below summarises our assessment of the option set out above. In summary, we would recommend harmonised injection charging rules at distribution level (for more detailed assessment and policy design work).

Figure 34 Assessment of potential solution to address the lack of an (injection) charging methodology



Source: See Appendix C for further detail on the assessment.

5.3.3 Incentive for grid operators to focus on gases compatible with their infrastructure

The design of the natural gas regulation encourages grid operators to optimise, build and maintain transmission infrastructure. This includes a number of incentives that may likely bias operators to facilitate access to the network for those gases that are compatible with their current infrastructure. This may hinder the level playing field between different renewable and low-carbon gases. Biases may arise from:

- **explicit incentives,** e.g. financial incentives on uptake like connection incentives at the distribution level, or booking or utilisation incentives at the transmission level; and/or

[38] We understand that ACER is of the view that such exemptions may run counter to NC TAR. See ACER (2019), "Agency Report: Analysis of the Consultation Document on the Gas Transmission Tariff Structure for Belgium", section 5.2.

- **implicit incentives,** for instance the fact that declining demand may drive per unit charges to consumers up and contribute to tougher negotiations between the network operator and the regulator at future price control reviews.

Additional biases may arise from places other than regulation, such as incentives placed on management regarding utilisation of the infrastructure.

The degree to which incentives prevail will depend on a wide range of conditions, including the framework for granting connections to the grid. In this regard, 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 ("RED II")[39] states:

> *"Where relevant, Member States shall assess the need to extend existing gas network infrastructure to facilitate the integration of gas from renewable sources."*

In addition, 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 (the "Gas Directive")[40] states the following:[41]

> *"Member States should take concrete measures to assist the wider use of biogas and gas from biomass, the producers of which should be granted non-discriminatory access to the gas system, provided that such access is compatible with the relevant technical rules and safety standards on an ongoing basis."*

The Gas Directive also requires NRAs to help achieve the "…*integration of large and small-scale production of gas from renewable energy sources and distributed production in both transmission and distribution networks*…" and to remove "…*barriers that could prevent access for new market entrants and of gas from renewable energy sources*".

Taken together, these provisions may provide some degree of reassurance for developers of renewable gases that Member States will take actions to facilitate their access to the gas system. However, it is not clear how the provisions of the Gas Directive would apply to (non-renewable) low-carbon gases and they do not specifically address issues related to network operator incentives.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for incentive for TSOs to focus on gases compatible with their infrastructure

Above we highlight a range of examples of situations in which network operators' incentives could result in them focussing on gases that are compatible with their current infrastructure at the expense of other gases. However, before arriving at concrete solutions to address these possible biases, a better understanding of their nature would be needed. The first step in addressing this barrier might therefore be **a review of regulatory frameworks to identify such biases in each Member State**.

As also noted above, the framework for granting connections to the grid is likely to be one specific factor affecting network owners' incentives to accommodate renewable and

[39] OJ L 328, 21.12.2018, p. 82–209.
[40] OJ L 211, 14.8.2009, p. 94–136
[41] Recital 26, Gas Directive.

low-carbon gases. The current framework (RED II and the Gas Directive) may offer some degree of reassurance that access to the gas system will be facilitated.

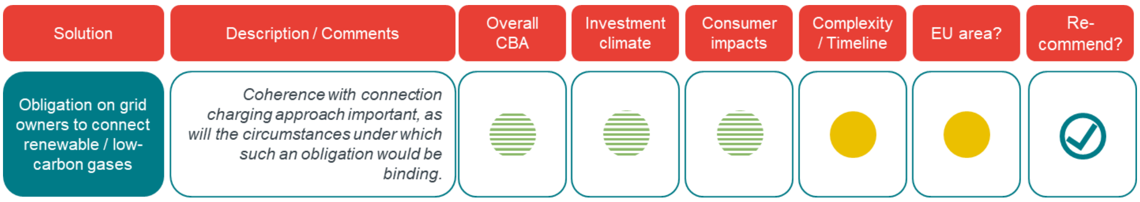
Nevertheless, we see room to be more specific that the framework in the Gas Directive also applies to (non-renewable) low-carbon gases and that there is an expectation that network operators will meet renewable and low-carbon gas sources' requests for connection to the grid. This could be implemented via an **obligation for network operators to connect renewable and low-carbon gas sources to the gas system**, provided certain conditions (specified in advance) are met:

- As is the case currently in the Gas Directive, such an obligation would need to be subject to the potential effect on security and safety of operation of the grid, including any relevant quality standards (see section 5.3.1 above).
- It might be possible to require connections to be made even in advance of all required reinforcement works being carried out. But if that is the case, rules to manage congestion (at distribution level – see section 5.3.4) become even more important.
- The coherence between any connection obligation and the connection charging approach adopted (see section 5.1.4) would need to be carefully considered. It will probably still be desirable to continue to apply an "economic test" for granting new connection requests.
- In cases where low-carbon or renewable gases developers were not satisfied with grid operators' attempts to connect them within a reasonable time-frame, developers might need to be able to have some form of recourse, for example a right of appeal to the NRA.

Due consideration would also need to be given to rules that offer network owners flexibility to justify delay or refusal of a connection under certain circumstances, while still ensuring that developers have sufficient trust that their connection request will be dealt with efficiently. At the very least, ensuring these conditions are transparent should increase certainty for developers. A connection obligation also has the potential to contribute to speeding up the deployment of renewable and low-carbon gas production, leading to a faster realisation of benefits from their deployment.

Figure 35 below summarises our assessment of the option set out above. In summary, as well as a regulatory review to identify possible biases, we would recommend taking forward an obligation to connect renewable and low-carbon gas sources for more detailed assessment and policy design work.

Figure 35 Assessment of potential solution to address incentive for grid operators to focus on gases compatible with their infrastructure



Source: See Appendix C for further detail on the assessment.

Steady State

5.3.4 LACK OF CLEAR RULES / COMPENSATION FOR INTERRUPTION OF GAS INJECTION

Renewable and low-carbon gas production is typically capital intensive. High utilisation rates are therefore important for the business case of these technologies and their competitiveness. Any constraints on utilisation rates imposed by external factors would undermine the development of these technologies, thereby constituting a barrier. And congestion may be such a constraint.

Contractual congestion can occur in gas networks when firm capacity bookings exceed network technical capacity. It can be managed through measures such as over-subscription and capacity buy-back mechanisms. At transmission level, guidelines for managing contractual congestion are set out in the Commission Decision of 24 August 2012 on amending Annex I to Regulation (EC) No 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks ("CMP Guidelines").[42]

Physical congestion can occur when expected flows exceed what the network can physically transport. This can either be addressed by network expansion or contractually, via flow commitments. In the gas system, physical congestion is relatively rare in the EU at transmission level today.[43] This is due to the configuration of the European gas system with entry from large interconnection points managed via capacity bookings. Curtailment of gas has therefore historically not been any issue.

However, given the expected role and geographical distribution of low-carbon and renewable gases production, congestion may become more frequent, for example during the production of:

- **Renewable gases from biomass**: The high load factor, i.e. the constant renewable gas supply, may result in congestion in summer in decentral, rural places when demand for e.g. heating is very low. This is particularly the case given that distribution grids have limited linepack flexibility. Increasing the use of compressors, to flow gas from distribution to transmission level (where additional flexibility sources, such as storage, may typically lie), may help address seasonal flexibility issues to a large extent. However, it may not always be the most efficient solution to deal with all congestion issues.
- **Gases from electricity**: Increasing use of intermittent renewable electricity may need to rely on non-intermittent energy sources such as gas to provide system flexibility. This holds for excess supply of renewable electricity when power-to-gas facilities can relieve the electricity system, and for excess demand situations where low-carbon and renewable gas fired electricity can supply the electricity system. However, this means the intermittency of renewable electricity sources will be imported to the gas sector, again possibly resulting in congestion where gas injections exceed gas demand in a given area.

Given the importance of volume certainty and utilisation (as described above), developers of renewable and low-carbon gases will want to have clarity on how congestion will be managed and how they will be remunerated if they are required to reduce or stop injections. At present, the CMP Guidelines require transmission system operators to take the most "cost-effective" measures[44] to resolve physical congestion. However, there are a few examples from the countries we reviewed of provisions of curtailment rules for unexpected reductions in the injection capacity as a result of saturation in the network at the transmission level, and none at distribution level.

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[42] OJ L 231, 28.8.2012.

[43] EY & REKK (2018), "Quo vadis EU gas market regulatory framework – Study on a Gas Market Design for Europe", Section 4.3.3.

[44] CMP Guidelines, recital 8.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendations for lack of clear rules / compensation for interruption of gas injection

To the extent physical congestion does indeed become more of an issue going forward (in particular at distribution level), Member States' most likely response would be to implement some rules to address this. We therefore assume some action to address this barrier in the counterfactual, whereby developers will eventually get some clarity on the congestion management rules that will be in place.

The form those rules might take is, however, uncertain. For the purposes of the assessment of different options, we assume that, in the counterfactual, Member States introduce priority rules governing injection rights at times of network congestion that are not necessarily market-based. For instance, in France, gas network operators hold a "capacity register" to determine the order in which biogas capacities are injected into the network. The allocation works on a "first come, last interrupted" basis, which means the producer at the top of the list will have the priority to inject its capacity into the network.

Such rules are not, however, the only possible solution. We consider three solutions below, each of which could be applied in different situations.

Perhaps the most straightforward solution to implement would be **interruptibility agreements.** By this we refer to longer-term agreements under which participants agree to interrupt injection on instruction by the network operator. These could define remuneration in the event of interruption and be awarded through competitive tendering. Alternatively, they could form a voluntary part of the connection agreement (i.e. the injection facility might in return benefit from a reduction in connection or grid use fees).

- Such agreements could provide an efficient way of managing congestion, particularly if awarded through competitive tendering. Those players providing congestion management services would be those able to provide flexibility at lowest cost.
- If used in conjunction with a system of (real-time) market-based curtailment (see below), agreements could provide clearer long-term signals regarding the value of flexibility, making this easier for developers to factor in their investment decisions.
- Overall, investors' technology choices (or their choices regarding where to invest) are likely to lead to lower costs of addressing network congestion issues than is otherwise likely to have been the case.

Shorter-term markets for resolving locational constraints could be another solution. For instance, network operators could set up a system inviting bids to reduce injection for resolving locational constraints. Such a system could also be open to demand-side response and (where this has the potential to help address issues at distribution level) actors connected to the transmission system.

- As for interruptibility agreements, market-based interruption and compensation would help to ensure that network congestion issues are dealt with cost-effectively and that market participants are rewarded for their contribution to addressing congestion.
- Shorter-term markets could allow for greater efficiency than (long-term) interruptibility agreements alone, since they would allow players to reflect the changes over time in the cost of providing flexibility.

- However, it may be more complicated to set up (depending on the arrangements individual Member States already have in place). Given this, its introduction may depend on the severity and nature of the congestion problem.

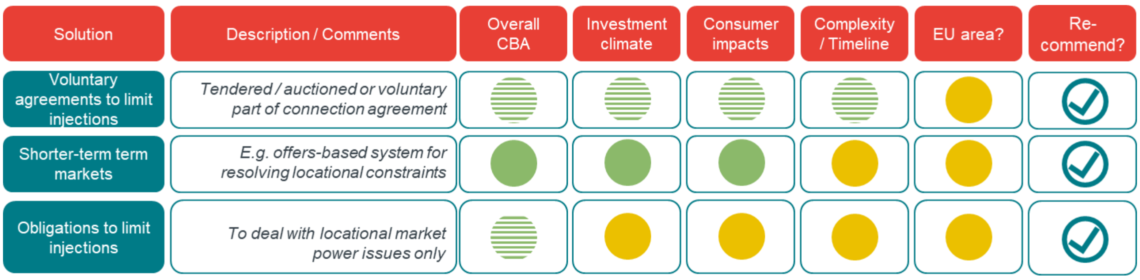
Alternatively, operators might be obliged (for example as part of their connection agreement) to interrupt when required by the network operator (possibly with remuneration for doing so). Such **interruptibility obligations** could be placed on operators in situations where there may be a limited number of options to address localised congestion issues, leading to possible market power concerns. In such situations, market-based congestion management may not necessarily result in the lowest costs to consumers (for example if some players can make excessively high bids, compared to their costs, to resolve congestion). Obligations could be used to help cap the cost of congestion management. However, to limit the potential for negative investor perception, use of such obligations by network operators may need to be subject to NRA approval.

Several stakeholders have called for priority access for renewable (and low-carbon) gases, though it is not clear from submissions exactly to what this refers. If analogous to terminology sometimes used in electricity, it would refer to some kind of guarantee regarding producers' ability to inject gases into the system as they are produced. Such a guarantee is unlikely to allow for efficient management of congestion. And if participation in congestion management is voluntary and market-based (i.e. flexibility need only be provided at a price nominated by the flexibility provider), it is not clear what value such a guarantee would offer to the producer. However, should congestion management not be market-based, there could be a rationale for granting priority access to renewable and low-carbon gases. Without market-based congestion management, it would be difficult for congestion management to be efficient. From that starting point, the risk of a further loss in efficiency (from granting priority access) may be seen as a price worth paying to ensure low-carbon and renewable gases producers have improved certainty regarding utilisation.

Figure 36 below summarises our assessment of the options set out above. In summary, we would recommend taking forward the following solutions (for more detailed assessment and policy design work):

- **Competitively tendered voluntary agreements** between network operators and participants to limit injections;
- **More sophisticated market-based systems** allowing for real-time adjustment of bids;
- **Obliging participants to limit injections** in situations where there are possible market power concerns.

Figure 36 Assessment of potential solutions to address the lack of clear rules / compensation for interruption of gas injection



Source: See Appendix C for further detail on the assessment.

5.3.5 UNCERTAINTY ON THE REGULATION OF HYDROGEN (& OTHER NEW GASES) INFRASTRUCTURE

While the Gas Directive sets out clear rules for unbundling, third-party access and tarification, it is not clear how these provisions might apply to gases other than natural gas, biogas and gas from biomass. In particular, it is not clear how EU rules apply to (low-carbon and renewable) hydrogen and potential other new gases. Typically, infrastructure for such gases are not regulated at the Member State level either.

Currently, development of hydrogen infrastructure is at relatively small scale. It may be possible to deal with any market power abuse issues under competition law. However, in principle, as hydrogen networks start to approach the scale of current natural gas networks, regulation in a similar way to existing gas networks may become required to ensure producers and consumers benefit from access to required infrastructure in a non-discriminatory and competitive manner. The question for investors (in long-lived assets) is therefore what the trigger for moving to regulation would be, and how existing investment might be dealt with if/when such a move happens.

- Therefore, there is a high uncertainty on whether hydrogen infrastructure will in the future be regulated similarly to natural gas infrastructure. This uncertainty may drive inefficient levels of investment in corresponding infrastructure, or investment at inefficiently high costs due to increased financing costs in the light of this uncertainty. **Energy producers, merchants or industry companies** may be prepared to invest in e.g. hydrogen pipelines connecting a power-to-hydrogen facility to an industry location. However, they may abstain from building this pipeline if they are uncertain that the infrastructure will fall under TPA requirements, or be mandated to be transferred to a third-party infrastructure operator, with the introduction of the next regulation.
- **Network operators** may also view the build-up of infrastructure for renewable and low-carbon gases as central to their strategy. However, as long as they are uncertain about whether this infrastructure will be part of their RAB, they may abstain from this investment.
- Whether or not infrastructure is regulated may be expected to have an impact on the rate of return required from investors to build the infrastructure, with this eventually being reflected in costs borne by end users. Costs will be minimised if investment is undertaken by those investors requiring the lowest level of return for a given level of risk or profile of regulation. The uncertainty around regulation may hinder this efficient matching of infrastructure projects with investors.
- Overall, this may lead to under-investment in hydrogen infrastructure, compared to what might be optimal from a societal perspective. It also creates a disincentive for developing hydrogen (compared to other gases for which the regulatory framework is clearer).

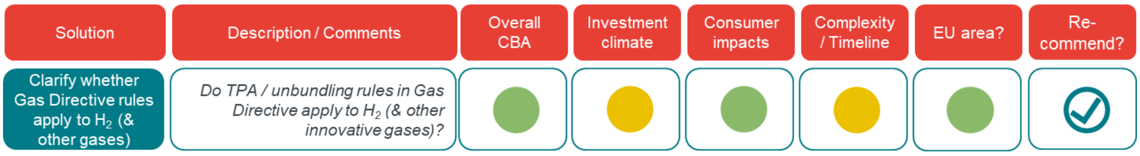
This gap has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for uncertainty on the regulation of hydrogen (& other new gases) infrastructure

As discussed above, in the absence of further action, the default position at present at EU-level is that hydrogen infrastructure is unregulated and that infrastructure is not required to provide Third Party Access (TPA). The potential solution we consider is to clarify **whether (and under what conditions) the provisions of the Gas Directive apply to hydrogen (and other gases)**. Doing so is likely to provide increased clarity for developers of renewable and low-carbon gases regarding their ability to secure access to infrastructure, reducing the risks to investment. That said, agreeing on the conditions for regulating hydrogen infrastructure and on the treatment of infrastructure build prior to regulating is likely to be a complex process.

Figure 37 below summarises our assessment of the options set out above. In summary, we would recommend further assessment of the conditions under which the provisions of the Gas Directive apply to hydrogen (and other gases).

Figure 37 Assessment of potential solutions to address uncertainty on the regulation of hydrogen (& other new gases) infrastructure



Source: See Appendix C for further detail on the assessment.

5.3.6 RESTRICTIONS ON TSOS' ABILITY TO OPERATE INFRASTRUCTURE FOR OTHER GASES

In some Member States regulation prohibits infrastructure operators from owning or operating any infrastructure that is not used to transport natural gas specifically. These regulations have sometimes resulted from historic developments rather than from a current regulatory need. For instance, in the Netherlands, Gasunie is not allowed to operate hydrogen infrastructure at the moment. This is the case because Gasunie was originally founded to exploit the natural gas in Groningen.

However, as it stands, such a prohibition may risk preventing TSOs from using gases containing hydrogen blends in their network. This risks slowing down the pace of decarbonisation of gas.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.3.7 OVERLY RIGID CALORIFIC VALUE REQUIREMENTS FOR BILLING DISADVANTAGING SOME GASES

Different gas types contain different calorific values. This may cause technical and regulatory barriers.

For technical reasons pipelines and appliances are sometimes not compatible with different gas qualities. In Germany, the Netherlands, France and Belgium, there are two different natural gas qualities, low calorific gas and high calorific gas, which have to be transported in separate systems within defined ranges[45]. However, while it is important to adhere to necessary technical and safety standards, overly rigid quality requirements may hamper the transport of different types of gases unnecessarily.

Issues can also arise where, instead of allowing for gases of different calorific value to be injected into the same network, a rigid standard is imposed. In the UK for example, the billing regime effectively requires lower calorific value gases (such as biomethane)

[45] Cf. Open Grid Europe, https://www.open-grid-europe.com/cps/rde/oge-internet/hs.xsl/L-H-Gas-Umstellung-2952.htm?rdeLocaleAttr=en&rdeCOQ=SID-93DC6E8F-5E23F933

to be upgraded (e.g. by adding propane) before injection to the grid. Work is ongoing to find solutions that would avoid the need for such pre-processing.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.3.8 London Protocol bans CO_2 exports

The "London Protocol" is an international agreement on the prevention of marine pollution. Article 6 of the London Protocol prohibits contracting parties from allowing the export of wastes or other matter to other countries for dumping or incineration at sea. The article has been interpreted by contracting parties as prohibiting the export of CO_2 from a contracting party for injection into sub-seabed geological formations.[46]

This is a barrier to cross-border co-operation on offshore CO_2 storage, which in turn may be a barrier to the development of CCS technologies.

An amendment was put forward in 2009 by some contracting parties to allow cross-border transport of CO_2 for storage. However, it has yet to be ratified by the required two thirds of contracting parties.[47] An interim solution could be using Article 25 of the Vienna Convention on the Law of Treaties which allows for the provisional application of international treaties if the negotiating states agree. [48]

This barrier has not been retained in the short list of issues as part of this study. However, this issue represents a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.4 Uncoupled and uncoordinated infrastructure planning

This group also encompasses barriers related to the infrastructure required for the efficient uptake of renewable and low-carbon gases and sector coupling technologies, but focuses on issues related to silos between infrastructure levels (transmission and distribution) and sectors (electricity and gas). These issues arise because decarbonisation of the energy system will result in an increasing level of integration of different energy carriers, in particular gas, electricity and heat. For the purpose of this study, we understand sector coupling as linking the EU electricity and gas sectors, both in terms of their markets and infrastructure.

Figure 38 gives an overview of the barriers identified in this category, as well as the potential solutions assessed.

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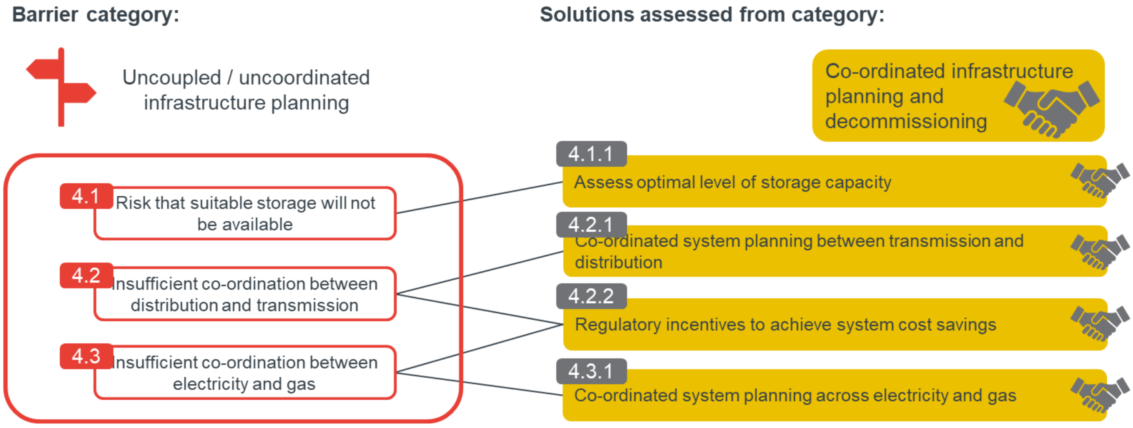
[46] Garrett, J and McCoy, S (2013) 'Carbon capture and storage and the London Protocol: recent efforts to enable transboundary CO_2 transfer', Energy Procedia 37 (2013) 7747 – 7755.

[47] https://ieaghg.org/ccs-resources/blog/slow-progress-again-on-ratification-of-the-london-convention-s-export-amendment-for-ccs

[48] https://treaties.un.org/doc/Publication/UNTS/Volume%201155/volume-1155-I-18232-English.pdf

Figure 38 Overview of short and long list barriers in category 4 and the solutions assessed for short list barriers



Source: Frontier Economics
Note: Barriers outlined light red belong to the transition, barriers outlined red are steady state barriers.

Steady State

5.4.1 *Risk that suitable storage will not be available*

Gas storage operators may be uncertain as to what extent there will be requirement for gas storage in the future energy system:

- Firstly, they face demand risks. The findings from the analysis to support Objectives 1 and 2 signal the possibility of reduced gas demand in the future energy system. This may lead to lower demand for gas storage.
- Secondly, storage operators face technical risks. Existing storage facilities may not be suitable for gases such as biomethane (due to high oxygen content) or hydrogen - either because the gases are incompatible with the pipeline infrastructure or with the storage facility itself.

Storage operators may therefore decide to stop operating storages. In addition to security of supply risks, which are not the focus of this report, this may impact the ability in the longer run for the system to benefit from the full value of gases, given part of this value resides in storability (in particular in an energy system with increasing volumes of intermittent renewable sources and increasing flexibility needs, including need for seasonal storage). Insufficient investment/too much divestment in storages thereby hinders a cost-efficient energy transition. In fact, currently there is no clear pattern on storage obligation on the Member State level.

We note that the manner in which this barrier materialises may vary across Member States depending on current regulations in place and adaptations already undertaken. For instance, the presence (and level of) storage obligations provides a signal to storage operators. However, this signal will only continue to be effective where the regulation is adapted to the emergence of low-carbon and renewable gases (that is, that any impact of changes in gas types on the presence and level of obligation is clarified). Some countries, like the Netherlands, have already adapted regulation in relation to storage obligations to low-carbon and renewable gases, but this is not the case across Member States where such obligations are currently in place.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for risk that suitable storage will not be available

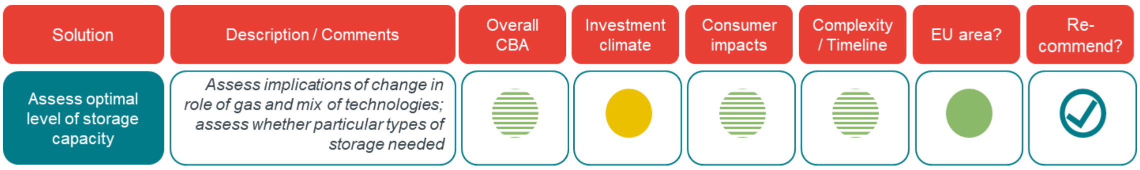
The first step towards overcoming this barrier would be to **assess the implications of the expected change in the role of gas as well as the mix of technologies on the likely optimal level of gas storage capacity** (at EU-level and its regional distribution). This would include assessing whether specific types of gas storage capacity are needed (for example to store particular gases). While we would envisage a focus on storage in gaseous form, any assessment of the optimal level of storage would need to take into account other forms of flexibility both in the gas system and elsewhere in the energy system, including other forms of energy storage.

The direct costs and benefits of such an assessment might be limited in magnitude. However, it might be an enabler of possible future action that might deliver benefits to society. Depending on the outcome of the analysis on the optimal level of storage capacity referred to above, there may be a need to assess the risks that market and regulatory signals received by storage operators could drive inefficient investment or closure decisions. Should this be the case, further intervention may be required, though we do not assess the possible options for the time being.

We note there is a risk that even a limited intervention such as this may create an uncertainty regarding the nature of possible future policy or regulatory intervention on storage. We also note this may be an area in which there are benefits to co-ordinated action at EU level, for example should there be risks that decisions in one Member State may affect the energy system in another Member State.

Figure 39 below summarises our assessment of the option set out above. In summary, we would recommend further work is carried out into a possible assessment of the implications of the expected change in the role of gas as well as the mix of technologies on the likely optimal level of gas storage capacity.

Figure 39 Assessment of potential solution to address risk that suitable storage will not be available



Source: See Appendix C for further detail on the assessment.

5.4.2 INSUFFICIENT CO-ORDINATION ON FUTURE USE OF TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE: GEOGRAPHIC MAPPING OF PRODUCTION, AND IMPLICATIONS FOR CONNECTIONS AND INFRASTRUCTURE ADAPTATION

Lack of coordination between transmission and distribution infrastructure operators may be a barrier to cost efficiency.

Gas infrastructure operators are currently competing for connections to renewable and low-carbon gas production sites, but due to different charging rules between the transmission and distribution level, the lowest connection cost signalled to the consumer may not represent the least cost option for the system. A similar issue may arise in the absence of harmonised charging rules across transmission and distribution networks.

Additionally, a consistent geographical mapping of production sites and of the underlying production potentials are important firstly to optimise the connection location and secondly to take into account the resulting required infrastructure adaptations. In the long run the optimal design of the gas system will depend on the least cost options to facilitate injection and transport of gases produced from least cost technologies. This may involve significant changes in the infrastructure design, such as enabling reverse flows or investment into additional linepack. Optimising the long run design of the gas system would require coordination between distribution and transmission level planning.

We note that, beyond investment, there is value in co-ordinated system operation. This may involve sharing of information on production / flows, or co-ordinated (real-time) system operation. However, we would expect this to be addressed by obligations and incentives on operators to ensure system stability. This indeed appears to be the explicit intention of Article 13 and Article 25 of the Gas Directive, which require TSOs and DSOs respectively to share information with other parties to facilitate "secure and efficient operation".

This regulatory gap has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for insufficient co-ordination on future use of transmission and distribution infrastructure: geographic mapping of production, and implications for connections and infrastructure adaptation

We consider a potential solution of **mandating co-ordinated system planning between transmission and distribution**. Such planning would involve the development of a consistent geographic mapping of current and projected production and demand as a first step. This would allow operators to identify required investments, having in mind the feasible options across both levels of the gas network. Co-ordinated planning does not itself guarantee minimising overall costs across the transmission and distribution systems of accommodating renewable and low-carbon gases. However, it may enable this, where network operators have incentives to achieve cost savings.

Given this, **regulatory incentives to achieve system cost savings** may also need to be part of the solution. While network operators will typically have incentives to achieve cost savings once price/revenue caps have been set, it may also be worth giving thought to how they can be incentivised to draw up network plans that maximise synergies across distribution and transmission. Information asymmetries can make it challenging in practice for regulators to implement such incentives.

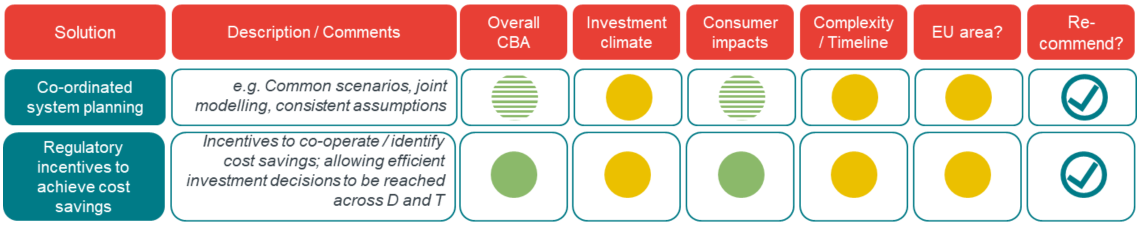
In some Member States (such as Denmark), the same company owns both gas transmission and distribution grids. This is clearly another way of ensuring co-ordination. However, we do not consider it further as it may not be reasonable to assume that adopting this model would be politically acceptable in other Member States. In addition, while joint ownership might facilitate co-ordination, it does not guarantee it, nor does it ensure that co-ordination leads to optimisation of costs from a system perspective.[49]

Figure 40 below summarises our assessment of the options set out above. In summary, we would recommend taking forward the following solutions (for more detailed assessment and policy design work):

- Co-ordinated infrastructure planning between transmission and distribution networks; and
- Regulatory incentives on individual operators to achieve cost savings at system level

[49] Although in Denmark's case there is an obligation on network operators to use social CBA analysis which may contribute to this objective.

Figure 40 Assessment of potential solution to address insufficient co-ordination on future use of transmission and distribution infrastructure



Source: See Appendix C for further detail on the assessment.

5.4.3 Insufficient co-ordination on future use of electricity and gas transmission infrastructure – and aligned operator incentives

Another current barrier may arise from the separate development of systems for electricity and gases. Integrated network planning of electricity and gas networks (both on the transmission or distribution levels) is essential to prevent inefficient bias towards single network types.[50] The long run optimal design of the network is driven by interactions between electricity and gases, such that the least cost infrastructure may only be designed and built if it is planned jointly by electricity and gas infrastructure operators. Not only could coordination enable the optimisation of the mutual investment programmes but also the realisation of possible operational gains[51].

ENTSOG and ENTSO-E have already taken the first steps in co-ordinating their respective Ten Year Network Development Plans (TYNDP). For the TYNDP 2018, ENTSOG and ENTSO-E developed joint scenarios intended to capture relevant interlinkages between the electricity and gas sectors. As part of this process, the ENTSOs are also developing an interlinked electricity and gas model. This model will eventually be used to support the cost-benefit analysis of projects for which electricity and gas interlinkages are deemed to be particularly relevant.[52] However, there may also be further benefits to be realised in ensuring greater co-ordination between electricity and gas TSOs (and DSOs) at national level.

We note that, beyond investment, there is value in co-ordinated system operation. This may involve sharing of information on production / flows, or co-ordinated (real-time) system operation. Provided that electricity and gas system operators can base their decisions on independently observable market conditions, such as the relative price of different heating options, there may be no need for explicit new provisions. However, where more complex flows or higher loads on either network imply the need for one or another system operator to take additional unobserved network actions that impact the other operator, it may be necessary to revisit whether scope for greater collaboration is desirable. Existing EU regulations do not explicitly require gas and electricity TSOs and DSOs to share information across sectors.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

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[50] A specific local example is in Italy. When new isolated areas such as Sardinia are connected to energy supply, currently there is no assessment on which energy carrier besides natural gas (whether it is electricity, hydrogen, heat etc.) are suitable options.
[51] Cf. Trinomics (2018), The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets
[52] ENTSO-E and ENTSOG joint presentation titled "Focus Study Interlinked Model Joint ENTSOs Workshop", dated 17 May 2018.

Recommendation for insufficient co-ordination on future use of electricity and gas transmission infrastructure – and aligned operator incentives

Our focus is on the planning-related aspects of the barrier. Similarly to above, we consider a potential solution of **mandating co-ordinated system planning across electricity and gas transmission (and potentially also at distribution level)**. First steps have already been taken in this direction, such as the joint scenario planning exercise carried out by the ENTSOs and the development of an interlinked gas and electricity model (described above). Similar co-ordination at national level (whether at TSO or DSO level) would also be beneficial. This would allow operators to identify required investments, having in mind the feasible options across electricity and gas networks and would be an important enabler for achieving cost savings.

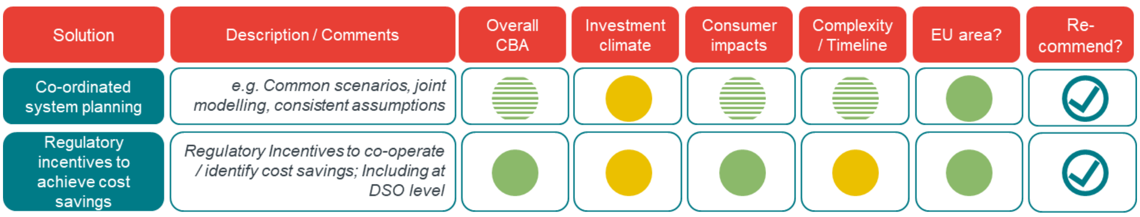
Regulatory incentives to achieve system cost savings may also need to be part of the solution. While network operators will typically have incentives to achieve cost savings once price/revenue caps have been set, it may also be worth giving thought to how they can be incentivised to opt for investments that maximise synergies across electricity and gas. Information asymmetries can make it challenging in practice for regulators to implement such incentives.

As above, while we note that common ownership of electricity and gas transmission networks is a feature in some Member States, and could theoretically aid co-ordination, it would not in itself ensure cost savings, and we assume that it would not be easily to apply more widely across Member States.

Figure 41 below summarises our assessment of the option set out above. In summary, we would recommend taking forward the following solutions (for more detailed assessment and policy design work):

- Co-ordinated infrastructure planning between electricity and gas network operators; and
- Regulatory incentives on individual operators to achieve cost savings at system level

Figure 41 Assessment of potential solution to address insufficient co-ordination on future use of electricity and gas transmission infrastructure

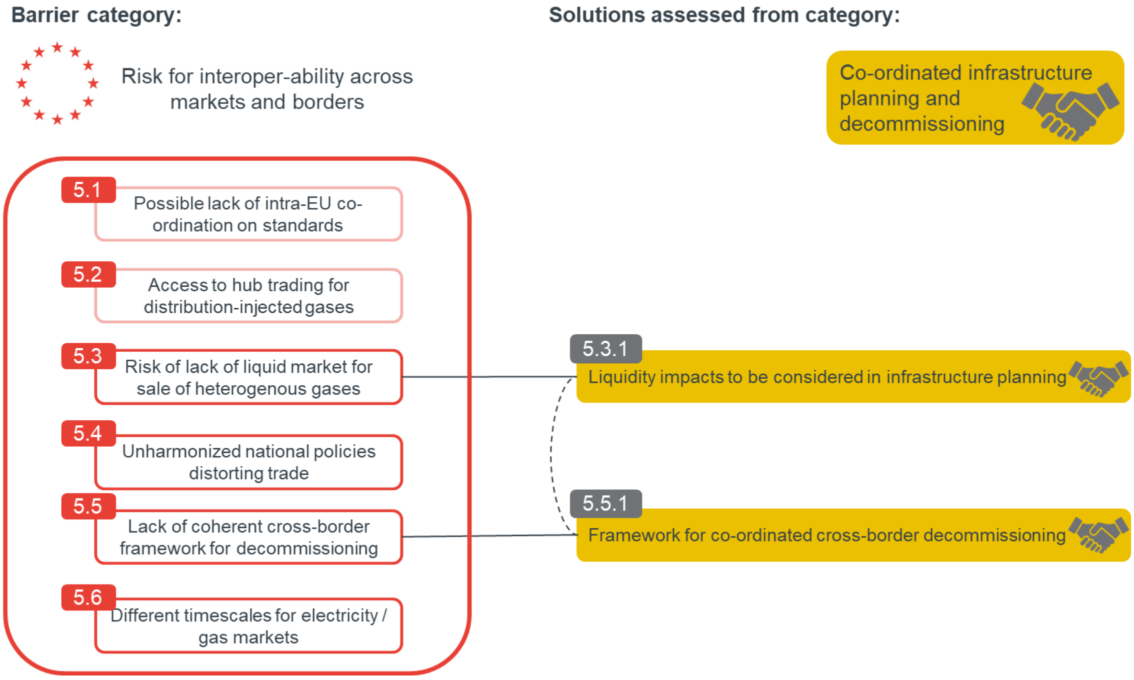


Source: See Appendix C for further detail on the assessment.

5.5 Risk for interoperability across markets and borders

Group five comprises barriers relating specifically to the interoperability between different markets. Figure 42 gives an overview of the barriers identified in this category, as well as the potential solutions assessed for the short-listed barriers.

Figure 42 Overview of short and long list barriers in category 5 and the solutions assessed for short list barriers



Source: Frontier Economics
Note: Barriers outlined light red belong to the transition, barriers outlined red are steady state barriers.

Transition

5.5.1 POSSIBLE LACK OF INTRA-EU CO-ORDINATION ON STANDARDS

There are numerous examples of gas standards being different across Member States.[53] For instance, there are differences between oxygen limits between Denmark and Northern Germany. These may, in the near future, result in barriers to cross-border trade in gases.[54] Other Member States may face similar issues as biomethane and hydrogen injection increases in the future.

[53] Cf. 6th CEER benchmarking report on the quality of electricity and gas supply (2016).
[54] There is a 0.5% (molar) limit on oxygen in biomethane in Denmark. In Germany, different oxygen limits can be applied by different gas system operators, depending on the vulnerability of the specific facilities located in each network. Gasunie Deutschland allows only 10ppm (molar) oxygen to flow from Denmark, given (we understand from Energinet) the vulnerability of storage facilities located on its network.
Energinet has informed us that currently they are able to design and operate the Danish transmission system such that only gas with less than 10ppm oxygen is flowing southbound on the Ellund border to Germany. When the Tyra field is shut down for maintenance 2019-22, no southbound flows are expected at all. From 2022, once Tyra is expected to be up and running again, an enduring solution would need to be in place to ensure gas can be exported from Denmark to Germany.
Energinet has therefore started a so-called 'Oxygen Task Force' considering potential solutions, such as removing the oxygen directly at the production site, at the border

There may be sound technical justifications for Member States adopting different gas quality standards. For example, domestic gas infrastructure may only be compatible with a specific gas quality.

The concern here is therefore not necessarily the lack of harmonisation. Rather, it is the lack of co-ordination between Member States and neighbouring TSOs, and whether this could end up being a barrier to physical trade.

In particular, we see potential risks to cross-border trade where Member States are insufficiently flexible in their application of gas quality standards. For example, Member States may apply stringent quality standards at the level of the whole grid when only certain installations are vulnerable. This may prevent imported and domestically produced gases from flowing in the parts of the network that are less vulnerable. Alternatively, Member States (or neighbouring TSOs) may fail to co-ordinate on the investments required to manage potential quality issues (for example on oxygen removal).

In principle, this co-ordination barrier is already addressed under Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules (the 'Interoperability network code')[55]. Under Article 15 of the Interoperability network code:

- TSOs are required to co-operate to avoid restrictions to cross-border trade due to gas quality differences;
- NRAs may require TSOs to co-operate to develop options, to perform a CBA on the assumptions and submit a joint proposal for removing the restriction and submit this for NRA approval
- NRAs are required to consult NRAs of other Member States concerned and take account of their opinion (ideally reaching agreement).

Given this this barrier is already addressed in principle by existing legislation, it has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

5.5.2 ACCESS TO HUB TRADING FOR GASES INJECTED AT DISTRIBUTION LEVEL

The European gas market is designed on the concept of 'hub' trading, with entry and exit points typically defined at interconnection points, storage facilities, LNG terminals and domestic exit points.

Historically, there has been limited gas production at distribution level, though this is changing with biomethane injection typically taking place at distribution level. Injection from power-to-gas facilities might also take place at distribution level.

To allow distribution-connected gases to be traded in the same way as other supplies, there is therefore a need to define an entry point to the 'hub' for them. Member States with biomethane injection (such as Italy and Denmark) have already done this.

Generally, we expect other Member States to take similar steps, if and when injection to local gas grids starts becoming a reality. However, we have still noted the issue in this study, as it would require a conscious decision from Member States to facilitate

point or at the connection point for the vulnerable assets etc. It is also developing a long-term view of how oxygen limits at European level can be set while minimising barriers to the growth of biomethane production.

[55] OJ L 113, 1.5.2015, p. 13–26.

trade of local gas production, potentially also requiring updates to metering arrangements.

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

Steady State

5.5.3 RISK OF LACK OF LIQUID MARKET FOR SALE OF HETEROGENOUS GASES

The competitiveness of natural gas today stems, among other, from the level of liquidity achieved in the internal market (albeit with ongoing differences across Member States). Given the heterogeneity in technologies that may be deployed to achieve the decarbonisation of the energy sector, which may vary by regions, there is a risk of fragmentation of the gas market into different products and different regions. This is less likely to be an issue where gases are blended together, since it should be possible to simply ensure trade in units of energy (subject to overcoming issues related to calorific value requirements – see section 5.3.7). However, it may be an issue to the extent that there is significant growth in infrastructure dedicated for particular gases (for example, for hydrogen).

This results in the risk that liquidity could fall, increasing costs and risks for gas market participants, and potentially also deterring investment. Future developments might partially mitigate this risk.

- Growing numbers of physical interconnections between hydrogen and methane supply chains (see section 3.3.3) will enhance price linkages between fuels. This could ultimately allow market participants to hedge price risks in one fuel by trading in another.
- Widening the EU market for gases through promoting interconnections or market reforms will help to reduce fragmentation further.
- The development of new gas sources could result in new players coming to the market with more diverse trading needs. For example, to the extent that power-to-gas production operates flexibly depending on electricity prices, this might drive greater short-term trading in gas markets.

However, it is difficult to predict with certainty the impacts such developments might have on liquidity. As a result, market participants may perceive a risk that liquidity could fall. This perception itself may increase the cost of investments in low-carbon and renewable gases. If levels of liquidity were to eventually fall, this would (in addition) result in an increase in the costs to market players associated with risk management.

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for risk of lack of liquid market for sale of heterogenous gases

While it may not be possible to entirely remove any risk market participants perceive regarding a possible fall in liquidity, some steps may help to both limit any eventual decline in liquidity.

One potential solution we consider is a **more systematic consideration of the potential impacts on liquidity in energy system planning**, in particular for infrastructure investment and decommissioning decisions.[56] For example, conversion of an existing pipeline to use hydrogen may bring benefits in terms of decarbonisation, but there may be a risk that it contributes to a fragmenting of the gas market. Considering liquidity impacts explicitly would allow this trade-off to be optimised. It should therefore promote 'least cost' infrastructure planning decisions in a wider sense.

There are different aspects to liquidity and so different issues might need to be assessed. For example, higher bid-offer spreads may lead to higher transaction costs (which can be quantified and included in a social cost-benefit analysis). However, they may also contribute (along with reduced availability of hedging products) to higher risks for developers, which may not be so easily quantified. Exactly how to include liquidity impacts in system planning, and the balance between a quantitative and qualitative assessment, would therefore need further consideration.

We focus above on a fairly limited intervention related to energy system planning, as this seems to be one of the areas that can be more easily regulated or legislated for in the EU environment. However, it is clear that strategic energy policy at local, national or EU level (such as regarding a switchover from natural gas to hydrogen) may have wider-ranging impacts on liquidity. It is therefore also important that energy policy decisions (continue to) consider impacts on market liquidity.

Figure 43 below summarises our assessment of the option set out above. In summary, we would recommend ensuring a more systematic consideration of the potential impacts on liquidity in energy system planning (for more detailed assessment and policy design work).

Figure 43 Assessment of potential solutions to address risk of lack of liquid market for sale of heterogenous gases

Solution	Description / Comments	Overall CBA	Investment climate	Consumer impacts	Complexity / Timeline	EU area?	Re-commend?
Liquidity impacts to be considered in system planning	*Liquidity impacts to be considered in infrastructure planning (incl. investment / decommissioning)*						

Source: See Appendix C for further detail on the assessment.

5.5.4 Unharmonised national policies distorting trade

Cross-border competition distortions may result from a range of unharmonised support system set-ups in Member States. For instance, domestic renewable and low-carbon gas, which is traded nationally, could be hindered if imported renewable and low-carbon gases not only receive support in the destination country but also in the country of origin.

For instance, in Sweden biogas producers suffer from distorted competition from imported biogas since renewable gas producers receive policy support in some countries. In Sweden, however, support policies target the consumption side, resulting in dual support of imported biogas relative to domestic gas.

Another example where regional rules complicate the situation is international trade between Baden-Württemberg, Germany, and Denmark. In Baden-Württemberg,

[56] Liquidity impacts are not, currently, considered in the ENTSOG CBA methodology.

existing rules for biomethane in heating create concerns of double-subsidisation of biogas produced in Denmark and consumed in Baden-Württemberg. Namely, the EWärmeG Baden-Würtemberg[57] obliges heat demand for houses to be 15% supplied by renewable energy. However, subsidies to Danish renewable gas production mean there is not a level playing field. Energy suppliers in Baden-Würtemberg may find it cheaper to purchase Danish renewable gas (to meet their obligations) since it is subsidised, even if other gas sources may entail lower resource costs to society. .

This barrier has not been retained in the short list of issues as part of this study. However, these issues represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities. We note that State aid control should, in principle, provide an existing tool to address such double-subsidy concerns.

5.5.5 Lack of coherent cross-border framework for decommissioning

As explained in section 3.3.2, some existing natural gas infrastructure might be re-purposed for renewable and low-carbon gases. However, overall gas demand is expected to fall in the coming decades. While a decrease in gas demand does not lead to a proportional decrease of infrastructure needs, as the same or most of the infrastructure may still be needed to satisfy peak supply, there is a possibility that some gas infrastructure may require decommissioning going forward. This would be expected to include cross-border infrastructure (i.e. interconnectors) as well as other infrastructure (such as long-distance transnational pipelines) that is currently used to serve load in multiple Member States.

According to the current cross-border cost allocation framework (under EU Regulation 347/2013, the "TEN-E Regulation"), the cost of infrastructure will have been allocated across Member States depending on the distribution of benefits over the expected lifetime of the infrastructure. But much of the existing capacity has been built before the cross-border cost allocation framework was introduced. This means that the default position for older existing infrastructure is that all resulting costs from decommissioning may be allocated purely to the country it was built in.[58]

This could lead to two potential inefficiencies:

- **Co-ordination issues**: Gas infrastructure located within a given Member State may influence flows (and costs) in other countries. If individual Member States perceive that the benefits of continuing to operate gas infrastructure located in their territory are outweighed by the costs of doing so, they may unilterally decide to decommission the assets in question. However, such assets may provide benefits to other countries, and might be beneficial from an EU-wide perspective.
- **Cost-recovery issues**: If Member States bear the entire cost of decommissioning assets within their territory (and these costs are recovered

[57] EWärmeG BW by ministry of Environment, Climate Protection and the Energy Sector Baden-Württemberg https://um.baden-wuerttemberg.de/fileadmin/redaktion/m-um/intern/Dateien/Dokumente/5_Energie/Energieeffizienz/EWaermeG_BW/150317_Novelle_Erneuerbare_Waerme-Gesetz.pdf

[58] In other cases, infrastructure may have been built with costs being shared across Member States based on the distribution of expected benefits.

from gas users), this may exacerbate issues related to sunk costs weighing on gas grid fees (see section 5.2.2 above).

This barrier has been retained in the short list of issues and potential solutions are therefore assessed below.

Recommendation for lack of coherent cross-border framework for decommissioning

One solution to address the barrier discussed is a **framework for co-ordinated cross-border decommissioning decisions**.[59] By 'cross-border' decommissioning we refer to both:

- Decommissioning of cross-border infrastructure (e.g. an interconnector); and
- Decommissioning of infrastructure which affects flows across borders (e.g. decommissioning storage in country A, which may also be used by users in country B).[60]

To work, such an option would need TSOs to share information on potential decommissioning decisions. Identification of infrastructure potentially subject to decommissioning may take place in the context of national development plans, and subject to approval by NRAs. TYNDP preparation may provide a forum whereby information on such plans could be shared and their potential implications assessed at EU level.

TSOs and NRAs could then jointly decide on action for infrastructure that may span across (or have impacts across) borders. ENTSOG could derive a 'decommissioning CBA methodology' (for the infrastructure not subject to CBA and cross-border cost allocation to begin with). A methodology for sharing costs between TSOs (either in the case of decommissioning or in the case of avoided or delayed decommissioning) would also need to be developed. In the first case NRAs would need to approve (and agree on) any cost sharing. However, as is the case for PCIs, ACER could play a role in approving or mediating such cross-border cost allocation decisions if needed.

The main benefit of a cross-border decommissioning framework is that it would provide a route to avoiding or delaying the decommissioning of assets that might deliver benefits outside of the Member State in which they are located. This in turn should lead to reduced costs of gas supply at the EU level and improved security of supply, compared to the counterfactual. By providing for more equitable sharing of decommissioning costs across borders, it may also help to reduce issues related to dismantling costs weighing on gas grid fees (see section 5.2.2).

Figure 44 below summarises our assessment of the options set out above. In summary, we would recommend taking forward a framework for cross-border decommissioning decisions along the lines described above (for more detailed assessment and policy design work).

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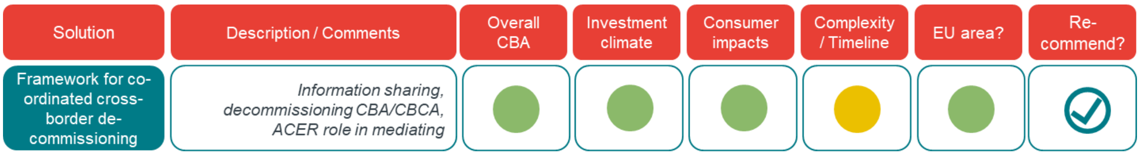
[59] CEER has outlined a similar process in its "Public Consultation Paper on Regulatory Challenges for a Sustainable Gas Sector" dated 22 March 2019 (see section 5.3).
[60] Infrastructure conversion decisions (e.g. from natural gas to hydrogen) are not considered under this heading.

Figure 44 Assessment of potential solution to address lack of coherent cross-border framework for decommissioning



Source: See Appendix C for further detail on the assessment.

5.5.6 DIFFERENT TIMESCALES FOR ELECTRICITY / GAS MARKETS

Across the EU, settlement periods for balancing are typically shorter for electricity (15-30 min) than for gas (1 hour – 1 day). Market players may therefore have a strong incentive to respond to short-term changes in market conditions on the electricity system (e.g. fluctuations in supply due to changing wind conditions). By contrast, on the gas side, players will only need to balance their portfolios on an hourly or daily basis.

With growth in sector coupling technologies such as power-to-gas, therefore, it is possible that volatility on the electricity system could induce volatility on the gas system (changing output from power-to-gas facilities). Given that players do not need to ensure their gas positions are balanced over timescales shorter than an hour or a day, gas system operators will need to carry out more actions to ensure system stability. The costs of such actions will typically be socialised across gas market participants (as opposed to being 'targeted' towards the players causing these actions). The reduced incentives for participants to balance could therefore lead to a higher overall cost of balancing the gas system.

It is not clear, however, whether this will be a significant issue. Gas system operators already face a similar issue today with gas power stations in systems with high RES penetration. They are able to manage risks given the inherent flexibility of the gas system (for example, using linepack flexibility). As long as system operators are incentivised to minimise costs and have the tools to ensure system stability (e.g. ability to buy/sell sub-hourly profiles of gas), balancing costs need not rise excessively. That said, we note the problem might become more complex going forwards, with greater gas injection taking place at distribution level, where linepack flexibility might be lower.

This barrier has not been retained in the short list of issues as part of this study. However, these issues may represent a risk for the achievement of the energy transition and would benefit from further investigation and potential intervention by relevant authorities.

6 Summary of Recommendations

In this section, we provide an overview of recommended solutions to address short-listed barriers and gaps.

We find that, overall, our recommendations can be grouped into five categories:

- **Interventions via climate and renewable policy, and support for innovation:** this group of solutions is designed to address barriers and gaps related to the relative immaturity of sector coupling and low-carbon and renewable gas technologies;

- **A regulatory toolbox to address cost recovery issues:** this group would serve to address barriers and gaps from group 2, that is to say issues contributing to an unlevel playing field across technologies;

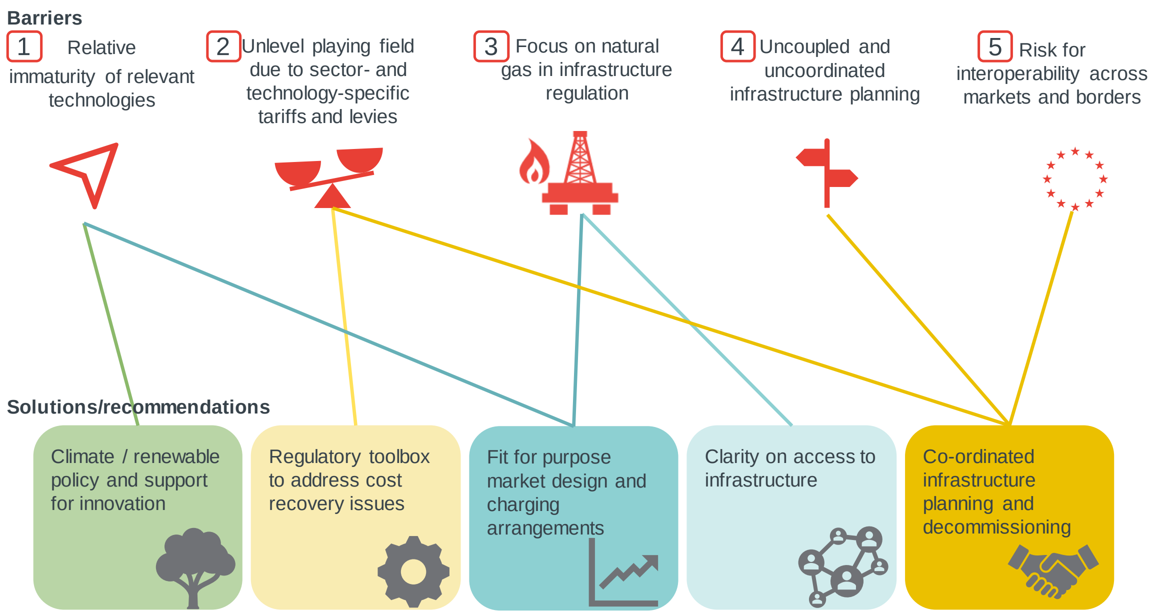
- **A number of changes to market design and charging arrangements to make them more fit-for-purpose in the face of the expected changes in the sector:** these would address issues stemming both from the relative immaturity of relevant technologies, and the historic focus on natural gas in infrastructure regulation;

- **The provision of increased clarity on access to infrastructure** would also aim to overcome barriers and gaps stemming from the historic focus on natural gas in infrastructure regulation; and

- **The facilitation of co-ordinated infrastructure planning and decommissioning,** which would be expected to help achieve a level playing field across technologies, avoid the risks of uncoupled and uncoordinated infrastructure planning, as well as the risks related to interoperability across markets and borders.

This is summarised in Figure 45 below.

Figure 45 Overview of barrier categories and solution categories



Source: Frontier Economics

As explained above (in section 4), our recommendations arise from the qualitative research and analysis undertaken as part of our assignment. Given the scope of this study, neither detailed work on design of individual policy options nor a robust quantitative assessment of costs, benefits and distributional impacts of all options have been carried out. Further work will be needed on these aspects.

6.1 Climate and renewable policy and support for innovation

Support for innovation is key to addressing some of the barriers particularly relevant in the transition phase for renewable and low-carbon gas technologies.

Indeed, **(financial) support for Research and Development (R&D), pilots or demonstration projects** and, potentially, beyond that, **ongoing support for further deployment following the demonstration phase** would be a direct way to address positive externalities related to innovation. State aid rules and/or internal energy market legislation would need to ensure that any ongoing support is granted in a way that promotes competition and market integration.

We see a case for **allowing network operator ownership (or involvement in) research-stage or pilot power-to-gas projects** in specific circumstances to address co-ordination barriers. Network operator involvement would need to be targeted in scope (e.g. limited to understanding technical impacts on the networks) and subject to conditions (such as time limits and knowledge sharing) to avoid potential longer-term negative effects on competitive and market-based investments. NRAs would need to play an important role in minimising potential negative consequences.

Power-to-gas ownership by network operators could also be relevant once the transition phase has ended, in situations where it is difficult (or disproportionate) to ensure market signals convey all possible system benefits (e.g. the benefits of the specific location of a facility) well enough. Again, NRAs would play an important role in ensuring that such projects would indeed be beneficial for the system and in verifying that it is not possible to secure market-based investment.

6.2 Regulatory toolbox to address cost recovery issues

As highlighted in the description of barriers above, the ways in which policy costs (such as RES support costs) and the costs of gas infrastructure are recovered matter for the uptake of renewable and low-carbon gases.

A direct solution to the issue of power-to-gas facing end-user taxes on electricity would be to ensure that **only final electricity consumption faces (cost-recovery) taxes and levies**.

Dealing with issues related to sunk and decommisisoning costs requires a suite of regulatory solutions.

To reduce the risk of over-investment in gas infrastructure, **leaving asset stranded risk with network operators** may be an option. However, this may only have limited scope of application: **for forward-looking investments over which network operators exercise a degree of discretion** (and provided such investments can be easily identified). For other types of costs, more frequent (regulatory) **reviews of whether prospective investments are necessary** may be beneficial.

Regarding the distribution of the costs of legacy investment (and of decommissioning costs):

- To minimise distortions between consumer choices between energy carriers, **sunk infrastructure costs could be distributed away from infrastructure users and towards taxpayers** instead.
- If this is not feasible (or not acceptable), ensuring **an equitable distribution of sunk costs between different energy carriers** (i.e. electricity, gas and heat) could be an alternative to investigate.
- **Allowing for faster recovery of costs** (e.g. accelerated regulatory depreciation) may also be part of the toolkit, although the benefit in terms of avoiding distortions to choices between energy carriers is less clear.

6.3 Fit for purpose market design and charging arrangements

Given the historical focus on natural gas, gas market design needs to evolve to efficiently accommodate renewable and low-carbon gases into the market. This is particularly the case given that much of the new capacity is expected to be connected at the distribution level.

There are **a variety of connection charging approaches that avoid the first-mover disadvantage while still preserving locational signals** (to varying degrees). While there may be complexities in their implementation, such options have the potential to encourage the development of low-carbon and renewable gases while minimising the risk of incentivising uptake of expensive connections. Consistency between the frameworks for connection charging and for dealing with connection requests (see "Clarity on access to infrastructure" below) would be important.

The creation of **harmonised injection charging rules** (at distribution level) would increase certainty for developers regarding how they might be charged for use of the gas grid, in turn reducing the costs across the EU of deploying renewable and low-carbon gases.

Successful integration of renewable and low-carbon gases into the market also **requires that the framework for managing physical congestion is complete** (in particular at distribution level).

- **Competitively tendered voluntary agreements** between network operators and participants to limit injections may be a relatively straightforward measure to implement.
- **More sophisticated market-based systems** allowing for real-time adjustment of bids may offer greater efficiency, but may not be a proportionate solution if congestion issues remain limited.
- **Obliging participants to limit injections** may be appropriate in situations where there may be a limited number of options to address localised congestion issues, leading to possible market power concerns.

6.4 Clarity on access to infrastructure

Many of the barriers historically stemming from the regulation on natural gas could be addressed through greater clarity on the access for new gases to infrastructure.

To reduce the risks to developers from uncertainty regarding quality standards, it would first be important to **provide improved visibility on gas quality for gas producers**. **Clear rules on how quality is managed on an ongoing basis** (such as the potential impacts on connection requests or on interruption of production and possible compensation) would help to further reduce risks.

The first step in addressing TSOs' incentives to focus on gases compatible with their infrastructure would be **a review of regulatory frameworks to identify such biases**. An additional specific (but partial) solution might be **an obligation for network operators to connect** renewable and low-carbon gas sources to the gas system, provided certain conditions (specified in advance, such as regarding gas quality) are met.

Finally, **clarifying whether (and under what conditions) the provisions of the Gas Directive apply to hydrogen (and other gases)** is likely to provide increased clarity for developers regarding their ability to secure access to infrastructure, reducing the risks to investment.

6.5 CO-ORDINATED INFRASTRUCTURE PLANNING AND DECOMMISSIONING

Improved co-ordination in planning and decommissioning decisions can help to improve the efficiency with which infrastructure is used. It could also help to improve interoperability across markets and sectors.

An assessment of the implications of the expected change in the role of gas as well as the mix of technologies on the likely optimal level of gas storage capacity would be a first step in addressing some of the uncertainty related to storage, and could provide a basis for assessing whether further intervention is needed.

Co-ordinated infrastructure planning (between transmission and distribution level, and between electricity and gas networks) would allow operators to arrive at a shared view on possible developments in demand and supply and identify and evaluate investment possibilities in different parts of the system. This would be an important enabler of lower costs. **Regulatory incentives on individual operators to achieve cost savings at system level** may provide the mechanism for ensuring any potential cost savings identified are actually achieved.

Ensuring a more systematic consideration of the potential impacts on liquidity in energy system planning, in particular for infrastructure investment and decommissioning decisions, would allow liquidity impacts to be traded off against other costs and benefits. This should therefore promote 'least cost' infrastructure planning decisions in a wider sense.

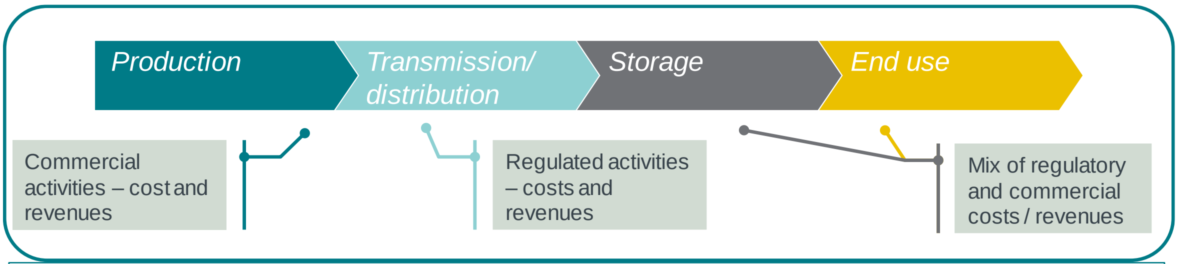
A framework for cross-border decommissioning decisions could provide a route to avoiding or delaying the decommissioning of assets that might deliver benefits outside of the Member State in which they are located. By providing for more equitable sharing of decommissioning costs across borders, it may also help to reduce issues related to dismantling costs weighing on gas grid fees.

Appendix A Regulatory barriers and gaps: detailed information on the research methodology and tools

Business Scenarios

We also take a micro perspective of stakeholders dealing with specific relevant technologies and respective business scenarios. We therefore ordered the barriers we had found in the country-based research along the value chain. The steps in the value chain are a) production, an area where revenues stem from commercial activities, b) transmission and distribution, an area where revenues are regulated, c) storage and d) end use, areas where revenues come from a mix of regulated and commercial activities. By structuring the barriers this way, we ensured that we do not miss a barrier that is specific to the interaction between different steps in the value chain.

Figure 46 Structure following the value chain of a technology along business scenarios



1. T-connected PtG facility (electrolysis) injecting gas (CH4 or H2) into dedicated gas infrastructure serving (industrial) final consumers
2. D-connected PtG facility (electrolysis) injecting gas (CH4 or H2) into existing gas D-grid (no direct link to final consumer)
3. Biomethane injection facility injecting into existing gas grid (T or D, no direct link to final consumer)
4. D-connected power-to-gas-to-power storage facility (hydrogen) with dedicated on-site gas storage, arbitraging between off-peak and peak electricity prices
5. Imported hydrogen produced from natural gas using CCS flowing through the transmission grid.

Source: Frontier Economics
Note: The business sceanrios are a small set of examples and aim to capture different perspectives, but they do not aspire to include all possible business scenarios.

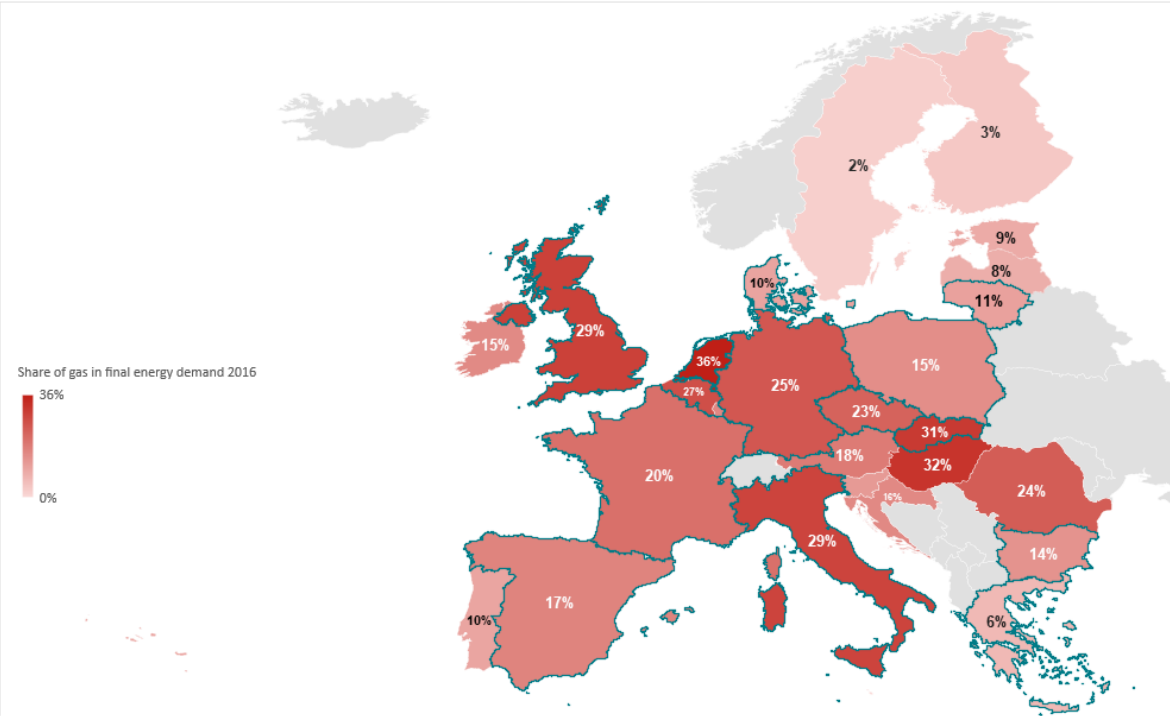
Appendix B Regulatory barriers and gaps: overview of the major findings of the country-based research

Selection of countries

The country-based research covers:

- The largest gas markets (by consumption) in the EU: the UK, Germany, Italy, France, the Netherlands, Spain and Poland
- Countries with high RES potential, e.g.
  - UK, Denmark, Germany, the Netherlands, for wind;
  - France, Greece, Italy and Spain for solar
- Countries with large biogas potential: e.g. France, Italy, Denmark
- Countries with high district heating coverage: Czech Republic, Denmark, Slovakia and Lithuania
- Certain countries to ensure a diverse geographical sample: Greece and Bulgaria

Figure 47 Country selection



Source: Eurostat 2016

The country-based research includes the systematic review of regulation with a view to identify potential barriers and gaps. Therefore we used the knowledge of our own country experts and identified pilot projects (see the Intermediate Report) and interviewed participating parties and analysed their feedback. Figure 48 gives an overview of the information collected as part of this exercise.

The table below explains the categories of information presented in Figure 48.

Topic	
Current role of gas	
in % of final energy demand	Percentage of final energy demand met by gas.
Demonstration/pilot projects	
for biogas/-methane	Are there any pilot projects for biogas production and/or biomethane injection to the grid?
for renewable or fossil-based hydrogen	Are there any pilot projects for hydrogen production and injection to the grid?
Technical regulation / access	
Gas quality standard covers biomethane	Does a national specification exist for biomethane?
Gas quality standard covers hydrogen	Does a national specification exist for hydrogen?
Definition exists for biogas/-methane, hydrogen	Are low-carbon and renewable gases defined in national law / regulation?
Limit for H_2 blending in place	Has there been an assessment of the amount of H_2 it is possible to blend with natural gas in the grid?
Regulation for H_2 and H_2 infrastructure in place	Is there tariff regulation for H_2 infrastructure?
Priority access for biomethane, hydrogen	Is there priority access for renewable gases?
Curtailment rules for biogas, hydrogen	Are rules (and compensation) defined for the interruption of gas injection to the grid?
Unbundling and TPA applies to biogas and hydrogen	Does national regulation provide that third party access and unbundling necessarily applies?
Tariffs	
Connection cost liability TSO and DSO	Are renewable gas producers required to pay for connection costs to the grid?
Specific network tariffs for biogas and hydrogen	Is low-carbon and renwable gas injection subject to a different network tariff structure?
Infrastructure regulation	
Depreciation period for gas infrastructure	What is the average remaining life of gas grid assets?
Decommissioning cost liability	How are infrastructure decommissioning costs expected to be recovered?
SoS and flexibility	
Storage obligation in place	Are there obligations to hold storage capacity?
Capacity mechanism in place + participation by gas sector / Power-to-Gas	Where a capacity remuneration mechanism is in place, can renewable and low-carbon gas-fired capacity participate in capacity mechanisms?
Balancing markets - participation by gas sector / Power-to-G	Could power plants running on renewable or low-carbon gases participate in reserves or the balancing market?
Renewable and climate policy	
Targets: specific for biogas, renewable hydrogen	Have sector-specific targets been set?
GoOs for biogas	Are guarantees of origin established for biogas?
GoOs for renewable hydrogen	Are guarantees of origin established for renewable hydrogen?
End-user taxes for electricity, gas	Are there energy and carbon taxes on natural gas and electricity?
Power-to-Gas exempted?	Would power-to-gas facilites be exempted from end-user taxes?

Figure 48 Country-based research overview

NE = not evidenced

Topic	Bulgaria	Czech Republic	Denmark	France	Germany	Great Britain	Greece
Current role of gas							
in % of final energy demand	13%	23%	10%	20%	25%	29%	6%
Demonstration/pilot projects							
for biogas/-methane	NO	NO	YES	NO	YES	NE	NE
for renewable or fossil-based hydrogen	NO	YES	YES	YES	YES	YES	NO
Technical regulation / access							
Gas quality standard covers biomethane	NO	NO	YES	YES	YES	NE	NE
Gas quality standard covers hydrogen	NO	NO	YES	NO	YES	NE	NO
Definition exists for biogas/-methane, hydrogen	NO	NO	NE	YES	YES	YES	NE
Limit for H_2 blending in place	NO	NO	YES	YES	YES	YES	NE
Regulation for H_2 and H_2 infrastructure in place	NO	NO	NE	NO	YES	NE	NE
Priority access for biomethane, hydrogen	NO	NO	NE	NE	YES	NO	NO
Curtailment rules for biogas, hydrogen	NE	NO	NE	NO	NO	NE	NO
Unbundling and TPA applies to biogas and hydrogen	YES	NO	NO	NE	YES	NO	NE
Tariffs							
Connection cost liability TSO and DSO[61]	100%	NE	0%	40%	75%	0%	NE
Specific network tariffs for biogas and hydrogen	NO	NO	NE	NO	YES	NE	NE

[61] Remaining connection cost to be paid by the facility operator

Topic	Bulgaria	Czech Republic	Denmark	France	Germany	Great Britain	Greece
Infrastructure regulation							
Depreciation period for gas infrastructure							
Pipelines	35	NE	30	NE	30-40	45	40
Other equipment	15	NE	NE	NE	NE	NE	NE
Decommissioning cost liability	NE	NE	TSO	NE	NE	NE	NE
SoS and flexibility							
Storage obligation in place	YES	YES	NO	YES	NO	NO	NO
Capacity mechanism in place + participation by gas sector / Power-to-Gas	NE	NO	NE	NE	NO	YES	NE
Balancing markets - participation by gas sector / Power-to-G	NE	NE	NE	NE	NE	NE	NO
Renewable and climate policy							
Targets: specific for biogas, renewable hydrogen	NO	NO	NO	YES	NO	NO	NO
GoOs for biogas	NO	NO	YES	YES	YES	YES	NO
GoOs for renewable hydrogen	NO	NO	YES	NE	YES	NO	NO
End-user taxes for electricity, gas	YES	YES	YES	YES	YES	YES	YES
Power-to-Gas exempted?	NO	NO	NE	YES	YES	NE	NE

Topic	Italy	Lithuania	Poland	Slovakia	Spain	The Netherlands
Current role of gas						
in % of final energy demand	37%	11%	14%	25%	NE	NE
Demonstration/pilot projects						
for biogas/-methane	YES	NO	NO	NO	NO	YES
for renewable or fossil-based hydrogen	NO	NO	YES	NO	NO	YES
Technical regulation / access						
Gas quality standard covers biomethane	YES	YES	NO	YES	NO	YES
Gas quality standard covers hydrogen	YES	NO	NO	NO	NO	YES
Definition exists for biogas/-methane, hydrogen	NO	YES	YES	YES	YES	YES
Limit for H_2 blending in place	NO	YES	NO	YES	NO	NO
Regulation for H_2 and H_2 infrastructure in place	NO	NO	NO	NO		
Priority access for biomethane, hydrogen	YES	NO	NO	NO	NO	NO
Curtailment rules for biogas, hydrogen	NO	YES	YES	YES	NO	YES
Unbundling and TPA applies to biogas and hydrogen	NO	YES	YES	YES	NO	NO
Tariffs						
Connection cost liability TSO and DSO	0-20%	40%	0%	75%	NE	NE
Specific network tariffs for biogas and hydrogen	NO	NO	NO	NO	NO	NE

Topic	Italy	Lithuania	Poland	Slovakia	Spain	The Netherlands
Infrastructure regulation						
Depreciation period for gas infrastructure						
Pipelines	50	55	NE	40-50	NE	32
other equipment	NE	4-60	NE	12-50	NE	NE
Decommissioning cost liability	Consumers	TSO/DSO	Consumers	TSO/DSO	NE	Infrastructure owner
SoS and flexibility						
Storage obligation in place	YES	YES	YES	YES	YES	NO
Capacity mechanism in place + participation by gas sector / Power-to-Gas	NO	NO	YES	NO	YES	NO
Balancing markets - participation by gas sector / Power-to-Gas	YES	YES	YES	YES		YES
Renewable and climate policy						
Targets: specific for biogas, renewable hydrogen	NO	NO	NO	NO	NO	YES
GoOs for biogas	YES	NO	NO	NO	NO	YES
GoOs for renewable hydrogen	NE	NO	NO	NO	NO	NO
End-user taxes for electricity, gas	YES	YES	YES	YES	YES	YES
Power-to-Gas exempted?	NE	NE	YES	YES	NO	NO

Appendix C Detailed information on solutions assessment

Contents

Methodology: Assessment of individual categories

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Positive	*Benefits outweigh costs.* *Indicates lower magnitude of impacts.*	*Positive for all investors; reduces risk*	*Reduces bills unambiguously; positive for fairness and choice*	*Low risk of unintended consequences; implementation time ≤1 year*	*Clear case for co-ordinated EU action*
Mixed / Neutral	*Balance of costs and benefits neutral or uncertain.*	*Mixed or neutral impacts on investors*	*Mixed or neutral impacts*	*Medium risk of unintended consequences OR 2-4 years for implementation*	*Uncertain / limited gain to co-ordinated EU action*
Negative	*Costs outweigh benefits.* *Indicates lower magnitude of impacts.*	*Negative for investors; increases risk*	*Bills increased; negative for fairness and choice*	*High risk of unintended consequences OR ≥5 years for implementation*	*No gain to co-ordinated EU action*

Assessed solutions: Category 1 - Relative immaturity of sector coupling and renewable gases technologies

Barrier category:

Relative immaturity of relevant technologies

Solutions assessed from categories:

- Fit for purpose market design and charging arrangements
- Climate / renewable policy for innovation

1.1 Lack of internalisation of positive externalities from innovation / learning

- **1.1.1** Support for R&D, pilots or demonstration projects
- **1.1.2** Ensure ongoing support promotes competition and market integration
- **1.1.3** EU-wide gas-sector specific targets
- **1.1.4** Network operator involvement in research-stage or pilot power-to-gas projects
- **1.1.5** Network operator involvement in power-to-gas projects where difficult ensure market signals convey all possible system benefits

1.4 First-mover disadvantage – high infrastructure connection costs

- **1.2.1** Sharing of connection costs across multiple connections (actual or projected)
- **1.2.2** Shallow connection costs (transitional)

Lack of internalisation of positive externalities from innovation / technology spillovers / learning: Assessment of recommendations

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Support for R&D, pilots or demon-stration projects	*The counterfactual is uncertain, and depends on the amount of innovation funded by Member States.* *Investment costs and operating costs associated with innovation projects entail a resource cost to society. To the extent such projects deliver environmental and security of supply benefits themselves, some of this cost may be offset in the short run by avoiding the costs of alternative measures to meet environmental and security of supply goals. In the short-run, it might be reasonable to expect there would still be a net cost to society associated with these projects. However, over the long-run, the costs of some supported technologies should fall (assuming technologies that fail to reduce costs stop being supported) and the number of technological options available should increase. Taken together, this increases the likelihood that, over the long-term, environmental and security of supply goals can be met at lower cost.* *To maximise benefits, a robust selection process will be central, noting that the nature of innovation means there is still a risk that some supported technologies may not prove beneficial (or may not reduce their costs).*	*Increased certainty over available funding may help to attract private sector finance into projects, given riskiness of early stage investments.*	*Consumers will bear higher costs in the short run. The distribution of costs depends on how support for technologies is funded (i.e. energy prices vs. general taxation, which energy carrier).* *Overall, consumers should benefit over the longer-term from cost reductions in the energy system (with benefits concentrated on those consumers using the supported technologies).* *Greater innovation could also lead to greater consumer choice.*	*For EU-wide funding (and in many MS), institutions to manage innovation funding are already in place (e.g. Innovation Fund), making it relatively quick to implement.* *To ensure benefits, innovation funding needs to be well-managed. In particular, there is a risk of picking the 'wrong' winners and/or capture by vested interests.*	*EU-wide funding may address the potential risk of individual MS not being fully in-centivised to fund innovation due to benefits spilling over to other countries.*

Lack of internalisation of positive externalities from innovation / technology spillovers / learning: Assessment of recommendations

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Ensure ongoing support promotes competition and market integration	*In the counterfactual, we assume there are no specific rules governing what form support schemes for renewable and low-carbon gases should take. This means that schemes introduced by MS may have less emphasis on the use of competitive tendering, technology neutrality and cross-border participation. There may also be less emphasis on market integration – support schemes may, for example, require TSOs/DSOs to manage producers' output, rather than producers/shippers being responsible for finding a route to market and ensuring balance.* *Increased emphasis on competitive tendering, technology neutrality and cross-border participation should in principle lead to greater efficiency (increasing the likelihood that projects supported are those that entail the lowest resource cost to society). This may be partially offset by a potential increased cost of capital, though we think this can be minimised (see 'Investment environment').* *While players may perceive additional risk if obliged to ensure flows are in balance and to procure the appropriate amount of capacity, this risk transfer is likely to be efficient since they are probably better-placed to manage these risks than network operators. For example, shippers can contract with producers who are better able to forecast and help balance. The resulting incentives for producers should lead to measures being taken that help to reduce costs of balancing the system both in the short- and long-run.*	*On the one hand, greater certainty on assessment framework could help investment.* *On the other hand, investors may perceive increased risk from competitive tendering and direct marketing.* *The risk from competitive tendering can be minimised if support is allocated at a sufficiently early stage of project development.*	*Overall, reduced costs in the energy system should lead to overall lower costs for consumers.*	*Some time required for thinking done on RES-E to be adapted for gases. But overall not radical departure from current arrangements.* *Design of cross-border support schemes will need careful consideration to achieve efficient outcomes where underlying market arrangements (e.g. connection charging) are not harmonised.*	*State aid guidelines and/or EU gas market legislation would need to be updated.*

Lack of internalisation of positive externalities from innovation / technology spillovers / learning: Assessment of recommendations

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
EU-wide gas sector-specific targets	*In the counterfactual, we assume that at EU level there are targets for decarbonisation, overall renewable energy and energy efficiency, but no gas-sector specific targets. Member States may have their own targets.* *The net effect of an EU-wide gas sector-specific target is uncertain. Decarbonisation and renewable goals may still be met under the counterfactual. Gas sector-specific targets may (if binding) simply result in an additional constraint for the EU (or individual MS) to meet, resulting in higher costs associated with meeting decarbonisation, renewable and energy efficiency goals.* *There is a possibility that, if sector-specific targets address a possible political engagement barrier (that can otherwise not be solved through existing or potential reforms to Energy Union governance arrangements), they may increase the likelihood that energy and climate goals (particularly in the non-traded sector, where there is no 'cap and trade' system) are met.*	*A target would provide greater certainty for those developers falling in its scope but potentially lower certainty for those out of its scope.*	*As noted (see 'net societal' costs), there is a risk that costs in the energy system could increase, which would ultimately feed through into higher energy prices for consumers.*	*New sector-specific targets would be a significant change relative to the status quo, likely requiring substantial consultation and analysis regarding the level of any targets and their design.* *If targets are not Member State-specific, governance arrangements will be needed to ensure Member State contributions add up to any EU target for gases.*	*EU action would be required to introduce a binding EU-wide target.*

Lack of internalisation of positive externalities from innovation / technology spillovers / learning: Assessment of recommendations

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Network operator involvement in research-stage or pilot power-to-gas projects	*If intervention targeted to areas where network operators may have a greater incentive to act compared to other players (e.g. researching impacts of gases on network) and if co-ordination with other players is otherwise difficult, this could lead to greater research into and deployment of power-to-gas technologies.* *This should in turn ultimately reduce costs of decarbonisation in the long run (see assessment for 'R&D / pilots / deployment support + innovation incentives for network operators'), assuming that any learning from such projects is made available to other market participants.* *TSOs might also have greater incentives to finance projects if there is a possibility of system benefits being significant. If/when this is established, possible mechanisms for rewarding delivery of these benefits (by non-regulated players) might be investigated (see next slide for more details).* *The assessment of a potential net benefit assumes that potential negative consequences (see 'Investment environment' and 'Complexity and timelines') can be limited.*	*There is a risk that allowing TSO participation could deter investment from non-regulated entities (since they are not able to access finance on similar terms). A further deterrent may arise if grid operators are allowed to sell output from such projects could be on the market (to ensure efficiency), .* *The risks might be mitigated to the extent that deployment levels do not reach significant quantities and intervention is targeted to cases where there may be co-ordination barriers in the initial stages of technology development.*	*In the short term, additional costs may be recovered through grid fees, leading to an increase in bills for consumers. Over long-run, energy consumers as a whole should benefit from lower costs in the energy system resulting from innovation.* *Which consumers bear the costs (electricity or gas) depends on which grid operator carries out the investment and how the benefits are distributed across the gas and electricity systems.*	*The degree of change and timescale required depends on whether legislative changes are required.* *The role of NRAs in approving funding could help to limit unintended consequences – in particular ensuring that projects are limited to R&D relevant to networks and ensuring that network operators do not engage in projects that might allow them to benefit from market power.*	*May involve changes to EU legislation (for example regarding un-bundling). There may also be a role for EU funding to ensure innovation is not con-centrated in a few Member States.*

Lack of internalisation of positive externalities from innovation / technology spillovers / learning: Assessment of recommendations

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Network operator involvement in power-to-gas projects where difficult to ensure market signals convey all possible system benefits	*Under the counterfactual, potential barriers may prevent market players from capturing system benefit (as well as commercial benefit). This includes the potential difficulty or inability to amend market design to allow capture of such benefits by market players. This may lead to under-investment in power-to-gas technologies compared to what would be efficient.* *Allowing network operator ownership in such circumstances could therefore lead to system benefits being maximised (i.e. lower costs of operating networks), provided they face incentives to realise such benefits. Such benefits may be highly location-specific. The assessment of a potential net benefit assumes that ways can be found to allow such projects to realise both commercial and system benefits (required to ensure efficiency), while limiting the potential for negative consequences (see 'Investment environment' and 'Complexity and timelines').* *Ownership could either be by electricity or gas network operators. Different types of operator may choose different locations for developing power-to-gas installations. Co-ordination and communication between operators would be important to ensure benefits are maximised.*	*The measure would be positive for TSOs, as they would be able to increase investment, on which they could earn a rate of return.* *However, there is a risk that if market design improvements were indeed a viable alternative, that other players are prevented from carrying out investments they might otherwise have done. And market players may be negatively affected if network operators can sell output from the facilities on the market.*	*Provided that both system and commercial benefits can be realised by such projects, this should help to reduce overall costs across the energy system, in particular those associated with system management. Ultimately this should feed through to lower energy costs for consumers, though different consumers (e.g. electricity or gas) may benefit differently.*	*Legislative changes are likely to be required.* *The role of NRAs in approving grid operator ownership could help to limit market distortions – for example ensuring that network operators' involvement is limited to projects that are socially desirable and where changes to market design or not feasible or proportionate and in which market players cannot be attracted to invest (for example by applying a 'market test').*	*May involve changes to EU legislation (for example as regards un-bundling).*

First-mover disadvantage – high infrastructure connection costs including 'deep' costs: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Sharing of connection costs across multiple connections (actual or projected)	*Connection charges often result from a 2-stage analysis. The first step is to calculate costs that should in principle be faced by individual connections (shallow or deep depending on the local framework). The second step is to compare this with expected tariff revenue from connections (which may include assumptions on factors such as future take up). Finally, a decision on what proportion of the costs (in step 1) to actually charge a given connection is made.* *Such approaches lead to a reduction in the costs borne by individual connections (for example due to spreading of costs over expected connections). As described above for shallow charging, this has the potential to lead to higher deployment of renewable and low-carbon gases, particularly in the steady state.* *Compared to shallow charging, however, charges would be more cost-reflective, and it may be possible (depending on precise design) to largely avoid incentivising expensive connections.*	*This might be viewed positively by investors in renewable and low-carbon gases. As for shallow charging, it does not guarantee that network owners can recover expenditure, although the risk should be lower than for shallow charging.*	*Customers face potentially higher network tariffs required to cover additional connection costs.* *Given the effect on deployment of renewable and low-carbon gases is uncertain, this is a source of further uncertainty around the short- and long-term costs to consumers.*	*Potentially some complexity in implementation. Risk of incentivising expensive connections (within regions) might remain.*	*Some degree of regional harmon-isation of approach may be beneficial. However, the value of co-ordinated action across the whole EU is not clear.*

First-mover disadvantage – high infrastructure connection costs including ‘deep’ costs: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Shallow connection costs (transitional)	*We assume in the counterfactual that some MS adopt a ‘pure’ deep connection charging approach.* *The main risk of shallow charging is that it could result in connections being encouraged that entail higher resource costs to society.* *Another issue to consider is whether costs and benefits are affected via the impact of a move to shallow charging on deployment of renewable and low-carbon gases. Here, the impacts are less certain.* *In the transitional phase while projects are still supported, support levels are likely to reduce in response to reductions in the costs of developing renewable and low-carbon gas production, with an unclear result for levels of deployment. In the steady-state, deployment may increase if costs to developers fall, since gas prices (the main driver of revenue) are likely to be determined more by global/regional factors. But the impact on costs and benefits is unclear, since additional deployment of renewable and low-carbon gases means other investments can be avoided and renewable and decarbonisation goals can still be met.*	*Shallow connection charging might be viewed positively by investors in renewable and low-carbon gases. However, it does not guarantee that network owners can recover expenditure (unless connections can be refused).*	*Customers face potentially higher network tariffs required to cover additional connection costs not charged to sites. Given the effect on deployment of renewable and low-carbon gases is uncertain, this is a source of further uncertainty around the short- and long-term costs to consumers.*	*The main risk lies in incentivising higher-cost connections.*	*Some degree of regional harmon-isation of approach may be beneficial. However, the value of co-ordinated action across the whole EU is not clear.*

Assessed solutions: Category 2 - Unlevel playing field due to sector and technology-specific tariffs and levies

Barrier category:

Unlevel playing field due to sector-/ technology-specific tariffs and levies

2.1 Power-to-gas facing end-user taxes on electricity

2.2 Sunk / dismantling costs of gas infrastructure weighing on gas grid fees

Solutions assessed from categories:

Regulatory toolbox to address cost recovery issues

Co-ordinated infrastructure planning and decommissioning

2.1.1 Taxes/levies on final electricity consumption only

2.2.1 More frequent regulatory review of necessary investments in gas infrastructure

2.2.2 Leave asset stranding risk with network operators (discretionary investments only)

2.2.3 Leave asset stranding risk with network operators (all costs)

2.2.4 State funding / guarantee for sunk and/or dismantling costs

2.2.5 Flexibility for gas sunk or dismantling costs to be spread across users of other energy carriers

2.2.6 Regulatory measures that allow for faster recovery of capex

2.2.7 Framework for co-ordinated cross-border decommissioning

Power-to-gas facing end-user taxes on electricity: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Taxes/levies on final electricity consumption only	*In the counterfactual, some power-to-gas facilities may still face (cost-recovery) taxes and levies on electricity consumption.* *Ensuring only final electricity use faces such taxes would place power-to-gas (and steam methane reforming) facilities on a level playing field compared to other renewable and low-carbon gas production (such as biomethane).* *Private investment (and operational) decisions on which technology in which to invest therefore no longer need to take into account such taxes/levies. Absent other distortions, this enables investor choices to be more in line with what is most cost-effective from a societal perspective. Overall, therefore, we would expect lower costs to society of achieving energy policy objectives.*	*This would be positive for investors in power-to-X (and steam methane reforming).* *There is a risk, if implemented as a 'tax exemption' (as opposed to a fundamental change of tax base), that investors could perceive a higher risk of reversion to the original policy.*	*Overall, and over the long-run, consumers should face lower prices, due to lower costs in the energy system.* *However, in the short run, (final) electricity consumers might pay more, to the extent electricity taxes/levies that would have been paid by power-to-gas facilities are redistributed among final consumers.*	*Changes to taxes can be done relatively quickly in many Member States. Though defining what counts as 'final' electricity consumption may need careful consideration.*	*MS may desire clarity that this would be allowable under EU legislation (State aid rules and Energy Taxation Directive).*

Sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
More frequent regulatory review of necessary investments in gas infra-structure	*This measure gives the potential for improved avoidance of investments that are not beneficial from a societal perspective. This should result in lower costs within the energy system.*	*May give grid operators more certainty of ability to recover costs – since investments should be based on better evidence of whether they are actually needed.*	*Consumers avoid paying for investments that might no longer be needed.*	*Requires individual NRA decision only*	*The measure would require only an individual NRA decision to implement; the gains from co-ordinated EU action are not clear.*

Sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Leave asset stranding risk with network operators (dis-cretionary investments only)	*On the one hand, TSOs bearing this risk could lead to higher costs (due to higher cost of capital) of the investments that are carried out. On the other hand, bearing this risk could lead to them being more cautious regarding planned investments, avoiding making investments that could be potentially stranded in the future (reducing costs to society).* *In principle some transfer of risk should be efficient, since investors are better-placed to manage the risks of demand being insufficient compared to the investment being made, to the extent investment goes beyond what might be needed to ensure security of supply or other policy goals. In practice (see 'complexity') identifying the point at which investments become discretionary may be complex.* *The significance of this impact is uncertain. In principle it would only apply to the fraction of new investment that was discretionary, although as discussed (see 'complexity') identifying this proportion would not be straightforward.*	*Investors would take on additional risk. On the other hand, this would be limited to risks they would be better-placed to anticipate and they should also be compensated for the additional risk (for example, in the form of a higher cost of capital allowance). On the other hand, a lower volume of investment may result in lower profits.*	*The net effect for consumers (or taxpayers) is uncertain. On the one hand, they may bear fewer costs associated with stranded investments. On the other hand, a higher cost of capital allowance for investors could result in higher tariffs to support the investments that are carried out.*	*Identifying the 'discretionary' component of an investment may not always be straightforward. For example, an investment may serve policy or security of supply goals. But it may include additional features that may only be profitable based on a relatively optimistic forecast of demand.* *Deciding on an approach to adjusting the cost of capital may be a novel issue for regulators and take some time to implement.*	*Difficult for EU to mandate the approach that should be taken here (for example how the rate of return should be adjusted).*

Sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Leave asset stranding risk with network operators (all costs)	*Bearing this risk could lead to TSOs being more cautious regarding some planned investments over which they exercise discretion, avoiding making investments that could be potentially stranded in the future (reducing costs to society).* *However, bearing this risk could lead to higher costs to society (arising from a higher cost of capital associated with risks that TSOs are less well-placed to manage – see 'Investment environment'). Alternatively, TSOs may invest less going forward (if allowed to), potentially leading to lower levels of security of supply and/or higher costs elsewhere in the energy system of transporting and storing energy.* *Overall, therefore, costs to society could increase*	*Investors may be required to bear risks that they may not be well-placed to manage (for example, the risks that investments will no longer be required if there is a significant change in public policy in the gas sector, or the risk of stranding for mandatory investments). A retrospective change in the degree of stranding risk may also drive an increase in the cost of capital in the wider economy, in particular in other regulated sectors.*	*Users of gas infrastructure may see their contribution to the recovery of sunk costs reduce. However, the overall cost of financing infrastructure will increase due to the increase in the cost of capital required by TSOs.* *Consumers in other sectors could be negatively affected if perceptions of increased risk spread across the wider economy.*	*Deciding on an approach to adjusting the cost of capital may be a novel issue for regulators and take some time to implement.* *As noted under 'investment environment', there is a strong risk of unintended consequences from such a measure.*	*Difficult for EU to mandate the approach that should be taken here (for example how the rate of return should be adjusted).*

Sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
State funding / guarantee for sunk and/or dismantling costs	*The costs grid users face will be closer to being fully cost-reflective (i.e. reflecting forward-looking costs only). This means their incentives (and resulting choices) are better aligned with what will be least-cost from a system perspective.* *Sunk (and/or dismantling costs) can be recovered using the full flexibility of the tax system. For example, there may be a potential to shift sunk cost recovery towards those goods/services for which demand is less responsive to changes in price ('more inelastic'). This can help to minimise the welfare losses to society from taxation. The tax system can also be used to ensure a more equitable distribution of costs (see 'consumer protection').*	*The measure would reduce risks for investors in gas, without significantly increasing risks for other energy carriers.*	*Lower-income households tend to spend a greater proportion of their income on energy. So network tariffs can be viewed as a 'regressive' tax. Shifting the burden of cost recovery towards general taxation may help ensure a more equitable distribution of costs.*	*Tax decisions can be made relatively quickly. However, it may be politically challenging to re-distribute costs across taxpayers. In addition, there may be State aid implications (see 'EU value-added').*	*Unclear value to co-ordinated EU action.* *Question of whether taxpayer funding or a State guarantee would constitute a 'new' or 'additional' protection that might need approval under State aid rules.*

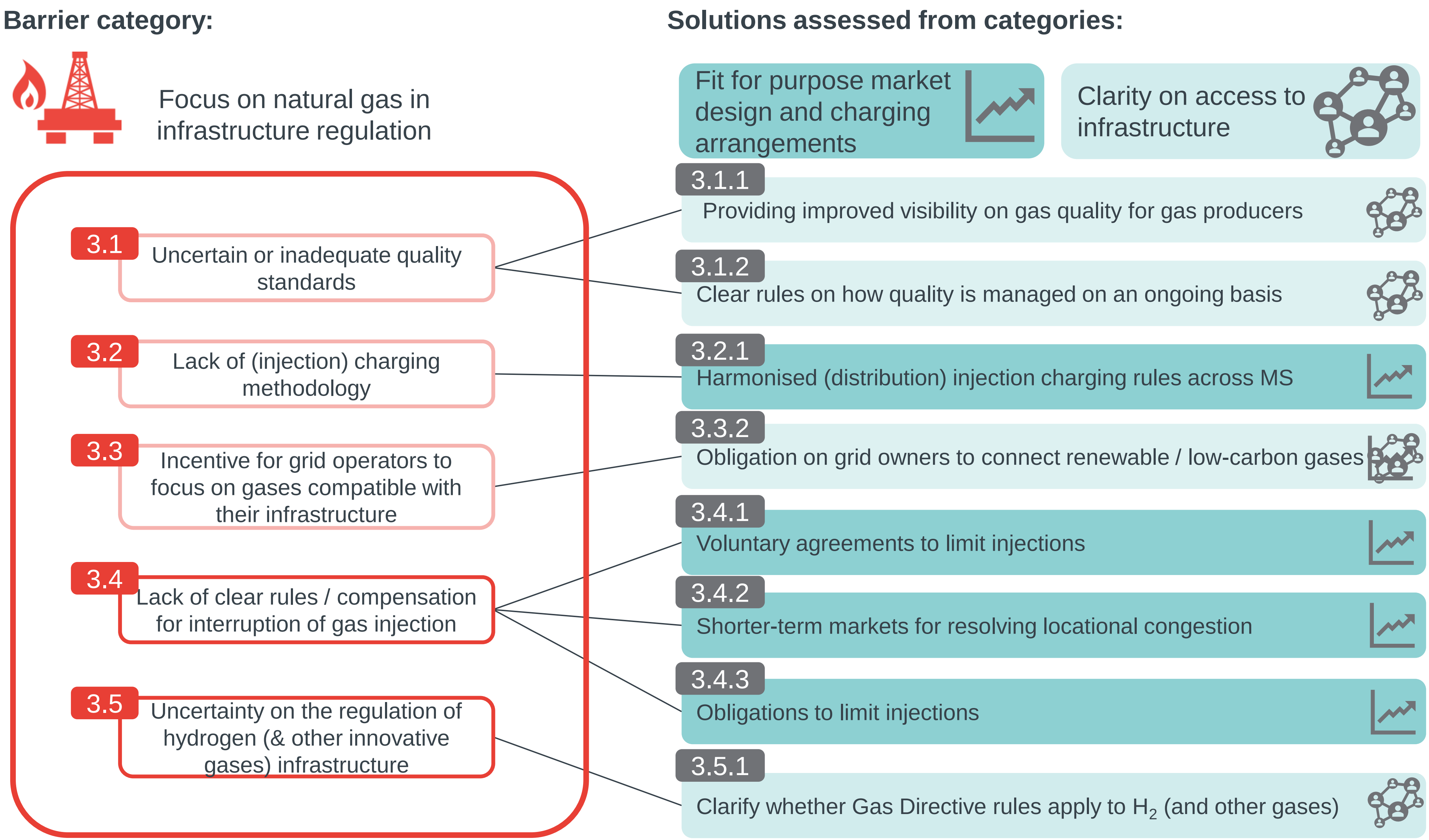
Sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Flexibility for gas sunk or dismantling costs to be spread across users of other energy carriers	*Compared to the counterfactual, the possibility of re-distributing (gas network) sunk cost recovery charges to other energy carriers could help to minimise distortions. In particular, it allows for the possibility of pure 'cost recovery' charges to be adjusted such that consumer choices between energy carriers are not distorted by sunk cost recovery (consumers should still face 'cost reflective' charges).* *Absent other distortions affecting the prices consumers face, this enables their choices to be more in line with what is most cost-effective from a societal perspective. Overall, therefore, we would expect lower costs to society of achieving energy policy objectives.*	*The measure could be positive for investors in gas, but be viewed negatively by investors in electricity / heat.*	*The measure mainly involves a possible redistribution of costs between consumers. Consumers with a gas connection may end up paying less overall for energy supplies, while those without a gas connection may pay more overall.*	*Question as to whether EU legislation needs to change to allow this (see 'EU value-added').* *Risk of inefficient outcomes in implementation (e.g. if too much of the burden of sunk cost recovery is placed on other energy carriers)*	*Question whether this would be allowable under EU legislation (for example TAR NC rules preventing cross-subsidy, or under State aid rules).*

Sunk costs and dismantling costs of gas infrastructure weighing on gas grid fees: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Regulatory measures that allow for faster recovery of capex	*For the purposes of this analysis, we assume limited or no measures are taken. That said, it is clearly possible that Member States / NRAs may respond if faced with possible difficulties in recovering costs.* *The first-order impact of this measure would be higher network tariffs in the short run.* *However, this might allow future tariffs to be lower, thereby potentially reducing any competitive disadvantage relative to other energy carriers. The measure could also be combined with (temporary and partial) move of sunk cost recovery to other energy carriers / general taxation (see below), thereby avoiding overly discouraging gas use. To the extent use of gas might contribute to lower costs to society of the energy transition, this would therefore result in lower costs.*	*The measure may give grid operators more certainty of ability to recover costs.*	*The measure would involve a redistribution of costs from future gas consumers to current consumers (gas or potentially other fuels).*	*Requires individual NRA decision only.*	*The measure would require only an individual NRA decision to implement; the gains from co-ordinated EU action are not clear.*

Assessed solutions: Category 3 - Focus on natural gas in infrastructure regulation



Uncertain access to infrastructure due to uncertain or inadequate quality standards: assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Providing improved visibility on gas quality for gas producers	*There would be a cost involved in providing the information.* *However, developers would receive greater clarity on whether their investment can be accommodated by the grid, reducing the cost of capital, and therefore the costs of deploying renewable and low-carbon gases.*	*Reduces risk for developers.*	*Consumers should ultimately benefit from lower costs of deployment*	*Providing information would not necessarily be complex. However, limits (for example for hydrogen) would need to be established.*	*Clarity on headroom in neigh-bouring TSOs/ DSOs reduces barriers to trade, though this may already be addressed (at least partially) by the inter-operability network code.*

Uncertain access to infrastructure due to uncertain or inadequate quality standards: assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Clear rules on how quality is managed on ongoing basis	*Clarity on the rules in place and compensation available can reduce risk to developers. By reducing the cost of capital, it potentially reduces the costs of deploying renewable and low-carbon gases.*	*Greater clarity could reduce risk for developers. However, players would need to have trust in the rules.*	*Consumers should ultimately benefit from lower costs of deployment*	*Rules could take time to design, and can only be implemented once limits have been established.*	*Clarity on headroom in neigh-bouring TSOs/ DSOs reduces barriers to trade, though this may already be addressed (at least partially) by the inter-operability network code.*

Lack of injection charging methodology: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Harmonised (distribution) injection charging rules across EU MS	*In the counterfactual, Member States may develop their own injection charging rules for renewable and low-carbon gases.* *The measure would Increase certainty for developers regarding how they might be charged for use of the gas grid.* *This may reduce the costs across the EU of deploying renewable and low-carbon gases, to the extent it reduces the associated risks to developers.* *The extent to which the efficiency of decisions on where to invest is improved is uncertain, and depends on whether any change to the rules would improve the cost-reflectivity of tariffs. However, we assume that cost-reflectivity would not be worsened by the introduction of harmonised charging rules, compared to the counterfactual.*	*Improved predictability of network charges could reduce risk to investors. .*	*Overall, consumers across the EU should benefit from reduced costs of deploying renewable and low-carbon gases.*	*Previous experience on network code development suggests the process of developing harmonised charging rules could be complex and time-consuming.*	*Possible change to network codes (or new network codes) required.*

Incentive for grid operators to focus on gases compatible with their infrastructure: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Obligation on grid owners to connect renewable / low-carbon gases	*In the counterfactual, Member States take (unspecified) steps to facilitate renewable gases and reduce barriers to access to the network.* *Depending on the measures already taken by Member States, a specific connection obligation could still lead to some increase in number or speed of deployment of renewable and low-carbon gas connections. The effect could be stronger for non-renewable gases, given these are not covered by the existing RED II text.* *If implemented in the transitional phase, this could result in a faster realisation of the benefits described under 'R&D / pilots / deployment support + innovation incentives for network operators'.*	*A specific connection obligation may reduced risk for developers.*	*In the short-term, consumers could end up paying more due to faster deployment of renewable and low-carbon gases,. However, the measure would contribute to the faster realisation of longer-term benefits.*	*A robust framework for managing congestion and for managing issues related to gas quality (see slides 29-31) would need to be in place before an obligation to connect could be implemented. In addition, an obligation may not be meaningful in Member States that use shallow connection charging – as it may prevent higher-cost connections from being refused.*	*Given the link to connection charging regime, it may be more appropriate for this decision to be left with Member States.*

Lack of clear rules / compensation for interruption gas injection: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Voluntary agreements to limit injections	*Interruptibility agreements would allow for players to signal the costs to them of selling capacity or reducing flows, helping to ensure lower-cost congestion management. However, it would not be as efficient as (real-time) market-based rules since players would not be able to signal any changes over time in the costs of helping to manage congestion.* *If used in conjunction with (real-time) market-based rules only, interruptible contracts could help to provide clearer longer-term signals regarding the value of flexibility. This in turn should also incentivise greater investment in flexibility, lowering long-run balancing costs.*	*Compensation means investors should not face additional risks.*	*In the short term, (gas) consumers may bear an additional financial cost involved in providing compensation. However, over the long-run, lower congestion management costs should ultimately mean lower prices (unless there are localised market power issues meaning that players are able to require compensation substantially in excess of the cost to them of interrupting).*	*Such agreements are relatively quick to implement.*	*The value of EU-wide co-ordination on measures to address congestion primarily focussed at distribution level is unclear, in particular given that cross-border part-icipation in congestion management is less likely to be relevant at distribution level.*

Lack of clear rules / compensation for interruption gas injection: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Shorter-term markets for resolving locational congestion	*In the counterfactual, we assume Member States adopt non market-based rules, without compensation.* *The impact of market-based compensation would be to ensure that (in real time) measures with least cost to society are used to address localised congestion (note: this assumes that policy action has been taken to ensure that players internalise all wider costs or benefits they impose on the system). In the long-run, the possibility of compensation should also send signals for investment in greater flexibility.*	*Compensation means investors should not face additional risks.*	*In the short term, (gas) consumers may bear an additional financial cost involved in providing compensation. However, over the long-run, lower congestion management costs should ultimately mean lower prices (unless there are localised market power issues meaning that players are able to require compensation substantially in excess of the cost to them of interrupting).*	*Market-based compensation could require changes to legislation to implement, and may be a more significant change in some Member States than in others (especially at distribution level).*	*The value of EU-wide co-ordination on measures to address congestion primarily focussed at distribution level is unclear, in particular given that cross-border part-icipation in congestion manageme nt is less likely to be relevant at distribution level.*

Lack of clear rules / compensation for interruption gas injection: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Obligations to limit injections	*Interruptibility obligations would allow network operators to manage congestion, although there is no guarantee this would be done efficiently. Doing so would rely on the network operator having knowledge of the costs to individual operators of helping to manage congestion. This would be difficult to achieve without use of a market mechanism to reveal such costs.* *However, used in conjunction with the other congestion management options, making interruptibility mandatory could help reduce the costs to network operators of managing congestion if there are localised market power issues. In turn, this could increase the efficiency of congestion management (i.e. lower costs to society) if, in the counterfactual, the market power issues might have prevented the lowest cost congestion management options from being utilised by the network operator. There is a risk, however, that costs of investment increase as a result (see 'Investment environment').*	*Mandating interruptibility runs the risk of deterring investment. Even if players receive remuneration, they may be unsure that the value of such remuneration will fully reflect the market value, for example if mandatory contracts are used even if there is limited market power.*	*The overall effects are uncertain and are likely to depend on implementation. On the one hand, the measure could help to reduce costs to network operators and, in turn, to consumers if market power is important. On the other hand, there is a risk that the costs of deploying gases rise, due to increased risk borne by investors. These costs would be borne by consumers.*	*Avoiding the potential negative effects may require robust oversight by the NRAs, to ensure that mandatory contracts are not used unless there are market power issues. Similar provisions exist for electricity distribution operators in the revised Electricity Directive.*	*The value of EU-wide co-ordination on measures to address congestion primarily focussed at distribution level is unclear, in particular given that cross-border part-icipation in congestion manageme nt is less likely to be relevant at distribution level.*

Uncertainty on the regulation of hydrogen (& other innovative gases) infrastructure: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Clarify whether Gas Directive rules apply to hydrogen (and other gases)	*Increased clarity on the rules may help to reduce the risks for investors in networks, as well as providing increased clarity for developers of renewable and low-carbon gases regarding their ability to secure access to infrastructure. Overall, this should reduce the risks to investment, and in turn the costs of deploying renewable and low-carbon gases.*	*Overall, increased clarity should reduce risks to investors.*	*Any consumer benefits may accrue primarily to larger consumers (i.e. industrial) in the transition phase, as these are the players most likely to be using hydrogen networks.*	*Agreeing on trigger points and treatment of investment carried out prior to the trigger point may prove complex. Time will be required to revise legislation.*	*Changes in this area are likely to require revision to EU legislation.*

Assessed solutions: Category 4 - Uncoupled and uncoordinated infrastructure planning

Barrier category:

Uncoupled / uncoordinated infrastructure planning

- 4.1 Risk that suitable storage will not be available
- 4.2 Insufficient co-ordination between distribution and transmission
- 4.3 Insufficient co-ordination between electricity and gas

Solutions assessed from category:

Co-ordinated infrastructure planning and decommissioning

- 4.1.1 Assess optimal level of storage capacity
- 4.2.1 Co-ordinated system planning between transmission and distribution
- 4.2.2 Regulatory incentives to achieve system cost savings
- 4.3.1 Co-ordinated system planning across electricity and gas

Risk that suitable storage will not be available: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Assess optimal level of storage capacity	Better understanding of the need for storage capacity in the future does not bring any direct benefits (and indeed there would be a cost associated with the assessment). However, having this understanding would help policy makers judge whether there is a risk that the current framework will not deliver sufficient storage (in particular the risk that storage may close prematurely from a societal perspective, given the difficulty in assessing future demand). This in turn would allow more informed choices to be made regarding possible further intervention on gas storage. That said, there is a risk (see 'Investment environment') that uncertainty for investors is increased.	On the one hand, investors may view the fact that some action is being taken to improve knowledge of the requirement for storage positively. On the other hand, there is a risk that even a limited intervention such as this may create an uncertainty regarding the nature of possible future policy or regulatory intervention on storage.	Any potential action following on from the assessment might benefit consumers, either because it prevents storage from closing inefficiently or because it prevents storage from being kept open inefficiently.	The assessment itself could be time-consuming, although not in itself a radical or controversial exercise.	There is a strong link to existing EU infra-structure planning processes (such as the TYNDP process). In addition, storage may have benefits that spill across boundaries

Insufficient co-ordination on future use of infrastructure (D vs T); implications for connections and infrastructure adaptation: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Co-ordinated system planning between transmission and distribution	*Co-ordination may come at a cost to network operators. However, a common understanding on the range of potential scenarios in terms of gas supply and demand as well as a shared understanding of the different solutions across different levels of infrastructure could maximise the chance of an optimal system design (when combined with the right incentives – see next slide for more details).*	*Co-ordinated planning would involve the development of a consistent geographic mapping of current and projected production and demand as a first step. This would allow operators to identify required investments. As such, the process of planning itself should not have direct impacts on investors. However, follow-on decisions (such as which investments are given regulatory approval) may affect investors (in different ways).*	*Any reduction in the costs across the energy system (see 'net societal costs and benefits') arising indirectly from improved co-ordination of network planning should ultimately be reflected in lower costs to consumers. Benefits might be distributed differently, however, within Member States depending on the type of consumer (e.g. electricity only or both electricity and gas) and their location.*	*It may be complicated and time-consuming to develop joint models, assumptions and ways of working if these did not exist previously. For example, currently according to Eurogas/CEDEC/ GEODE, DSOs only have a clearly defined role in the scenario process in a few national grid development plans.*	*The nature of T and D grid co-operation is likely to vary between MS. But there is still value to co-ordinated action at EU level, since (with increasing amounts of de-centralised production) issues at D-level could increasingly spill over to other MS.*

Insufficient co-ordination on future use of infrastructure (D vs T); implications for connections and infrastructure adaptation: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Regulatory incentives to achieve cost savings	*In the counterfactual, TSOs and DSOs (in some Member States) may focus primarily on their respective infrastructure, leading to inefficient investment decisions from society's perspective.* *Effective incentives could reduce the costs to society of investing in/operating gas infrastructure. However, the extent to which incentives might be effective is uncertain (see 'Complexity').*	*Such incentives could be perceived negatively by individual network operators, for example if there was a risk it might mean a lower RAB value.*	*Lower costs to society should ultimately be reflected in lower costs to consumers.*	*There is a risk of unintended consequences from new types of regulatory incentives, in particular the risk of (creating unforeseen) perverse incentives for network operators.* *In addition, there is a risk that NRAs suffer from information asymmetry, making it difficult for them to judge when savings have been truly made. Information gained through co-ordinated planning and CBA may offset this to some extent.*	*The nature of T and D grid co-operation is likely to vary between MS. But potentially still value to co-ordinated action at EU level since issues at D-level could increasing-ly spill over to other MS.*

Insufficient co-ordination on future use of transmission infrastructure electricity vs gas – and aligned operator incentives: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Co-ordinated system planning across electricity and gas	*Co-ordination may come at a cost to network operators. However, a common understanding on the range of potential scenarios in terms of gas supply and demand as well as a shared understanding of the different solutions across different levels of infrastructure could maximise the chance of an optimal system design (when combined with the right incentives – see next slide for more details).*	*The process of co-ordinated planning itself should not have direct impacts on investors. However, follow-on decisions (such as which investments are given regulatory approval) may affect investors (in different ways).*	*Overall, there should be benefits to EU consumers from reduced expenditure on infrastructure. However, the benefits might potentially be distributed differently between electricity and gas customers (and perhaps also between Member States)*	*The ENTSOs already developed joint scenarios intended to capture relevant interlinkages between the electricity and gas sectors. As part of this process, the ENTSOs are also developing an interlinked electricity and gas model. This model will eventually be used to support cost-benefit analysis of relevant projects. Further work may be required to ensure greater co-ordination between energy network operators at national level.*	*Planning in one Member State, particular-ly of intercon-nection or assets used primarily for transit is likely to have impli-cations for other Member States.*

Insufficient co-ordination on future use of transmission infrastructure electricity vs gas – and aligned operator incentives: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Regulatory incentives to achieve cost savings	*In the counterfactual, electricity and gas TSOs may focus primarily on their respective infrastructure, leading to inefficient investment decisions from society's perspective.* *Effective incentives could reduce the costs to society of investing in/operating gas infrastructure. However, the extent to which incentives might be effective is uncertain (see 'Complexity').*	*Such incentives could be perceived negatively by individual network operators, for example if there was a risk it might mean a lower RAB value.*	*Overall, there should be benefits to EU consumers from reduced expenditure on infrastructure. However, the benefits might potentially be distributed differently between electricity and gas customers (and perhaps also between Member States)*	*There is a risk of unintended consequences from new types of regulatory incentives, in particular the risk of (creating unforeseen) perverse incentives for network operators.* *In addition, there is a risk that NRAs suffer from information asymmetry, making it difficult for them to judge when savings have been truly made. Information gained through co-ordinated planning and CBA may offset this to some extent.*	*Planning in one Member State, particular-ly of intercon-nection or assets used primarily for transit is likely to have impli-cations for other Member States.*

Assessed solutions: Category 5 - Risks for interoperability across markets and borders

Barrier category:

Risk for interoperability across markets and borders

Solutions assessed from category:

Co-ordinated infrastructure planning and decommissioning

5.3 Risk of lack of liquid market for sale of heterogenous gases

5.3.1 Liquidity impacts to be considered in infrastructure planning

5.5 Lack of coherent cross-border framework for decommissioning

5.5.1 Framework for co-ordinated cross-border decommissioning

Risk of lack of liquid market for sale of heterogenous gases: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Liquidity impacts to be considered in infrastructure planning	*In the counterfactual, potential liquidity impacts would not be considered systematically in CBAs carried out to evaluate infrastructure investment, conversion and decommissioning decisions. Some decisions (e.g. decommissioning / H2 conversions) may fragment the gas market geographically or by product. Given that liquidity can have impacts on costs of trading as well as on the cost of investment (by affecting the offtake and revenue risk faced by participants), the lack of systematic consideration of liquidity impacts could lead to inefficient decision-making due to an incomplete CBA methodology.* *More systematic consideration of liquidity impacts could therefore lead to lower costs overall from a societal perspective.*	*To the extent that this assessment indirectly contributes to better future liquidity, it reduces risks to market participants.*	*Consumers overall should benefit from reduced costs in the energy system.*	*Considering liquidity impacts would require updates to CBA methodologies, but it is unclear whether legislative changes would be required to achieve this.* *Modelling liquidity impacts may also be complex and subject to uncertainty*	*Impacts of decisions in one MS could spill over to other MS. A standard-ised approach to assessing liquidity impacts would be important in ensuring con-sistency.*

Lack of coherent cross-border framework for decommissioning: Assessment

	Net societal costs and benefits	Investment environment	Consumer protection	Complexity and timelines	EU value-added
Framework for co-ordinated cross-border decom-missioning	*In the counterfactual, Member States may take unilateral decisions to decommission gas infrastructure that could be delivering benefits in other Member States.* *Co-ordinated cross-border decommissioning may therefore lead to avoided or delayed decommissioning in such cases. Overall, from an EU-wide perspective, costs to society should be lower as a result. However, in such cases, the savings in resource costs are distributed differently between Member States. Those that were planning to decommission may face increased costs (they may avoid decommissioning costs but would continue to incur opex). Other Member States may benefit from increased security of supply and/or reduced costs of gas supply or avoided costs of switching to alternatives to gas.*	*Cross-border cost allocation provides greater reassurance for infrastructure owners around the financing base.*	*Cross-border cost allocation methodology provides a means of ensuring that consumers are no worse off as a result.*	*May require change to EU regulation (TEN-E). Could take 2-3 years for consultation/ adoption and then time for ENTSOG to develop CBA methodology.*	*There is a clear EU-wide benefit to co-ordination between Member States on this issue.*

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