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Towards decarbonised gas markets: an analysis of the current and future market design for gaseous fuels based on EU legislation

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Summary

S.1 Goal, scope and structure of this report

Significant changes to the market design for gaseous fuels have been proposed by the European Commission to enable the transition towards decarbonised gas markets. On 15 December 2021 the European Commission adopted a proposal for a “Hydrogen and Decarbonised Gas Markets Package” (hereafter: proposed Decarbonisation Package). The package includes a proposal for a revision of the current Gas Directive and Gas Regulation. In addition, the proposed Decarbonisation Package includes some amendments to the Gas Security of Supply Regulation (hereafter Gas SoS Regulation). Subsequently, in March 2022 short-term amendments of both the Gas SoS Regulation and Gas Regulation regarding the role of natural gas storages have been proposed by the European Commission as part of the REPowerEU plan and entered into force in July 2022.[1] Moreover, a revision of the Regulation on trans-European Energy Infrastructure (hereafter: TEN-E Regulation) entered into force in June 2022, which contains relevant changes for both natural gas and hydrogen infrastructure. Together, these changes significantly impact the market design for gaseous fuels.

In this report we describe how these proposed and recently adopted legislations change the market design for gaseous fuels to enable the transition towards decarbonised gas markets (i.e. natural gas and hydrogen). This report is targeted at policy makers, regulators, natural gas and hydrogen undertakings, industry associations and researchers. Therefore, the report assumes some prior knowledge on energy market design in the European Union, but no in-depth knowledge of these proposals of the European Commission. We describe the changes to the market design by describing both the “current” and “future” market design. By describing the current and future gas market design for natural gas and hydrogen we analyse, and make more easily accessible, the changes to the gas market design that have been proposed by the European Commission. However, the description of the “future” market design excludes most of the interventions to address the ongoing energy crisis that have been proposed by the European Commission and adopted during the last year (see textbox 1 for explanation of what is what is not included). Based on the analysis of the current and future market design, we present some reflections on the proposals and recommendations to policy makers.

[1] Regulation (EU) 2022/1032 of the European Parliament and of the Council of 29 June 2022 amending Regulations (EU) 2017/1938 and (EC) No 715/2009 with regard to gas storage.

The description of the current market design is based on the (i) Gas Directive[2], (ii) Gas Regulation[3], (iii) TEN-E Regulation[4], (iv) Gas SoS Regulation[5] and (v) the network codes and guidelines that have been adopted on the basis of the Gas Regulation. In the description of the current market design we exclude the recent changes to the Gas Regulation, TEN-E Regulation and Gas SoS Regulation, so the "current" market design is actually based on those regulations on 1 January 2022. In the description of the current market design we also include how elements of the market design have been implemented in The Netherlands.

The description of the future market design is based on (i) the proposed revision of the Gas Directive[6], (ii) the proposed revision of the Gas Regulation[7] (iii) the adopted revision of the TEN-E Regulation[8] and (iv) the proposed and adopted amendments of the Gas SoS Regulation[9]. Because the proposed revision of Gas Directive and Gas Regulation have not been adopted yet (i.e. they are proposals), they are not implemented in The Netherlands yet. Therefore, we cannot include a description of the implementation of provisions of the Gas Directive in The Netherlands. Similarly, network codes and guidelines that need to be developed on the basis of the revised Gas Regulation need to be developed once the revised Gas Regulation enters into force and, therefore, they cannot be included in the description. Moreover, because the proposals for a revision of the Gas Directive and Gas Regulation have not been adopted yet, their content could change as a result of negotiations between the European Parliament and the Council which would impact the analysis in this report. Lastly, the most recent interventions from the European Commission to address the energy crisis are not included in this report (see textbox 1 for an explanation).

In S.2 of this summary we describe the changes to the market design for gaseous fuels (see Chapters 2 and 3 of this report). In S.3 of this summary, we summarise some reflections on the proposals and recommendations to policy makers (see Chapter 4 of this report).

[2] 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.

[3] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009.

[4] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009.

[5] Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010

[6] Proposal for a directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen.

[7] Proposal for a regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen.

[8] Regulation of the European Parliament and of the Council on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013.

[9] Proposal for a Regulation of the European Parliament and of the Council amending Regulation (EU) 2017/1938 of the European Parliament and of the Council concerning measures to safeguard the security of gas supply and Regulation (EC) n°715/2009 of the European Parliament and of the Council on conditions for access to natural gas transmission networks.

Textbox 1 – Interventions to address the energy crisis

Throughout 2022 the European Commission has proposed several short term and emergency measures to address security of supply concerns and high energy prices as a result of the reduction of gas supply from Russia. Given the goal of these proposals (i.e. short term measures) most of them were quickly adopted, resulting in rapid changes to the gas market design while the proposed Decarbonisation Package is being discussed in the European Parliament and the Council. In this textbox we discuss to what extent these short-term changes are included in the analysis in this report.

On 8 March 2022 the European Commission presented the REPowerEU plan. The goal of the REPowerEU plan is two-fold (European Commission, 2022):

1 Addressing the emergency in the short-term by:
   1.1 mitigating retail prices and supporting heavily exposed companies and
   1.2 preparing for next winter by ensuring sufficient gas storage.
2 Reducing the dependency on Russian fossil fuels through a combination of energy savings, diversifying supplies and accelerating the clean energy transition.

To mitigate retail prices and support heavily exposed companies (1.1) the European Commission initially provided guidance on the possibilities for retail price regulation within the existing legislative framework and announced that it would use the full flexibility of its State Aid toolbox to enable Member States. Therefore, at the time, this did not result in legislative proposals that affect the gas market design. To ensure sufficient gas storage (1.2) the European Commission proposed a Regulation with regard to gas storage (hereafter: Gas Storage Regulation) that amends the Gas Regulation and Gas Security of Supply Regulation and was adopted on 29 June 2022 (Regulation 2022/1032). These amendments to the Gas Regulation and Gas Security of Supply Regulation are included in the description of the future market design in this report. To reduce dependency on Russian fossil fuels (2) the European Commission adopted several strategies, communications and recommendations as well as a set of legislative proposals. The legislative proposals increased targets already proposed in fit-for-55 package, such as an increased energy saving target (from 9% to 13%) and an increased renewable energy target (from 40% to 45%). In addition, the European Commission submitted legislative proposals to ensure the necessary financing of investments. These legislative proposals did not affect the gas market design. Therefore, they are not discussed in this report.

On 20 July 2022 the European Commission submitted a proposal for a Council Regulation on coordinated measures to reduce gas demand (hereafter: Demand Reduction Regulation), which was adopted by the Council on 5 August 2022 (Regulation 2022/1369). The regulation requires Member States to use their best efforts to reduce their gas consumption by 15% in the period from 1 August 2022 and 31 March 2023. In addition, the European Commission and the Council can declare a Union Alert, which triggers mandatory demand reductions. The Demand Reduction Regulation complements the Gas Storage Regulation, because the demand reduction enables storage filling (or reduces storage depletion) during a period with low gas supply.

On 14 September 2022 the European Commission submitted a proposal for a Council Regulation on an emergency intervention to address high energy prices, which was adopted by the Council on 30 September 2022 (Regulation 2022/1854). The Regulation contains the following measures to address high energy prices:
1 Reduction of electricity demand;
2 A cap on market revenues from inframarginal electricity producers;
3 A solidarity levy for fossil fuel producers; and
4 Temporarily allows Member States to set a price for the supply of electricity to households and small and medium-sized enterprises below the costs.

Of these four measures, only measure 4 impacts the analysis in this report. Measures 1 and 2 address the fact that high natural gas prices result in high electricity prices, by reducing electricity demand and redistributing surplus revenues from inframarginal electricity producers to final customers. Therefore, they do not impact the gas market design. Measure 3 concerns a fiscal measures that increase the taxation of profits from fossil fuel producers. Because this is a fiscal measure, the gas market design remains unaffected. Although measure 4 only addresses the supply of *electricity* to household and small and medium-sized enterprises this measure does impact the analysis in this report because it rolls back some of the proposals in the proposed Decarbonisation Package on the regulation of retail prices. We explain this with more detail in textbox 7 in paragraph 3.10.

Most recently, on 18 October 2022 the European Commission submitted a proposal for a Council Regulation enhancing solidarity through better coordination of gas purchases, exchanges of gas across borders and reliable price benchmarks. The proposed regulation contains a list of measures that would severely impact gas market design, including:
- Joint purchasing of gas at the EU-level;
- Extending gas demand reduction requirements beyond March 2023;
- Ensuring additional protection of critical gas fired power plants;
- Default rules for bilateral solidarity measures;
- Rules concerning the allocation of capacity in a regional or Union emergency;
- A price formula in the default solidarity agreements;
- Development of a new complementary LNG price benchmark to be developed by ACER; and
- A gas TTF pricing correction mechanism.

At the time of finishing this report, these proposals have not been adopted yet. Because these proposals were presented just before publication of this report, they are not included in this report.

S.2 Changes to the market design for gaseous fuels

We structure the description of the current and future market design by discussing the following topics:
1 Background of the current/proposed gas market design;
2 Legal framework;
3 Definition of gas(es);
4 Segments of value chain of gas(es);
5 Unbundling of activities;
6 Third party access to infrastructure;
7 Infrastructure development;

8 Regulation of network tariffs;
9 Wholesale market;
10 Retail market and customer protection;
11 Gas quality; and
12 Security of supply.

S.2.1 Background of the current and proposed gas market design

The current gas market design is the result of a decades long process of liberalisation and gas sector restructuring. The process of liberalisation and gas sector restructuring was driven by several consecutive legislative packages. The general objective of these packages was to complete an integrated internal energy market and move towards a competitive, secure and sustainable Energy Union (European Commission, 2021a). In order to enable competition in gas markets, gas undertakings had to be granted non-discriminatory access to key infrastructure (third party access), notably to the gas transmission and distribution networks. The Third Energy Package - being the latest of these packages for gas - builds on previous packages, further restructured the gas sector and focussed on five main areas (European Commission, 2021a):
- unbundling energy suppliers from network operators;
- strengthening the independence of regulators;
- establishing the Agency for the Cooperation of Energy Regulators (ACER);
- enhancing cross-border cooperation between transmission system operators and the establishment of European Network for Transmission System Operators for Gas (ENTSOG);
- open, fair retail markets and consumer protection.

The need to now change the gas market design results primarily from the EU's objective to become the first climate neutral continent in 2050 and to reduce greenhouse gas emissions by at least 55% in 2030, as stated in the European Climate Law. To achieve the 2030 target, the European Commission proposed the *Fit-for-55* package. In fact, the European Commission considers the proposed Decarbonisation Package to be an integral part of the Fit-for-55 proposals. The Fit-for-55 proposals will require the role of gaseous fuels in the system to change, which will impact the (to be developed) infrastructure. According to the European Commission (2021b) the decarbonisation of gaseous fuels will result in:
1. a hydrogen infrastructure that progressively complements the network for natural gas; and
2. a gas infrastructure in which fossil gas is progressively replaced by other sources of methane.

Against this background, the European Commission has evaluated the current gas market design and identified four problem areas that need to be addressed:
- Problem area I: Barriers exist for the development of a cost-effective hydrogen infrastructure and competitive and integrated hydrogen market.
- Problem area II: Untapped potential of renewable gases and barriers blocking the access of biomethane to gas market and infrastructure.
- Problem area III: Insufficient energy system integration in network planning
- Problem area IV: Low levels of consumer engagement and protection in the decarbonised retail market.

The goal of the proposed Decarbonisation Package is to remove barriers for the decarbonisation of the gas sector by addressing the four problem areas.

S.2.2 Legal framework

Although the proposals significantly change the gas market design, the legal framework remains largely unchanged. The Gas Directive and Gas Regulation remain the key legislative acts, with the TEN-E Regulation and Gas SoS Regulation relevant for specific elements of the market design. A difference is that the European Network of Network Operators for Hydrogen (ENNOH) has to be established and the EU DSO entity will also include gas DSOs (in addition to electricity DSOs).[10] Both the ENNOH and EU DSO entity have a role in the development of network codes (i.e. EU implementing regulations that further detail elements of the market design).

S.2.3 Definition of gas(es) and certification

The current gas market design does not include a definition of ‘gas’. In the proposed Decarbonisation Package, however, a list of several definitions is included. The definitions ensure that hydrogen is also included in the gas market design, by introducing a definition of ‘gases’. Gases are defined as ‘natural gas and hydrogen’. In addition, definitions of renewable and low-carbon gases (i.e. natural gas and hydrogen) are included. Renewable gases are defined in reference to the Renewable Energy Directive. To qualify as low-carbon gas the greenhouse gas emissions savings from the use of gas should be at least 70% compared to the conventional fossil gas. To enforce provisions that require demonstration of the fact that gas is renewable or low-carbon, a system of certification of renewable and low-carbon gases has to be implemented. Whereas certification of renewable gases was already required on the basis of the Renewable Energy Directive, the proposed Decarbonisation Package is the first legislative proposal that acknowledges low-carbon gases and determines criteria for the certification of low-carbon gases.

S.2.4 Segments of gas value chain

A key change is that the scope of the gas market design is extended to include dedicated hydrogen infrastructure and hydrogen markets. The proposals include definitions of the different hydrogen infrastructure segments (i.e. hydrogen networks, hydrogen terminals, hydrogen storage facilities, hydrogen interconnector). The definitions largely mirror those of the same types of infrastructures for natural gas. However, there are some key differences. For example, for hydrogen networks no distinction is made between transmission and distribution. As a result, there will be no hydrogen TSOs and DSOs, but simply hydrogen network operators (HNOs). Moreover, some definitions that apply to natural gas infrastructure, such as a direct line, upstream pipeline network or closed distribution system are not applicable to hydrogen infrastructure.

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[10] The EU DSO entity is a new association of European distribution system operators, which has been established on the basis of the Electricity Regulation (Regulation 2019/943). The proposed Gas Regulation extends the scope of the EU DSO entity to also include natural gas distribution system operators.

S.2.5 *Unbundling of activities*

The current gas market design requires gas and electricity transmission and distribution to be unbundled from the activities of gas and electricity production and supply. The proposals extend the unbundling to activities related to hydrogen. As a result, hydrogen transport has to be unbundled from gas, electricity or hydrogen production and supply. Exemptions to the unbundling requirements (and some other requirements) are allowed for geographically confined hydrogen networks as well as for existing hydrogen networks.

S.2.6 *Third party access to infrastructure*

The proposals determine the third party access model for hydrogen infrastructure segments. Two types of third party access can be distinguished. Under negotiated third party access, the infrastructure operator can negotiate the terms and conditions with the infrastructure users. Under regulated third party access, the national regulatory authority sets or approves the tariffs and access conditions. Until 31 December 2030 negotiated third party access can be applied for hydrogen networks (if a Member States decides so). After that, regulated third party access has to be applied. A Member State can also decide to apply regulated third party access earlier.

For hydrogen storages regulated third party access is introduced from the start (i.e. from entry into force and not after a transition period). This differs from the third party access model for natural gas storages, for which the Member State has the option to choose between regulated or negotiated third party access. The European Commission proposes regulated third party access to hydrogen storages because the potential for large scale underground hydrogen storage is expected to be limited and concentrated in specific areas of the EU.

For hydrogen terminals, negotiated third party access has to be applied. This also differs from the third party access model for LNG terminals, for which regulated third party access has to be applied.

S.2.7 *Infrastructure development*

Third party access to infrastructure can only be ensured if there is sufficient capacity to meet the demand. Therefore infrastructure will have to be developed. There are several mechanisms that influence the (need for) infrastructure development. First, the proposals determine under which conditions infrastructure operators are allowed to refuse access on the basis of a lack of capacity. The key principle is that infrastructure operators have to invest in additional capacity to meet the demand, with some exceptions. Second, changes are proposed to ensure better integrated network planning, by requiring all TSOs to develop ten year network development plans based on common scenarios (i.e. TSOs and DSOs for electricity and gas have to use the same scenarios). Third, the development of infrastructure can be incentivised by temporarily exempting the infrastructure from key requirements (such as unbundling and third party access). Fourth, the development of trans-European networks for energy is stimulated through the TEN-E Regulation. The changes to the TEN-E Regulation make sure that hydrogen infrastructure is eligible, whereas natural gas infrastructure no longer is.

S.2.8 *Regulation of network tariffs*

The proposals introduce a number of changes for the regulation of network tariffs:

- Transmission tariff structures: The proposals introduce several discounts specifically for renewable and low-carbon natural gas transported through the transmission system. A 75% discount to the transmission tariffs has to be applied at entry points from production facilities and at entry points to and exit points from storages.[11] In addition a 100% discount has to be applied at interconnection points and entry points from LNG facilities. If the revenue-loss resulting from the latter discount exceeds 10% for a TSO, an inter-TSO-compensation mechanism has to be implemented to compensate for the redistribution of tariff revenues between TSOs.
- Transmission tariff revenues: For the determination of the transmission revenues ACER will commission an EU-wide efficiency comparison of TSOs every four years, which NRAs have to take into account when determining the allowed or target revenue for the TSO. In addition, NRAs have to assess the evolution of transmission tariffs until 2050 by analysing expected changes in allowed or target revenues as well as the development of gas demand.
- Hydrogen network tariffs: Hydrogen network tariffs will only be subject to regulation once regulated third party access is applied. Once regulated third party access is applied, the same general criteria apply as for natural gas. However, in contrast to the natural gas transmission tariffs no specific discounts apply to renewable and low-carbon hydrogen. Another difference is that for hydrogen networks, no tariffs shall be charged on interconnection points. In addition, an inter-hydrogen network operator compensation mechanism has to be implemented to compensate for the redistribution of tariff revenues between hydrogen network operators resulting from the lack of interconnection tariffs.
- Financial transfer and dedicated charge: Temporary cross-subsidies between hydrogen network users and natural gas transmission system users are allowed through a dedicated charge and a financial transfer between transmission system operator and hydrogen network operator. This is especially relevant for the repurposing of transmission assets for hydrogen network operation. By default, when natural gas transmission assets are repurposed to hydrogen network assets the regulated value of those assets (i.e. the regulatory asset base) has to be transferred from the natural gas transmission system operator to the hydrogen network operator. The regulated value of those assets is then used to determine the hydrogen network tariffs. As a result, the costs of those assets are charged to the users of those assets. As an exception to this rule, temporary cross-subsidies allow to charge part of the costs of the repurposed assets to the (remaining) users of the natural gas transmission system through a dedicated charge. The transmission system operator thus receives revenue for the costs of assets it no longer operates. This revenue resulting from the dedicated charge has to be passed-through (financial transfer) to the hydrogen network operator.

[11] However, the proposed storage discount of 75% specifically for renewable and low-carbon natural gas has to some extent been superseded, because since July 2022 national regulatory authorities are allowed to implement a 100% discount on the capacity based entry and exit tariffs to storages as a result of short-term measures of the REPowerEU plan. When implemented, this discount applies to natural gas in general (i.e. not specifically to renewable and low-carbon natural gas).

S.2.9 *Wholesale market*

Because the hydrogen market is included into the scope of the gas market design, the proposals include some general provisions on the design of the wholesale hydrogen market. During the transition period (until 31 December 2030) only some general principles apply. After that, roughly the same general principles shall apply to the hydrogen wholesale market as to the natural gas wholesale market, including the fact that the hydrogen systems shall be operated as entry-exit systems (see paragraph 2.9.1 for an explanation of the concept of an entry-exit system). However, important choices on many aspects such as the balancing mechanism, capacity allocation, congestion managements procedures and network tariff structures still have to be made (see paragraph 2.9 for an explanation of these concepts). Presumably, yet to be developed hydrogen network codes will further detail those elements.

The proposed Decarbonisation Package also include some changes to the natural gas wholesale market design. These changes aim to ensure that production facilities of renewable and low-carbon gases connected to the distribution system get firm access to the transmission system, including by requiring investment in reverse flow (i.e. from distribution to transmission system) and extending the definition of entry-exit system to also include the distribution system.

S.2.10 *Retail market and customer protection*

The proposed Decarbonisation Package harmonises the provisions that apply to natural gas (i.e. not hydrogen) retail markets and customers with the provisions in the Electricity Directive (that has been revised as part of the Clean Energy Package). This means that the scope for Member States to implement retail price regulation is limited to the prices for vulnerable and energy poor customers and subject to conditions. However, the recent intervention of the European Commission to address high energy prices extends the possibilities for retail price regulation for electricity. Therefore it is unlikely that the limitation of natural gas retail price regulation in the proposed Decarbonisation Package will be adopted.

In addition, many provisions in the proposed Decarbonisation Package that ensure a higher level of customer protection and participation are copied from the Electricity Directive, with some exceptions. Of these provisions ensuring customer protection only some apply to hydrogen consumers. As a result, the level of protection of (small) hydrogen consumers is effectively the same as for larger natural gas consumers.

S.2.11 *Gas quality*

Regarding the quality of natural gas the proposed Decarbonisation Package leaves the actual determination of gas quality standards to the Member States (as is currently the case). The package does contain procedural rules that govern the roles and responsibilities with respect to gas quality management. The only exception is that transmission system operators have to accept a hydrogen content of 5% in the natural gas flows at interconnection points.

For hydrogen the determination of quality standards is also left to the Member States and the same procedural rules as for natural gas apply.

S.2.12 Security of supply

The proposed Decarbonisation Package already included some changes to the Gas SoS Regulation. These changes include the requirement for Member States to include storage filling in their supply risk assessments, the possibility of joint procurement of strategic stocks to ensure security of supply and the requirement to include cybersecurity risks and measures in their preventive action plans.

However, in March 2022 the European Commission adopted a separate proposal that also changes the Gas SoS Regulation (and the Gas Regulation) which aims to reduce the dependency on Russian gas supplies in the short term. The proposal amends the Gas SoS Regulation by introducing a storage filling obligation on Member States. In addition, the proposal amends the current Gas Regulation by introducing certification of storage system operators in relation to security of supply risks and increase the network tariff discount for entry points from and exit points to storages to 100%. In July 2022 the proposal was adopted .

In addition, the European Council adopted a regulation to reduce gas consumption by 15% in the period from 1 August 2022 to 31 March 2023. This demand reduction complements the storage filling requirements, because it enables storage filling in a period with low gas supply.

S.3 Reflections and recommendations

S.2.13 Reflections on the proposals

The proposals by the European Commission are an important step for the decarbonisation of gaseous fuels. There is an urgent need to update the gas market design to enable the transition to decarbonised gases. As noted by the European Commission, the decarbonisation of gas markets will lead to changes to the role of gaseous fuels. Without any changes to the gas market design there will be barriers for the development of hydrogen infrastructure and markets, because there will be uncertainty on the regulatory framework, which could lead to postponed investments. Moreover, market power in specific infrastructure segments could result in inefficient market outcomes.

A key policy choice results from the fact that the precise role of hydrogen in the energy system and the pace of development of hydrogen infrastructure and markets is uncertain. This uncertainty requires some regulatory flexibility to allow for the market to develop. To that end, the proposed Decarbonisation Package introduces a transition period until 2031 during which there is more regulatory flexibility. At the same time the proposed Decarbonisation Packages provides clarity of the regulatory framework after the transition period. However, the proposed Decarbonisation Package does assume that hydrogen will be used in industry and heavy-duty transport and not in other sectors. If, however, unexpectedly, hydrogen will be used in other sectors, such as the built environment or electricity production, the market design might prove to be inadequate for that situation. An alternative approach that is more agnostic about the role of hydrogen in the energy system would be to more closely mimic the market design for natural gas. For example, the Gas Directive could implement the same retail market and consumer protection rules for hydrogen and natural gas household and SME consumers. Although the European Commission expects – and probably rightly so – that there will be almost no household and SME hydrogen consumers, if they do exist they will have the same level of consumer protection. If not, there is no harm done.

Another key question, that comes to mind when analysing the proposed Decarbonisation Package is how the package interacts with the fit-for-55 proposals. Whereas the proposed Decarbonisation Package aims to *remove barriers* for the uptake of renewable and low-carbon gases, the other fit-for-55 proposals (such as the proposals for amendments of the Renewable Energy Directive and the EU ETS) provide *support* for the production and consumption of renewable gases. The certification of renewable and low-carbon gases will play a key role in this policy framework, because certificates will likely be used to serve many different purposes (i.e. to demonstrate whether national renewable energy targets are reached, to receive discounts on network tariffs, to receive public support that is exempted from state-aid rules, to be exempt from the EU ETS when emitting CO2 from renewable and low-carbon gases). Although the outline of this policy framework is clear, a more detailed analysis of the interaction between these proposals is needed for a complete picture.

A development that is not well reflected in the proposed Decarbonisation Package is the fact that the energy transition will likely result in declining natural gas demand and the phase-out of part of the natural gas infrastructure. The package only takes into account the fact that fossil natural gas will gradually be replaced by renewable and low carbon natural gas. However, in many sectors (i.e. built environment) natural gas will be replaced by other energy sources, such as electricity or district heating. This will result in natural gas networks with a lower usage rate or networks that are decommissioned. The package does not address some of the policy questions related to the switch from natural gas to other energy sources (electricity, district heating).

S.3.1 Recommendations to policy makers

Based on the analysis of the proposed Decarbonisation Package we present some recommendations to EU legislators and national policy makers. The recommendations to EU legislators are shown in Table 1. The recommendations to other policy makers are shown in Table 2.

Table 1 Recommendations to EU legislators

Recommendation	Argumentation
Speed-up delegated act low-carbon fuels	The deadline for a delegated act that will specify the methodology to assess whether the emissions saving criterium for low-carbon fuels is achieved is due ‘before 31 December 2024’. Clarity on this methodology is needed much sooner to avoid postponed investments.
Introduce a definition of biomethane	The term biomethane is used frequently in the proposals but is not explicitly defined. In the proposals the term is used different than in common practice. To avoid unclarity a definition of biomethane should be included.
Change the definition of a hydrogen terminal	The definition of a hydrogen terminal refers only to the liquefaction and regasification of hydrogen and ammonia, but excludes liquid organic hydrogen carriers. To ensure a level playing field between different hydrogen carriers, liquid organic hydrogen carriers should be included in the definition.
Clarify if and under which conditions mandatory fuel	The transition may require mandatory switching from natural gas to other energy sources (electricity, district heating). However, mandatory fuel switches are at odds with the concept of providing third party

Recommendation	Argumentation
switches are allowed	access to natural gas networks. Therefore it should be clarified if and under which conditions mandatory fuel switching in allowed.
Reconsider regulated third party access to hydrogen storages	The proposals assume insufficient (potential) competition between hydrogen storages and therefore proposes regulated third party access. However, it is unclear at this stage whether there will indeed be insufficient competition. We recommend to create more flexibility to choose between regulated and negotiated third party access depending on the actual competition.
Reconsider the definition of an entry-exit system	The introduced definition of an entry-exit system might have much more consequences than presumably intended, because existing network codes and guidelines use the term entry-exit system in a different context. An alternative definition of the entry-exit system should be included.
Consider simplifying the network tariff structures	The proposed network tariff structures for natural gas and hydrogen create lot of complexity for the determination of network tariffs, while it is unclear this complexity is needed to achieve policy objectives. A simplification of network tariff structures should be considered.
Clarify options to redistribute natural gas network costs in case of declining natural gas demand	A network in decline raises a number of questions for the regulation of network tariffs. Specifically, the package should make clear whether there is a need for TSOs and DSOs to earn back historic investments. If there is such a need, it should be clear how captive customers of TSOs and DSOs can be protected by NRAs and Member States.
Implement measures ensuring security of supply of hydrogen	The proposed Decarbonisation Package does not contain any measures to ensure security of supply of hydrogen. Although large scale hydrogen supply still needs to develop, it is necessary to already consider security of supply during the development phase.

Table 2 Recommendations to other policy makers

Recommendation	Argumentation
Implement hydrogen wholesale market design	The proposals do not specify a hydrogen wholesale market design for the near future (at least until 2031). However, for the hydrogen market to develop there has to be clarity on connection conditions, network tariffs, capacity allocation, imbalance settlement and hydrogen quality standards.
Determine when access to the hydrogen system can be refused	In principle, the hydrogen network will have to be developed to meet the demand for hydrogen transport. However, from an energy system perspective it might not be optimal to expand the hydrogen network to remote areas or when alternative infrastructure is available (i.e. electrification is possible). Therefore, determining how the costs of network expansion are allocated to hydrogen network users and when access can be refused is an important policy choice that requires careful consideration.
Consider implementing the same level of consumer protection for hydrogen supply to households and SMEs as for natural gas	The proposals assume hydrogen consumption in industry and heavy-duty transport, but not in other sectors. Although that is a reasonable assumption, national policy makers should take into account possible hydrogen consumption in other sectors. For example, hydrogen consumption by households and SMEs might occur in pilots or on a limited scale. If that is the case, a similar level of consumer protection as for natural gas should be ensured.
Analyse the impact of a 5% hydrogen content by volume in natural gas on the natural gas system	The proposals require TSOs to accept up to 5% hydrogen content by volume in natural gas on interconnection points. The effect this has on the national natural gas system can vary due to national circumstances. It is important to analyse whether adjustments to infrastructure are needed to accommodate 5% hydrogen content in natural gas on interconnection points.

Contents

1 Introduction

This report analyses the changes to the market design for gaseous fuels (natural gas and hydrogen) that have been proposed by the European Commission to enable the decarbonisation of gaseous fuels. We analyse the changes by describing both the “current” and “future” market design for gaseous fuels (natural gas and hydrogen) based on EU legislation. After describing the changes, we reflect on the proposals and present some recommendations to policy makers. This report is targeted at policy makers, regulators, natural gas and hydrogen undertaking, industry associations and researchers. Therefore, the report assumes some prior knowledge on energy market design in the EU, but no in-depth knowledge of the proposals of the European Commission.

In Chapter 2 we describe the “current” gas market design, only for natural gas. This description is primarily based on the Gas Directive[12] and the Gas Regulation[13] which were adopted as part of the Third Energy Package in 2009. On the basis of the Gas Regulation the European Commission has adopted several network codes and guidelines, which are implementing regulations and are also included in the description. Where relevant, we also include how provisions have been implemented in The Netherlands. In addition to the Gas Directive and Gas Regulation, the Gas Security of Supply Regulation[14] (hereafter: Gas SoS Regulation) and the Trans-European Networks in Energy Regulation[15] (hereafter: TEN-E Regulation) concern specific topics of the gas market design and are also included in the description. The TEN-E Regulation has recently been revised and the Gas SoS Regulation has recently been amended. We include the version before these changes in the description of the “current” gas market design, because the goal of this report is to show how, together with the proposed Decarbonisation Package, the market design for gases is updated to enable the transition towards decarbonised gas markets. Thus, the description of the “current” market design actually reflects the market design on 1 January 2022.

In Chapter 3 we describe the “future” gas market design (for natural gas and hydrogen) based on the Hydrogen and Decarbonised Gas Markets Package proposed by the European Commission in December 2021 (hereafter: proposed Decarbonisation Package). The Decarbonisation Package aims to facilitate the decarbonisation of the gas system, inter alia by including hydrogen infrastructure and hydrogen markets in the gas market design. The package consists of a revision of the Gas Directive and Gas Regulation. The package creates the opportunity to

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[12] 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.

[13] Regulation 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005

[14] Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010

[15] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009.

adopt new network codes and guidelines, for example by adopting network codes for hydrogen. However, these network codes and guidelines will have to be developed at a later stage and, therefore, they cannot be included in the description in Chapter 3. Again, the TEN-E Regulation[16] and Gas SoS Regulation are of relevance for specific topics. Changes to both regulations have recently been adopted and we include those changes in the description of the “future” market design. Lastly, the most recently proposed interventions from the European Commission to address the energy crisis are not included in this report (see textbox 1 in the summary for an explanation).

We structure both chapters by discussing the following topics:
1 Background of the current/proposed market design;
2 Legal framework;
3 Definition of gas(es);
4 Segments of value chain of gas(es);
5 Unbundling of activities;
6 Third party access to infrastructure;
7 Infrastructure development;
8 Regulation of network tariffs;
9 Wholesale market;
10 Retail market and customer protection;
11 Gas quality; and
12 Security of supply.

In Chapter 4 we reflect on the changes to the gas market design and present some recommendations to policy makers.

[16] Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013.

2 Current gas market design

2.1 Background of the current gas market design

The current gas market design is the result of a decades long process of liberalisation and gas sector restructuring. The process of liberalisation and gas sector restructuring was driven by several consecutive EU legislative packages, the latest – for gas – being the so called "Third Energy Package" which dates back to 2009.[17]

The general objective of these packages was to complete an integrated internal energy market and move towards a competitive, secure and sustainable Energy Union (European Commission, 2021a). Historically, in many countries, an - often state owned - integrated gas monopolist was responsible for production, storage, transmission and supply of gas. The consecutive energy packages restructured and liberalised the gas sector to create competitive gas markets. To enable competition in gas markets, gas undertakings had to be granted non-discriminatory access to key infrastructure (third party access), notably to the gas transmission and distribution networks.

Based on a sector inquiry that took place from 2005 to 2007 the European Commission concluded that (European Commission, 2021c, pp. 5-6):

> *"(…) significant obstacles to competitive cross-border markets remained, and that consumers could still not fully benefit from liberalisation. Incumbent companies – mostly still state owned – had managed to maintain their dominant positions and tried to avoid competition from domestic and foreign companies. They notably used their control over their networks to avoid competition from new energy suppliers."*

The result of the sector inquiry triggered the European Commission's proposal for a Third Energy Package. The Third Energy Package - being the latest of these packages - builds on previous packages, further restructured the gas sector and focussed on five main areas (European Commission, 2021a):
- unbundling energy suppliers from network operators;
- strengthening the independence of regulators;
- establishing the Agency for the Cooperation of Energy Regulators (ACER);
- enhancing cross-border cooperation between transmission system operators and the creation of European Networks for Transmission System Operators (ENTSOG);
- open, fair retail markets and consumer protection.

2.2 Legal framework

Table 3 shows the legislative acts of the Third Energy Package. Of these, we refer to the Gas Directive and Gas Regulation together as the Third Gas Package (see Textbox 2 for an explanation).

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[17] The First Energy Package was adopted in 1996 and the Second Energy Package in 2003.

Table 3 Overview of legislative acts of the Third Energy Package

Short reference	Complete reference
Gas Directive	Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.
Gas Regulation	Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005
Electricity Directive	Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC
Electricity Regulation	Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003
ACER Regulation	Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators

Textbox 2 - Third energy package

The electricity sector went through a similar decades long process of liberalisation and restructuring to create an integrated European electricity market. The Third Energy Package covered both the electricity and the gas sector. However, since the adoption of the Third Energy Package, the Electricity Directive, Electricity Regulation and ACER Regulation have already been revised as part of the Clean Energy Package, which dates back to 2019. Following the European Commission (2021a), we will refer to the Third Energy Package for principles and concepts applicable to both gas and electricity markets at the time, whereas aspects specific to the gas market are described under the heading of the Third Gas Package.

The Gas Directive and Gas Regulation are the key legislative acts that govern the gas market design. The Gas Regulation has direct legal force. The Gas Directive does not have direct legal force, but has to be transposed into national law by Member States. In The Netherlands the Gas Directive is transposed into national law in the Gas Act (in Dutch: *Gaswet*).

On the EU-level, the Gas Directive and Gas Regulation set general principles, rules and criteria regarding the gas market design. Some of those are further detailed by the European Commission in network codes and guidelines. The network codes and guidelines are EU implementing regulations that the European Commission can adopt on the basis of the Gas Regulation.[18] The goal of the network codes and guidelines is to further integrate EU gas markets by harmonising market rules. Consequently, in practice the scope of the network codes and guidelines is for the most part limited to the transmission systems and wholesale gas market.

The development of network codes follows a specific process, where both ACER, ENSTOG and the European Commission have a specific role. Figure 1 shows the process for the adoption of network codes.[19] Guidelines are adopted by the

[18] The European Commission's authority to adopt network codes and guidelines is limited by the relevant articles in the Gas Regulation. See articles 6 to 10 and article 23 of the Gas Regulation. Because the network codes and guidelines are regulations, they have direct legal force and do not have to be transposed into national law.

[19] This is a simplification of the process for the adoption of network codes. See article 6 of the Gas Regulation for the complete description of the process.

European Commission without such involvement of ACER and ENTSOG. There are currently four network codes and two guidelines. An overview of the network codes and guidelines is shown in Figure 2.

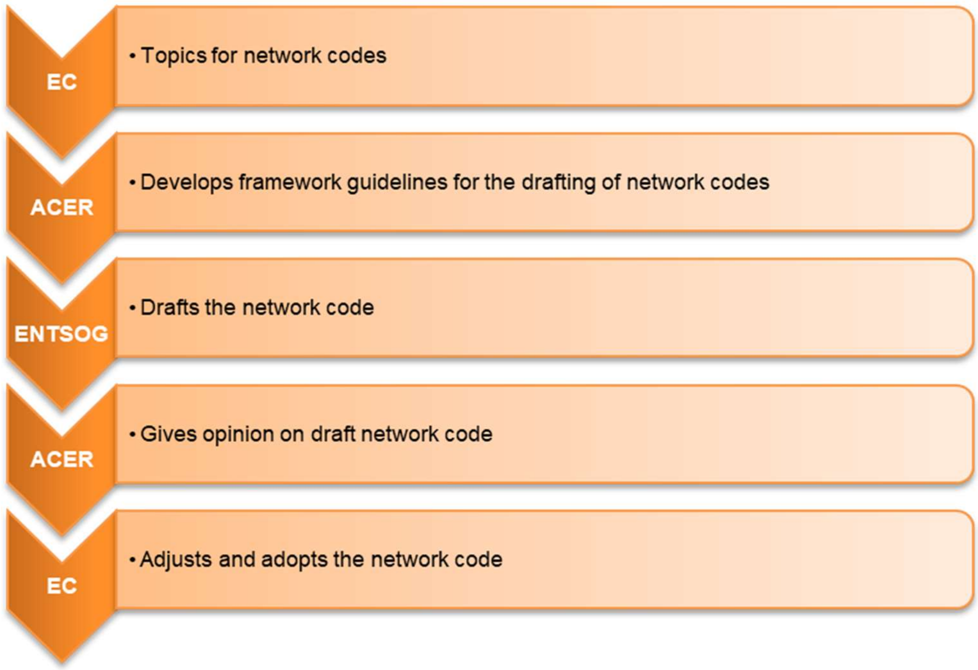

Figure 1 Process for the adoption of network codes

Another important element of the legal framework is the role of national regulatory authorities (NRAs) and the Agency for the Cooperation of Energy Regulators (ACER). NRAs need to be independent from Member States' governments and take decisions that enforce EU rules or further implement specific aspects of the market design (such as national implementation of network codes). In addition, ACER has specific tasks and powers to decide on certain (cross-border) aspects of the market design.

Because energy policy is not the exclusive competence of the EU, but a shared competence between the EU and Member States, Member States can set additional rules or regulations with respect to the market design.[20,21] However, such rules and regulations need to respect the general rules and principles laid down in EU legislation and further detailed in the network codes and guidelines, including the independence of the NRA. Given the fact that many aspects related to the transmission system and wholesale market are governed by network codes and guidelines (which often have to be implemented by decisions by the NRA and/or ACER), there is less room for Member States to set additional national rules. However, for the distribution system and retail market the EU legislation is of more general nature and requires further elaboration in national legislation.

[20] Article 194, TFEU

[21] The scope for national energy policy is generally broader than what we consider "market design" in this report. For example, the national energy policy of The Netherlands also includes decisions on where and under which conditions natural gas may be produced (including foreclosing the Groningen field). Such a decision is clearly part of national energy policy, but we do not consider it part of the market design. However, such a decision can impact the market design.

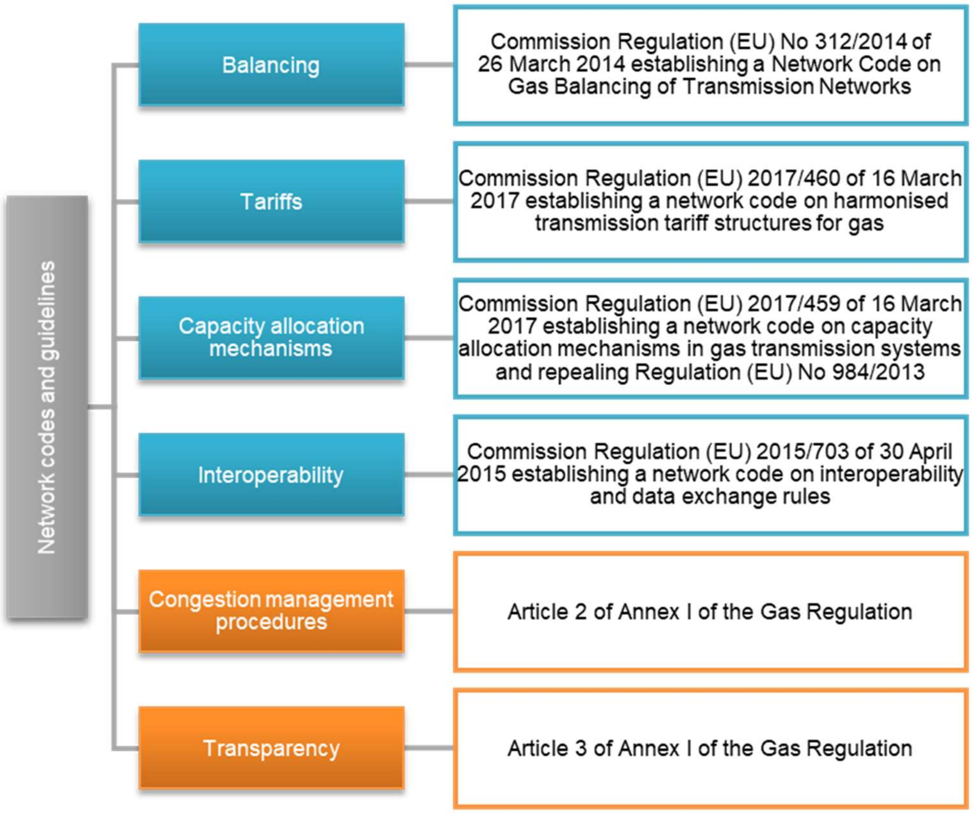

Figure 2 Overview of current network codes and guidelines. Network codes are shown in blue. Guidelines are shown in orange.

2.3 Definition of gas(es)

Somewhat surprisingly, the Third Gas Package does not contain a definition of (natural) gas. However, the Gas Directive states with respect to the scope:

> *"The rules established by this Directive for natural gas, including LNG, shall also apply in a non-discriminatory way to biogas and gas from biomass or other types of gas in so far as such gases can technically and safely be injected into, and transported through, the natural gas system"*[22]

Thus, it is clear that any type of gas that can be technically and safely transported through the natural gas system is included in the scope of the Directive. However, the scope remains to some extent undefined because exactly which gases can technically and safely be injected into, and transported through, the natural gas system is not a given. For example, technical measures might be possible that enable the safe transport through the natural gas system of specific types of gas.

[22] Article 1(2) of the Gas Directive.

In The Netherlands, the national Gas Act does contain a definition of gas (translation by the authors):

> *"b. gas:*
>
> *1°.natural gas that is in a gaseous state at a temperature of 15° Celsius and a pressure of 1.01325 bar and which consists mainly of methane or another substance that is equivalent to methane in terms of its properties and*
>
> *2°.substance that:*
> *– is generated in a production installation that only uses renewable energy sources or*
> *– is generated in a hybrid production installation that uses both renewable and fossil energy sources and*
> *– at a temperature of 15° Celsius and at a pressure of 1.01325 bar, it is in a gaseous state and consists essentially of methane or another substance equivalent to methane in terms of its properties, as far as possible and safe to use this substance in accordance with Chapter 2 to transport"*[23]

The definition shows that both natural gas (in Dutch: *aardgas*) and produced gas from renewable energy or fossil fuels are considered gas. Furthermore, a criterium is that the gas is in a gaseous state at a defined temperature and pressure and mainly consist of methane. The scope of the Gas Act therefore currently excludes other gaseous fuels like hydrogen.

2.4 Segments of gas value chain

Figure 3 presents a schematic overview of the gas value chain. The figure shows the different sources of natural gas supply (including import) in orange. From these sources natural gas flows through different infrastructure segments to the of demand (including export) shown in yellow.[24] Part of the domestic demand is connected to the transmission system (large industries and electricity production) and part is connected to the distribution system (i.e. built environment, horticulture and smaller industries). The blue blocks show the infrastructure segments that are defined in the Gas Directive (see Table 2).

Figure 3 also makes a distinction between the wholesale market and retail market. The wholesale market and retail market are not defined terms in the Third Gas Package and the distinction between wholesale and retail market is not black and white. Typically the retail market concerns the supply of natural gas to final customers. Thus, the retail market is the interface between final customers and the natural gas system. The wholesale market concerns all other trade in natural gas using the natural gas system. However, sometimes large industries procuring natural gas are considered to be directly active in the wholesale market and the retail market is a term used to describe the supply of natural gas to smaller customers.

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[23] Article 1, sub b, of the national Gas Act.

[24] We note that in the EU there are no LNG-terminals for export of natural gas, but the Gas Directive does describe LNG-terminals as installations for both import and export. Moreover, through the EEA-agreement the Gas Directive also applies to Norway, which does have LNG-export terminals. Therefore we included LNG-export in the schematic representation.

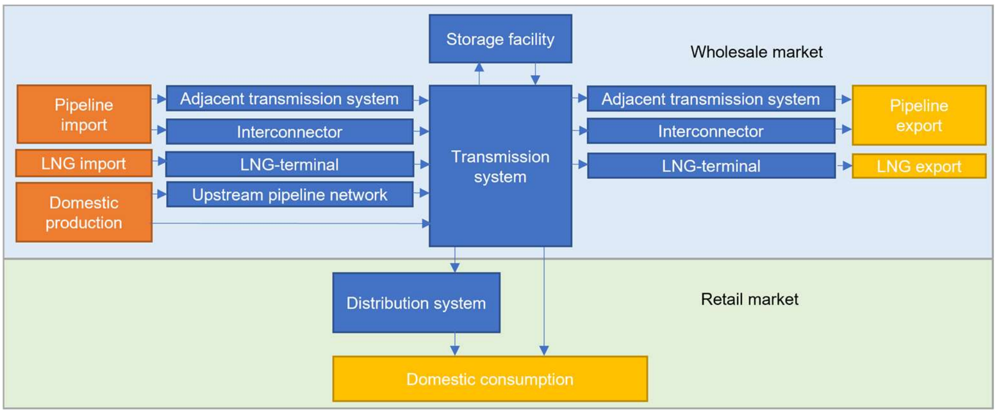

Figure 3 Segments of gas value chain based on current market design

Table 4 Definitions of infrastructure segments in the Gas Directive

Term	Definition
Upstream pipeline network	Any pipeline or network of pipelines operated and/or constructed as part of an oil or gas production project, or used to convey natural gas from one or more such projects to a processing plant or terminal or final coastal landing terminal
LNG facility	A terminal which is used for the liquefaction of natural gas or the importation, offloading, and re-gasification of LNG, and includes ancillary services and temporary storage necessary for the re-gasification process and subsequent delivery to the transmission system, but does not include any part of LNG terminals used for storage
Interconnector	A transmission line which crosses or spans a border between Member States for the sole purpose of connecting the national transmission systems of those Member States
Transmission	The transport of natural gas through a network, which mainly contains high-pressure pipelines, other than an upstream pipeline network and other than the part of high-pressure pipelines primarily used in the context of local distribution of natural gas, with a view to its delivery to customers, but not including supply
Storage facility	A facility used for the stocking of natural gas and owned and/or operated by a natural gas undertaking, including the part of LNG facilities used for storage but excluding the portion used for production operations, and excluding facilities reserved exclusively for transmission system operators in carrying out their functions
Distribution	The transport of natural gas through local or regional pipeline networks with a view to its delivery to customers, but not including supply

2.5 Unbundling of activities

One of the key principles of the Third Energy Package is that market participants should get non-discriminatory third party access to infrastructure, notably to the transmission and distribution system because these are monopolistic segments of the gas value chain. To fully ensure non-discrimination, the Third Energy Package separates network activities from activities of production and supply (effective unbundling). The idea behind effective unbundling is that it removes the incentive for the monopolist to discriminate between different network users. The Gas Directive contains many provisions that deal with the unbundling of activities.

To implement unbundling (and enforce other provisions) it has to be clear who is the transmission system operator (TSO) or distribution system operator (DSO). To that end, a TSO and DSO have to be designated.[25] In addition, TSOs have to be certified, which means it has to be checked whether they meet the unbundling requirements before an owner of a transmission system can be designated as the TSO of that system.[26,27]

For the unbundling of transmission from production and supply three different unbundling models are allowed:[28]
- Ownership unbundling (OU);
- Independent system operator (ISO); and
- Independent transmission operator (ITO).

The OU model is the strictest form of unbundling that is considered the standard form of unbundling. The OU model requires a full separation of ownership of the transmission system on the one hand and production or supply activities on the other hand.[29]

The ISO model allows a vertically integrated gas undertaking to passively maintain ownership of transmission assets, but effectively give the control over the transmission system to an independent system operator.[30] The ISO model is only allowed if on 3 September 2009 the transmission system belonged to a vertically integrated undertaking and the Member State has decided not to apply the OU model.[31]

The ITO model allows a vertically integrated gas undertaking to stay a vertically integrated gas undertaking by implementing a set of behavioural restrictions that effectively create “Chinese walls” between the transmission system operator and production and supply.[32] The ITO model is only allowed if on 3 September 2009 the transmission system belonged to a vertically integrated undertaking and the Member State has decided not to apply the OU model.[33]

In the OU and ISO model the unbundling of transmission from production and supply also includes electricity.[34] Thus, a transmission system operator for gas is not allowed to be active in production or supply of electricity.

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[25] Articles 10 and 24 of the Gas Directive.
[26] Article 10 of the Gas Directive.
[27] In addition, article 11 of the Gas Directive describes an additional procedure for the certification of a transmission system operator owned or controlled by a person from a third country. The goal of this procedure is to ensure that designating this person as a TSO does not result in security of supply risks.
[28] The fact that a certain unbundling model is allowed based on the Gas Directive implies that the Member State has the competence to allow for these different unbundling models. If a Member State chooses to implement full ownership unbundling a vertically integrated undertaking cannot opt for another unbundling model.
[29] Article 9(1) to (3) of the Gas Directive.
[30] Article 14 of the Gas Directive.
[31] Article 9(8) of the Gas Directive.
[32] Article 9(8) of the Gas Directive combined with Chapter IV of the Gas Directive.
[33] Article 9(8) of the Gas Directive.
[34] Article 9(3) of the Gas Directive.

For the unbundling of distribution from production and supply activities, a more relaxed form of effective unbundling is allowed. If the distribution system operator is part of a vertically integrated undertaking, the distribution system operator has to be independent from other activities at least in terms of its legal form, organisation and decision making.[35, 36]

In The Netherlands, ownership unbundling – the strictest form of unbundling – has been implemented for both transmission and distribution and for both gas and electricity.

2.6 Third party access to infrastructure

The Third Gas Package sets rules that ensure third party access to infrastructure. These rules differ per infrastructure segment. Therefore we discuss these rules separately for different types of infrastructure segments.

2.6.1 Transmission and distribution

As discussed, TSOs and DSOs have to be unbundled from production and supply to ensure non-discriminatory third party access to the transmission and distribution system. The conditions for access to the transmission system include:
- conditions to get a connection to the transmission system;
- conditions to use the network, once connected; and
- tariffs that network users need to pay for a connection and using the network.

Because TSOs and DSOs are (local) monopolies, the third party access conditions are subject to regulation by the NRA. The conditions to get access to the networks describe many different aspects of the market design, which we discuss in subsequent paragraphs. For example:
- Third party access to the networks requires that network users can get a connection and that there is sufficient network capacity. The conditions to get a connection and to use the system have to be determined. In addition, third party access requires that TSOs and DSOs invest in network expansion. TSOs and DSOs can only refuse access to their system under specific conditions. We discuss how the Third Gas Package balances third party access to infrastructure with the need for infrastructure development in paragraph 2.7.
- The NRA sets or approves the tariffs, taking into account the relevant criteria listed in the European legislation. We discuss the regulation of network tariffs separately in paragraph 2.8.
- Because of the central position the TSO has in the gas market, the conditions to use the transmission system also determine the wholesale market design. In turn, the wholesale market design is crucial for the integration of EU gas markets. Therefore, many aspects that determine “the conditions to use the network” such as capacity allocation, congestion management and balancing rules are the scope of the network codes and guidelines. Together they determine the wholesale market design. The wholesale market is further discussed in paragraph 2.9.

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[35] Article 26(1) and (2) of the Gas Directive.

[36] For distribution system operators serving less than 100.000 connected customers the Member States may decide not to apply the unbundling requirements.

2.6.2 *Closed distribution systems, direct lines and upstream pipeline networks*

Not all gas pipelines have to be owned and operated by transmission and distribution system operators and are subject to regulation by the NRA. There are some exceptions for specific types of pipelines.

First, a 'direct line' is defined as a natural gas pipeline complementary to the interconnected system. In the national Gas Act the definition is transposed in a more detailed definition, that specifies that a direct line is a pipeline with a very limited scope. A direct line connects a producer to a consumer within the premises of the producer and consumer.[37] A direct line is generally not considered a transmission or distribution system and therefore the rules that apply to TSOs and DSOs do not apply to direct lines.

Second, a 'closed distribution system' can be exempted from certain obligations that normally apply to distribution system operators. A closed distribution system is a distribution system within a geographically confined industrial, commercial or shared service sites such as train station buildings, airports, hospitals, large camping sites with integrated facilities or chemical industry sites.[38] The reason to exempt a closed distribution system is that the obligations that apply to "normal" distribution system operators would lead to an unnecessary administrative burden, given the particular nature of the relationship between the closed distribution system operator and the users of the system. In the Netherlands a closed distribution system is exempted from unbundling requirements and the regulation of network tariffs, while the closed distribution system operator does have to provide a connection to its system and enable a free choice of suppliers for a connected network user.[39]

Third, an 'upstream pipeline network' is defined in the Gas Directive as any pipeline or network of pipelines operated and/or constructed as part of an oil or gas production project, or used to convey natural gas from one or more such projects to a processing plant or terminal or final coastal landing terminal.[40] Upstream pipeline networks are not considered transmission networks and, therefore, most of the obligations that apply to TSOs do not apply to upstream pipeline networks. Given the nature of upstream pipeline networks unbundling requirements do not apply. However, the Gas Directive does require Member States to ensure some form of access to upstream pipeline networks.[41] In The Netherlands there are upstream pipeline networks that connect offshore gas fields to the onshore transmission system.

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[37] See article 1, sub an, of the national Gas Act for the precise definition.
[38] See article 28 and recital 28 of the Gas Directive. A closed distribution system is not defined in the Third Gas Package. Article 1, sub am, of the national Gas Act does contain a definition of a closed distribution system.
[39] Article 2a of the national Gas Act.
[40] Article 2(2) of the Gas Directive. Article 1, sub c, of the national Gas Act contains a similar definition.
[41] Article 34 of the Gas Directive.

2.6.3 *LNG facilities*

The general idea of granting non-discriminatory third party access to LNG facilities is to prevent large incumbents who own or operate the LNG facilities from hoarding the capacity. For LNG facilities the Gas Directive sets third party access conditions similar to the third party access conditions for transmission and distribution systems. LNG facilities have to grant non-discriminatory third party access to the infrastructure based on tariffs set or approved in advance by the NRA.[42]

However, the Gas Regulation contains slightly less specifications of third party access conditions that apply to LNG facilities compared to transmission and distribution systems. The Gas Regulation contains articles that set general rules or principles with respect to:
- Third party access services concerning LNG facilities;[43]
- Principles of capacity allocation mechanisms and congestion management procedures concerning LNG facilities;[44]
- Transparency requirements concerning LNG facilities.[45]

However, for example, article 13 of the Gas Regulation which contains a set of criteria for the tariffs for access to the networks does not apply to the tariffs for LNG facilities. So although the NRA has to set or approve the tariffs for access to LNG facilities, the criteria that apply for setting the tariffs are not further described in EU legislation. Furthermore, for TSOs the conditions for granting access to their networks are further detailed in network codes and guidelines, which is not the case for access conditions to LNG facilities.

2.6.4 *Storage facilities*

Member States may decide between negotiated or regulated access to storage and may decide whether the Member State or the NRA has the authority to enforce or implement the (regulated or negotiated) access conditions. Negotiated third party access means that the storage operator can negotiate the applicable terms and conditions with its users, while taking into account some general principles. Under regulated third party access those conditions are set by the NRA or Member State. Thus, for storage facilities the Gas Directive allows for more flexibility because the NRA does not have to set or approve the tariffs for access to storages.[46] Although there is more flexibility for the type of third party access (i.e. negotiated or regulated), almost the same general principles apply to storages as to LNG facilities.[47]

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[42] Article 32(1) of the Gas Directive.
[43] Article 15 of the Gas Regulation.
[44] Article 17 of the Gas Regulation.
[45] Article 19 of the Gas Regulation.
[46] Compare article 33 of the Gas Directive with Article 32(1) of the Gas Directive.
[47] Articles 15, 17 and 19 of the Gas Regulation apply equally to storages and LNG facilities, although the subparagraphs of the articles in some instances do make a distinction between storages and LNG facilities.

2.7 Infrastructure development

Effective third party access to infrastructure (networks, storages, LNG facilities) also requires that there is sufficient capacity to meet the demand. Therefore, the development of infrastructure determines if, and to what extent, third party access is ensured. In this paragraph we discuss the balance between effective third party access and the need for infrastructure development. We do that by discussing:
- Under which conditions infrastructure operators can refuse access to their system;
- Specifically for TSOs, how they have to approach network planning; and
- Which specific incentives for infrastructure development there are.

2.7.1 Refusal of access

As discussed previously, Member States have to ensure third party access to transmission and distribution networks and LNG facilities.[48] For storages a choice between negotiated and regulated third party access is possible.[49] However, the principle of third party access does not imply that the infrastructure operator has to grant access unconditionally. There will be conditions to get a connection and use the infrastructure (including applicable tariffs).

Specifically for access to the networks, the Third Gas Package ensures that network users can get non-discriminatory access to the system and, thus, ensures the right to a connection. The conditions to get a connection to the transmission or distribution system have to be fixed or approved by the NRA.[50] In addition, the technical safety criteria and technical rules for a connection have to ensure interoperability.[51]

In certain situations it is allowed to refuse access to the infrastructure. The Third Gas Package specifies when a natural gas undertaking can refuse access to its system. A natural gas undertaking can refuse access to its infrastructure on the basis of a lack of capacity, which has to be duly substantiated.[52, 53] Member States may take measures to ensure that when a natural gas undertaking refuses access to its infrastructure the necessary enhancements (i.e. investment in capacity expansion) are made (i) as far as it is economic to do so or (ii) when a potential customer is willing to pay for them.

This implies that in principle infrastructure has to be developed to meet the demand. That also follows from the tasks of transmission, distribution, storage and LNG-system operators. Transmission, storage and LNG-operators have to:

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48 Article 32(1) of the Gas Directive.
49 Article 33 of the Gas Directive.
50 Article 41(6)(a) of the Gas Directive.
51 Article 8 of the Gas Directive.
52 Article 35(1) of the Gas Directive.
53 In addition, the access may be refused if allowing access would prevent the operator from meeting so called public service obligations. Public service obligations can be imposed on natural gas undertakings on the basis of article 3(2) of the Gas Directive.

> *"operate, maintain and develop under economic conditions secure, reliable and efficient transmission, storage and/or LNG facilities to secure an open market, with due regard to the environment, ensure adequate means to meet service obligations"*[54]

Similarly, distribution system operators have to ensure:

> *"the long-term ability of the system to meet reasonable demands for the distribution of gas, and for operating, maintaining and developing under economic conditions a secure, reliable and efficient system in its area, with due regard for the environment and energy efficiency"*[55]

To summarise, Member States and NRAs have to define conditions for access to infrastructure. Access to infrastructure only has to be granted if the user accepts those conditions. When a user accepts those access conditions, refusal of access is only allowed on the basis of a lack of capacity. When access is refused on the basis of a lack of capacity, in principle the necessary enhancements have to be made to increase the capacity. However, Member States can determine when it is not economic to make those enhancements. Even then, if the customer is willing to pay for the necessary enhancements the capacity has to be expanded.

2.7.2 Network planning

Because network operators have to invest in capacity to meet the demand, the planning of those investments is an important element. The Third Gas Package contains several provisions with respect to network planning by TSOs specifically:
- Only for TSOs unbundled according to the ITO model (and, thus, not for the TSOs unbundled according to the OU and ISO model), there is an obligation to develop a ten year network development plan which has to be submitted to the NRA for review. In principle the TSO has to execute the investments in the ten year network development plan and the NRA can take measures to enforce this.[56]
- In addition, TSOs have to establish regional cooperation within ENTSOG (i.e. cooperation of a number of countries in a region). For each of those regions regional network development plans have to be published every two years.[57]
- Lastly, ENTSOG has to develop a non-binding EU network development plan every two years.[58] The plan has to include the modelling of the integrated network, scenario development and a European supply adequacy outlook.[59] The non-binding EU network development plan serves as a basis for (i) the review of national ten year network development plans by NRAs and (ii) the identification of projects of common interest (see 2.7.3).

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[54] Article 13(1)(a) of the Gas Directive.
[55] Article 25(1) of the Gas Directive.
[56] Article 22 of the Gas Directive.
[57] Article 12(1) of the Gas Regulation.
[58] Article 8(3)(b) of the Gas Regulation.
[59] Article 8(1) of the Gas Regulation.

2.7.3 Incentives for infrastructure development

The gas market design contains two mechanisms that incentivise infrastructure development.

First, new infrastructure can be exempted from (i) unbundling requirements, (ii) third party access and (iii) regulation of tariffs and access conditions by the NRA. An exemption for new infrastructure is allowed when:[60]
- The investment enhances competition in gas supply and security of supply;
- The risk of the investment is such that the investment would not take place without an exemption;
- The infrastructure is owned by a natural or legal person which is separate at least in terms of its legal form from system operators;
- Charges for the new infrastructure are levied on the users of that infrastructure; and
- The exemption is not detrimental to competition or effective functioning of the internal market or of the system to which the infrastructure is connected.

Second, there is a legal framework that aims to promote the integration of European energy infrastructure by facilitating the development of energy infrastructure with a cross-border impact. The TEN-E Regulation determines a list of priority corridors for the development of trans-European energy infrastructure, i.e. a list of bottlenecks for cross-border energy infrastructure. To ensure infrastructure is developed that addresses these bottlenecks, a list of projects of common interest has to be developed. A project of common interest needs to have a positive effect on welfare, analysed by a cost benefit analysis. Furthermore, the costs of the project can be allocated to different countries involved on the basis of a cross-border cost allocation. For gas transmission projects, a prerequisite is that the project has been included in the non-binding Union wide ten year network development plan that ENTSOG has to publish every two years.

Selected projects of common interest can benefit from better streamlined, coordinated and accelerated permit granting processes.[61] In addition, a project of common interest can benefit from specific regulatory incentives or receive financing for studies or works from the Connecting Europe Facility (CEF).

2.8 Regulation of network tariffs

Because transmission and distribution system operators are monopolists, the tariffs for access to their networks are subject to regulation by the NRA. The goal of the regulation of network tariffs is to prevent network operators abusing their market power by charging high tariffs or discriminating between different network users. The NRA either sets or approves the tariffs or the methodologies used to calculate them.[62]

For transmission system operators, article 13 of the Gas Regulation describes the principles and criteria that the NRA has to take into account when setting or approving the tariffs. Tariffs, or the methodologies used to calculate them, should

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[60] Article 36(1) of the Gas Directive.
[61] Article 1(b) of the TEN-E Regulation.
[62] Article 41(1)(a) of the Gas Directive.

be non-discriminatory, reflective of efficiently incurred costs, transparent and take into account an appropriate return on investments. The tariffs have to facilitate efficient gas trade and competition, while at the same time avoid cross-subsidies between network users and provide incentives for the maintenance or expansion of transmission networks.

For distribution system operators there are no criteria in the Gas Regulation that the NRA has to take into account. However, the Gas Directive does state the following with respect to the fixing or approving of the tariffs:

> *"(…) regulatory authorities shall ensure that transmission and distribution system operators are granted appropriate incentive, over both the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities"*[63]

In practice, for the regulation of network tariffs a distinction can be made between (i) determining the allowed or target revenue for transmission and distribution system operators (tariff revenues) and (ii) determining how the allowed or target revenues are translated to the tariffs that network users need to pay for using the network (tariff structures). The determination of the allowed or target revenues determines the incentives for transmission and distribution system operators, whereas the tariff structure determines the incentives for network users. Some of the criteria in the EU legislation are particularly relevant for the determination of tariff revenues (efficiently incurred costs, appropriate return on investments), whereas others are particularly relevant for the tariff structures (avoid cross-subsidies, non-discriminatory).

The determination of the allowed or target revenues is for the most part left to the NRAs, because the Third Gas Package only describes general principles and criteria. As a result, the determination of allowed or target revenues differs between countries. Typically, the determination of allowed or target revenues includes determining the costs of the network operator as well as setting efficiency parameters to incentivise cost reductions. The costs are equal to the sum of operating expenditure, depreciation and capital costs. For the determination of depreciation and capital costs, the regulated asset base (RAB), the weighted average costs of capital (WACC) and depreciation periods are key parameters that have to be determined. For the determination of efficiency parameters generally a distinction can be made between static and dynamic efficiency parameters.

For the determination of the tariff structures for transmission system operators the network code on harmonised transmission tariff structures sets more detailed rules. Because transmission tariff structures determine the incentives for network users on how to use the transmission system, the tariff structures are an important element of the wholesale market design. Therefore, these rules are discussed further in paragraph 2.9 where we discuss the wholesale market design.

The determination of the tariff structures for distribution system operators is mostly left to the NRA.

[63] Article 41(8) of the Gas Directive.

2.9 Wholesale market

In this subparagraph we discuss the current wholesale gas market design. We discuss the wholesale market by discussing the following concepts or elements of the wholesale market design:
- Entry-exit system;
- Trade on a virtual point;
- Trading in different markets;
- Capacity allocation mechanisms;
- Nomination;
- Market-based balancing;
- Congestion management; and
- Transmission tariff structures.

2.9.1 Entry-exit system

The entry-exit system generally refers to the transmission system. A transmission system has entry points where gas is injected into the system and exit points where gas is extracted from the system (see arrows to and from the transmission system in Figure 3). Typically, there is one national entry-exit system that coincides with the service area of the transmission system operator, but other configurations are also possible.[64] Interconnection points are the border points between connected entry-exit systems or between an entry-exit system and an interconnector.[65] Thus, interconnection points are the intra-EU points that enable pipeline imports and exports.

2.9.2 Trade on virtual point

In an entry-exit system, gas that has entered the system can be exchanged on a virtual trading point. The establishment of a virtual trading point allows a gas producer/importer to inject gas into the system at an entry point (domestic production, interconnection point or LNG entry point), transfer the ownership of the gas to another network user “on the virtual point” who in turn either extracts the gas from the system at an exit point (i.e. supplies gas to a connected customer), exports or stores the gas or resells the gas to another owner “on the virtual point”.

2.9.3 Trading in different markets

The transfer of gas on the virtual point enables trading between parties. Generally a distinction is made between the type of products traded and the platform/intermediaries used for trading. The types of products traded can be distinguished in (i) a spot market where gas is traded for the next day or the remaining part of the day (day-ahead and intraday markets) and (ii) forward or future markets where gas is traded for delivery over a certain period in the future (monthly, quarterly and yearly products). On an exchange standardised products are traded anonymously and the exchange takes on the counterparty risk. Trading bilaterally allows for more tailor made products to be traded in whatever form the parties can agree on.

[64] For example, there can be more transmission system operators each with their own service area combined in one entry-exit system.
[65] Or between an entry-exit system and an interconnector.

2.9.4 *Capacity allocation*

To be allowed to inject gas into the system network users have to contract entry capacity at entry points. Similarly, to be allowed to extract gas at exit points, network users have to contract exit capacity at exit points. To be allowed to transport gas from one entry-exit system to another, network users have to contract capacity at interconnection points. Contracted capacity gives the network user the right to inject or extract gas at the specified entry or exit point, but does not obligate a network user to do so.

The network code on capacity allocation mechanisms determines how the capacity at interconnection points has to be allocated. The key principle is that entry and exit capacity at interconnection points are sold as a bundle and allocated through auctions, based on a fixed auction calendar that is harmonised within the EU. Standard capacity products for different durations are defined. Table 5 presents an overview of the standard capacity products at interconnection points. Furthermore, in case there are multiple physical interconnection points between entry-exit systems, these interconnection points need to be bundled into one virtual interconnection point.[66]

At domestic entry and exit points – i.e. all points other than interconnection points – different capacity allocation mechanisms can apply, such as first come first served.

Table 5 Overview of standard capacity products on interconnection points

Standard capacity product	Explanation
Yearly	Capacity that a network user may request for all gas days during a particular gas year starting on 1st October
Quarterly	Capacity that a network user may request for all gas days during a particular quarter, which can start on 1st October, 1st January, 1st April or 1st July
Monthly	Capacity that a network user may request for all gas days in a month starting the first day of each month
Daily	Capacity that a network user may request for one gas day
Within-day	Capacity that a network user may request within a day until the end of that gas day

2.9.5 *Nomination*

Because contracted entry or exit capacity gives the right to inject or extract gas at entry or exit points, the TSO also has to be notified of the actual use of that right. Network users therefore inform the TSO in advance of their intention to make use of contracted entry and exit capacities at each entry and exit point for a specific day or hour. Such notifications are called nominations.[67] Changing the nomination between the first submission of nomination and the physical delivery is called re-nomination.[68]

[66] The idea being that the interconnection capacity at all physical interconnection points practically provide the same capacity to transport gas from one entry-exit system to the other.
[67] See definition in article 2(1)(7) of the Gas Regulation.
[68] See definition in article 2(1)(8) of the Gas Regulation.

2.9.6 *Market based balancing*

To ensure the safe operation of the transmission system, the pressure in the pipelines has to stay within certain limits. That implies that injection (supply) and extraction (demand) of gas need to be in balance. Compared to electricity systems, the gas system has more inherent flexibility (linepack flexibility) which allows for temporary differences between supply and demand. However, a sustained mismatch between supply and demand has to be avoided.

To balance supply and demand, a market based balancing regime is used. The key principle of a market based balancing regime is that (i) the TSO buys or sells gas in the market to correct the imbalance and (ii) causers of the imbalance are charged with the costs of correcting the imbalance. The network code on balancing sets most of the requirements for the balancing mechanism.

Network users have to submit a schedule with their planned (i.e. nominated) entry and exit of gas at entry and exit points for each hour of the next day. In addition, all exchanges of gas on the virtual point have to be included in the schedule. For example, a gas producer who has sold gas to a supplier has to include entry of gas and the transfer of ownership on the virtual point in the submitted schedule. As a result, the submitted schedule is in balance (entry on physical entry point equals exit on virtual point). The submitted schedules can be updated (for example after trading in the intraday market).

The actual entry and exit of gas in measured. Network users can get near real time information on the imbalance of their own portfolio (i.e. deviations from the submitted schedule) and the imbalance of the system (i.e. deviations from all submitted schedules combined). When the imbalance of the system exceeds certain thresholds, the TSO buys or sells gas to restore the balance of the system. The costs (or revenues) of buying or selling gas are passed-through to the causers of the imbalance.

The balancing mechanism incentivises network users to trade in the wholesale market to balance their portfolio and limit the risk of high imbalance charges.

2.9.7 *Congestion management*

Because interconnection capacity and the actual use of that capacity for trade are separated, there is a risk of capacity hoarding. A domestic incumbent gas producer could, for example, buy all the cross-border capacity that is needed for import of gas, not with the intention of using it but with the intention of preventing other gas suppliers from importing gas. As a result, the domestic incumbent producer would shield itself from competition in the wholesale gas market.

More generally, there is a risk of contracted capacity that remains unused and limits trade options for other network users which leads to inefficiency. This is called ‘contractual congestion’. Congestion management procedures are procedures aimed at mitigating (the effect of) contractual congestion on interconnection points. To explain contractual congestion and congestion management procedures, we first have to explain some key definitions. Table 6 contains an overview of those definitions.

Table 6 Definitions of capacity and congestion

Term	Definition
Capacity	The maximum flow, expressed in normal cubic meters per time unit or in energy unit per time unit, to which the network user is entitled in accordance with the provisions of the transport contract
Firm capacity	Gas transmission capacity contractually guaranteed as uninterruptible by the transmission system operator
Interruptible capacity	Gas transmission capacity that may be interrupted by the transmission system operator in accordance with the conditions stipulated in the transport contract
Technical capacity	The maximum firm capacity that the transmission system operator can offer to the network users, taking account of system integrity and the operational requirements of the transmission network
Contracted capacity	Capacity that the transmission system operator has allocated to a network user by means of a transport contract
Available capacity	The part of the technical capacity that is not allocated and is still available to the system at that moment
Unused capacity	Firm capacity which a network user has acquired under a transport contract but which that user has not nominated by the deadline specified in the contract
Physical congestion	A situation where the level of demand for actual deliveries exceeds the technical capacity at some point in time
Contractual congestion	A situation where the level of firm capacity demand exceeds the technical capacity

A distinction can be made between firm and interruptible capacity. When a TSO sells firm capacity, the TSO guarantees that the capacity can be used by the network user. By contrast, when the TSO sells interruptible capacity, the network user faces a risk that, when nominating, the capacity cannot be used (there is a risk of interruption).

The technical capacity is the maximum firm capacity that the TSO can offer to the network users, taking into account the security of the system. Thus, the technical capacity defines the limit of the capacity that can be used by network users. A TSO is required to offer the maximum technical capacity to the market. It is possible that the TSO sells more than the technical capacity, for example by selling interruptible capacity. When more than the technical capacity is sold, there is a risk that total nominations exceed the technical capacity. In that case (part of the) interruptible capacity will be interrupted, to ensure that the total flow of gas does not exceed the technical capacity.

Physical congestion is a situation where the demand for actual deliveries (i.e. nominations) exceeds the technical capacity at some point in time. There is contractual congestion when the demand for firm capacity exceeds the technical capacity. Contractual congestion does not have to result in physical congestion, because it is possible that network users do not nominate their capacity at the same time. In that case, all firm capacity is sold and there is unserved demand for firm capacity but the physical flow of gas is lower than the technical capacity. Therefore, when there is contractual congestion, there is still unused capacity. Thus, whereas physical congestion can only be solved by expanding the technical capacity, contractual congestion can also be solved by congestion management procedures.

The congestion management procedures are further detailed in the congestion management procedures guideline. Annex I of the Gas Regulation and describes

the congestion management procedures.[69] This guideline only applies to interconnection points and, optionally, to entry- or exit point to and from third countries. The guideline describes different options to mitigate contractual congestion. The options are:
- Capacity increase through oversubscription and buy-back (OBB);
- Firm day-ahead use-it-or-lose-it mechanism (FDA UIOLI);
- Surrender of contracted capacity (SoCC); and
- Long-term use-it-or-lose-it (LT UIOLI).

Table 7 describes these different congestion management procedures. The default is that OBB, SoCC and LT UIOLI are all implemented (which is the case in The Netherlands). The FDA UIOLI mechanism is considered an alternative for OBB in case the implementation of OBB does not solve the problem of contractual congestion.

Table 7 Congestion management procedures

Mechanism	Description
OBB	– The TSO can sell more firm capacity than the technical capacity – When the nominations of firm capacity exceed the technical capacity the TSO shall buy back part of the firm capacity – The buy-back shall be market based (auctioned) – The TSO has to be incentivised to find an optimal balance between the benefit of selling additional capacity and the costs of potential buy-back auctions.
FDA UIOLI	– The mechanism limits the option of renominating the contracted capacity. – After the initial nomination, a shipper can only renominate up to 90% of the contracted capacity or down to 10% of the contracted capacity. – Because of the restrictions on the renominations the TSO can offer part of the contracted capacity to the market, because the TSO knows it will not be used.
SoCC	– TSOs have to accept any surrender of firm capacity which is contracted by the network user at an interconnection point, with the exception of capacity products with a duration of a day and shorter. – The network user shall retain its rights and obligations under the capacity contract until the capacity is reallocated by the TSO and to the extent the capacity is not reallocated by the transmission system operator. – Surrendered capacity shall be considered to be reallocated only after all the available capacity has been allocated.
LT UIOLI	– TSOs partially or fully withdraw systematically underutilised contracted capacity on an interconnection point by a network user where that user has not sold or offered under reasonable conditions its unused capacity and where other network users request firm capacity. – Withdrawal results in the network user losing its contracted capacity partially or completely for a given period or for the remaining effective contractual term.

[69] Annex I, Article 2, of the Gas Regulation.

2.9.8 Transmission tariff structures

TSOs charge network users for contracting entry- or exit capacity.[70] Thus, network tariffs are set for each entry- and exit point in the entry-exit system. Furthermore, network tariffs may differ for different types of capacity products (i.e. yearly, quarterly, monthly, daily and within-day capacity products) and for periods of the year (i.e. months of the year).

The network code on harmonised transmission tariffs describes how these tariffs should be calculated. The overall goal of the network code is to avoid discrimination and cross-subsidies by ensuring cost-reflective, transparent and predictable transmission tariff structures. The network code assumes that for a given tariff year there is an allowed or target revenue for the TSO that serves as the basis for the tariff calculation. The network code sets rules with respect to:

- The part of the allowed or target revenue that has to be recovered from transmission tariffs (transmission tariffs revenue) and non-transmission tariffs (non-transmission tariffs revenue).
- The part of the transmission tariffs revenue that needs to be recovered from capacity based transmission tariffs (i.e. tariffs for contracting entry and exit capacity) and the part of the revenue that may be recovered from commodity-based transmission tariffs (i.e. tariffs for nominated entry or exit capacity).
- How the transmission services revenue to be recovered from capacity-based transmission tariffs has to be allocated to entry and exit points using a reference price methodology. The reference price for an entry or exit point is the price for a yearly capacity product at that entry or exit points. For interconnection points, the reference price determines the reserve price for the auction of the yearly capacity product.[71]
- The discount for entry points from and exit points to and from storage facilities and entry points from LNG facilities. For storage facilities the discount has to be at least 50%. For LNG facilities the network code does not specify a minimum discount but states that a discount may be applied for the purpose of increasing security of supply.
- How the prices for products with a shorter duration than a year need to be derived from the reference prices by using multipliers and seasonal factors. The multiplier determines the price of a short term capacity product relative to the time proportionate share of the price of a yearly capacity product. The seasonal factors determine the price differentiation between different periods of the year (i.e. summer versus winter).
- How the discount for interruptible capacity products has to be calculated.

2.10 Retail market and customer protection

Whereas the Third Gas Package (including the network codes and guidelines) details many aspects of the wholesale market design, most of the retail market design is left to the Member States. The Gas Directive does contains some general

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[70] In addition to tariffs charged for contracting entry- or exit tariffs, other types of tariffs can apply such as tariffs for connecting a network user to the system.

[71] In practice often the tariff year and the gas year do not coincide. Thus, the reserve price for the yearly capacity product (from October to September) will typically be a weighted average of the reference prices for the respective two tariff years.

principles regarding the retail market and some more detailed requirements regarding (retail) customer protection.

According to the European Commission (2010) the following applies to retail markets based on the Third Gas Package:

- Member States must ensure that the roles and responsibilities of transmission system operators, distribution system operators, supply undertakings and customers and if necessary other market parties are defined with respect to contractual arrangements, commitment to customers, data exchange and settlement rules, data ownership and metering responsibility.[72] Member States must ensure that all customers connected to the gas network can choose a supplier, regardless of the Member State where the supplier is registered, as long as the supplier follows the applicable rules.[73] Member States are allowed to require a license to supply to customers, but the licensing requirements cannot not be unnecessarily restrictive.
- Member States must ensure proper customer protection, which covers the following elements:
  - If a consumer, while respecting the contractual conditions, wishes to switch suppliers, (i) the switch has to be effected within three weeks and (ii) the consumer must receive a final closure account following any change of electricity or gas supplier no later than six weeks after the change of supplier has taken place.[74]
  - Consumers must be given the right to receive all consumption data in an easily understandable format and be permitted to share the consumption data with other suppliers free of charge.[75] Consumers must be properly informed about actual gas consumption and costs frequently enough for them to regulate their own gas consumption.[76]
  - Member States have to define which consumers qualify as vulnerable consumers and ensure their protection.[77] The protection of vulnerable customers may refer to a prohibition of disconnection at critical times.
  - Member States must ensure that there is an independent mechanism to deal with complaints and a single point of contact to provide consumers with all necessary information about their rights.[78] The mechanism has to be transparent, simple and inexpensive.[79]
  - Member States have to ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the gas supply market. The implementation of those metering systems may be subject to an economic assessment of all the long-term costs and benefits to the market and the individual consumer or which form of intelligent metering is economically reasonable and cost-effective and which timeframe is feasible for their distribution.[80]

[72] Article 45 of the Gas Directive.
[73] Article 3(5) of the Gas Directive.
[74] Article 3(6)(a) of the Gas Directive and Annex I(1)(j) of the Gas Directive.
[75] Article 3(6) of the Gas Directive and Annex I(1)(h) of the Gas Directive.
[76] Annex I((1)(i) of the Gas Directive.
[77] Article 3(3) of the Gas Directive.
[78] Article 3(9) of the Gas Directive.
[79] Annex I(1)(f) of the Gas Directive
[80] Annex I(2) of the Gas Directive.

Although these provisions open up retail markets for competition (i.e. free choice of supplier) and ensure customer protection, the provisions do not imply that retail market prices are actually based on retail market competition. In fact, in many countries some form of price regulation of retail prices persists (European Commission, 2021c). That is the case because regulation of retail market prices is allowed under article 3(2) of the Gas Directive (if the conditions in that article are met), which allows Member States to (underlining by the authors):

> *"(…) impose on undertakings operating in the gas sector, in the general economic interest, public service obligations which may relate to security, including security of supply, regularity, quality and price of supplies, and environmental protection, including energy efficiency, energy from renewable sources and climate protection. Such obligations have to be clearly defined, transparent, non-discriminatory, verifiable and guarantee equality of access for natural gas undertakings of the Community to national consumers. (…)"*[81]

In The Netherlands, the following applies to the gas retail market:
- To supply gas to small consumers[82] a supplier needs a permit from the NRA.[83] The NRA grants a permit when:[84]
  - the supplier can show contracts for the procurement of gas and transport capacity that matches the suppliers expected supply of gas;
  - the supplier possesses the required organisational, financial and technical qualities
  - the supplier applies reasonable conditions, which is considered to be the case when the supplier (i) uses clear offers and agreements, in which the level of the rates and the structure thereof is indicated, (ii) uses a transparent and reasonable payment arrangement, (iii) uses a transparent and reasonable arrangement for terminating or dissolving agreements, (iv) is able to handle complaints and disputes in an adequate manner, and (v) uses conditions that are in accordance with what is determined by or pursuant to the law with regard to the withdrawal of the permit.
- When a supplier no longer meets any of the criteria for the permit (which includes the case of bankruptcy), the NRA can decide to withdraw the permit. If a permit is withdrawn the customers of the former permit holder will be assigned to all other permit holders, based on an allocation key.[85]
- A light form of retail price regulation applies to the supply of gas to small consumers, because the NRA judges whether the supplier charges unreasonably high rates. The supplier must submit the rate changes every year and four weeks before the rate changes. The NRA assesses whether the submitted rates are unreasonably high. When the rates are considered unreasonably high the NRA requests an explanation of the supplier for the high rates. If there is no satisfying explanation of the rates, the NRA sets the maximum price for the supply to small consumers. The goal of this mechanism is not to extensively regulate retail prices, but to protect some customers who

81 Article 3(2) of the Gas Directive.
82 In Dutch: *kleinverbruikers*, which is defined as any customer with a connection to the gas grid with a capacity smaller or equal to 40 m^3 per hour.
83 Article 43 of the national Gas Act.
84 Article 3, Besluit vergunning levering gas aan kleinverbruikers.
85 Article 3, Besluit leveringszekerheid Gaswet.

are unlikely to switch suppliers from paying excessive prices (Autoriteit Consument & Markt, 2019).

2.11 Gas quality

The composition of natural gas (gas quality) can differ depending on the source of the gas. The specification of the composition of the gas that can safely be injected into the system is an important variable for access to the system. Typically, end-users (especially industries) want a stable gas quality. However, the quality of gas will differ depending on the origin of the gas. For producers being allowed to inject the gas without gas quality treatment is desirable, because gas quality treatment is costly. Because the quality of gas depends on the origin, the gas quality also differs per country or entry-exit system. Such quality differences can be a barrier for cross-border trade because the cross-border flow of gas may have to be restricted to avoid exceeding gas quality standards.

Although gas quality is an important variable that determines access to the market and market integration, the Third Gas Package does not set EU-wide gas quality standards. Instead, the network code on interoperability specifies how TSOs should coordinate when gas quality differences hamper cross-border trade. The concerned TSOs have to make a list of potential solutions, estimate the potential of each solution, conduct a public consultation and submit a joint proposal for removing the restriction for approval of the respective NRAs. Moreover, TSOs have to monitor the gas quality both in the short term (for each hour) and in the long term (the next ten years). The long term monitoring has to be done by ENTSOG. Every two years ENTSOG has to publish a long-term quality monitoring report to identify potential trends of gas quality parameters and their variability. The report has to take the Union wide ten year network development (also developed by ENTSOG) into account.

In addition, specifically for the Netherlands, a distinction is relevant between low-calorific gas and high-calorific gas. Gas from the Groningen field has a lower calorific value than most other gases (such as from Dutch offshore fields, Norway or Russia). Low-calorific and high-calorific gas are transported in separate pipelines, because many of the end-user appliances are not suitable for high-calorific gas. High calorific gas can be converted to low calorific gas (quality conversion) by (i) blending of high and low-calorific gases and (ii) injecting nitrogen into high calorific gas resulting in low-calorific gas. Thus, the Dutch gas system combines two separate gas systems. Although in fact there are two separate gas systems the Dutch wholesale gas market is organised as one “quality-less” gas market. There is one entry-exit system where market participants can trade gas per MWh without taking into account the quality of the gas and the need for quality conversion.

In the Netherlands gas quality standards have been determined by the Government in a Ministerial Regulation on Gas Quality.[86]

[86] Regeling gaskwaliteit.

2.12 Security of supply

Initially, the Third Gas Package contained some provisions on the security of gas supply. For example, article 3(2) allows Member States to impose public service obligations on natural gas undertakings, which may relate to security of supply. In The Netherlands, on the basis of this article the system of licensing suppliers of residential consumers has been adopted, which includes a supplier of last resort mechanism in case of bankruptcy of a supplier. Also on the basis of this article the TSO has been made responsible for ensuring the supply to residential consumers on very cold days (peak supply). See Textbox 3 for an explanation of peak supply. Moreover, article 6 of the Gas Directive describes the principle of regional solidarity between Member States.

Textbox 3 - Peak supply to residential consumers
The Dutch government has implemented a mechanism to ensure the supply to small consumers, also on very cold days with a high natural gas demand. Suppliers of small consumers are required to ensure the supply of gas required for a day with an effective average daily temperature of -9 ºC. If the effective average daily temperature is lower than -9 ºC the TSO will supply the additional demand of gas (i.e. the difference between the gas demand at an effective daily temperature of -9 ºC and the gas demand at the actual effective daily temperature). To ensure the supply of gas the TSO contracts production or storage capacity based on a market based procurement. The costs of the procurement are charged to the suppliers of small consumers. The obligation of the TSO is to ensure the supply of gas to residential consumers between an effective daily temperature of -9 ºC and -17 ºC. At even colder temperatures the security of supply is no longer ensured. The TSO is also required to ensure sufficient transmission capacity for the supply of gas at an average effective daily temperature of -17 ºC

However, after the adoption of the Third Gas Package a separate “Security of Supply Regulation” was adopted in 2010 (hereafter: Gas SoS Regulation),[87] which has been revised in 2017.[88] As noted by the European Commission (Evaluation report accompanying the proposal for a Hydrogen and Decarbonised Gas Markets Package, 2021c, p. 53):

> *“The Third Package, and in particular its Article 6, on regional solidarity, represented an important step forward that contained the embryo of subsequent EU rules on security of gas supply. Its provisions were quickly superseded by Regulation (EU) No 994/2010 and further developed by the Gas SoS Regulation (EU) 2017/1938.”*

The Gas SoS Regulation, thus, superseded some of the provisions on security of supply in the Third Gas Package. However, the authority of Member States to impose public service obligations on natural gas undertakings relating to security of supply remains unaffected by the Gas SoS Regulation.

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[87] Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC.

[88] Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010.

The goal of the Gas SoS Regulation is to safeguard the security of gas supply in the EU. The Gas SoS Regulation aims to ensure this by (i) defining roles and responsibilities of different actors with respect to security of gas supply, (ii) determining security of supply standards, (iii) requiring that risk assessments are carried out (iv) requiring that preventive and emergency action plans are developed (v) determining roles and responsibilities for the declaration of a crisis and (vi) establishing the principle of solidarity between Member States. We now discuss these elements.

2.12.1 *Roles and responsibilities with respect to security of supply of gas*

The Gas SoS Regulation states that security of gas supply is a shared responsibility of natural gas undertakings[89], Member States, the competent authority designated by the Member State and the European Commission. Each of these actors is responsible within their respective area and competence. A key element of the Gas SoS Regulation is that each Member State has to designate a competent authority. The Gas SoS Regulation assigns specific responsibilities to the competent authority. However, the competent authority can decide to delegate specific tasks to other bodies, such as TSOs or DSOs. In The Netherlands the Ministry of Economic Affairs and Climate has designated itself as the competent authority.

In addition, a gas coordination group (GCG) has to be established which assists the European Commission on security of supply issues.[90] The GCG is composed of Member States, their competent authorities, ACER, ENTSOG and representative bodies of industry and other gas consumers.

2.12.2 *Security of supply standards*

The Gas SoS Regulation sets two standards for the security of supply:
- a gas infrastructure standard; and
- a gas supply standard.

The idea behind these two standards is that the gas supply can be interrupted either because the import/production (i.e. supply) is disrupted or because the operation of gas infrastructure (pipelines, LNG terminals, storages) is disrupted.

The infrastructure standard determines that in the event of a disruption of the single largest gas infrastructure the capacity of the remaining infrastructure has to be able to satisfy total demand during a day of exceptionally high gas demand (N-1 criterium).[91,92] In principle, the analysis of the single largest disruption has to be done for each Member State. However, neighbouring Member States in the same risk assessment group may decide to do the analysis jointly. In addition, the infrastructure standard also determines that TSOs have to ensure that their network

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[89] TSOs, DSOs, storages operators, LNG facility operators, suppliers or traders.
[90] Article 4 of the Gas SoS Regulation.
[91] Article 5(1) of the Gas SoS Regulation.
[92] As an exception, this requirement is also considered to be fulfilled when in case of disruption of the single largest infrastructure the disruption can be sufficiently compensated for by market-based demand side measures.

is able, with some exceptions, to transport gas in both directions (bi-directionally) and develop sufficient cross-border entry and exit capacity.[93]

The gas supply standard determines that competent authorities have to ensure that a natural gas undertaking takes measures to ensure the supply of gas to 'protected customers'. A protected customer is defined as:

> *(…) a household customer who is connected to a gas distribution network and, in addition, where the Member State concerned so decides, may also mean one or more of the following, provided that enterprises or services as referred to in points (a) and (b) do not, jointly, represent more than 20 % of the total annual final gas consumption in that Member State:*
> *(a) a small or medium-sized enterprise, provided that it is connected to a gas distribution network;*
> *(b) an essential social service, provided that it is connected to a gas distribution or transmission network;*
> *(c) a district heating installation to the extent that it delivers heating to household customers, small or medium-sized enterprises, or essential social services, provided that such installation is not able to switch to other fuels than gas;*[94]

The supply of gas to protected customers has to be ensured in the following situations:
- extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years;
- any period of 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years;
- for a period of 30 days in the case of disruption of the single largest gas infrastructure under average winter conditions.

In The Netherlands the protected customers have been defined as the residential consumers (in Dutch: *kleinverbruikers*) and a higher supply standard of the coldest day once in 50 years has been used as the supply standard. The supply to these consumers is ensured by the public service obligation on peak supply (see also textbox 3 on peak supply) (Ministry of Economic Affairs and Climate, 2019).

2.12.3 Risk assessments

The Gas SoS Regulation requires that several different risk assessments are carried out. Table 8 gives an overview of these risk assessments. Both the common risk assessment and the national risk assessment have to analyse to what extent the gas supply standard and infrastructure standard are met in extreme scenarios of exceptionally high demand and disruption of supply scenarios (including disruption of supply due to geopolitical risk) with varying filling levels for storage. All three risk assessments have to be updated every four years, unless circumstances warrant more frequent updates.

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[93] Article 5(4) and (8) of the Gas SoS Regulation.
[94] Article 2(5) of the Gas SoS Regulation.

Table 8 Different risk assessments to be carried out on the basis of article 7 of the SoS Regulation

Type	Carried out by	Description
Union-wide simulation	ENTSOG	Every four years, ENTSOG has to carry out a Union-wide simulation of gas supply and infrastructure disruption scenarios
Common risk assessment	Competent authorities of risk group	For each risk group (a group of Member States exposed to the same security of supply risk defined in Annex I of the Gas SoS Regulation) the competent authorities have to carry out a common risk assessment of all relevant risk factors for the security of supply for the risk group, such as natural disasters, technological, commercial, social, political and other risks
National risk assessment	Competent authority of Member State	For each Member State a national risk assessment has to be carried out by the competent authority.

2.12.4 Preventive action plans and emergency plans

The competent authority of each Member State has to develop both a preventive action plan and an emergency plan.

The preventive action plan has to describe the measures needed to remove the or mitigate the risks identified in both the common and national risk assessment. The emergency plan has to describe the measures to remove or mitigate the impact of a disruption of the gas supply. Both plans have to include a chapter on each risk group that is relevant for the Member State (and this chapter has to be the same in each national plan). Both plans have to be submitted to the European Commission and the European Commission has to issue an opinion on the plans.

Both the preventive action plan and the emergency plan have to be updated every four years (unless circumstances warrant more frequent updates or the European Commission request a more frequent update), taking into account the updated risk assessments.

2.12.5 Declaration of a crisis

The competent authority of each Member State can declare a crisis with three different crisis levels:
- Early warning: where there is concrete, serious and reliable information that an event which is likely to result in significant deterioration of the gas supply situation may occur.
- Alert: where a disruption of gas supply or exceptionally high gas demand which results in significant deterioration of the gas supply situation occurs but the market is still able to manage that disruption or demand without the need to resort to non-market-based measures.
- Emergency: where there is exceptionally high gas demand, significant disruption of gas supply or other significant deterioration of the gas supply situation and all relevant market-based measures have been implemented but the gas supply is insufficient to meet the remaining gas demand so that non-market-based measures have to be additionally introduced to safeguard the supply of gas to protected customers.

When the competent authority declares any of these crisis levels, the competent authority has to inform the European Commission, the competent authorities of Member States in the risk group and the competent authorities of directly connected Member States. When an emergency is declared the European Commission's Emergency Response Coordination Centre also has to be informed.

The (competent authorities) of the Member States have to ensure that:
- no measures are introduced which unduly restrict the flow of gas within the internal market at any time;
- no measures are introduced that are likely seriously to endanger the gas supply situation in another Member State; and
- cross-border access to infrastructure is maintained as far as technically and safely possible, in accordance with the emergency plan.

If a competent authority declares an emergency, it has to carry out all the actions in its emergency plan. In addition, the declaration of an emergency triggers the following actions:
- If other Member States in the same risk group have chosen to implement a higher gas supply standard, those standards shall be reduced to the regular gas supply standard during the emergency.
- The TSO of a neighbouring state has to prioritise capacity at the interconnection point to the state that declared an emergency over exit capacity to storages.
- During an emergency a Member State may decide to prioritise the supply of gas to gas-fired power plants over the supply of gas to protected consumers if the lack of gas supply to power plants could result in damage to the functioning of the electricity system or would hamper the production or transportation of gas.

After the declaration of an emergency, the European Commission has to verify:
- whether there is indeed an emergency;
- whether the actions taken are according to the emergency plan
- that no measures are introduced which unduly restrict the flow of gas within the internal market at any time;
- that no measures are introduced that seriously endanger the gas supply situation in another Member Sate; and
- that cross-border access to infrastructure is maintained as far as technically and safely possible, in accordance with the emergency plan.

When a single Member State has declared an emergency the European Commission can decide to declare a regional or Union emergency. When more than one Member State has declared an emergency, the European Commission must declare a regional or Union emergency. When the European Commission declares a regional or Union emergency, the European Commission coordinates the actions taken.

Textbox 4 - Disruption of supply from Russia and declaration of a crisis

Following the war in Ukraine, Russia has disrupted the supply of natural gas to Europe. In a response to this supply disruption many countries increased the emergency level. For example, both The Netherlands and Germany increased the crisis level to “alert”.

The supply disruption resulted in soaring gas and electricity prices to which the European Commission recently responded with a proposal emergency market interventions (see textbox 1). This emergency intervention was deemed necessary even though the emergency crisis level has not been declared yet. This demonstrates that the high market prices have resulted in demand reductions to such an extent that there is no need for non-market based measures to balance supply and demand. Therefore, the criterium to increase the crisis level to “emergency” is not met (i.e. no need for non-market based measures). So the market was able to manage the disruption of supply but only at the expense of extremely high energy prices.

2.12.6 *Solidarity*

The Gas SoS Regulation also establishes the principle of solidarity, which requires Member States (and their competent authorities) to help each other safeguard the supply to “solidarity protected customers”. Solidarity protected customer is defined as:

> *“(…) a household customer who is connected to a gas distribution network, and, in addition, may include one or both of the following:*
> *(a) a district heating installation if it is a protected customer in the relevant Member State and only in so far as it delivers heating to households or essential social services other than educational and public administration services;*
> (b) *an essential social service if it is a protected customer in the relevant Member State, other than educational and public administration services;*[95]

The supply to solidarity protected customers can be safeguarded by other Member States by limiting the supply to non-protected customers (a solidarity measure). A solidarity measure can only be taken as a last resort when the requesting Member State has:

- not been able to cover the deficit in gas supply to its solidarity protected customers despite the declaration of an emergency;
- exhausted all market-based measures and all measures provided in its emergency plan;
- notified an explicit request to the Commission and to the competent authorities of all Member States with which it is connected either directly or indirectly via a third country, accompanied by a description of the implemented market-based measures and measures in its emergency plan; and
- undertaken to pay fair and prompt compensation to the Member State providing solidarity.

[95] Article 2(6) of the Gas SoS Regulation.

3 Future gas market design

3.1 Background of the proposed market design

On 15 December 2021 the European Commission published what it calls the "Hydrogen and Decarbonised Gas Markets Package". The package is a proposal for a recast of the Gas Regulation and the Gas Directive.[96, 97] Combined with the Clean Energy Package (which dates back to 2019), that already revised the Electricity Directive, Electricity Regulation and ACER Regulation, the proposal results in a revision of all legislative acts of the Third Energy Package.

Hereafter we will refer to the "Hydrogen and Decarbonised Gas Markets Package" simply as the "proposed Decarbonisation Package" when referring to both the proposal for a changed Gas Directive and Gas Regulation.[98] We will refer to the "proposed Gas Directive" and "proposed Gas Regulation" when referring to either the Directive or Regulation.

The need to change the gas market design results from the EU's objective to become the first climate neutral continent in 2050 and to reduce greenhouse gas emissions by at least 55% in 2030, as stated in the European Climate Law. To achieve the 2030 target, the European Commission proposed the Fit-for-55 package.[99] These EU climate policies will require the role of gas in the system to change, as envisioned by the European Commission. According to the European Commission (2021b):

- Gaseous fuels will continue to play an important role in a climate neutral energy system.
- Biogas, biomethane, renewable and low-carbon hydrogen as well as synthetic methane (all together renewable and low-carbon gases) would represent some 2/3 of the gaseous fuels in the 2050 energy mix, with fossil gas with CCS/U (carbon capture, storage and utilisation) representing the remainder.
- Hydrogen is expected to be used mainly in the areas where electrification is not an option, including today's energy-intensive industry (e.g. refineries, fertilisers, steel making) and certain heavy-duty transport sectors (maritime transport, aviation, long distance heavy vehicles)
- In the short and medium term (i.e. up to 2030) other forms of low-carbon gases, in particular low-carbon hydrogen, can play a role, primarily to rapidly reduce emissions from existing hydrogen production and support the parallel and future uptake of renewable hydrogen.

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

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

98 When we refer to the Decarbonisation Package we exclude the proposal for a "Methane Regulation" that the European Commission adopted at the same time as the Hydrogen and Decarbonised Gas Markets Package.

99 In fact, the European Commission considers the Decarbonisation Package to be an integral part of the Fit-for-55 proposal.

According to the European Commission (2021b) the decarbonisation of gaseous fuels will result in:

1. a hydrogen-based infrastructure that progressively complements the network for natural gas; and
2. a natural gas infrastructure in which fossil gas is progressively replaced by other sources of methane.

Against this background, the European Commission has evaluated the current gas market design and identified four problem areas that need to be addressed:

- Problem area I: Barriers exist for the development of a cost-effective hydrogen infrastructure and competitive and integrated hydrogen market.
- Problem area II: Untapped potential of renewable gases and barriers blocking the access of biomethane to gas market and infrastructure.
- Problem area III: Insufficient energy system integration in network planning
- Problem area IV: Low levels of consumer engagement and protection in the decarbonised retail market.

Each problem area is the result of several problem drivers. Figure 4 is copied from the impact assessment report and shows the problem areas and their problem drivers.

Without addressing these problem areas, the European Commission expects that significant barriers will prevent the uptake of renewable and low-carbon gases and the gradual phase out of fossil natural gas. The European Commission states that the general objective of the proposed Decarbonisation Package is to facilitate the cost-effective decarbonisation by creating of a European hydrogen market and the gradual decarbonisation of gaseous fuels markets, while ensuring energy security.

For each problem area the European Commission has outlined several policy options, analysed their impact and selected a preferred option in the impact assessment report. The preferred options combined result in the proposed Gas Directive and the proposed Gas Regulation.

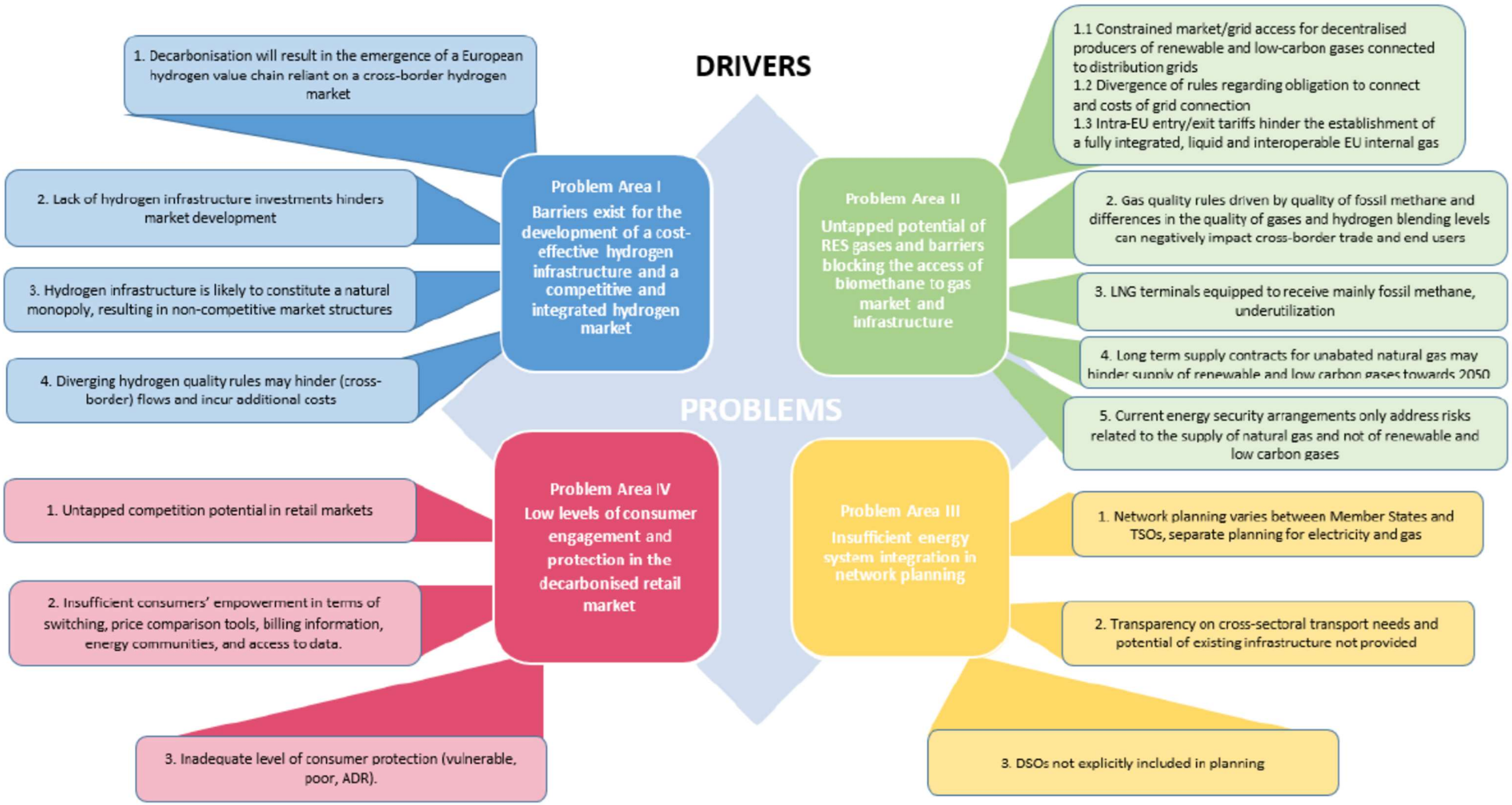

Figure 4 Problem areas and problem drivers

Source: European Commission (2021d), Impact Assessment Report accompanying the proposed Decarbonisation Package part I, p. 7

3.2 Legal framework

Although the proposed Decarbonisation Package will result in significant changes to the market design for gases, the legal framework governing the market design does not change in a significant way compared to the current gas market design. The proposed Gas Directive and Gas Regulation remain the key legislative acts governing the gas market design. Member States will have to transpose the (changes to) the Gas Directive into national law, whereas the Gas Regulation will have direct legal force.

However, the proposed Gas Regulation establishes two additional entities that can have a role in the development of network codes. As explained in Paragraph 2.2, the current Gas Regulation is the legal basis for the European Commission to adopt network codes and guidelines that further detail aspects of the market design. The adoption of network codes follows a specific process in which both ACER, ENTSOG and the European Commission have a role. In addition to ENTSOG, the proposed Gas Regulation also establishes the European Network of Network Operators for Hydrogen (hereafter: ENNOH).[100] ENNOH will get a similar responsibility for network codes related to hydrogen infrastructure and hydrogen markets as the responsibility of ENTSOG for natural gas infrastructure and natural gas markets. Furthermore, the proposed Gas Regulation includes natural gas DSOs in the EU DSO entity, which has already been established for electricity DSOs based on the Clean Energy Package revision of the Electricity Regulation.[101] The EU DSO entity shall participate in the development of network codes which are relevant to the operation and planning of distribution systems for natural gas (i.e. not hydrogen networks).

3.3 Definition of gases

The proposed Decarbonisation Package extends the scope of the Third Gas Package by also including hydrogen infrastructure and markets. To do so, article 2 of the proposed Gas Directive contains several definitions of different types of ‘gas’. The definitions make a distinction between ‘natural gas’ and ‘hydrogen’, both of which fall under the definition of ‘gases’ (which is defined as ‘natural gas or hydrogen’).[102,103]

‘Natural gas’ is defined as:

> *“all gases that primarily consist of methane, including biogas and gas from biomass, in particular biomethane, or other types of gas, that can technically and safely be injected into, and transported through, the natural gas system”*[104]

[100] Article 40 of the proposed Gas Regulation.
[101] Articles 36 to 38 of the proposed Gas Regulation.
[102] Article 2(3) of the proposed Gas Directive defines ‘gases’ as ‘natural gas and hydrogen’.
[103] Interestingly, ‘hydrogen’ is not defined. Furthermore, given the fact that only gases (plural of gas) is defined as both ‘natural gas’ and ‘hydrogen’, the meaning of ‘gas’ (singular of gases) is somewhat unclear.
[104] Article 2(1) of the proposed Gas Directive.

In addition, the proposed Gas Directive contains several definitions related to the level of decarbonisation of gases, in part by referring to definitions in the Renewable Energy Directive.[105,106] Table 9 presents an overview of these definitions. In short, from these definitions it follows that for both natural gas and hydrogen, a distinction can be made between (i) renewable gas and (ii) low-carbon gas. Renewable gas consist of biogas or renewable fuels of non-biological origin (primarily renewable hydrogen and its derivatives). Low-carbon gas consists of the gaseous part of recycled carbon fuels, low-carbon hydrogen or synthetic gaseous fuels. For all of these a threshold of 70% greenhouse gas emission reduction applies to qualify as “low-carbon”. There is no definition of ‘high carbon gases’, but from the other definitions it follows that there are gases that fall under the definition of ‘gases’ but do not qualify as either ‘renewable gas’ or ‘low-carbon gas’.

The relationship between the terms biogas and biomethane is somewhat unclear. In practice, the term biogas is often used to refer to a mixture of methane, CO2 and small quantities of other gases produced by anaerobic digestion (European Commission, 2021d). The term biomethane in practice generally refers to a near-pure source of methane produced either by upgrading biogas or through the gasification of solid biomass followed by methanation (European Commission, 2021d). According to these definitions biomethane can be safely injected in the natural gas system, whereas biogas cannot. In the proposed Decarbonisation package, however, biogas is defined as any gaseous fuels produced from biomass. Thus, biogas includes biomethane.[107] In turn, biomethane is not defined in the package. We interpret the term biomethane as the subset of biogas that has natural gas quality and, thus, can be safely transported in the natural gas system. Thus, biomethane excludes the part of biogas (as defined in the package) that cannot be safely injected in the natural gas system (i.e. what is in practice generally referred to as biogas) and, as a result, does not fall under the definition of natural gas.

The provisions in the proposed Gas Regulation and Gas Directive mostly refer to the definitions of renewable and low-carbon gases together, to which specific conditions (i.e. network tariff discounts) apply. To apply those provisions, some form of certification is necessary to proof that gas is in fact renewable or low-carbon gas. For the certification of renewable gases, the Decarbonisation Package refers to the system of certification that has already been included articles 29 and 30 of the Renewable Energy Directive.[108]

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[105] (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.

[106] In the proposed Gas Directive definitions refer to the Renewable Energy Directive. However, the fit-for-55 package amends some of those definitions in the Renewable Energy Directive. See Proposal for a Directive of the European Parliament and of the Council amending Directive (EU) 2018/2001 of the European Parliament and of the Council, Regulation (EU) 2018/1999 of the European Parliament and of the Council and Directive 98/70/EC of the European Parliament and of the Council as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652. We assumed that the definitions in the proposed third version of the Renewable Energy Directive will be referenced, because the European Commission considers that both the proposed Gas Directive and the proposed third revision of the Renewable Energy Directive are part of the fit-for-55 package. We included the definitions from the proposed third version of the Renewable Energy Directive in the table (where relevant).

[107] This also follows from the definition of renewable gas, defined as “biogas, including biomethane, (…)”.

[108] Article 8(1) of the proposed Gas Directive.

Table 9 Definitions of renewable and low-carbon gas, including related definitions

Term	Definition
Renewable gas	Biogas, including biomethane, and renewable gaseous fuels part of fuels of non-biological origins (RFNBO)
Biogas	Gaseous fuels produced from biomass
Renewable fuels of non-biological origin (RFNBO)	Liquid and gaseous fuels the energy content of which is derived from renewable sources other than biomass
Low-carbon gas	The part of gaseous fuels in recycled carbon fuels, low-carbon hydrogen and synthetic gaseous fuels, the energy content of which is derived from low-carbon hydrogen, which meet the greenhouse gas emission reduction threshold of 70%
Low-carbon hydrogen	Hydrogen, the energy content of which is derived from non-renewable sources, which meets a greenhouse gas emission reduction threshold of 70%
Low-carbon fuels	Recycled carbon fuels, low-carbon hydrogen and synthetic gaseous and liquid fuels the energy content of which is derived from low-carbon hydrogen, which meet the greenhouse gas emission reduction threshold of 70%
Recycled carbon gas	Recycled carbon fuels, low-carbon hydrogen and synthetic gaseous and liquid fuels, the energy content of which is derived from low-carbon hydrogen, which meet the greenhouse gas emission reduction threshold of 70%
Recycled carbon fuels	Liquid and gaseous fuels that are produced from liquid or solid waste streams of non-renewable origin which are not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC, or from waste processing gas and exhaust gas of non-renewable origin which are produced as an unavoidable and unintentional consequence of the production process in industrial installations

Article 29 of the Renewable Energy Directive describes the sustainability and greenhouse gas emissions saving criteria for biofuels, bioliquids and biomass fuels (which includes biogas). To count as renewable energy, biogas has to meet the sustainability criteria and meet the emissions saving criteria. Article 30 of the Renewable Energy Directive describes the verification of compliance with the sustainability and greenhouse gas emissions saving criteria (i.e. the certification of renewable energy) for both biofuels, bioliquids and biomass fuels as well as for renewable fuels of non-biological origin (thus, this includes renewable hydrogen from electrolysis). Certification has to be based on a mass-balance approach.[109] In addition, certification can be based on national certification schemes set up by a Member State or voluntary national or international certification schemes approved by the European Commission.[110] For renewable fuels of non-biological origin (e.g. renewable hydrogen for electrolysis) article 27 of the Renewable Energy Directive refers to a Delegated Act that will specify when hydrogen produced from electricity can count as renewable hydrogen.[111] Recently the European Commission published a proposal of this Delegated Act for a public consultation.[112] Once this delegated act has been adopted, the methodology for the certification of renewable gases from both biological and non-biological origin has been established.

[109] Article 30(1) of the Renewable Energy Directive.
[110] Article 30(4) to (6) of the Renewable Energy Directive.
[111] Article 27(3) of the Renewable Energy Directive.
[112] Draft Commission delegated regulation (EU) supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin.

However, articles 29 and 30 of the Renewable Energy Directive only consider the certification of *renewable* gases and therefore exclude the certification of *low-carbon* gases. Therefore, article 8 of the proposed Gas Directive includes additional provisions on the certification of low-carbon gases. The framework for the certification of low-carbon gases described in article 8 of the proposed Gas Directive is quite similar to that described in article 30 of the Renewable Energy Directive. Certification has to be based on a mass-balance approach according to either national certification schemes set up by a Member State or voluntary national or international certification schemes approved by the European Commission. However, the article does not specify the methodology for assessing whether the emission saving criterium of 70% that has to be met to qualify as low-carbon gas. To that end, the proposal refers to a delegated act that will be adopted by 31 December 2024. Thus, the precise methodology to determine whether gas is low-carbon gas will remain uncertain for quite some time.

3.4 Segments of value chain of gases

As discussed in paragraph 3.1, the European Commission expects two key changes for the value chain of gases:
1 a hydrogen-based infrastructure that progressively complements the network for natural gas; and
2 a gas infrastructure in which fossil gas is progressively replaced by other sources of methane.

We discuss how both these developments impact the overall value chain of gases.

3.4.1 Gradual development of a parallel hydrogen system

In parallel to the natural gas system a hydrogen system will gradually develop. The ‘hydrogen system’ is defined in the proposed Gas Directive as:

> *“A system of infrastructure, including hydrogen networks, hydrogen storage, and hydrogen terminals, which contains hydrogen of a high grade of purity”*[113]

From the definition it follows that the value chain of “hydrogen with a high grade of purity” is expected to include a hydrogen network, hydrogen terminals and hydrogen storage. Although not specifically mentioned in the definition of ‘hydrogen system’ we can assume the value chain will also include hydrogen production, which injects hydrogen into the hydrogen system. Thus, the infrastructure layer of the hydrogen value chain is expected to be quite similar to the infrastructure layer of the natural gas value chain. Hydrogen is either produced domestically, imported through pipelines (adjacent hydrogen network or hydrogen interconnector) or through ships (hydrogen terminal). Hydrogen is transported through the hydrogen network to the users and can be stored in hydrogen storages (hydrogen storage facility). The proposed Gas Directive also defines these infrastructure segments (see Table 10).

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[113] Article 2(5) of the proposed Gas Directive.

Table 10 Definitions of hydrogen infrastructure segments in the proposed Gas Directive.

Term	Definition
Hydrogen network	a network of pipelines used for the transport of hydrogen of a high grade of purity with a view to its delivery to customers, but not including supply
Hydrogen terminal	an installation used for the transformation of liquid hydrogen or liquid ammonia into gaseous hydrogen for injection into the hydrogen network or the liquefaction of gaseous hydrogen, including ancillary services and temporary storage necessary for the transformation process and subsequent injection into the hydrogen network, but not any part of the hydrogen terminal used for storage
Hydrogen storage facility	a facility used for the stocking of hydrogen of a high grade of purity: (a) including the part of a hydrogen terminal used for storage but excluding the portion used for production operations, and facilities reserved exclusively for hydrogen network operators in carrying out their functions; (b) including large, in particular underground, hydrogen storage but excluding smaller, easily replicable smaller hydrogen storage installations
Hydrogen interconnector	a hydrogen network which crosses or spans a border between Member States, or between a Member State and a third country up to the territory of the Member States or the territorial sea of that Member State

However, there are some interesting differences compared with the definitions of natural gas infrastructure segments. A key difference is that for hydrogen there is no distinction between transmission and distribution (see definition of hydrogen network in Table 10). From this definition it follows that a hydrogen network can include both transmission and distribution activities, at different pressure levels and is thus not limited to hydrogen in industry and heavy-duty transport. This is underlined by the definition of ‘hydrogen transport’ (underlining by the authors):

> *“the transport of hydrogen through a hydrogen network with a view to its delivery to customers, but not including supply, <u>irrespective of the pressure, the geographic coverage or the connected customer group of the network</u>”*[114]

Consequently, there is no distinction between TSOs and DSOs for hydrogen networks. There is simply a hydrogen network operator (HNO), which is defined as:

> *“a natural or legal person who carries out the function of hydrogen transport and is responsible for operating, ensuring the maintenance of, and, if necessary, developing the hydrogen network in a given area and, where applicable, its interconnections with other hydrogen networks, and for ensuring the long-term ability of the system to meet reasonable demands for the transport of hydrogen”*[115]

This also implies that whenever the proposed Decarbonisation Package uses the terms transmission, distribution, TSO or DSO, those terms are used in reference to the natural gas system and not the hydrogen system.

In addition, there is no definition of an upstream pipeline network or direct line for hydrogen. This basically means that all hydrogen pipeline networks fall under the definition of a hydrogen network.

[114] Article 2(21) of the proposed Gas Directive.
[115] Article 2(22) of the proposed Gas Directive.

Figure 5 presents a schematic overview of the segments of the hydrogen value chain based on the proposed Decarbonisation Package. The supply (including import) is shown in orange. Demand (including export) is shown in yellow. The infrastructure segments are shown in blue. The figure also distinguishes between a wholesale market and retail market layer.

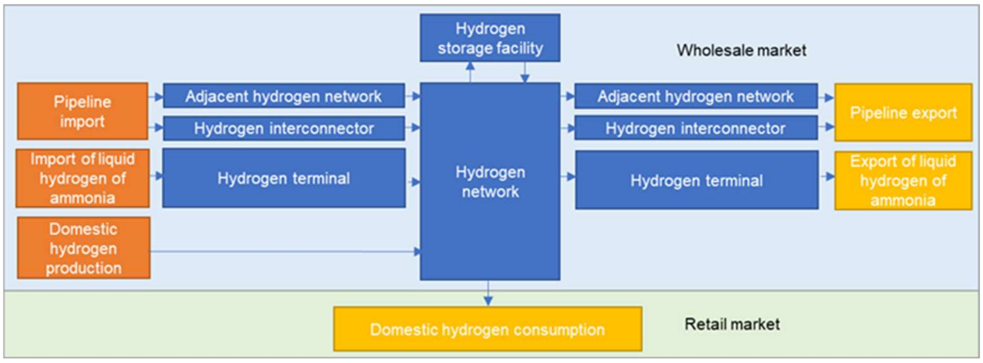

Figure 5 Segments of hydrogen value chain based on the proposed Decarbonisation Package

3.4.2 *Phase out of fossil natural gas in the natural gas system*

The phase out of fossil natural gas has an impact on the value chain of natural gas. The share of fossil natural gas in the natural gas system is expected to gradually decrease. To a large extent, fossil natural gas will be replaced by renewable and low-carbon natural gas, which includes biomethane. Biomethane is generally produced in smaller scale installations connected to the distribution system. Thus, an increasing share of the production of natural gas will be replaced by injection of renewable and low-carbon gas in the distribution system.

This development increases the need to balance supply and demand in the distribution system. Currently, the flow of gas from the transmission to the distribution system can often be controlled to make sure supply and demand in the distribution system are balanced. However, with an increasing share of production connected to the distribution system the pressure in the distribution system can increase to a level that exceeds the operational limits. That is especially the case when the demand from customers connected to that distribution system is low (i.e. summer months).

A solution – which has already been implemented in The Netherlands - is to inject gas from the distribution system into the transmission system, which requires increasing the pressure.[116] Other solutions, such as interconnecting distribution systems, local gas storage or demand response in distribution systems are also possible. Without any of these solutions, the production of biomethane will have to be curtailed to avoid exceeding the operational limits of the distribution system.

In order to avoid curtailment of biomethane production, the proposed Decarbonisation Package aims to ensure that biomethane producers get firm access (i.e. not interruptible) to wholesale natural gas markets. To do so, the

[116] There are also issues related to the natural gas quality, because biogas typically doesn't have the gas quality required by, for example, industrial consumers connected to the transmission grid.

proposed Gas Regulation includes an extended definition of the concept of an 'entry-exit system' and includes two articles that ensure firm access to wholesale markets for producers of renewable and low-carbon natural gas. These articles oblige transmission and distribution system operators to invest in compressors enabling physical reverse flow from the distribution to the transmission system, when necessary. We further discuss these changes in subsequent paragraphs. Here, we note that the value chain of natural gas changes because an increasing share of the production will be injected into the distribution system and gas can flow from the distribution system to the transmission system.

Figure 6 shows a schematic representation of the segments of the value chain of natural gas based on the proposed Decarbonisation Package. Compared with Figure 5 (i.e. the same schematic overview based on the current market design) the following has changed:
– Domestic biogas and biomethane production are included in the figure;
– The flow of natural gas from the distribution to the transmission system is included; and
– The wholesale market layer is extended to include the distribution system.

We note that actually these changes were already allowed under the Third Gas Package, but the proposed Decarbonisation Package explicitly strengthens the position of biomethane producers.

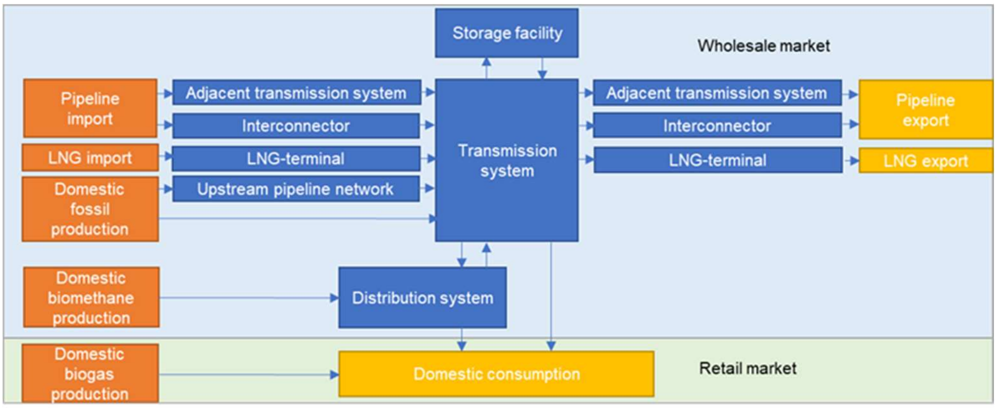

Figure 6 Segments of the value chain of natural gas based on the proposed Decarbonisation Package.

3.5 Unbundling of activities

As discussed in Paragraph 2.5, effective unbundling of the activities of transmission and distribution from production and supply aims to ensure non-discriminatory access to the transmission and distribution system by removing incentives for discrimination. For transmission system operators, the current Gas Directive allows three different unbundling models: ownership unbundling (OU), independent system operator (ISO) and independent transmission operator (ITO). For distribution system operators, a lighter form of unbundling is allowed. These requirements for natural gas transmission and distribution system operators remain unchanged in the proposed Decarbonisation Package.

Because a hydrogen system will complement the natural gas system, the question is (i) how the vertical unbundling of hydrogen network operators from hydrogen producers and suppliers should be organised and (ii) how horizontal unbundling of natural gas and hydrogen network operators should be organised. We discuss how the proposed Decarbonisation Package answers both these questions.

3.5.1 Vertical unbundling of hydrogen network operators

As explained in its impacts assessment report the European Commission's (2021d) preferred option to address problem area I is to introduce key regulatory principles from the start, whilst providing clarity on the final (future) regulatory regime. For the vertical unbundling of hydrogen network operators this means that the unbundling requirements that apply to TSOs to a large extent shall also apply to hydrogen network operators. The proposed Gas Directive includes the following vertical unbundling options for hydrogen network operators:

- The ownership unbundling model (OU);[117]
- The independent system operator model (ISO), if the hydrogen network belonged to a vertically integrated undertaking one year after the package enters into force;[118]
- The independent transmission system operator model (ITO), which is only allowed during a transition phase until 2031.[119]

A difference is that the ITO model is only allowed during a transition phase until 2031. The idea being that with respect to the vertical unbundling of hydrogen network operators it is possible to benefit from the 'greenfield' nature of hydrogen infrastructure regulation (European Commission, 2021d).[120] The greenfield nature of hydrogen infrastructure regulation is an argument to not allow the ITO model. However, hydrogen networks will be developed by repurposing natural gas networks of TSOs unbundled as ITO. Therefore, despite the greenfield nature of hydrogen network regulation the Decarbonisation Package allows the ITO model until 2031 so that during the transition phase, the ITO model can still be used by the current (ITO unbundled) natural gas TSOs that repurpose their assets for hydrogen transport.

The vertical unbundling requirements also apply across the energy carriers electricity, natural gas and hydrogen.[121] Thus, an undertaking that performs the activity of production or supply of either natural gas, hydrogen or electricity has to be unbundled from the activity of transport of electricity, natural gas or hydrogen and vice versa.

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[117] Article 62(1) of the proposed Gas Directive states that hydrogen network operators shall be unbundled in accordance with the rules on ownership unbundling that applies to transmission system operators. Article 62(1) appears to contain an incorrect reference to article 56(1) to (3), which should presumably be a reference to article 54(1) to (3) were the ownership unbundling model is described.

[118] Article 62(3) of the proposed Gas Directive.

[119] Article 62(4) of the proposed Gas Directive.

[120] When natural gas markets were liberalised there was already an established market with infrastructure. For hydrogen, however, most of the infrastructure still needs to be developed, which means there is less need to take existing infrastructure into account.

[121] Article 62(2) of the proposed Gas Directive ensures that this also applies to hydrogen.

An exemption to the vertical unbundling requirements for hydrogen network operators is allowed for (i) geographically confined hydrogen networks and (ii) existing hydrogen networks. These exemptions are discussed in Textboxes 4 and 5.

Textbox 4 - Geographically confined hydrogen networks
A geographically confined hydrogen network is not explicitly defined in the proposed Decarbonisation Package. However, from the article on geographically confined hydrogen networks it follows that a geographically confined hydrogen network is a hydrogen network that transports from one entry point to a limited number of exit points within a geographically confined industrial or commercial area. Article 48 of the proposed Gas Directive determines that for geographically confined hydrogen networks Member States may decide that NRAs can grant a derogation from the vertical unbundling requirements. A derogation applies at least until 31 December 2030. After that, a derogation automatically expires when (i) a competing renewable hydrogen producer wants to get access to the network or (ii) where the exempted hydrogen network becomes connected to another hydrogen network. In short, a derogation with a limited scope (only vertical unbundling) can be given for the full 'transition period' and possibly even longer for hydrogen networks that can be considered geographically confined hydrogen networks.

The fact that a derogation shall apply 'at least until 31 December 2030' raises some questions. It appears as though during this period the derogation will continue to apply even when the conditions for the derogation no longer apply (i.e. when a geographically confined hydrogen network can no longer be considered a geographically confined hydrogen network).

Textbox 5 - Existing hydrogen networks
An existing hydrogen network is not defined in the proposed Decarbonisation Package, but from the context it can be concluded that an existing hydrogen network is any hydrogen network that exists when the package enters into force. An existing hydrogen network can be part of a vertically integrated undertaking at the time of entry into force. Article 47 of the proposed Gas Directive determines that for existing hydrogen networks Member States may decide to grant a derogation from (i) the vertical and horizontal unbundling requirements, (ii) third party access conditions and (iii) the cooperation between hydrogen network operators in ENNOH. The derogation automatically expires:
- When the hydrogen network that received the derogation is connected to another hydrogen network;
- When the hydrogen network that received the derogation expand their network or its capacity; or
- At the latest on 31 December 2030.

In short, a derogation from most of the key requirements can be given to existing hydrogen networks under a set of strict conditions.

In The Netherlands several existing hydrogen networks which are part of a vertically integrated undertakings are present in the industrial clusters. These networks could receive a derogation. When these networks either (i) expand their network or its capacity or (ii) connect to another (i.e. the national) hydrogen network and (iii) at the latest on 1 January 2031, they will need to comply with all the obligations (including unbundling and third party access conditions) for hydrogen network operators.

3.5.2 Horizontal unbundling of transmission system, distribution system and hydrogen network operators

Because a dedicated hydrogen system is expected to gradually complement the natural gas system, in part by repurposing the natural gas infrastructure, a relevant question is to what extent the activity of hydrogen network operation should be separated from natural gas transmission or distribution (horizontal unbundling). The European Commission proposes a light form of horizontal unbundling that requires that a hydrogen network operator is independent from transmission or distribution in terms of its legal form.[122] In addition, natural gas and hydrogen undertakings need to keep separate accounts in their internal accounting for each of their transmission, distribution, LNG, hydrogen terminal, natural gas and hydrogen storage and hydrogen transport activities as they would be required to do if the activities in question were carried out by separate undertakings.[123] In addition, when a transmission or network operator provides *regulated* services (i.e. the NRA sets or approves the tariffs) for gas, hydrogen or electricity, it must have a separate regulated asset base to avoid cross-subsidies between services.[124] However, there are some exceptions to this rule which we discuss in paragraph 3.8 on the regulation of network tariffs.

3.6 Third party access to infrastructure

The changes to the third party access conditions in the proposed Decarbonisation Package primarily concern the development of hydrogen infrastructure and a hydrogen market. Because new hydrogen infrastructure is expected to develop, the third party access to the infrastructure has to be determined. Therefore, we discuss the third party access conditions for the hydrogen infrastructure segments (i.e. hydrogen networks, hydrogen terminals and hydrogen storages) in this paragraph.

In addition, the proposed Decarbonisation Package contains some important changes to other aspects that can be seen as access conditions to the networks, such as:
- The conditions for access to the transmission and distribution system for renewable and low-carbon natural gas; and
- The regulation of network tariffs for both hydrogen and natural gas networks;
- The rules governing gas quality.

We discuss these changes in subsequent paragraphs.

3.6.1 Hydrogen networks

In short, the proposed Decarbonisation Package ensures that after a transition period the general third party access conditions to hydrogen networks will be equivalent to the third party access conditions to natural gas transmission systems. However, during the transition period (until 31 December 2030) the package allows for more flexibility if a Member State wishes to use that flexibility.

[122] Article 63 of the proposed Gas Directive.
[123] Article 64 together with article 69 of the proposed Gas Directive.
[124] Article 4(1)(a) of the proposed Gas Regulation.

The proposed Gas Directive states that, in principle, Member States need to ensure the implementation of 'a system of regulated third party access' to hydrogen networks.[125] Regulated third party access means that tariffs for access to the networks and other access conditions are set or approved by the NRA and published prior to their entry into force.[126] However, a Member State may decide not to implement regulated third party access until 1 January 2031.[127] In that case, and until that time, negotiated third party access has to be implemented. Negotiated third party access means that the hydrogen network users can negotiate the applicable network tariffs and other access conditions with the HNO. The negotiated third party access conditions have to be based on objective, transparent and non-discriminatory criteria.

In addition, article 6 of the proposed Gas Regulation describes general principles for the 'third party access *services*' provided by HNOs. Again, a distinction can be made between the principles that apply during the transition phase and the more detailed rules that apply after the transition period.

During the transition phase the following applies to the services provided by HNOs:
– Non-discrimination: When a HNO offers the same service to different customers, it has to do so under the same contractual terms and conditions. Thus, a HNO cannot negotiate lower tariffs with a related undertaking than with a similar unrelated undertaking unless there is an objective reason for a tariff difference.[128]
– No capacity withholding: A HNO has to offer the maximum capacity of a hydrogen network to network users, taking into account system integrity and efficient network operation.[129]
– Limitation on long-term contracts: Capacity contracts shall be at most 20 years for existing infrastructure (at entry into force) and 15 years for new infrastructure (completed after entry into force).[130]
– Congestion management procedures: HNO have to implement and publish non-discriminatory and transparent congestion-management procedures.[131]
– Market demand assessment: HNOs have to regularly assess market demand for new investments, taking into account security of supply and the efficiency of final hydrogen use.[132]

Together, these general principles provide some legal certainty to hydrogen network users who want to get access to the hydrogen network, but the provisions are much less detailed than similar provisions for the natural gas transmission system. As described in 2.9, many of the third party access conditions for the gas transmission system together also describe the wholesale market design and are detailed in network codes and guidelines (capacity allocation, congestion management, balancing, network tariff structures). For the hydrogen network, there are no network codes and guidelines yet, so it is possible that these general principles described above will be further detailed at a later stage. However, it

[125] Article 39(1) of the proposed Gas Directive.
[126] Article 39(2) of the proposed Gas Directive.
[127] Article 39(4) of the proposed Gas Directive.
[128] Article 6(1) of the proposed Gas Regulation.
[129] Article 6(2) of the proposed Gas Regulation.
[130] Article 6(3) of the proposed Gas Regulation.
[131] Article 6(4) of the proposed Gas Regulation.
[132] Article 6(5) of the proposed Gas Regulation.

appears to be the intention of the European Commission to only set general principles during the transition phase and implement a more detailed 'hydrogen wholesale market design' after the transition phase. This follows from the fact that several paragraphs of article 6 of the proposed Gas Regulation kick in from 1 January 2031. At that point in time:
- Hydrogen networks shall be organised as entry-exit systems;[133]
- The criteria that apply to network tariffs for natural gas transmission systems also apply to hydrogen networks;[134]
- The criteria that apply to natural gas transmission system operators concerning (i) third party access services, (ii) capacity allocation and congestion management and (iii) balancing, shall also apply to hydrogen network operators.[135]

In short, after the transition period most general principles concerning the natural gas wholesale market design shall also apply to hydrogen markets.[136]

An important question during the transition phase is how to balance a gradually developing hydrogen network with the principle of third party access. The fact that the hydrogen network still needs to be developed, implies that there will be potential hydrogen network users who cannot reasonably be connected and get access to the hydrogen system yet. Which users can and which users cannot get access will depend on the prioritisation of hydrogen network investments. We further discuss this balance in paragraph 3.7 on infrastructure development.

3.6.2 *Hydrogen terminals*

For hydrogen terminals the proposed Decarbonisation Package prescribes that Member States have to implement 'a system of negotiated third party access'.[137] The European Commission expects that there will be no significant barriers to competition between hydrogen terminals and therefore regulated third party access is not necessary.[138] This differs from the current system of regulated third party access for LNG facilities.

The negotiated third party access conditions have to be objective, transparent and non-discriminatory and apply to the 'third party access services' provided by hydrogen terminals. These general principles are elaborated upon in the following criteria:

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[133] Article 6(6) of the proposed Gas Regulation.
[134] Article 6(7) of the proposed Gas Regulation.
[135] Article 6(8) of the proposed Gas Regulation.
[136] Or to be more precise: most of the principles and key aspects of the natural gas wholesale markets design shall also apply to hydrogen markets. That is the case because the articles that describe those principles for the natural gas wholesale market shall also apply to hydrogen markets. However, that doesn't imply that the current natural gas network codes that further detail the natural gas market design shall apply to hydrogen markets. It's likely that hydrogen network codes will be developed that are based on similar principles, but the content of which differs from natural gas network codes.
[137] Article 32(1) of the proposed Gas Directive.
[138] Regulated third party access refers to the situation where the regulator sets or approves the applicable access conditions, including the tariffs. Negotiated third party access refers to the situation where the hydrogen terminal operator can determine the access conditions, including tariffs, based on negotiations with (potential) users.

- No capacity withholding: Hydrogen terminals have to offer the maximum capacity to market participants, taking into account system integrity and operation.[139]
- Capacity allocation: Hydrogen terminals have to implement and publish non-discriminatory and transparent capacity-allocation mechanisms which shall (i) provide economic signals for the efficient use of the capacity and facilitate investments in new infrastructure and (ii) be compatible with the market mechanism including spot markets and trading hubs.[140]
- Non-discrimination: Hydrogen terminals have to offer services on a non-discriminatory basis to all network users that accommodate market demand. Where a hydrogen terminals offers the same service to different customers, it has to do so under equivalent contractual terms and conditions. Specifically, hydrogen terminal contracts with a shorter duration than a standard contract on an annual basis shall not result in arbitrarily higher tariffs.[141]
- Interoperability: Hydrogen terminals have to offer services that are compatible with the use of the interconnected hydrogen transport system and facilitate access through cooperation with the hydrogen network operator.[142]
- Transparency: Hydrogen terminals have to make relevant information public, in particular data on the use and availability of services, in a time-frame compatible with the users' reasonable commercial needs, subject to the monitoring of such publication by the NRA.[143]
- Congestion management: Hydrogen terminals have to implement measures to prevent capacity-hoarding. In case of contractual congestion hydrogen terminals have to (i) offer unused capacity to the market and (ii) facilitate the transfer of contracted capacity on a secondary market.[144]
- Minimum contract size: Contractual limits on the required minimum size of hydrogen terminal capacity has to be justified on the basis of technical constraints.[145]
- Creditworthiness: Hydrogen terminals can ask appropriate guarantees from users with respect to their creditworthiness, but such guarantees should not constitute undue market barriers.[146]

The NRA has to monitor these conditions and take measures if they negatively impact the hydrogen market.

3.6.3 *Hydrogen storage facilities*

In contrast to hydrogen terminals the proposed Decarbonisation Package prescribes that Member States have to implement 'a system of regulated third party access' to hydrogen storage facilities.[147] The tariffs for access to hydrogen storage facilities, or the methodologies underlying their calculation, have to be approved by

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[139] Article 10(1) of the proposed Gas Regulation.
[140] Article 10(2)(a) and (b) of the proposed Gas Regulation.
[141] Article 7(1)(a) of the proposed Gas Regulation.
[142] Article 7(1)(b) and 10(2)(c) of the proposed Gas Regulation.
[143] Article 7(1)(c) of the proposed Gas Regulation.
[144] Article 10(3) of the proposed Gas Regulation.
[145] Article 7(6) of the proposed Gas Regulation.
[146] Article 7(5) of the proposed Gas Regulation.
[147] Article 33 of the proposed Gas Directive.

the regulatory authority prior to their entry into force. In addition, also the terms and conditions for access to storages have to be set or approved by the NRA.[148]

The choice for regulated third party access to hydrogen storage facilities deviates from the current practice for natural gas storages. As described in paragraph 2.6, Member States can currently choose between regulated and negotiated third party access for storages for natural gas storages. This remains unchanged for natural gas storages, but for hydrogen storages only regulated third party access is allowed.

The European Commission has motivated its choice for regulated third party access to hydrogen storage as follows (Impact assessment report part II, 2021e, p. 155):

> *"Ensuring access to large scale storage is expected to be conducive to investment incentives in renewable hydrogen production (e.g. via electrolysers) and consumption and therefore considered to be an important driver for the development of competitive upstream and downstream hydrogen markets. Ensuring access to large scale storage will allow renewable hydrogen producers to decouple production from consumption thereby allowing them to optimize their electrolyser operations on the basis of price variations for renewable electricity. It enables a stable hydrogen supply for initial (industrial) consumers. As large scale storage is expected to be scarce (especially during the hydrogen ramp-up phase) and only available in certain member states due to geological conditions, a strict access regime is justified."*

From this quote it follows that the European Commission expects that there will be scarcity of large scale hydrogen storage which can result in market power, higher storage tariffs and inefficient market outcomes. To prevent such outcomes, the European Commission proposes regulated third party access were the regulator limits the tariffs.

A downside to regulated third party access is that the incentives to invest in additional large scale underground hydrogen storage could also be reduced, although this depends on the approach to tariff setting by the regulator. It appears to be the case that there are no specific criteria that the regulator has to take into account when setting or approving the tariffs.[149] Thus, the regulator might allow higher tariffs than strictly cost-based tariffs to incentivise investment while limiting the possibilities for excessively high tariffs.

In addition, for the provision of third party access *services* by storage facilities the same general principles apply as for hydrogen terminals described above (i.e. no capacity withholding, capacity allocation et cetera).[150]

[148] Article 72(7)(b) of the proposed Gas Directive.

[149] In that sense regulated third party access to hydrogen storages is fundamentally different from regulated third party access to natural gas networks or, from 2031, hydrogen networks because the proposed Gas Regulation contains a list of criteria the regulator has to take into account when setting or approving tariffs for access to networks.

[150] Article 7(2) of the proposed Gas Regulation adds that hydrogen (and natural gas) storage facilities have to offer (i) both firm and interruptible services, (ii) both short and long term services and (iii) both bundled and unbundled services of storage space, injectability and deliverability. Such an obligation does not apply to hydrogen terminals.

3.7 Infrastructure development

Ensuring third party access also requires the development of infrastructure to ensure sufficient capacity to meet demand. Similar to paragraph 2.7, in this paragraph we discuss:
- Under which conditions infrastructure operators can refuse access to their system;
- Specifically for TSOs, how they have to approach network planning; and
- Which specific incentives for infrastructure development there are.

3.7.1 Refusal of access or a connection

The proposed Decarbonisation Package contains some changes with respect to the right to access for different types of network users to different types of infrastructure.

Natural gas and hydrogen undertakings may still only refuse access or a connection to the natural gas or hydrogen system (i.e. transmission system, distribution system, hydrogen network, natural gas storage facility, hydrogen storage facility, LNG regasification facility or hydrogen terminal) on the basis of a lack of capacity, which has to be substantiated.[151] However, Member States have to ensure that when access or a connection is refused on the basis of a lack of capacity, and *taking into account national and EU decarbonisation objectives*, the necessary enhancements are made (i.e. investments in new infrastructure) when (i) it is economic to do so or (ii) when a potential customer is willing to pay for them.[152] The notion that Member States have to take into account national and EU decarbonisation objectives means that investments in additional infrastructure to meet the demand are required if such investments are necessary to be able to be in line with decarbonisation objectives (such as hydrogen infrastructure). Vice versa, this also implies that Member States may exempt undertakings from investing in enhancements if such enhancements are not in line with decarbonisation objectives (such as investments in natural gas infrastructure).

Somewhat contradictory, TSOs and HNOs are not allowed to refuse a connection of a new natural gas or hydrogen storage facility, LNG regasification facility, hydrogen terminal or industrial customer on the grounds of possible future limitations to available network capacities or additional costs linked with necessary capacity increase.[153] The TSO and HNO have to ensure sufficient entry and exit capacity for the new connection. This underlines that a *possible future* limitation of capacity is not a duly substantiated reason for the refusal of access, whereas an actual lack of capacity presumably is. However, the fact that the additional costs associated with the capacity increase is not a valid reason to refuse a connection and sufficient entry and exit capacity has to be ensured appears contradictory with the notion that a TSO or HNO can refuse access when it is uneconomic to make the necessary enhancements or a customer is unwilling to pay for the enhancements.

In addition, TSOs and DSOs are not allowed to refuse 'technically and economically feasible' requests for a connection from a production facility installation of

[151] Article 34(1) of the proposed Gas Directive.
[152] Article 34(2) of the proposed Gas Directive.
[153] Article 38(2) of the proposed Gas Directive.

renewable and low-carbon gases.[154, 155] What exactly is technically and economically feasible has to be determined by the NRA by approving the connection conditions. In addition to the connection, TSOs and DSOs also have to ensure firm capacity for producers of renewable and low-carbon gases, including by investing in reverse flow, if necessary.[156]

Together, these articles ensure different levels of access for different types of network users. For some network users (i.e. natural gas or hydrogen storage facility, LNG regasification facility, hydrogen terminal or industrial customer or renewable and low-carbon natural gas producers), access can only be refused under strict conditions and the network operators (TSOs, HNOs and DSOs) will in most cases have to invest in capacity expansion to meet the demand. However, for other network users (such as natural gas production facilities, non-industrial users or producers of renewable or low-carbon hydrogen) refusal of access is allowed in more situations (i.e. when access is not in line with national and EU decarbonisation plans or access is uneconomic or the network user is unwilling to pay for the enhancements).

3.7.2 Network planning

As discussed in paragraph 3.1, problem area III concerns the need for more integrated network planning. To address this problem area the European Commission has chosen to implement ‘national planning based on European scenarios’. This results in changes with respect to national network development plans.

At least every two years each TSO has to submit a national ten year network development plan to the NRA.[157] The plan has to forecast supply and demand after having consulted relevant stakeholders. The plan has to describe:
- the infrastructure that needs to be built in the next ten years;
- the investments already decided and the investments that need to be executed in the next three years; and
- information on infrastructure that will be decommissioned.

The plan has to:
- be based on joint scenarios (i.e. for gas and electricity and for TSOs and DSOs),
- be in line with integrated national energy and climate plans and report,
- support the objective of climate neutrality in the European Climate Law
- comply with the infrastructure standards in the Gas SoS Regulation, and
- be consistent with both the common and national risk assessments carried out in accordance with the Gas SoS Regulation.

The NRA has to verify whether the plan meets the requirements.

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[154] Article 37(1) of the proposed Gas Directive.
[155] Article 40(9) of the proposed Gas Directive.
[156] Article 18 and article 33 of the proposed Gas Regulation.
[157] Article 51 of the proposed Gas Directive.

In addition, ENTSOG has to develop the non-binding Union-wide network development plan including a European supply adequacy outlook, which has to build on the national development plans.[158]

Together, these changes ensure more integrated network planning on the basis of joint scenarios that are in line with climate objectives.

A lighter network planning regime can apply to hydrogen network planning. Hydrogen network operators have to regularly assess market demand for new investments, taking into account security of supply and the efficiency of final hydrogen uses.[159] Hydrogen network operators have to submit to the NRA 'at regular intervals' an 'overview' of hydrogen network infrastructure they aim to develop.[160] The overview has to include information on capacity needs, information on the repurposing of natural gas pipelines and should be in line with integrated national energy and climate plans and the climate neutrality objective in the European Climate Law. The NRA has to examine the overview. In its examination the NRA has to take the overall energy-economic necessity of the hydrogen network and the joint scenario developed for the TSO's development plan into account.[161] However, if a Member States decides that it wants to implement the stricter regime for TSO development plans also to HNOs, that is allowed.[162]

3.7.3 Incentives for infrastructure development

The proposed gas market design contains several mechanisms that incentivise infrastructure development.

First, similar to the current market design, article 60 of the proposed Gas Regulation allows NRAs to grant an exemption for new infrastructure from most of the key provisions of the proposed Decarbonisation Package.[163] The requirements for an exemption that applied in the current gas market design also apply in the proposed Gas Regulation.[164] However, an additional requirement is included that the investment in new infrastructure contributes to decarbonisation. Moreover, the scope is extended to also include investments in hydrogen infrastructure.

Second, and also similar to in the current gas market design, based on the Trans-European Networks for Energy Regulation (TEN-E) projects of common interest can be determined that can benefit from coordinated planning and permitting and receive funding from the Connecting Europe Facility. However, the TEN-E

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158 Article 29(a) of the proposed Gas Regulation.
159 Article 6(5) of the proposed Gas Regulation.
160 Article 52(1) of the proposed Gas Directive.
161 Article 52(3) of the proposed Gas Directive.
162 Article 52(6) of the proposed Gas Directive.
163 New infrastructure can be exempted from all provisions in the Gas Regulation and from key provisions in the Gas Directive, such as unbundling requirements and third party access conditions.
164 See Paragraph 2.7. The requirements in the current gas market design are (i) the investment enhances competition in gas supply and security of supply, (ii) the risk of the investment is such that the investment would not take place without an exemption (iii) the infrastructure is owned by a natural or legal person which is separate at least in terms of its legal form from system operators (iv) charges for the new infrastructure are levied on the users of that infrastructure and (v) the exemption is not detrimental to competition or effective functioning of the internal market or of the system to which the infrastructure is connected.

Regulation has recently been revised.[165] Textbox 6 describes the changes to the TEN-E Regulation. One of the important changes for the gas market design is the fact that natural gas transmission infrastructure is no longer eligible, whereas hydrogen infrastructure, smart gas grid infrastructure and infrastructure for the development of offshore wind is eligible.

Third, when a cross-border hydrogen infrastructure project is included in the EU-wide ten year network development plan developed by ENTSOG, but does not reach the project of common interest status, the proposed Gas Directive still requires that adjacent and affected HNOs develop a project plan. The project plan, including a cost-benefit analysis and cross-border cost allocation, has to be submitted for approval to the relevant NRAs.[166] It appears as though these requirements for the financing of cross-border hydrogen infrastructure only apply during the transition phase (and possibly a few years longer), because after that an inter-HNO-compensation mechanism has to be introduced that deals with the cross-border costs allocation of costs of cross-border hydrogen networks. We discuss this in 3.8.

Textbox 6 - Revised TEN-E Regulation

On 23 June 2022 a revision of the TEN-E Regulation entered into force. The revision of the TEN-E Regulation was needed to better align the development of trans-European energy networks with the EU climate objectives. The goal of the revised TEN-E Regulation is to develop the trans-European energy infrastructure for 11 priority corridors and 3 priority areas. The revised TEN-E regulation excludes natural gas infrastructure corridors (with some minor exceptions) and includes electricity, offshore grid and hydrogen infrastructure corridors. The three priority areas relate to investment in smart electricity and gas grids as well as CO2-networks. Moreover, a sustainability requirement for infrastructure is introduced.

The general framework of the TEN-E Regulation remains intact. The TEN-E Regulation still (i) provides for the selection of projects of common interest, that (ii) can benefit from more streamlined and coordinated permit granting processes, (iii) of which the costs can be allocated to Member States on the basis of a cross-border cost allocation (iv) that can benefit from risk-related specific incentives and (v) apply for funding of studies or works. However, there are changes to several of those aspects, such as the process for the selection of projects of common interest.

3.8 Regulation of network tariffs

The proposed Gas Regulation changes the regulation of network tariffs in a number of ways:
- The tariff structures for transmission tariffs are changed, because discounts for renewable and low-carbon gases have to be applied;

[165] Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013.
[166] Article 59(1) to (4) of the proposed Gas Directive.

- Some additional criteria for determination of the allowed or target revenue for transmission system operators are introduced;
- The regulation of network tariffs for hydrogen network operators is introduced; and
- The option of a dedicated charge that allows for temporary cross-subsidies between regulated services (i.e. natural gas and hydrogen networks) is introduced.

We discuss these changes.

3.8.1 Transmission tariff structures

Article 15 of the proposed Gas Regulation sets the general principles and criteria that apply to the regulation of network tariffs for gas transmission system operators. This article remains largely unchanged relative to article 13 of the current Gas Regulation which means that tariffs, or the methodologies used to calculate them, should be non-discriminatory, reflective of efficiently incurred costs, transparent and take into account an appropriate return on investments. The tariffs have to facilitate efficient gas trade and competition, while at the same time avoiding cross-subsidies between network users and providing incentives for the maintenance or expansion of transmission networks.

Article 16, however, is new. Article 16 states that specific discounts shall apply for the transportation of renewable and low-carbon gases:
- 75% production point and storage point discount: A discount of 75% has to be applied to the capacity based transmission tariffs (i.e. the tariff for contracting entry or exit capacity at the entry or exit point) at (i) entry points from renewable and low-carbon production facilities and (ii) at entry points to and exit points from storage facilities.[167]
- 100% discount at interconnection points and LNG entry points: A discount of 100% has to be applied to the entry and exit tariffs of transmission system operators on interconnection points, including entry points from and exit points to third countries as well as entry points from LNG terminals.

Article 16 states the following with respect to this “production point and storage point discount”:
- NRAs may decide to apply lower discounts than the two discounts mentioned above, provided that the discount is in line with the general principles laid down in article 15 and in particular the principle of cost-reflectivity;
- The European Commission can set more detailed rules with respect to the mentioned discounts in (a changed version of) the network code on tariff structures; and
- The European Commission will evaluate the applied discounts 5 years after entry into force and, if necessary, can change the level of the discounts.

Article 16 states the following with respect to this “interconnection point and LNG entry point” discount:

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[167] Regulation 2022/1032 adopted as part of the REPowerEU plan increases this discount to 100% (see paragraph 3.12 on security of supply for more details). As a result, the storage discount of 75% in the proposed Decarbonisation Package is superseded by this Regulation.

- To receive this discount, network users have to provide the transmission system operator with a valid proof of sustainability. Thus, the certification of renewable and low-carbon gases is necessary to qualify for this discount.[168]
- The discount shall apply only to the "shortest possible route" between the location where the certificate was recorded and where it has been cancelled as considered consumed, which requires the determination of the shortest possible route.
- The auction premium – interconnection capacity is auctioned – is not covered by the discount.
- TSOs have to monitor the effect of applying the "interconnection and LNG entry point discount" on their revenues and report the results to the NRA.
- The effect of applying the discount could result in a redistribution of revenues between TSOs. For example, a TSO that transits a large share of renewable and low-carbon gases has to facilitate the gas flow, but cannot charge any interconnection tariffs. To mitigate this effect, an inter TSO compensation mechanism has to be introduced once the effect on the revenues of applying this discount is 10% or higher.
- Further details with respect to this discount can be set in a network code.

3.8.2 *Transmission tariff revenues*

Article 17 considers the determination of the allowed or target revenue of transmission system operators by the NRAs. The article states the following:
- <u>Transparency:</u> The methodology and parameters used by the NRA to determine the allowed or target revenue has to be transparent;
- <u>Cost benchmarking:</u> An EU-wide efficiency comparison of TSOs has to be commissioned by ACER and repeated every 4 years. NRAs have to take the results of the analysis into account when periodically determining the allowed or target revenues of the TSOs.
- <u>Long-term tariff projections:</u> NRAs have to assess the evolution transmission tariffs until 2050, by analysing expected changes in allowed or target revenues as well as the development of gas demand. These projections have to take national energy and climate plans as well as the scenarios used for the integrated network development plan into account.

3.8.3 *Hydrogen network tariffs*

In first instance, article 15 only applies to TSOs (and, consequently, only to natural gas) because during the transition phase negotiated third party access to hydrogen networks can be applied and, therefore, the tariffs will not be set or approved by the NRA. However, if a Member States decides to apply regulated third party access before the end of the transition phase, article 15 will apply from that time.[169, 170] In addition, it is stated that no tariffs shall be charged at interconnection points for dedicated hydrogen networks from 1 January 2031. This is not only the case for renewable and low-carbon hydrogen, but also for fossil hydrogen. It appears

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[168] The fact that a reference to the Renewable Energy Directive is made makes sense for renewable gas, but not for low-carbon gas. Because low-carbon gas is not renewable it will not be certified as renewable gas. Instead, article 8 of the proposed Gas Directive enables the certification of low-carbon gases.

[169] Article 6(7) of the proposed Gas Regulation.

[170] A potential issue with these provisions is that article 15(1) implicitly assumes that hydrogen networks are operated as entry-exit systems, although that is not a requirement yet.

possible to charge interconnection tariffs during the transition phase, also when a Member state has decided to apply regulated third party access.

By abolishing (or not introducing) tariffs at interconnection points the costs of hydrogen networks are redistributed between HNOs. HNOs that need to invest in their network to facilitate transit flows are confronted with costs that they cannot charge to the transit users of their network. That implies that the network tariffs for the domestic entry and exit points will increase, which leads to cross-subsidies between network users. To mitigate this effect, a mechanism of financial transfers between HNOs has to be introduced. After 31 December 2030 all HNOs have to negotiate 'a system of financial compensation to ensure financing for cross-border hydrogen infrastructure'.[171] A procedure is introduced in case no agreement can be reached on such a mechanism.[172] Moreover, a network code has to be developed that sets more detailed rules for the development process of this inter-HNO compensation mechanism.[173]

3.8.4 Financial transfer and dedicated charge

As mentioned in paragraph 3.5 the principle is that a separate regulatory asset base is determined for the calculation of allowed or target revenues for natural gas, hydrogen and electricity networks in order to avoid cross-subsidies between regulated services. When assets are transferred from one regulatory asset base to another, the value of the transferred assets has to be determined by the NRA and the regulatory asset base for both services has to be changed accordingly to avoid cross-subsidies.

This requirement is relevant for the repurposing of gas transmission assets to hydrogen network assets. In that case, the default rule is that the value of the transmission assets that is used to determine the allowed or target revenue is transferred to the hydrogen network operator. As a result, the costs of the transferred assets will be recovered through the tariffs charged to the hydrogen network users and, thus, cross-subsidies are avoided.

However, the proposed Gas Regulation introduces the option of a temporary financial transfer between regulated services. A dedicated charge can be introduced that allows financial transfer between the TSO and HNO (and their network users). The TSO can charge part of the costs of the repurposed hydrogen network to the transmission network users and transfer the revenue to the HNO even though those assets are used by hydrogen network users. By introducing this option the European Commission aims to stabilise hydrogen network tariffs during the ramp-up phase (European Commission, 2021d). Specific requirements for this financial transfer and dedicated charge are introduced.[174] NRAs have to decide on the financial transfer and dedicated charge and ACER has to issue recommendations for the calculation of the size and maximum duration of the dedicated charge and financial transfer.[175]

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[171] Article 53(5) of the proposed Gas Directive.
[172] Article 53(6) to (8) of the proposed Gas Directive.
[173] Article 53(9) of the proposed Gas Directive.
[174] Article 4(2) of the proposed Gas Regulation.
[175] Article 4(3) and (4) of the proposed Gas Regulation.

3.9 Wholesale market

In this paragraph we discuss the wholesale hydrogen and wholesale natural gas market design.

3.9.1 Wholesale hydrogen market

The proposed Decarbonisation Package does not detail many of the aspects of the hydrogen wholesale market. As described in paragraph 3.6, the Gas Regulation describes general principles and criteria for the third party access services provided by HNOs. These principles are very general during the transition period. After the transition period, the wholesale market design will more closely mimic the natural gas market design because hydrogen networks will be operated as entry-exit systems.

This means that much is left open and still needs to be developed (either on a national level or through the adoption of hydrogen network codes and guidelines). Aspects like balancing mechanisms, capacity allocation, congestion management procedures and hydrogen network tariff structures will need to be developed.

3.9.2 Wholesale natural gas market

For the most part, the wholesale market design is not changed by the proposed Decarbonisation Package. However, the Gas Regulation does introduce a definition of ‘entry-exit system’ which extends the definition compared with current practice to also include distribution systems.[176] The proposed definition of ‘entry-exit system’ is:

> *“the aggregation of all transmission and distribution systems or all hydrogen networks to which one specific balancing regime applies”*[177]

The proposed definition defines the entry-exit system by the applicable balancing regime. If the same balancing regime applies to the transmission and distribution system, the distribution system is part of the same entry-exit system as the transmission system. If, however, a separate balancing regime applies to the distribution system and transmission system, the transmission system is an entry-exit system and the distribution system is a different entry-exit system. Both cases, however, differ from the current (most common) market design were the entry-exit system is in practice defined by the entry- and exit points to and from the transmission system and the distribution system is not considered to be part of the entry-exit system.

This definition raises questions, because the concept of the entry-exit system and the defined entry and exit points are also the basis for other parts of the market design. For example, the network code on harmonised transmission tariffs structures requires that network tariffs are set for entry- and exit points. It could be argued that extending the entry-exit system to include (part of the) distribution system means that the exit point from the transmission to the distribution system is

[176] The current Gas Regulation and Gas Directive do not contain a definition of the ‘entry-exit system’ although the term is used frequently. Thus, the introduced definition is new. However, in the current practice the entry-exit system often overlaps with the transmission system, with the connections between transmission and distribution systems being an exit point.

[177] Article 2(30) of the proposed Gas Regulation.

abolished and the transmission system operator cannot charge exit tariffs for the transportation of gas to the distribution system. Instead, the points where gas is extracted from the distribution grid should be considered the exit points, possibly all the way down to the level of household connections. However, it is not clear whether this is indeed the (intended) implication of extending the definition of the entry-exit system.

3.10 Retail market and customer protection

The proposed Decarbonisation Package harmonises the provisions concerning retail market and customer protection *for natural gas* with the provisions in the Electricity Regulation and Electricity Directive (that have been revised as part of the Clean Energy Package). Only part of those provisions apply *to hydrogen*, resulting in a lower level of customer protection for hydrogen consumers, which is similar to the level of customer protection for large natural gas consumers. This reflects the expectation of the European Commission that hydrogen will primarily be consumed by large customers (i.e. industry and heavy transport) that require less protection compared to for example household customers that use natural gas for heating (European Commission, 2021d).

The proposed Gas Directive significantly limits possibilities for Member States to regulate retail prices compared with the current gas market design. In the proposed Decarbonisation Package the European Commission proposes to limit the possibilities for retail price regulation because it considers retail price regulation a distortive measurement that often leads to the accumulation of tariff deficits.[178] Instead, Member States should apply other policy tools such as social policy to safeguard affordability of natural gas. The proposed Gas Directive therefore requires that Member States ensure competitive, consumer-centred, flexible and non-discriminatory markets *for gases* (i.e. natural gas and hydrogen).[179] In these markets, customers have to be free to choose their supplier and suppliers are free to determine the (retail) price for their supply to customers.[180] In principle, Member States have to ensure the protection of vulnerable and energy poor households customers through social policy and not through public interventions in the price setting of gases.[181] However, specifically for *natural gas* (i.e. not for hydrogen), by way of derogation Member States are allowed to apply public interventions in the price setting for the supply of natural gas to vulnerable and energy poor household consumers, subject to conditions.[182] The option to implement retail price regulation as part of a public service obligation is cancelled.[183]

However, it is unlikely that the proposal to limit the possibilities for retail price regulation as proposed in the Decarbonisation Package are adopted, because recent developments have caused the European Commission to move in the opposite direction. See Textbox 7 for an explanation.

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[178] Recital 13 of the proposed Gas Directive.
[179] Article 3 of the proposed Gas Directive.
[180] Article 4(1) of the proposed Gas Directive.
[181] Article 4(2) of the proposed Gas Directive.
[182] Article 4(3) and (4) of the proposed Gas Directive.
[183] Article 5 of the proposed Gas Directive still allows Member States to impose public service obligations on natural gas or hydrogen undertakings, but such obligations can no longer relate to the price of the supply of natural gas or hydrogen.

Textbox 7 - Temporarily allowing below cost retail price-caps for supply to household and SMEs

The recently adopted Council Regulation to address high energy prices temporarily extends the possibility of Member States to regulate retail *electricity* prices for SMEs and explicitly states that regulating retail prices at below cost levels is allowed. This is only necessary for electricity because for natural gas, based on the current Gas Directive, that is already allowed. Therefore, the Council Regulation does not have to extends possibilities for Member States to regulate retail prices for natural gas.

However, the proposed Decarbonisation Package limits the possibilities of Member States to regulate retail prices in such a way that if the proposed Gas Directive were in force today (i.e. possibilities for regulation of natural gas retail prices were reduced), the Council Regulation to address high energy prices would presumably also extend the possibilities to regulate retail prices for natural gas in the same way as it does for electricity.

Given the fact that the Council Regulation to address high energy prices extends the possibilities to regulate retail prices for electricity, it is highly questionable whether the proposals in the Decarbonisation Package to limit those same possibilities will be adopted.

In addition, the proposed Gas Directive includes a new chapter on consumer empowerment and protection and retail markets. In this chapter many of the provisions from the similar chapter in the Electricity Directive are copied to natural gas (with some minor changes). This is the case for the articles on:[184]
- basic contractual rights;[185]
- right to switch and rules on switching-related fees;[186]
- comparison tools;[187]
- active customers;[188]
- citizen energy communities;[189]
- bills and billing information;[190]
- smart metering systems;[191]
- functionality of smart meters;[192]
- entitlement to a smart meter;[193]
- conventional meters;[194]
- data management;[195]
- interoperability requirements and procedures for access to data;[196]
- single points of contact;[197]

[184] The Electricity Directive also contains several articles that are not apply to natural gas, such as the articles on (i) the entitlement to a dynamic electricity price contract, (ii) aggregation contract, (iii) demand response through aggregation, (iv) universal service and (v) energy poverty.
[185] Article 10 of the proposed Gas Directive and article 10 of the Electricity Directive.
[186] Article 11 of the proposed Gas Directive and article 12 of the Electricity Directive.
[187] Article 12 of the proposed Gas Directive and article 14 of the Electricity Directive.
[188] Article 13 of the proposed Gas Directive and article 15 of the Electricity Directive.
[189] Article 14 of the proposed Gas Directive and article 16 of the Electricity Directive.
[190] Article 15 of the proposed Gas Directive and article 18 of the Electricity Directive.
[191] Article 16 of the proposed Gas Directive and article 19 of the Electricity Directive.
[192] Article 18 of the proposed Gas Directive and article 20 of the Electricity Directive.
[193] Article 19 of the proposed Gas Directive and article 21 of the Electricity Directive.
[194] Article 20 of the proposed Gas Directive and article 22 of the Electricity Directive.
[195] Article 21 of the proposed Gas Directive and article 23 of the Electricity Directive.
[196] Article 22 of the proposed Gas Directive and article 24 of the Electricity Directive.
[197] Article 23 of the proposed Gas Directive and article 25 of the Electricity Directive.

- right to out-of-court dispute settlement;[198] and
- vulnerable customers.[199]

Only some of these articles also apply to hydrogen consumers. The articles on basic contractual rights, right to switch and rules on switching-related fees, bills and billing information, data management, single points of contact, right to out-of-court dispute settlement and vulnerable customers also apply to hydrogen consumers. The articles on active customers, citizen energy communities, interoperability requirements and procedures for access to data do not apply to hydrogen.[200] The articles on smart metering systems, functionality of smart meters, entitlement to smart meters and conventional meters also do not apply to hydrogen. However a separate article on smart metering systems in the hydrogen system is introduced, which requires Member States to ensure the deployment of secure smart meters (from the start).[201] The article on comparison tools aims to ensure that *at least* household natural gas customers and microenterprises have access to comparison tools, which leaves Member States the option open to introduce a similar right for hydrogen consumers.

3.11 Gas quality

There are several developments that result in a need to change the rules concerning gas quality. We discuss the changes for natural gas and hydrogen separately.

3.11.1 Natural gas quality

For natural gas there are two developments that can lead to more variation of gas quality. First, the expected increased production of biogas and biomethane will lead to varying gas quality. Second, the European Commission allows Member States to decide on blending of hydrogen into the natural gas system.

Regarding the quality of natural gas the proposed Decarbonisation Package leaves the actual determination of gas quality standards to the Member States, but the package does contain many procedural rules that govern the roles and responsibilities with respect to gas quality management. The only exception is that transmission system operators have to accept a hydrogen content of 5% in the natural gas flows at interconnection points.[202]

The roles and responsibilities with respect to gas quality management are as follows:
- TSOs have to ensure efficient gas quality management in their facilities in line with the applicable gas quality standard.[203] The TSOs have to make public detailed information regarding the quality of the gases transported in its networks.[204]

[198] Article 24 of the proposed Gas Directive and article 26 of the Electricity Directive.
[199] Article 25 of the proposed Gas Directive and article 28 of the Electricity Directive.
[200] For the articles on active consumers and citizen energy communities, this follows from the definition of active consumer and citizen energy community.
[201] Article 17 of the proposed Gas Directive.
[202] Article 20 of the proposed Gas Regulation.
[203] Article 35(4) of the proposed Gas Directive.
[204] Article 30(7) of the proposed Gas Regulation.

- DSOs can be responsible for efficient gas quality management in their networks if that is necessary for system management due to the production of renewable and low-carbon gases (and so decided by the NRA).[205] If DSOs are responsible for gas quality management they have to make public detailed information regarding the quality of gases transported in their network as well.[206]
- TSOs have to cooperate to avoid restrictions on cross border gas flows due to gas quality differences (but accept at least 5% hydrogen content).[207] When such restrictions occur the concerned TSOs have to make a list of potential solutions, estimate the potential of each solution, conduct a public consultation and submit a joint proposal for removing the restriction for approval of the respective NRAs.[208] NRAs shall decide on a solution.[209] If the concerned NRAs cannot decide, ACER has to take a decision.[210] Further details to implement these provisions shall be set in a network code.[211]
- ENTSOG has to make a gas quality monitoring report every two years which describes the development of gas quality parameters, the development of the level and volume of hydrogen blended into the natural gas system, forecasts for the expected development of gas quality parameters and of the volume of hydrogen blended into the natural gas system, the impact of blending hydrogen on cross-border flows as well as information on cases related to differences in gas quality specifications or in specifications of blending levels and how such cases were settled.[212] The EU DSO entity has to provide input to ENTSOG for its reporting on gas quality, with regard to the distribution networks where distribution system operators are responsible for gas quality management.[213]
- NRAs have to monitor the development of gas qualities and gas quality management by transmission system operators and where relevant by distribution system operators, including monitoring the development of costs related to the management of gas quality by system operators and the developments related to the blending of hydrogen into the natural gas system.[214] NRAs have to take all reasonable measures to eliminate restrictions on natural gas trade due to gas quality differences.[215]

3.11.2 Hydrogen quality

Similar to natural gas quality management, the determination of hydrogen quality standards is left to the Member States. The proposed Decarbonisation Package does determine the roles and responsibilities of different actors with respect to hydrogen quality management. Those roles and responsibilities are similar to those for natural gas quality management.[216]

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[205] Article 40(2) of the proposed Gas Directive.
[206] Article 40 of the proposed Gas Regulation.
[207] Article 19(1) of the proposed Gas Regulation.
[208] Article 19(2) to (5) of the proposed Gas Regulation.
[209] Article 19(6) to (8) of the proposed Gas Regulation.
[210] Article 19(9) to (10) of the proposed Gas Regulation.
[211] Article 19(11) of the proposed Gas Regulation.
[212] Article 23(3)(g) of the proposed Gas Regulation.
[213] Article 23(3)(h) of the proposed Gas Regulation.
[214] Article 72(1)(f) of the proposed Gas Directive.
[215] Article 71(c) of the proposed Gas Directive.
[216] The only difference is that HNOs can be made responsible for hydrogen quality management in a similar way as DSOs for natural gas. In addition, ENNOH is responsible for monitoring hydrogen quality developments instead of ENTSOG and there is no role for the EU DSO entity because there is no distinction between transmission and distribution for hydrogen networks.

3.12 Security of supply

The proposed Decarbonisation Package changes the security of supply policy in a number of ways by amending the Gas SoS Regulation.[217] The proposed changes to the Gas SoS Regulation clarify that the Gas SoS Regulation only applies to natural gas (i.e. not to hydrogen).[218] Thus, no specific policy with respect to hydrogen security of supply is proposed.

The proposed Gas Regulation adds the following elements to the Gas SoS Regulation:
- Storage filling analysis and measures: Requires Member States to explicitly make storages part of their security of supply risks assessments at regional level, including risks linked to the control of storage by entities from third countries. If necessary, based on the common risk assessments, Member States have to take regional measures related to the filling of storages. The costs of such measures have to be fairly allocated to the Member States within the relevant risk group.[219]
- Voluntary joint procurement of strategic stocks: TSOs are allowed to reserve storages for natural gas exclusively for carrying out their function and for the purpose of security of supply, if Member States decide this is an adequate preventive measure to ensure security of supply. The filling of these storages can be done through joint purchasing of strategic stocks. The strategic stocks can be used in case of an emergency or when needed for the safe and secure operation of the transmission network.[220]
- Cybersecurity: Member States are required to include cybersecurity risks and measures in their preventive action plans.[221]

However, after submitting the proposed Decarbonisation Package the geopolitical situation changed significant due to the war in Ukraine. The European Commission, in coordination with the Gas Coordination Group, carried out a dedicated risk analysis which showed a need for better use of storage facilities. The European Commission concluded that short-term measures are required to ensure storages are well-filled before the 2022/2023 winter. Therefore, the European Commission proposed a separate regulation with such short term measures, that amends both the Gas Regulation and the Gas SoS Regulation. After swift negotiations between European Parliament and the Council, Regulation 2022/1032 entered into force on 1 July 2022.[222] Thus, it appears that some of the changes proposed in the Decarbonisation Package have been superseded by these short-term measures.

[217] Article 67 of the proposed Gas Regulation includes amendments of the Gas SoS Regulation.
[218] Article 67(2) amends the Gas SoS Regulation by including a definition of 'gas' in article 2(27) of that regulation. Gas, in the context of the Gas SoS Regulation, is defined to be equal to natural gas in the Gas Regulation. Thus, in the Gas SoS Regulation the terms natural gas and gas are used interchangeably, whereas in the Gas Regulation the term gas (or gases) is used to indicate both natural gas and hydrogen.
[219] Article 67(8) of the proposed Gas Regulation amends the Gas SoS Regulation by introducing article 7b on storage filling analysis and measures.
[220] Article 67(8) of the proposed Gas Regulation amends the Gas SoS Regulation by introducing article 7d on the join procurement of strategic stocks.
[221] Article 67(11) of the proposed Gas Regulation amends the Gas SoS Regulation by introducing article 8a on the inclusion of cybersecurity measures in preventive action plans.
[222] Regulation (EU) 2022/1032 of the European Parliament and of the Council of 29 June 2022 amending Regulations (EU) 2017/1938 and (EC) No 715/2009 with regard to gas storage.

The short-term measures include the following elements:

- Storage filling obligation: Member States are required to ensure that the storage facilities in their territory filled up to at least 90% of their capacity at Member State level by 1 November of the year (filling target). In 2022 the filling target is set at 80%, taking into account the limited time left to implement this requirement.[223,224] Member States have to ensure that the filling target is reached according to the filling trajectory, which they can achieve through several different measures. Because gas storages are unevenly distributed among Member States, a larger burden falls on Member States with relatively large storage capacities, whereas all Member States benefit from to positive effects of increased storage filling. A burden sharing mechanism is introduced to redistribute the costs of the storage filling obligation. To monitor whether the storage filling target will be reached, intermediate targets for other months of the year are determined (filling trajectory). If a Member State does not meet the filling trajectory the European Commission can ultimately take a decision on the measures that the Member State has to take to reach the filling trajectory.
- Certification of storage system operators: NRAs have to certify storage system operators to ensure they do not pose a risk for the security of supply. If the NRA decides that a storage system operator may put the security of supply at risk (i.e. hoarding storage capacity), the NRA can grant the certification under conditions that mitigate the security of supply risk or, ultimately, refuse the certification. When the NRA refuses the certification the person or persons that may put the security of supply at risk has to dispose the shareholding or rights they have over the storage system operator.
- Transmission tariff storage discount: A discount of 100% has to be applied on the capacity-based transmission tariffs for entry points from and exit points to storage facilities.

The storage filling obligation is implemented by amending the Gas SoS Regulation. The certification of storage system operators and the network tariff discount for storages are implemented by changing the current Gas Regulation.

Subsequently, on 20 July 2022 the European Commission submitted a proposal for a Council Regulation on coordinated measures to reduce gas demand (hereafter: Demand Reduction Regulation), which was adopted by the Council on 5 August 2022 (Regulation 2022/1369). The regulation requires Member States to use their best efforts to reduce their gas consumption by 15% in the period from 1 August 2022 and 31 March 2023. In addition, the European Commission and the Council can declare a Union Alert, which triggers mandatory demand reductions. The Demand Reduction Regulation complements the Gas Storage Regulation, because the demand reduction enables storage filling (or reduces storage depletion) during a period with low gas supply.

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223 Article 6(a)(1) of the amended Gas SoS Regulation.

224 For Member States with a relatively large share of underground gas storage in their territory relative to the annual gas consumption, the storage filling obligation is reduced to 35% of the average annual gas consumption over the preceding five years.

4 Reflections and recommendations

In Chapters 2 and 3 we described the “current” (natural gas) and “future” (natural gas and hydrogen) market design for gaseous fuels. In this chapter we reflect on the proposed changes to the market design for gases and present some recommendations.

4.1 Reflections on the proposals

4.1.1 Uncertainty regarding the role of hydrogen and pace of development of hydrogen infrastructure

There is an urgent need to update the gas market design to enable the transition to decarbonised gas markets. As noted by the European Commission, the decarbonisation of gas markets will lead to changes to the role of gaseous fuels. Without any changes to the gas market design there will be barriers for the development of hydrogen infrastructure and markets, because there will be uncertainty on the regulatory framework and a lack of harmonisation which could lead to postponed investments. Moreover, market power in specific infrastructure segments could result in inefficient market outcomes.

However, the precise role of hydrogen and the pace of development of hydrogen infrastructure and markets is uncertain. This uncertainty requires some regulatory flexibility to allow for the market to develop. To that end, the proposed Decarbonisation Package strikes a balance between regulatory flexibility and regulatory certainty by proposing a transition period during which there is more regulatory flexibility, while at the same time providing clarity on the regulatory framework after the transition period. That approach makes sense given the early stage of development of the hydrogen market and hydrogen infrastructure.

However, the proposed Decarbonisation Package does make certain assumptions about the role of hydrogen in the future energy system. Notably, the European Commission expects hydrogen will primarily be used in industry and heavy transport (aviation, navigation) and based on these assumptions the proposed Decarbonisation Package determines the hydrogen market design. It appears that, based on this assumption, the European Commission decided (i) not to distinguish between hydrogen transmission and distribution, (ii) not to implement similar consumer protection rules for household and SME hydrogen users and (iii) not to implement policies to address hydrogen security of supply. If, however, unexpectedly, hydrogen will be used in other sectors, such as the built environment or electricity production, the market design might prove to be inadequate for that situation.

A more agnostic approach about the role of hydrogen in the energy system would be to more closely mimic the market design for natural gas. For example, the Gas Directive could implement the same retail market and consumer protection rules for hydrogen and natural gas household and SME consumers. Although the European Commission expects – and probably rightly so – that there will be almost no household and SME hydrogen consumers, if they do exist they will have the same level of consumer protection. If not, there is no harm done.

4.1.2 Interaction with fit-for-55 proposals

As discussed in paragraph 3.1, the proposed Decarbonisation Package aims to remove barriers for the uptake of renewable and low-carbon gases. With the exception of the network tariff discounts for renewable and low-carbon gases discussed in paragraph 3.8, the proposed Decarbonisation Package does not provide specific support for the scale-up of production, storage and consumption of renewable and low-carbon gases.

Support for the uptake of renewable and low-carbon gases will result of the implementation of the fit-for-55 package. The fit-for-55 package includes, inter alia, proposals to:
- further limit the emission rights in the EU ETS;
- introduce a carbon border adjustment mechanism;
- introduce a separate emission trading system for transport and the built environment;
- increase the share of renewable energy production, including by setting national targets for the use of renewable fuels of non-biological origin in the transport sector and in industry;
- increase national emission reduction targets for non ETS sectors;
- increase targets for energy efficiency;
- strengthen emission standards for cars and vans; and
- revise energy taxation to align energy taxation with energy and climate objectives.

A key question that comes to mind when analysing the proposed Decarbonisation Package (but that is out-of-scope for this report) is how the fit-for-55 proposals interact with the proposed Decarbonisation Package to facilitate the required scale-up of renewable and low-carbon gases.

Certification of renewable and low-carbon gases appears to play a key role in this, because certification:
- Serves as the basis to demonstrate whether national renewable energy targets determined in the Renewable Energy Directive are reached;
- Serves as the basis for network tariff discounts for natural gas;
- Could serve as proof that the emissions from burning biogas and biomethane should not be taken into account in the EU ETS.

Although in general this framework of interacting support mechanisms is clear. Their application in practice raises questions that require further analysis. How will renewable and low-carbon gases be certified? How are the certificates used for different purposes? And how does this influence the hydrogen and natural gas market?

For Member States an important question is to what extent national policies to achieve national targets are required (such as the targets for renewable fuels of non-biological origin in the proposal for a Renewable Energy Directive) and which policies are most effective. The design of such national policies should match the market design described in the proposed Decarbonisation Package.

4.1.3 Reduction of natural gas demand and phase-out of natural gas infrastructure

As mentioned in paragraph 3.1 the European Commission expects that the role of natural gas in the energy system to change. The proposed Decarbonisation Package mainly addresses barriers for the switch from fossil natural gas to renewable and low-carbon natural gas.

However, a key development will be the switch away from natural gas to other energy sources, such as the transition in the built environment where natural gas will mostly be replaced by electricity or district heating systems. Thus, large parts of the existing natural gas infrastructure will have to be decommissioned. In the remaining parts of the natural gas network, the usage rate might drop. In other words, the “tree” of existing natural gas infrastructure will likely be “trimmed”.

The switch away from natural gas raises some policy questions that the proposed Decarbonisation package does not address:

- The switch away from natural gas could happen voluntarily, but it is also possible that mandatory switching is needed. Without mandatory switching it is possible that a natural gas distribution network will need to be maintained to serve only a few remaining customers. A mandatory fuel switch is at odds with the principle of third party access (i.e. whoever wants a connection should be able to get one). Thus, whether and under which conditions mandatory fuel switches are allowed is an important question.
- The switch away from natural gas has consequences for the regulation of network tariffs. Based on the current and proposed legislation, the principle is that the users of the natural gas grid pay for the costs of the grid. However, this raises questions on how to avoid extremely high grid tariffs for the remaining natural gas users.

4.2 Recommendations to EU legislators

4.2.1 Speed-up delegated act low-carbon fuels

The proposed Decarbonisation Package is the first proposal by the European Commission that acknowledges the role of low-carbon fuels for the decarbonisation of gaseous fuels. Especially low-carbon hydrogen is expected to play a role in the short-term (i.e. until 2030) decarbonisation of existing hydrogen use, while facilitating the development of a hydrogen market.

The proposed Decarbonisation Package acknowledges the role of low-carbon hydrogen by including a definition and providing the legal basis the certification of low-carbon gases. From the definition of low-carbon fuels it follows that a 70% greenhouse gas emission saving is required to qualify as “low-carbon”. However, the precise methodology to determine when this 70% threshold is met will be determined in a delegated act by 31 December 2024.

The deadline for this delegated act is simply too late if low-carbon fuels are indeed expected to play a key role for the decarbonisation of gaseous fuels until 2030. After all, investments will likely be postponed until there is clarity about the methodology to determine whether the 70% threshold is met. Therefore we recommend to speed-up the delegated act.

4.2.2 Introduce a definition of biomethane

The proposed Decarbonisation Package aims to remove barriers for the uptake of biomethane, which will gradually replace an increasing share of fossil gas in the natural gas system. However, the proposed Decarbonisation Package creates some unclarity about the definition of biomethane and its relation to the definition of biogas. It appears that biomethane is the subset of biogas that can be safely injected into the natural gas system. In other words, biomethane is biogas that meets the nationally determined gas quality standards. To avoid unclarity about the definition we recommend including a definition of biomethane in article 2 of the proposed Decarbonisation Package.

4.2.3 Change the definition of a hydrogen terminal

The proposed Decarbonisation Package defines a hydrogen terminal as an installation used for the transformation of liquid hydrogen or liquid ammonia into gaseous hydrogen for injection into the hydrogen network or the liquefaction of gaseous hydrogen. Because the definition of a hydrogen terminal only includes the transformation of liquid hydrogen or liquid ammonia to gaseous hydrogen, other hydrogen carriers such as methanol, synthetic methane, synfuels and liquid organic hydrogen carriers (LOHC) are missing from the definition. It can be expected that methanol, synthetic methane and synfuels will be used as such and thus not converted back to hydrogen. However, that is not the case for LOHCs which appears to be missing from the definition. We recommend to add the transformation of liquid organic hydrogen carriers to gaseous hydrogen to the definition.

4.2.4 Clarify if and under which conditions mandatory fuel switching is allowed

As discussed in paragraph 4.1.3, the proposed Decarbonisation Package does not address the phase-out of natural gas infrastructure due to fuel switching. The energy transition in the built environment will predominantly be the result from switching from natural gas to other energy sources (i.e. electricity or district heating). For an efficient transition, mandatory switching might be required. Mandator fuel switching seems contradictory to the principle of third party access to the natural gas system. Therefore, the proposed Decarbonisation Package should specify if and under which conditions mandatory switching from natural gas to electricity or district heating systems is allowed.

4.2.5 Reconsider regulated third party access to hydrogen storages

As discussed in paragraph 3.6, the European Commission proposes to implement regulated third party access to hydrogen storages. This deviates from the third party access conditions for natural gas storages, where Member States can choose between regulated and negotiated third party access.

The reason the European Commission proposes regulated third party access for hydrogen storages is that the technical potential for large scale underground hydrogen storage is limited. Hydrogen can be safely stored in salt caverns. This implies the potential for large scale underground hydrogen storage is concentrated in specific countries and it is questionable whether the potential is sufficient to meet the demand. As a result, hydrogen storage operators might have considerable market power resulting in unreasonably high prices and inefficient market outcomes. To prevent such outcomes, the European Commission proposes to regulate the storage tariffs and access conditions.

However, there are some counter arguments to this line of reasoning:

- The proposals of the European Commission assume hydrogen will only be stored in salt caverns. However, it is not inconceivable that in the future hydrogen storage in depleted gas fields will become a possibility (TNO & EBN, 2022). That would increase the technical potential for large scale underground hydrogen storages, which would increase competition between hydrogen storage operators.
- The definition of hydrogen storage facility not only includes large scale underground hydrogen storages, but also hydrogen storage that is part of a hydrogen terminal.[225] Unlike salt caverns the technical potential of hydrogen terminals is not limited by geological factors. Thus, operators of salt caverns might face competition from hydrogen storage in hydrogen terminals.
- Large scale underground hydrogen storages are yet to be developed. Therefore, investments in hydrogen storages are needed. Temporary high storages fees signal that investment in storage expansion is needed. So if there are possibilities to invest in additional hydrogen storages, market based storage fees (rather than regulated storage fees) can provide price signals for investments in expansion of storage capacity. Moreover, reducing prices through regulation does not address the fact that demand for hydrogen storage capacity exceeds the supply. Therefore, regulated fees do not ensure that the storage supply and demand are balanced. At cost-based storage fees, demand can exceed the supply. This raises the question how the scarce storage capacity should be allocated to different potential storage users.

Thus, it is questionable whether hydrogen storages will have considerable market power due to geological limitations to large scale underground hydrogen storage. An alternative to regulated third party access might be to implement the same rules as for natural gas storages, where Member States can choose between regulated and negotiated third party access. If that raises concerns because hydrogen storage capacity is concentrated in specific countries[226], an alternative could be that ACER or the European Commission analyses whether hydrogen storages have market power and based on the analysis determines whether negotiated or regulated third party access should be applied.

4.2.6 Reconsider the definition of an entry-exit system

The proposed Decarbonisation Package aims to ensure firm access to wholesale natural gas markets for biomethane producers connected to the distribution system. To that end, the European Commission also introduces a definition of an entry-exit system. An entry-exit system is defined as the aggregation of all transmission and

[225] Article 2(6) of the proposed Decarbonisation Package.

[226] If hydrogen storages have considerable market power due to geological limitations and hydrogen storages are concentrated in specific Member States, than those Member States might not be inclined to reduce the adverse effect of market power on European welfare because that could reduce their national welfare.

distribution system to which a specific balancing regime applies.[227] This definition raises a number of questions.

First, an entry-exit system is defined by the applicable balancing regime. However, a balancing regime is not defined in the proposed Decarbonisation Package. It could be argued that two separate entry-exit systems that apply *the same rules for balancing* (rather than a zone for which the system imbalance is calculated) apply the same balancing regime and, as a result, are the same entry-exit system.

Second, the definition implies that the distribution system is always part of an entry-exit system. The distribution system is either part of an entry-exit system that includes both the transmission and distribution system (in case the same balancing regime applies to the transmission and distribution system) or the distribution system can be a separate entry-exit system (in case separate balancing regimes apply to both the transmission and distribution system). In the first case (i.e. the same balancing regime applies to the transmission and distribution system) the consequence would be that the connection point between transmission and distribution system is not an entry- or exit point. After all, an exit (entry) point is defined as a point subject to booking procedures by network users or final customers (producers) *providing access to an entry-exit system*. Therefore, if the transmission and distribution system are part of the same entry-exit system, the connection point between the transmission and distribution system is not an entry or exit point. Furthermore, all connections from the distribution system to final customers are exit points (because the distribution system is always part of an entry-exit system). This is a fundamental change to the gas market design, that could have major consequences. For example, this definition could result in a major change of the network tariff structures. It is not clear whether this is indeed the intention of the introduced definition. If not, we recommend changing the definition.

4.2.7 Consider simplifying the network tariff structures

The proposed Decarbonisation Package changes the network tariff structures. The proposals significantly increase the complexity of network tariff setting for a number of reasons.

First, for hydrogen networks - once regulated third party access has to be applied - the proposed Decarbonisation Packages requires that there shall be no networks tariffs for interconnection points. This implies that when there is no congestion on the interconnection points, gas can flow across Europe without any interconnection tariffs. This requires the implementation of an inter-HNO compensation mechanism, because HNOs that incur a relatively large share of hydrogen transit are faced with the costs of network capacity that enables transit. Without a compensation mechanism the domestic hydrogen producers and users would be charged the costs of enabling transit. The European Commission has previously considered abolishing network tariffs on interconnection points for natural gas after a study commenced by the European Commission advised to so do (European Commission, 2018). However, the proposal received little enthusiasm and the European Commission did not proceed with the proposal. Now, the European Commission does propose a similar tariff structure for hydrogen. However, the

[227] Article 2(53) of the proposed Gas Directive.

European Commission gives a limited motivation for this proposal, although it is a proposal with pro's (such as more efficient use of existing network capacity) and con's (such as increased complexity and risk of capacity hoarding).[228] Moreover, the European Commission does not propose to implement a similar tariff structure for natural gas.

Second, for natural gas, specific tariff discounts for renewable and low-carbon natural gas (i.e. primarily biomethane and fossil natural gas with CCS) are proposed:

- A 75% discount to entry points from renewable and low-carbon natural gas producers;
- A 75% discount (already increased to 100% as part of the short-term measures to ensure security of supply) to entry points to and exit points from natural gas storages; and
- A 100% discount to interconnection points and entry points from LNG facilities.

For the discount on interconnection points tariffs and entry points from LNG facilities, a proof of sustainability is required. That implies that the certification system for renewable and low-carbon gases will also be used by natural gas traders to demonstrate to TSOs that they qualify for the network tariff discount. It is not precisely clear how this would work in practice. Furthermore, if the level of the discounts results in a revenue loss larger than 10%, an inter-TSO-compensation mechanism has to be implemented. This further increases the complexity of the tariff structure.

To a certain extent these specific discounts for renewable and low-carbon natural gas conflate climate policy with gas market design. As stated by the European Commission, the goal of the proposed Decarbonisation Package is to *remove barriers* for the scale-up of renewable and low-carbon gases. However, applying discounts to network tariffs is not merely removing barriers but *a support mechanism* for the scale-up of renewable and low-carbon natural gas. After all, the costs of transporting renewable and low-carbon gas are the same as for unabated fossil gas. Although public support for renewable and low-carbon gas is required, the question is whether network tariffs are the most suitable instrument to provide this support. Other fit-for-55 proposals seem to already introduce support mechanisms for renewable and low-carbon gas through more suitable policy instruments (i.e. EU ETS and specific targets in the Renewable Energy Directive). Therefore, the question is whether these network tariff discounts are necessary to achieve climate targets.

Third, the proposals create differences between hydrogen network tariffs and natural gas network tariffs. For example, entry points from renewable hydrogen producers do not receive a hydrogen network tariff discount. However, when the renewable hydrogen is injected in the natural gas system (which could be possible because a hydrogen content of 5% by volume in natural gas is allowed), a discount

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[228] In the impact assessment report the European Commission states: " Learning from the past, it seeks to avoid the 'pancaking effect' that currently characterises the natural gas system by prohibiting cross-border tariffs, thereby setting the stage for an EU hydrogen market with a true level playing field later." The 'pancaking effect' refers to the cumulation of intra-EU interconnection point tariffs for gas flowing through different entry-exit systems.

of 75% on the entry tariff has to be applied. In addition, for hydrogen interconnection points no network tariff shall be applied (for hydrogen produced from unabated fossil gas), whereas for natural gas interconnection point tariffs are applied to unabated fossil gas. These differences further increase the complexity and could create perverse incentives.

Together, the proposals significantly complicate the network tariff structures and the calculation of network tariffs, while their effect on overall policy objectives is likely limited (or those objectives can be reached through more suitable policy instruments). Therefore we recommend simplifying the network tariff structures. Two alternatives that could be considered are:
- To keep the network tariff structures for natural gas as they currently are and implement similar network tariff structures for hydrogen networks; and
- Abolish network tariffs on interconnection points for both natural gas and hydrogen, but without introducing specific network tariff discounts for renewable and low-carbon natural gas.

4.2.8 Clarify options to redistribute natural gas network costs in case of declining natural gas demand

As discussed in paragraph 4.1.3, the proposed Decarbonisation Package does not address the decline in natural gas demand and the phase-out of natural gas *infrastructure*. The shift away from natural gas to other energy sources (electricity, district heating) has three potential effects on costs:
- The usage rate of existing infrastructure declines, resulting in higher costs per unit of gas transported (i.e. the same pipe is used to transport less gas);
- The natural gas network is decommissioned in an area (i.e. entire neighbourhood switches to other energy source), potentially resulting in costs of the decommissioned assets (i.e. if they are not fully depreciated yet); and
- A decommissioned natural gas grid has to be removed (i.e. pipes dug up from the ground) for security reasons, resulting in costs for removal.

A network in decline raises a number of questions for the regulation of network tariffs (Decker, 2016). For example, questions can arise about:
- The need to continue regulation of network tariffs, given the fact that competition from alternative energy sources exists;
- The need for the network operator to earn back historic investments; and
- The need to protect remaining captive customers against a vicious cycle of increasing network tariffs.

The proposed Decarbonisation Package does not address such questions, aside from the fact that the proposed Gas Regulation requires NRAs to analyse the effect of the energy transition on the development of natural gas network tariffs.[229] We recommend to provide clarity on the need for network operators to earn back historic investments while facing declining demand and the tools available to NRAs and Member States to protect captive customers against extremely high network tariffs (i.e. a small group of ‘remaining’ natural gas consumers pay for historic investments in natural gas networks).

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[229] Article 17(3) of the proposed Gas Regulation.

4.2.9 Implement measures to ensure security of supply of hydrogen

The proposed Decarbonisation Package does not include any provisions that ensure the security of supply of hydrogen (i.e. the Gas SoS Regulation is not amended to include hydrogen). This probably stems from the fact that the current policy to ensure security of supply for natural gas primarily focusses on the security of supply to protected customers (typically household and SMEs). The European Commission envisions that hydrogen will primarily be used in industry and heavy-duty transport. Therefore, the European Commission does not expect households and SMEs will use hydrogen. Another argument to not implement measures ensuring security of supply of hydrogen is that there first needs to be a hydrogen market and hydrogen infrastructure (i.e. there first needs to be a supply, before it can become secure).

However, the question is whether it is truly not necessary to implement policies to ensure security of supply of hydrogen. There are three reasons to consider such policies:

1 The current situation with the disruption of natural gas supply from Russia demonstrates that it can be better to prevent becoming too dependent of a supplier than to wait and see how the market develops. That implies acting even before the market develops.
2 The Gas SoS Regulation does not only describe the mechanisms to ensure security of supply to protected customers, but also sets a supply norm and infrastructure norm. Setting similar norms for the development of the hydrogen system and market is useful, because then these norms can be taken into account when developing the hydrogen system.
3 Although the European Commission envisions hydrogen will primarily be used in industry and heavy-duty transport, it is not unthinkable that in specific situations hydrogen supply to protected customers might emerge. Without additional policies the security of supply of those customers will not be ensured. In addition, hydrogen might become an important flexibility option for the electricity system, which would imply that hydrogen security of supply impacts security of supply of electricity.

Therefore, we recommend implementing measures to ensure an adequate level of security of supply of hydrogen, taking into account the development phase of the hydrogen system.

4.3 Recommendations to national policy makers

4.3.1 Quickly implement connection conditions, network tariff structures, capacity allocation and balancing mechanisms and hydrogen quality standards

The proposed Decarbonisation Package does not specify the hydrogen wholesale market design. It is only stated that after the transition period, hydrogen markets shall be operated as entry-exit systems. This means that during the transition period, there are no rules that determine how hydrogen undertaking will interact with each other in a hydrogen wholesale market.

A minimum requirement, however, is that there is clarity about:

– The conditions to get a connection to the hydrogen network;

- The allocation mechanism of hydrogen network capacity;
- The applicable hydrogen network tariffs;
- The hydrogen quality standards; and
- The settlement of imbalances.

Without clarity on these market design elements, the market cannot develop. Therefore, we recommend that Member States or their NRAs quickly provide this clarity. When doing so, the fact that after the transition period the hydrogen market shall be operated as an entry-exit system and that hydrogen network codes will ensure EU-harmonisation should be taken into account. Fragmentation of hydrogen wholesale market design during the transition phase resulting in high costs of harmonisation at a later stage should be avoided.

4.3.2 Determine when access to the hydrogen system can be refused because it is uneconomic to do so or a potential customer is unwilling to pay for them

An element that is important to consider is the fact that the first large scale hydrogen networks will be a combination of repurposed natural gas pipelines and existing hydrogen networks. As a result, there might be potential hydrogen consumers located at significant distance from the hydrogen network. However, hydrogen consumers who want to get access in principle have to be granted access (with some exceptions). Connecting a hydrogen consumer in a remote area might be suboptimal from a system perspective if the costs of hydrogen network expansion do not outweigh the benefit to the consumer (i.e. uneconomic to make the necessary enhancements). A solution might be to charge “deep connection costs” to the potential hydrogen consumer, such that only a consumer willing to pay for all connection costs requires being connected to the hydrogen network. However, a disadvantage of charging “deep connection costs” is that is can disincentivise consumers from switching to hydrogen and that the costs of hydrogen network development can fall heavily on first-movers (i.e. one a new area has been connected to the hydrogen network other consumers in that area can typically connect at lower costs). To summarise, determining (i) when it is uneconomic to connect remote areas and (ii) which part of the connection costs should be charged to the consumer is a key choice for national policy makers.

4.3.3 Consider ensuring the same level of consumer protection for household and SME hydrogen consumers as for natural gas

As discussed in paragraph 4.1.1, the proposed Decarbonisation Package assumes hydrogen will be used primarily in industry and heavy-duty transport and not in other sectors such as the built environment. Therefore, the proposed Decarbonisation Package ensures a level of customer protection that is similar to that of larger natural gas consumers. Although the assumption that hydrogen will be used in industry and heavy-duty transport makes sense, the possibility that hydrogen will be used in the built environment (such as in pilot programmes) should be taken into account. Therefore, if the proposed Decarbonisation Package does not ensure this, Member States should consider ensuring the same level of customer protection for household and SME hydrogen consumers as for household and SME natural gas consumers.

4.3.4 Analyse the impact of a 5% hydrogen content in natural gas at interconnection points on the natural gas system

The proposed Decarbonisation Package requires TSOs to accept a hydrogen content of up to 5% by volume in natural gas on interconnection points. Although a hydrogen content of up to 5% is *generally* considered safe, the impact this has on the national natural gas system has to be analysed because the impact may vary depending on specific national circumstances. For example, a key question is how accepting a content of 5% hydrogen in natural gas on interconnection points impacts the gas quality on different exit points. After all, import from interconnection points will be blended with LNG-imports and domestic production. As a result, the hydrogen content in natural gas can vary in different parts of the natural gas system. Moreover, an analysis of the impact of a specific hydrogen content in natural gas on end-user appliances is required.

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