ENTSOG 2050 ROADMAP FOR GAS GRIDS

ABOUT ENTSOG

The European Network of Transmission System Operators for Gas (ENTSOG) represents 44 gas Transmission System Operators (TSOs), 3 Associated Partners and 8 Observers from 36 countries across Europe.

ENTSOG was established on 1 December 2009 and was given legal mandates by the EU's Third Legislative Package for the Internal Energy Market, which aims to further liberalise the gas and electricity markets in the EU.

With new challenges ahead to meet EU Climate and Energy goals, ENTSOG with the expertise of its members and in dialogue with European Commission (EC), Agency for the Cooperation of Energy Regulators (ACER), industry and other stakeholders will collaborate to achieve the decarbonisation of the gas grids.

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INTRODUCTION

In ENTSOG's '2050 Roadmap for Gas Grids' the European gas Transmission System Operators (TSOs) propose how to make gas grids ready for decarbonisation. This Roadmap is a reflection of our TSO members' views to propose possible pathways for the Member States to achieve net-zero GHG emissions by 2050. The aim of the Roadmap is to provide ENTSOG's recommendations and actions in view of the discussion on the European Green Deal.

Decarbonisation of gas supplies with increasingly renewable, decarbonised and low carbon gases is already taking place in Europe. Development of these gases is dependent on political choices and decisions beyond the remit of the gas TSOs.

TSOs are responsible for managing the gas grids in a way that those assets can be enablers of transition. The choices and decisions are influenced by the overall EU climate and energy policies and will differ amongst the EU Member States. Therefore, TSOs will manage diversity of technological choices while ensuring that achievements of the internal energy market for gas are maintained and further developed, in the realities of both a methane and hydrogen-based economy.

To achieve a cost-efficient decarbonisation there will be a need to review the regulatory framework and, where necessary, to amend it to ensure the development also of gas-based decarbonisation technologies.

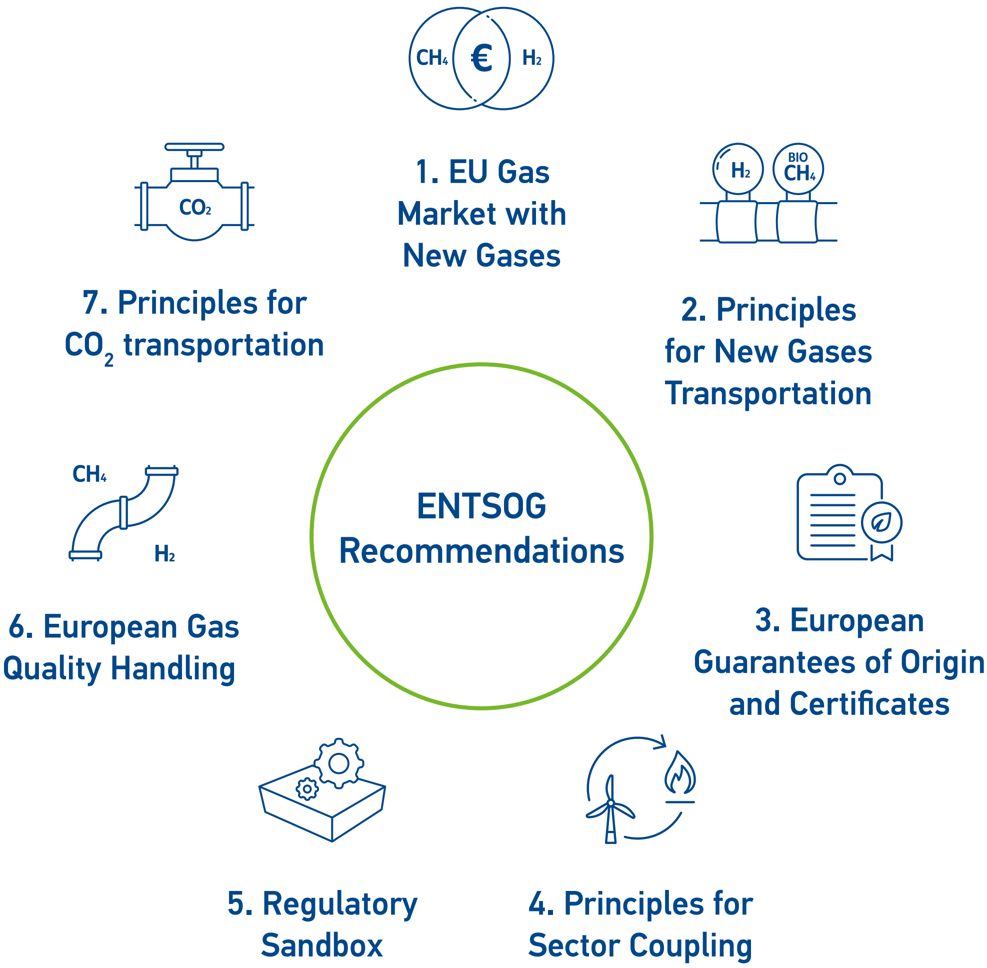


Figure 1: ENTSOG Recommendations, ENTSOG, 2019.

ENTSOG RECOMMENDATIONS AND ACTIONS

The ENTSOG Roadmap 2050 explores the various aspects of how decarbonisation of the gas infrastructure can materialise as ENTSOG's input to the European Green Deal – based on some key principles:

- **Gas and gas grids can decarbonise** – utilising existing gas systems and thereby supporting an efficient energy transition – time and cost-wise.
- **Biomethane, hydrogen and Carbon Capture, Utilisation and Storage (CCUS) will be important elements** in this transition.
- **Natural gas will remain an important part of the energy mix** in many Member States and is still representing substantial potentials for CO_2 and local pollution reductions by substituting other fuels.
- **The Hybrid Energy System** builds on infrastructure synergies and efficiencies between the electricity and gas sectors – including long-haul energy transport, short- and long-term energy storage, security of supply and resilience of having two main energy carriers. It addresses issues on balancing, flexibility and dispatching of the European energy supplies.

Development of renewable, decarbonised and low-carbon gases is dependent on political choices and decisions and beyond the remit of the gas TSOs. The choices and decisions – as well as the speed at which they materialise – are influenced by the overall EU climate and energy policies and will differ amongst the EU Member States.

The gas grids will have to be ready for and able to adapt to the EU decarbonisation process. ENTSOG and the gas TSOs will actively be supporting such development to reach the EU sustainability goals.

To progress the decarbonisation of the gas transmission system, ENTSOG has the following recommendations, which are both policy recommendations for an upcoming European Green Deal, as well as focus areas for the future activities of ENTSOG.

1 EU GAS MARKET WITH NEW GASES

During the last ten years a lot has been achieved regarding well-functioning gas markets, a robust gas infrastructure and a high level of security of supply. On this basis, ENTSOG finds that maintaining and further developing these achievements should be a key goal for the future development of gas and gas infrastructure.

It is obvious that the emergence of new gases – in particular biomethane and hydrogen – will create some challenges for the gas infrastructure in its present form. Nevertheless, irrespective of a chosen pathway, ENTSOG suggests aiming for keeping one European gas market for the commercial as well as for the technical aspects (see figure 2).

This will imply that the various types of gases are being handled in a way where the **technical** aspects are solved by the gas grid companies – by blending, conversion, flow management, etc. The grid companies will have to invest in and operate such facilities, including most likely digitalisation (related to smart metering, gas quality detection, certification and data sharing) and data provision by and between the gas grid companies and consumer appliances. Such services should be considered as services delivered to the market and as such be reasonably remunerated.

Furthermore, the **energy** value of biomethane, hydrogen and natural gas will be based on the energy content of the gas – irrespective of its composition – which will support maintaining and developing the gas-to-gas competition which has been widely achieved in the European gas market. Climate value would be expressed by certificates and supported technically by the grid companies. This aspect will also require a significant level of digitalisation and data provision.

In order to track and transfer the **climate** value of a given source of gas, a trustworthy EU-wide Guarantees of Origin (GOs) and certificate system has to be established. Such a system will ensure that biomethane, hydrogen and other renewable, low-carbon and decarbonised gases can be tracked from production and/or import to consumption – across borders as well as across types of energy, i.e. Power to Gas (P2G). This will be based on a virtual approach to the GOs/certificates and will require digital and automated handling through the gas value chain.

Such a concept for maintaining and developing a single European gas market will require a number of elements to be developed, of which the most important are included in the following recommendations.

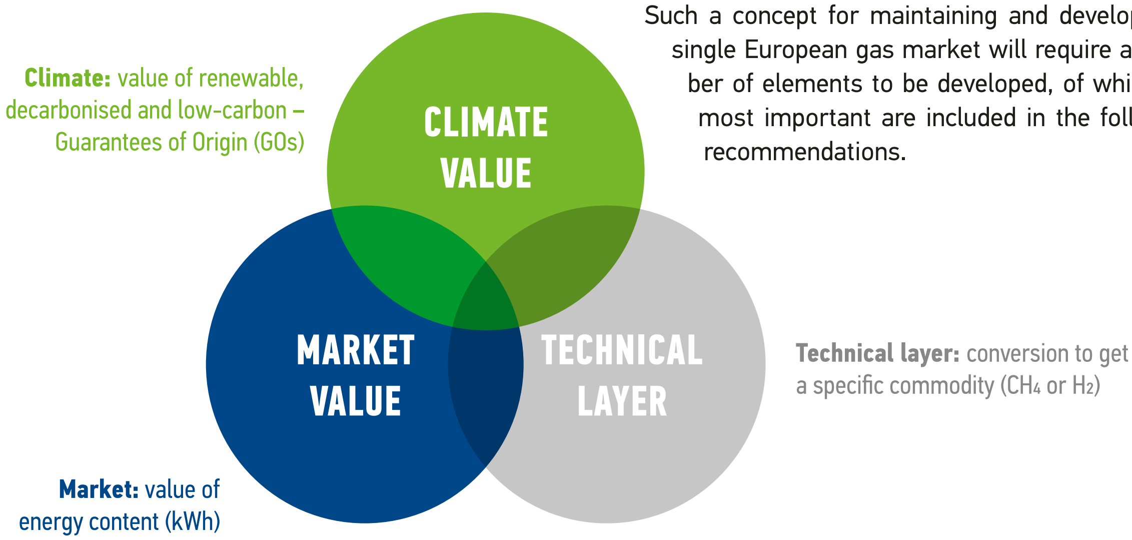


Figure 2: EU Gas Market with New Gases, ENTSOG, 2019.

RECOMMENDATIONS:

Maintain and further develop the internal market achievements and gas market design:

1. Aim for existing gas legislation to include hydrogen and strengthen the role of biomethane
2. **Technical layer:** Include in TSOs' services and establish the principles for reasonable remuneration of services provided by the gas grid companies: blending, conversion, flow management, digitalisation and data provision, providing the flexibility for energy system
3. **Energy value:** Continue to trade biomethane, hydrogen and natural gas based on energy content
4. **Climate value:** Document and track climate value of a given source of gas, a trustworthy EU-wide GOs/certificate system should be established

ENTSOG ACTIONS:
AIM FOR PUBLIC DEBATE IN Q1/Q2 2020

— Launch dialogue with new gases stakeholders and EU Institutions on establishing a common legal framework for all gases

— Facilitate value chain cooperation of relevant stakeholders on all three layers (technical, energy and climate) and develop new market design elements (TSOs' services and integrated market for diverse gas qualities and GOs/certificates)

— Prepare position on missing legal framework for sector coupling and innovation (P2G)

2 PRINCIPLES FOR NEW GASES TRANSPORTATION

Blending of natural gas and biomethane with hydrogen will also enable smaller initial volumes of hydrogen to be utilised by being injected in existing gas flows – contributing to a gradual decarbonisation of the gas mix.

Hydrogen can be produced by different technologies – electrolysis, Steam Methane Reforming (SMR), pyrolysis – and can be transported in dedicated hydrogen pipelines as well as in blended form together with methane.

Biomethane can also be produced from various feedstock without major adjustment to the existing network. CO_2 transportation will depend on the choice of the pathway. Refurbishing parts of existing infrastructure to 100% hydrogen readiness or construction of the new large-scale hydrogen pipelines may require support schemes (like Projects of Common Interest) for projects to ensure transfer across borders and sectors.

For this, TSOs have chosen to work for coordination of planning, reflecting sector needs related to methane and hydrogen demand, preventing market fragmentation as hydrogen and biomethane usage develops. The schematic representation below shows how the new gases could be transported via different pathways.

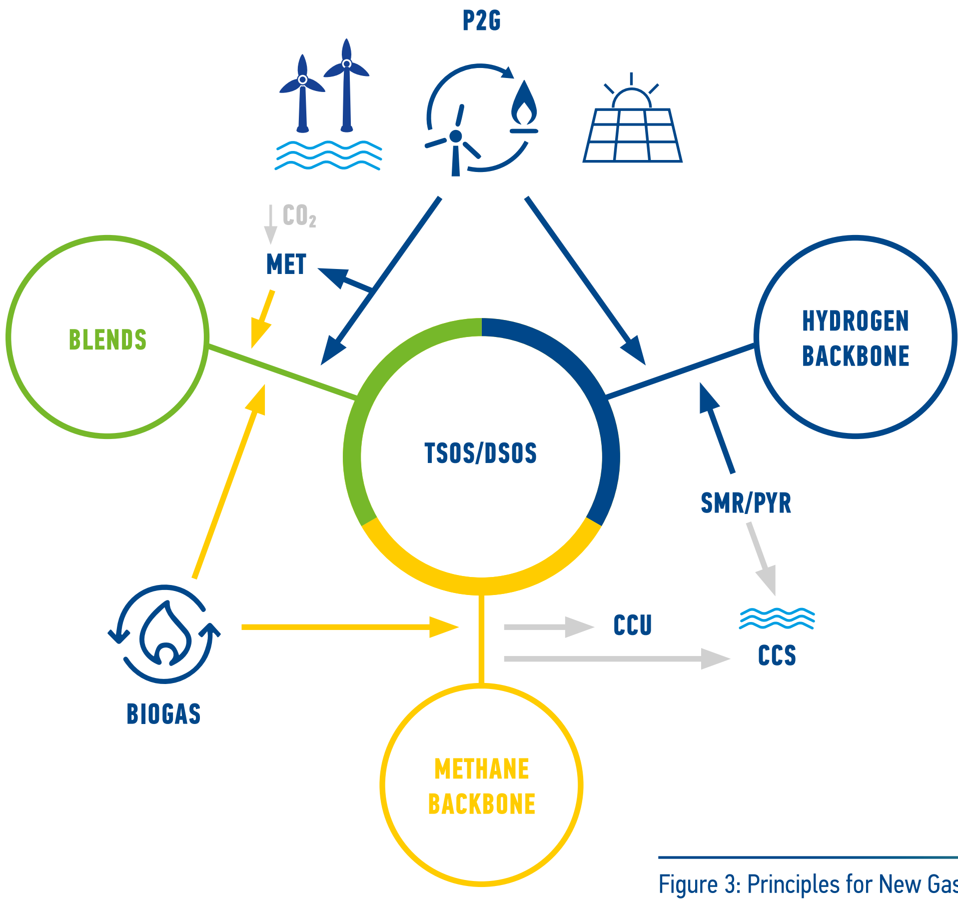


Figure 3: Principles for New Gases Transportation, ENTSOG, 2019.

RECOMMENDATIONS:

1. Establish principles for how to transport hydrogen and biomethane, maintaining one gas market
2. Coordinate planning reflecting sector needs with methane and hydrogen demand
3. Ensure existing level of interoperability and security of supply, in particular for emergency situations
4. Convert some parts of the existing network to hydrogen network while integrating existing hydrogen pipelines and islands, if the hydrogen pathway is chosen
5. Integrate hydrogen and biomethane with the market to deliver a common price signal to gaseous energy, similar to H-gas and L-gas zones that are currently integrated in some EU countries
6. Ensure TSOs' conversion services and their cost recovery
7. Reopen Trans-European Networks – Energy (TEN-E) to address renewable, low-carbon and decarbonised gases

ENTSOG ACTIONS:
AIM FOR PUBLIC DEBATE IN Q1/Q2 2020

— Launch dialogue with stakeholders and EC to establish role of TSOs, including new services

— Set technical dialogue on new gases' readiness – standardisation, appliances producers and institutions

— Establish TSOs ability to invest in facilities enabling decarbonisation and sector coupling – maintaining the legal compliance

— Ensure consistency between interoperability, gas quality, gas markets and TSOs products

— Prepare for TEN-E Regulation re-opening, allocation of funds via Connecting Europe Facility (CEF), TEN-E or TEN-T and Horizon 2020

3 EUROPEAN GUARANTEES OF ORIGIN AND CERTIFICATES

Pan-EU trade of renewable, decarbonised and low carbon gases does not only require a well-interconnected and integrated market to move molecules across borders, but also the development of a certificate system to document and trade the 'climate value' across Member States.

ENTSOG welcomes the **development** of national registers and the cross-border trade of biomethane and hydrogen certificates among the member registries by establishing an **European GOs/certificates system** (see figure 4).

ENTSOG supports EU schemes for cross-border tradability of GOs for renewable, decarbonised and low-carbon gases and their link to the EU emissions trading system (EU ETS) and transport sectors – covering the 'renewable', 'decarbonised' and 'low-carbon' climate values of all types of gases to be exchanged across the Member States. For biomethane, those certificates would be accounted for fulfilment of targets as set out by the revised Renewable Energy Directive 2018/2001/EU (RED II), while CCUS activities would need to be linked to ETS, recognising benefits of feed-in tariffs at European level to encourage and enable biomethane production – and to be applied at a national level. The RED II already recognises benefits brought by renewable gas producers, which are reflected in costs of connecting such new producers to gas networks. Socialisation of connection charges (up to 100 %) as introductory measures to promote renewable, decarbonised and low carbon gases is an important enabler for this.

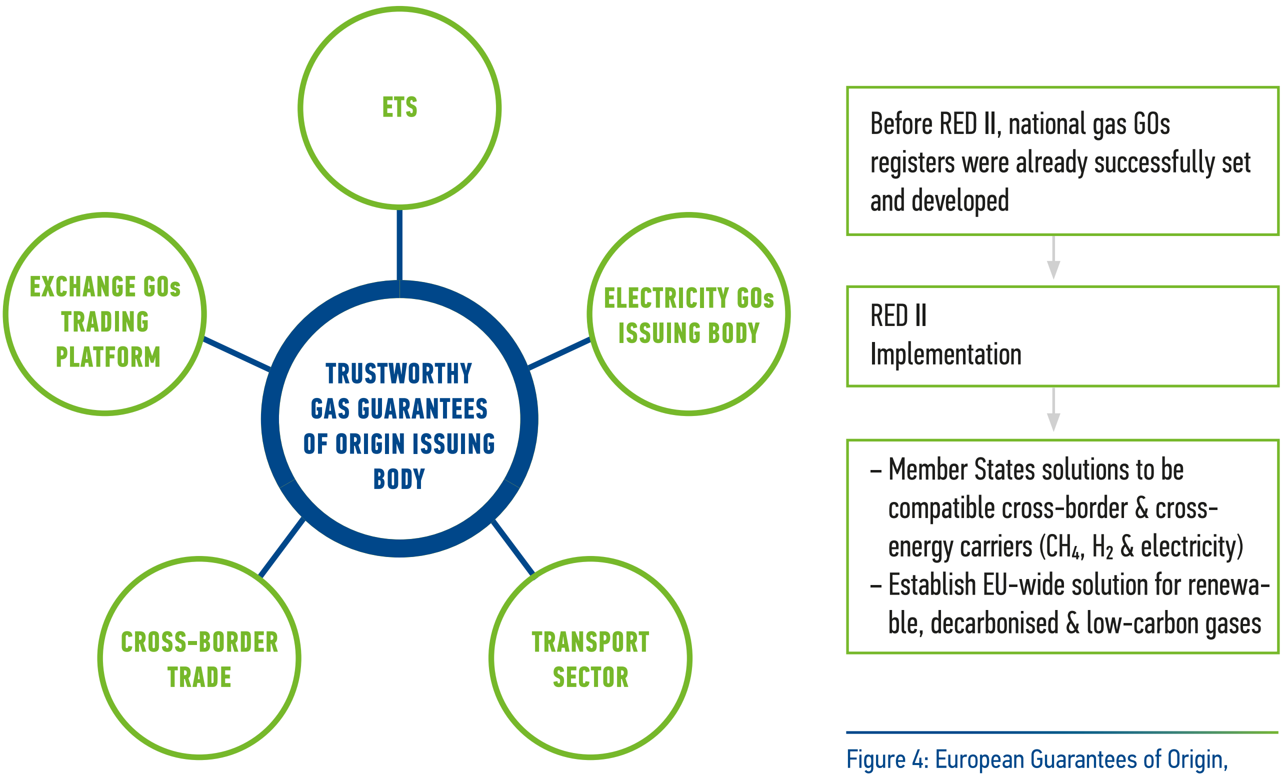


Figure 4: European Guarantees of Origin, ENTSOG, 2019.

RECOMMENDATIONS:

1. Establish a standardised EU-wide GOs/Certificate framework for renewable, decarbonised and low-carbon gases
2. Ensure GOs/Certificates transferability from one energy carrier to another (molecules and electrons) as well as transferability across borders
3. Make GOs/Certificate framework for gas compatible with the ETS and transport sectors (i. e. ETS directive and CO_2 emission performance standards for new heavy-duty vehicles)
4. Enable synthetic methane to be classified as a renewable energy. However, guidance is needed to avoid double counting of CO_2 reduction between the provider and the user of CO_2

ENTSOG ACTIONS:
AIM FOR PUBLIC DEBATE IN Q1/Q2 2020

— Continue ENTSOG's and Gas Infrastructure Europe (GIE) collaboration with stakeholders & EC (bilateral and public)

— Facilitate coordination of electricity, hydrogen and biomethane registries, which could include the establishment of an EU-wide issuing body

— Establish a common position with shippers and consumers on linking GOs/certificates to ETS – engage with European Federation of Energy Traders (EFET) on products standardisation

— Support EC for changes in legal and standards (CEN 16325) framework

— Involve non-EU producers into certification debate

— Clarify role of TSOs/GIE/ENTSOG in an EU-wide certificate system

4 PRINCIPLES FOR SECTOR COUPLING

Cooperation between the energy sectors, in particular electricity and gas, will reduce the costs of the energy transition and gas sector's decarbonisation.

A Hybrid Energy System (see figure 5) building on the regional strengths of existing energy infrastructure, will also require EU-wide principles for **Sector Coupling**. Recent work by the EC, different organisations and ACER clearly shows the need for further discussion on sector coupling approaches. An important point is also to properly value the ability to integrate the renewable energy sources by electricity and gas systems.

The legislative framework for sector coupling should be considered from sector coupling perspectives on aspects which have not been integrated in the legislation so far. In particular, the P2G concept alleviates local/regional infrastructure congestions in electricity infrastructure and can contribute to avoiding curtailment of non-dispatchable renewable electricity and thereby reduce occurrence of negative/very low electricity wholesale prices. **The operation of P2G facilities can be considered as commercial or regulated activity.**

The present market conditions do not seem to sufficiently support an up-scaling of commercial activities needed for optimising gas and electricity infrastructure functioning. ENTSOG finds that TSO ownership of P2G facilities should be considered – as a way of socialising costs as well as ensuring third-party access to such infrastructure. **P2G should be considered as conversion facilities – converting from the electricity system to the gas system.** As a system activity, some similarities to LNG terminals can be seen. Neither electricity consumed, nor hydrogen produced by P2G, should be subject to end-user taxes and levies before the produced energy is being finally consumed. European investment funding, such as the Connecting Europe Facility (CEF) programme, should be available for P2G facilities for facilitating a feasible business case and reducing the level of service fees.

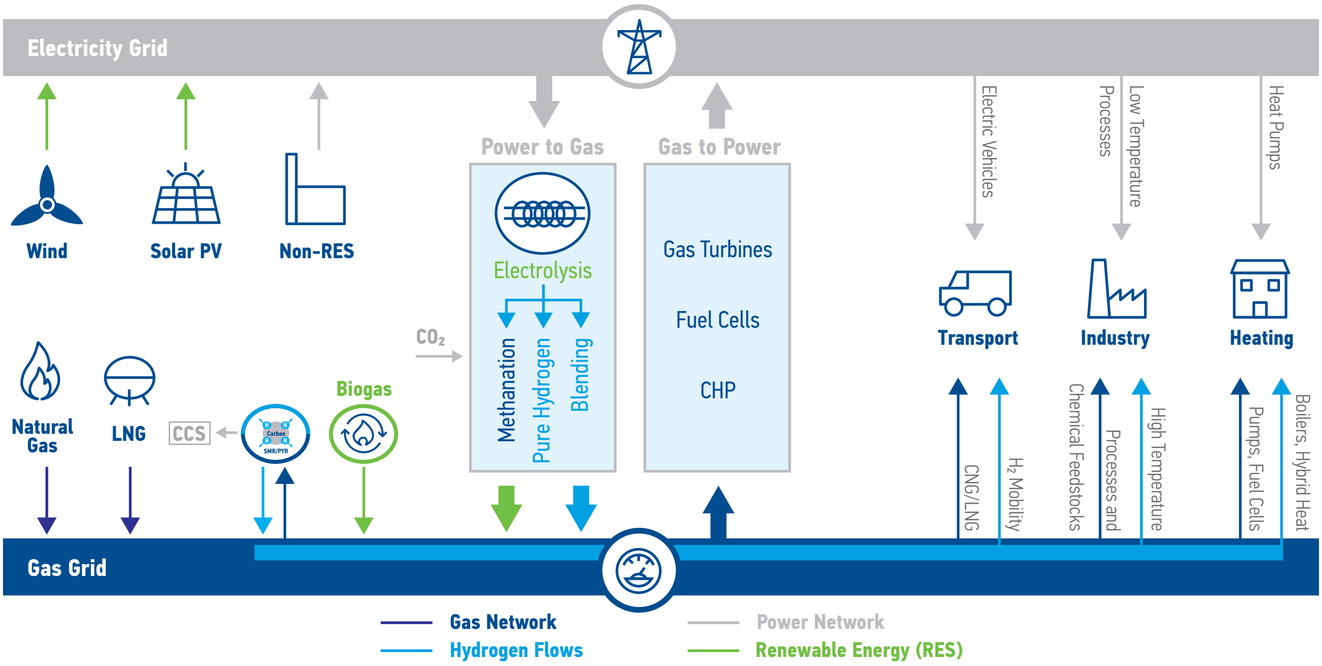


Figure 5: Hybrid Energy System, ENTSOG, 2019.

RECOMMENDATIONS:

1. Establish the regulatory framework for the Hybrid Energy System
2. Align regulatory framework for electricity and gas where relevant
3. Coordinate planning of electricity and gas investment in infrastructure at national and EU level
4. Consider P2G definition as a conversion facility in gas legislation
5. Clarify the roles and responsibilities of the electricity and gas players
6. Clarify attribution of costs and benefits between gas and electricity consumers
7. Address distortion by taxes/levies on P2G in the context of sector coupling

ENTSOG ACTIONS:
AIM FOR PUBLIC DEBATE IN Q1/Q2 2020

— Continue cooperation with ENTSO-E on interlinked model and dialogue with stakeholders on results of Focus Study

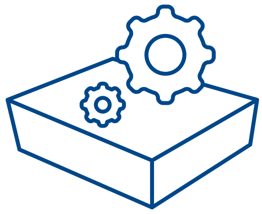
— Analyse benefits of P2G in a Hybrid Energy System

— Follow-up with EC, ACER, Council of European Energy Regulators (CEER) on EC's Sector Coupling Study on responsibilities and cost allocation between electricity and gas

— Develop the concept of co-existing regulated and commercial activities of TSOs: P2G for system needs and for hydrogen transportation

— Develop proposals on CEP mirroring and missing regulatory framework (conversion definition similar to LNG, ownership unbundling application, P2G scalability)

5 REGULATORY SANDBOX



The current market framework does not provide sufficient incentives for development of the necessary technologies. Gas decarbonisation technologies should be assessed for their maturity and necessity for support under the regulatory, financial and market mechanisms.

Regulatory sandboxes should be applied and understood as a concept of a regulatory framework. It will allow R&D activities to be handled under more flexible terms regarding some general rules like state aid, funding access criteria, ownership unbundling, costs socialisation via regulated assets and based on a specific regulatory oversight and cross-sectoral consultation. The access criteria for projects to the regulatory sandbox could be linked to sustainability criteria in (renewed) PCI process under the upcoming TEN-E revision.

Regulatory sandboxes can provide support for early business models and immature technologies to scale up – in case the market is not yet ready (see figure 6).

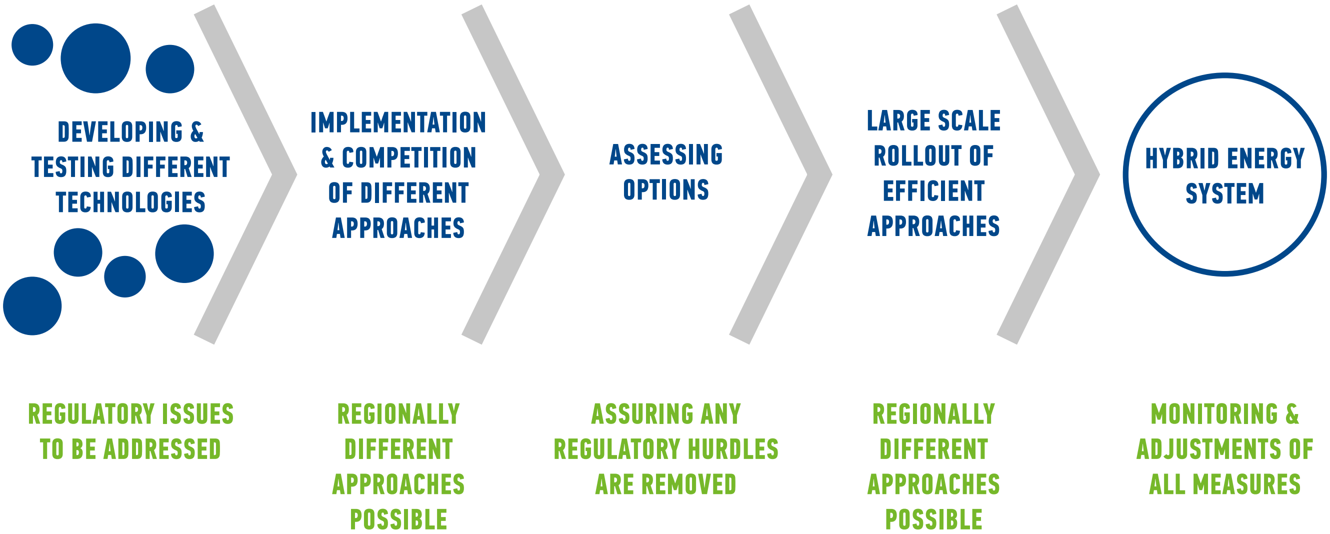


Figure 6: Regulatory Sandbox, ENTSOG, 2019.

RECOMMENDATIONS:

1. Accept the framework concept of regulatory sandbox at EU level and implement also at national level under supervision by the NRAs, so that the TSOs can develop R&D and pilot decarbonisation projects
2. Provide framework for regulatory sandbox to address issues on need for regulatory innovation in controlled and transparent manner to facilitate investment framework allowing for flexibility/freedom from general EU rules (i.e. state aid, funding access criteria, ownership unbundling, cost socialisation via Regulated Asset Base) under regulatory oversight
3. Assess gas decarbonisation technologies for maturity and necessity for support under R&D friendly framework, targeted in time and effect under certain conditions
4. Establish Regulatory Sandbox guidelines to offer some regulatory flexibility for TSOs' pilot projects and clarity for NRAs for cost allocation in technology incubation/roll out phase

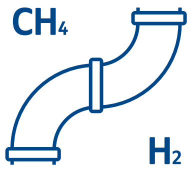
**ENTSOG ACTIONS:
AIM FOR PUBLIC DEBATE IN Q1/Q2 2020**

— Work for implementing a regulatory sandbox concept by establishing dialogue with EC, ACER and CEER on regulatory principles for routing the projects to an EU and national regulatory sandboxes and best ways to address non-mature business models: regulated vs. commercial activities

— Involve stakeholders in setting criteria and transparency requirements

— Discuss relevant financing of projects bearing first higher costs of innovation, comparison of possible financial support schemes: subsidies, RAB, direct EU funding

6 EUROPEAN GAS QUALITY HANDLING



The development of renewable, decarbonised and low-carbon gases will bring a European gas system with diverse gas compositions which need to be handled technically.

The European gas TSOs have experience and knowledge in gas quality management as part of their daily business is handling gasses from different sources. With decarbonisation and increasing shares of hydrogen and biomethane in the system, the management of differing qualities becomes even more important and challenging (see figure 7). The handling of the diverse gas qualities should go hand-in-hand with maintaining and developing the achievements of integrating the European gas markets.

The EU gas quality standard (EN16726) including renewable gases will be an important element for the hydrogen-methane blends pathway, provided that the application will follow the flexible approach as foreseen in the initial CEN concept presented at the Madrid Forum in June 2019. A coordinated EU approach for managing the changes and possibly fluctuating gas compositions across Europe should set the basis for the revision of gas quality standards and for end-user appliances, including CNG vehicles. Development of hydrogen readiness targets could be considered, including analysis of costs and benefits of such a transformation which should be performed. Measuring and sharing of data of the gas composition in both the distribution and transmission grids will be needed.

Precise and quick exchange of gas quality data will be crucial for operating the gas systems, providing information to end-user appliances as well as for ensuring fair and transparent billing processes. In the framework provided by the Interoperability Network Code and Data Exchange Rules, TSOs are actively cooperating on cross-border issues related to gas quality with a special focus on biomethane and hydrogen. With growing complexity of gas quality handling, these services must be taken into account and reasonably remunerated.

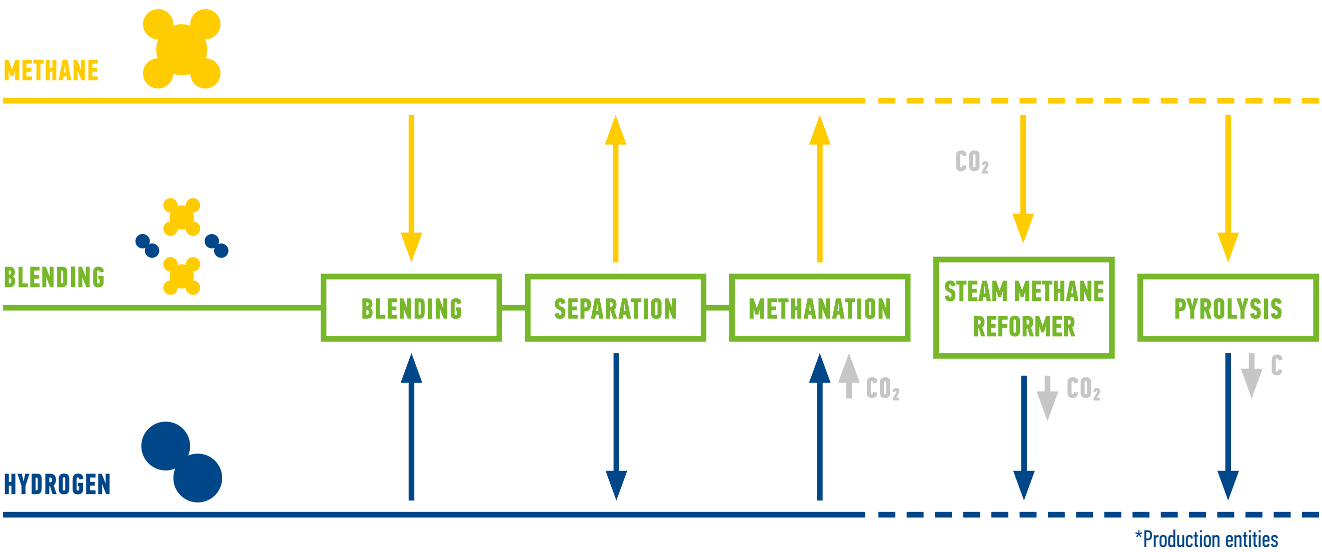


Figure 7: European Gas Quality Handling, ENTSOG, 2019.

RECOMMENDATIONS:

1. Establish EU-wide hydrogen threshold assessment and necessary alignment at inter-connection points to prevent market fragmentation
2. Coordinate cross-border and regional gas quality inventory, in dialogue with consumers
3. Create Roadmap for end users' safety thresholds for hydrogen-methane blends – review of national/EU safety and standardisation
4. Establish principles for cost recovery mechanisms for gas quality handling
5. Establish principles for market and technical interfaces for single quality/off-grid islands

ENTSOG ACTIONS:
AIM FOR PUBLIC DEBATE IN Q1/Q2 2020

— Work internally on recommendations for Interconnection Point relevant model for hydrogen/biomethane handling

— Develop principles for consumer gas quality needs management, together with stakeholders

— Assess tolerance for different levels of hydrogen concentration, transmission and end use per country/region

— Address legal gaps for TSOs conversion services (mirroring, legal text proposals)

7 PRINCIPLES FOR CO_2 TRANSPORTATION

ENTSOG and its members find that an efficient and sustainable approach to decarbonisation will include CCUS and which, besides storage, will require CO_2 transportation systems in regions where needed.

Principles for CO_2 transportation should address how to ensure efficient and safe transport and management (logistics and economics) of CO_2 from emitting locations to storage or usage locations.

INCENTIVES OUTSIDE ENTSOG'S REMIT

CCUS obligations and certificates are policy instruments for delivering efficiency in the roll-out phase for specific regions and market structures. A CCUS obligation would require all suppliers of fossil fuels either to have stored a given percentage of the carbon content of their fuels, or else to have bought in the market sufficient CCUS certificates to cover their content.

Establishment of an energy dialogue with producers for the implementation of climate neutral gases – with involvement of the major natural gas producers, European policy should create a stable political framework to the extent to which imported natural gas must be made CO_2 neutral.

CO_2 price at a level that encourages the use of renewable and low carbon energy and allows existing support schemes for renewables to be reduced or phased out will be a subject of Green Deal debate

Tax incentives – could be used to stimulate the scale-up of CCUS technologies and the required infrastructure for its use.

Feed-in tariffs – in the renewable electricity sector, feed-in tariffs have contributed to the growth and development of various technologies, playing an important role in decarbonising the energy system. Gas can further contribute to the decarbonising process in a similar manner to renewable electricity.

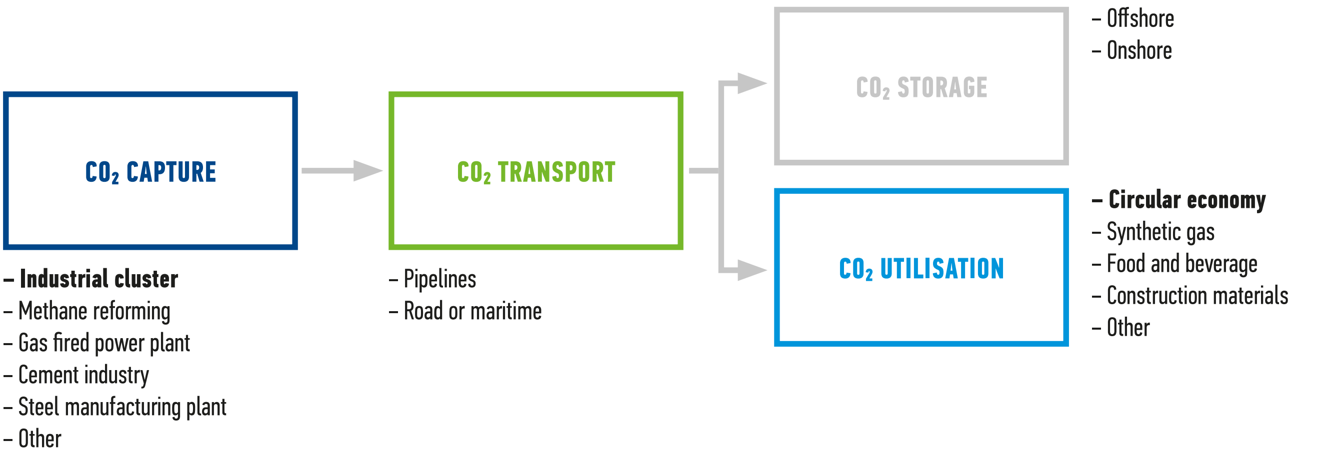


Figure 8: CO_2 transportation, ENTSOG, 2019.

INCENTIVES WITHIN ENTSOG REMIT

Regulatory support for R&D and European funding – ENTSOG believes regulatory support is necessary as it can be directed, with other elements, towards investment in R&D that can be carried out by TSOs amongst others.

Share connection charges – ENTSOG recognises the benefits of mutualisation of connection charges for CO_2 emitters in the same cluster using CCUS infrastructure. The implementation details could be drafted at national level as per country specific requirements.

TSOs able to transport CO_2 – ENTSOG believes that legislation changes should take place, including the 2009/73/EC Directive which explicitly mentions that TSOs can transport CO_2 in addition to (natural) gas.

GOs/certificates – the EU trade of renewable, decarbonised and low carbon gases requires the development of a certificate system to trade the 'renewable value' as well as the 'low carbon value' between Member States.

TSO initiatives – non-regulatory initiatives can also be developed by TSOs to help and encourage CCUS deployment.

RECOMMENDATIONS:

1. Develop EU regulatory approach to CO_2 infrastructure, including third-party access (TPA), role of gas TSOs, transmission charges and liabilities
2. Promote CCU technologies and CCS as a service of common good
3. Provide rules for CO_2 accounting/avoided CO_2 emissions – i.e. pyrolysis, low-carbon gases
4. Include CCUS activities in National Energy & Climate Plans

ENTSOG ACTIONS:
AIM FOR PUBLIC DEBATE IN Q1/Q2 2020

— Participate actively in the International Association of Oil & Gas Producers (IOGP)'s work on CCUS development

— Establish a dialogue with the EC on the above recommendations

— Discuss CO_2 infrastructure needs with industrial associations

1.

RATIONALE

1.1 DRIVERS OF DECARBONISATION BY 2050

To move towards a low-carbon economy and to comply with commitments under the Paris Agreement the EU has set ambitious binding climate and energy targets for 2030. **By 2050 the EU aims for 80–95% of emissions reduction targets,** but also declare its aspiration to meet higher ambition levels, by adopting the 2018 EU Long Term GHG emissions reduction strategy with the view to **achieve net-zero GHG emissions by 2050, as announced in the plan for European Green Deal**.

To achieve these targets, the EU emissions trading system (ETS) has been revised for the period after 2020. Sectors will have to cut emissions by 43% and non-ETS sectors by 30% (compared to 2005). This has been translated into individual binding targets for Member States. This approach is currently legally binding for the Member States and a prerogative of the national governments, evident in the National Climate and Energy Plans (NCEPs), which will be adopted by the end of 2019.

Decarbonisation will come at substantial costs. The **EC Long-term Strategy for GHG Emissions reduction** gives a direction on how all sectors need to contribute. The EU sustainability agenda needs to be implemented by the energy, transport, agriculture and heating sectors without undermining EU industry's competitiveness and benefits to the consumer.

The new EC has committed to develop a European Green Deal. It will include the first European Climate Law to enshrine the 2050 climate neutrality target into law, to propose a comprehensive plan to increase the European Union's target for 2030 towards 55% and a strategy for green financing and a Sustainable Europe Investment Plan. In view of these developments, ENTSOG has developed a Roadmap 2050 for Gas Grids in line with EU Energy Union priorities – competitiveness, security of energy supply and sustainability.

1.2 FUTURE ROLE OF GAS INFRASTRUCTURE

ENTSOG believes that the role of the gas infrastructure goes beyond the role of being a bridging solution in addressing the emissions reduction challenge in Member States. The EU carbon budget calls for significant and rapid emission reductions, that will be facilitated both by:

1. switch from coal/lignite/oil to natural gas,[1]

   and

2. development of renewable, decarbonised and low-carbon gases in the mid-term perspective.[2]

The CO_2 reduction can be addressed in the following ways:

- For countries/sectors which are still strongly dependent on coal and oil, (e.g. CEE electricity/industry, mobility sector, steel, etc.), first by switching to less GHG emitting natural gas.
- For countries/sectors which are already significantly advanced in coal and oil phaseout (North West Europe electricity, urban mobility, etc), by developing biomethane and/or new gases.

1 For coal to gas switch in the power sector 150 $MtCO_2$/y can be saved with no delay. Source: Scenarios Report 2020, ENTSOG, 2020.

2 The GHG reduction is calculated on the BAT 91 gCO2/MJH2 derived from CertifHy and could be replaced by a comparable threshold pending confirmation of the methodological basis for CertifHy. Source: New Gases Network -Terminology Gas industry perspective presentation, 33rd Madrid Forum 2019, https://ec.europa.eu/info/sites/info/files/energy_climate_change_environment/events/presentations/02.a.02_mf_33_presentation_-_new_gases_network_-terminology_gas_industry_perspective_-_deblock.pdf.

Numerous studies have shown the potential for gas grids to contribute to the decarbonisation of the EU economy, by lowering the costs of the transition.[3] The use of renewable, decarbonised and low-carbon gases with existing gas infrastructure, optimally combined with renewable electricity in sectors where it adds most value, can lead to more than 200 billion EUR societal cost savings annually[4] compared to decarbonisation without a role for renewable gas.

THE GAS INFRASTRUCTURE WILL BE PART OF A FUTURE SOLUTION FOR DECARBONISING BOTH ETS AND NON-ETS SECTORS BY:

– **Replacing more polluting fossil fuels:** Switch from coal and oil to gas, including natural gas, quickly reduces CO_2 emissions and other polluting elements such as NO_x, SO_x and particles, with a positive impact on local and regional air quality.

– **Decarbonising heat-intensive industries:** The core industrial production processes are expected to be significantly costlier than today, with new low-CO_2 production technologies to raise cost by 20–30% more for steel and by 20–80% for cement and chemicals.

– **Providing secure and reliable long-term storage:** Gas storages already facilitate greater flexibility of the overall energy system and can make hydrogen or other green gases available for the system and for consumers.

– **Using existing infrastructure to transport renewable, decarbonised and low-carbon gases. Hydrogen** offers potential for synergies between economy sectors and energy carriers as well as storage potential for renewable electricity. **Biomethane** produced from anaerobic digestion or gasification of organic feedstocks (such as biogenic waste) today supports the fulfilment of RES target shares.[5] When combined with carbon sequestration through CCUS it even enables negative emissions. The existing gas network is already fit for growing injection of biomethane.

Natural gas grids in Europe have seen substantial and sustained investment over an extended period with the aim to create a well-developed, resilient gas system, and have supported the achievement of a well-functioning gas market. Years of achievements on security of gas supply and competitive gas markets constitute a good basis to further improve the internal gas market and to work on sustainability by incorporating new gases.

The gas value chain, including the TSOs, have already knowledge, experience and resources (including infrastructure) that will help making the transition cost-efficient and smoother. The EU can and should build on those assets.

3 Navigant study (2019), Ecofys (2018), Pöyry (2019), DENA-Leitstudie (2018). Frontier Economics study (2019) claims that total cost savings in the EU-28 would be equivalent to approximately € 1,300 billion to 2,100 billion between today and 2050. Source: https://www.frontier-economics.com/media/3113/value-of-gas-infrastructure-report.pdf

4 Navigant study (2019) indicates a cost difference of ca. € 217 billion/y between an optimised gas and a minimum gas scenario, Previous Navigant study quoted energy system cost savings of € 138 bn annually. Though, the number was amended in the new version following a more extensive analysis into hydrogen supply and into energy demand in industry and transport. Source: https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

5 Potential of EU28 biomethane production is 1,150 TW. Source: Trinomics study (2019) Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure.

1.3 DEVELOPING A HYBRID ENERGY SYSTEM

ENTSOG believes that the future EU energy system should build on a **Hybrid Energy System** – an interlinkage between the gas and electricity systems based on synergies between these two international energy carriers.

The Hybrid Energy System will allow the EU economy to meet decarbonisation targets, obtain flexibility, storage options, cross-border transportation capacities and security of supply in the most efficient way – realising synergies between the existing infrastructures and building on new technologies and taking advantage of each energy carrier.

A HYBRID ENERGY SYSTEM WILL PROVIDE BENEFITS, IN PARTICULAR:

— **Integration of Renewables:** Maximised integration of renewable energy, both in the form of electrons and molecules.

— **Flexibility:** Growing shares of renewable electricity generation make the electricity system exposed to weather patterns, including a no-sun-no-wind-cold-spell ("Dunkelflaute") situations. This creates the need for back up and short- and long-term flexibility technologies working in the base load and ensuring the hourly to seasonal balance between production and demand. Gas decarbonisation technologies can bring the required flexibility for balancing the variable input from wind and PV power generation units.

— **Sector coupling:** The electricity system and the gas system should be seen as complementary. The electric system allows for the production of large quantities of renewable energy but has challenges with regards providing long-term energy storage, handling peak production and consumption as well as facilitating long-distance transportation.

— **Sectoral integration:** Hydrogen and P2G will bring renewable energy into other sectors where substantial amounts of energy are required and where some processes are otherwise difficult or expensive to electrify.

— **Cybersecurity:** Risks could be higher in an all-electricity system. The two energy systems together will offer more resilience, more time to react and better options to recover when needed.

— **Robust system:** Hybrid Energy System will provide a higher level of security of supply and better integration of renewables in general, due to the capabilities on long term, seasonal gas storage and peak production and demand.

CONCLUSIONS OF CHAPTER 1

Numerous studies have shown the possible gas grid contributions to the decarbonisation of EU economy, by lowering the costs of transition, up to more than 200 bn EUR annually.

Currently, gas supplies cover 24 % of European energy needs, contributing to competitiveness and lowering costs, by providing efficient long-term energy transport of bulk energy over large distances as well as substantial flexibility and long- and short-term storage.

Gas offers the opportunity to decarbonise all sectors at a lower cost than all-electric scenarios with the continued use of existing transmission and end-user assets, either through biomethane and synthetic methane or by deploying CCUS solutions. Based on today's natural gas infrastructure as well as regional resources and national preferences, the 2050 gas networks will transport and store (bio)methane and hydrogen molecules. Electrolysis, P2G, pyrolysis, SMR, CCUS and biomethane production technologies deserve support in order to achieve scalability.

A Hybrid Energy System – an interlinkage between the gas and electricity systems will allow the EU economy to meet decarbonisation targets, obtain flexibility, storage options, cross-border transportation capacities and security of supply in the most efficient way – realising synergies between the existing infrastructures and building on new technologies.

The gas sector is already undertaking R&D as well as moving towards increasing levels of biomethane and hydrogen today. Nevertheless, a clear regulatory framework and support for technologies to mature will be needed.

2.

FUTURE GRID CONFIGURATIONS

2.1 INTRODUCTION

Depending on the evolution of hydrogen, biomethane and natural gas supply potential and user demand – grid functioning will change, depending also on Member States' choice of technologies (e.g., P2G, biomethane, CCUS) best serving their national needs and circumstances. The future EU energy system will have to combine the specificities of each Member State or region intending to make best use of their potential, whilst achieving the decarbonisation targets in a cost-effective manner.

While many other options may be possible, ENTSOG identified the following possible grid configurations towards a close to carbon-neutral gas system:

- **Methane (with CCUS, biomethane, synthetic methane)**
- **Blending hydrogen and methane**
- **Hydrogen**

TSOs expect that these configurations are likely to evolve over time and co-exist, interoperate and complement each other in a given territory, where local conditions dictate. TSOs will be integrators of the different blocks – besides gas transportation, another key role of TSOs and Distribution System Operators (DSO) will be the technical services enabling quality management, energy conversion and interoperability of different gases. **ENTSOG foresees that these technology choices will be made by the Member States and the market depending on:**

- Local renewable gas (biomethane and P2G) production potential
- Local demand requirements and consumer technology interests
- Access and distance to off-shore and on-shore CO_2 storage facilities
- Availability of CCUS technologies and applications
- Feasibility of producing hydrogen from natural gas: SMR, Auto-Thermal Reforming (ATR), pyrolysis, etc, which could be realised either at the beginning of the value chain or closer to the end-use
- Access to renewable and low-carbon gas import routes
- Development status of electricity infrastructure
- Storage potential and technical feasibility for hydrogen, methane and hydrogen-methane blends
- Country-specific subsidy systems
- Status of sector coupling
- Individual member state energy mix, decarbonisation targets and pathways

As these developments will impact the gas quality management, **European TSOs are preparing for managing the diversity of gas compositions. New TSO/DSO services will help to preserve and facilitate cross border trade** for the benefit of all consumers and to ensure that achievements of the internal energy market are not hampered. A detailed description per grid configuration is presented on the next pages.

2.2 GRID CONFIGURATION 1: METHANE

To efficiently abate CO_2 emissions, this network configuration is based on the use of biomethane and synthetic methane, which requires no adaptation of end use applications. To the extent natural gas supply is needed to fulfil gas demand, it will have to be combined with CCUS (mainly at industrial sites).

Under this grid configuration (shown in figure 9), gas production moves towards decentralisation, with biomethane being produced locally via anaerobic digestion or thermal gasification of renewable and sustainable feedstock.

Due to insufficient production of biomethane to meet increased demand in winter, distribution networks may still need to be supplied from the transmission network with natural gas – or biomethane, – which can be injected using DSO-TSO backhaul capacity and stored to manage seasonality. Potential CO_2 emissions from natural gas combustion in diffuse sectors can be compensated along the year when biomethane production exceeds domestic demand, typically in summer. The excess of biomethane can be injected into the transmission network where it can serve industry equipped with CCUS or be stored for consumption in winter. Therefore, while winter periods may result in net emissions, summer periods may be carbon negative. In addition, depending on the feedstock, biomethane consumption may result in even negative emissions[1] if combined with CCUS.

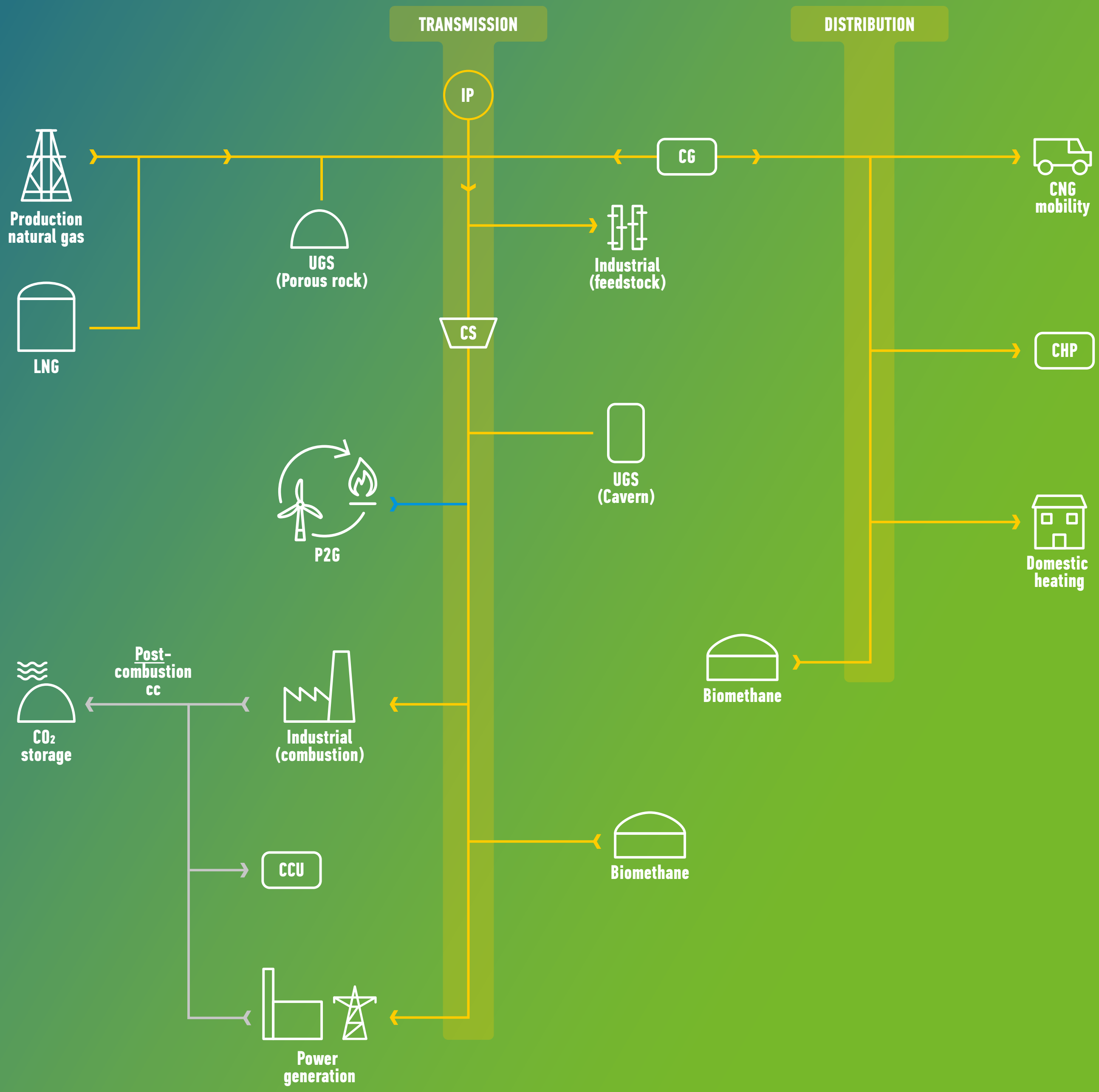
This configuration may apply in those regions where there is a good supply potential for biomethane and/or limited potential for P2G with respect to the size of the energy market. Therefore, renewable hydrogen might be injected in only a few locations and to the extent that can be accepted without significant transformations of the end use applications or otherwise transformed into synthetic methane via a methanation process. In any case, hydrogen contribution is assumed to be less prominent in this configuration.

To the extent that natural gas is not displaced by biomethane, this configuration assumes the establishment of a CO_2 value chain that efficiently manages and ensures emissions reduction. Offshore and, where accepted, onshore CCS is part of the solution and the one offering the substantial mitigation effects in the short run before CCU technologies develop while. In the long-run, this configuration will enable achieving negative emissions by storing biogenic CO_2.

1 Biomethane net emissions can be as low as – 50 gCO_2/kWh, according to “Producing low carbon gas” report from Policy Connect (UK). Anyhow, when combined with CCS biomethane can be considered a negative emission technology as it is storing CO_2 that was previously taken up from the atmosphere during biomass growth (Biomass with carbon capture and storage. Jasmin Kemper IEA Greenhouse Gas R&D Programme, Cheltenham, UK).

FIGURE 9:
SCHEMATIC CONFIGURATION OF THE GAS GRID FOR METHANE (ENTSOG, 2019)

CH_4 | H_2 | CNG = Compressed Natural Gas
CH_4H_2 | CO_2 | CS = Compressor station
CC = Carbon Capture | IP = Interconnection Point
CCU = Carbon Capture Utilisation | LNG = Liquified natural gas
CG = City Gate | P2G = Power to Gas
CHP = Combined Heat and Power | UGS = Underground Gas Storage



2.3 GRID CONFIGURATION 2: BLENDING HYDROGEN AND METHANE

The configuration (shown in figure 10) considers the case of increasing shares of hydrogen over time as a permanent solution or – in some cases – as a way to reach the hydrogen pathway, if technical and economic circumstances provide to do so.

Hydrogen production can increase in following possible ways:

- as renewable hydrogen coming from electrolysis based on renewable generated electricity (P2G),[1]
- as decarbonised/low carbon hydrogen from reforming of natural gas with CCUS technologies: SMR[2], ATR and pyrolysis[3].

In the areas where P2G or SMR large scale facilities are first established there could be regional concentrations of hydrogen depending on consumer flexibility and separation technology. This network configuration is based on transporting blends of hydrogen with methane to an acceptable threshold for appliances and relies on the availability of renewable power to feed P2G units to produce renewable hydrogen. This is supplemented by the local decentralised production of biomethane from a renewable feedstock, synthetic methane based on renewable hydrogen, and natural gas in combination with CCUS. The infographic published by Marcogaz for the Madrid Forum (2019) shows potential for hydrogen usage between 15 and 50 % hydrogen in the industrial sector (except feedstock) while for residential appliances up to 20 %.[4]

Current research shows that most applications, except industry using methane as a raw material, could be adapted to work with hydrogen-methane blends from 15 to 20 % of hydrogen.[5] Beyond those limits gas quality variability may increase significantly, possibly leading to suboptimal use of applications or imposing the need to store hydrogen in dedicated tanks as a buffer at nearby P2G facilities to handle this variability. While certain applications may handle variable concentrations of hydrogen better in the future, thanks to automatic combustion control,[6] with every increase in hydrogen concentration, the infrastructure and end user applications may require adaptation and/or replacement. In addition, the variability could make the billing process more complex, although digitalisation may offer solutions in this regard. End-user sensitivity may require grid operators to control gas quality either by injecting greater amounts of (bio)methane or by methanising or storing hydrogen to avoid curtailing production. Alternatively, where certain customers – typically within the industrial segments - remain especially sensitive to hydrogen-rich biomethane, the grid may need to utilise, for example, a membrane filter technology close to the point of supply to remove excess hydrogen and redirect it to supply hydrogen applications.

For all the above-mentioned reasons, it might not be feasible to gradually increase the hydrogen fraction in gas networks from 0 to 100 %. Instead, once a certain "tipping point" is reached that makes a full transition to hydrogen more economical, it might be recommendable to do so, rather than increasing hydrogen concentration in a methane/hydrogen blend in several incremental steps, each of them requiring adjustment and replacement of equipment at grid or end user level. For those cases, blending would be only a transitional solution before a switch to a hydrogen only configuration. However, blending hydrogen up to a reasonable threshold for appliances can be

1 Electrolysis (P2G) is a technology that converts electrical power to another energy carrier, namely gas/hydrogen, a P2G facility could be treated as a conversion facility for energy from the electricity to the gas system. Hydrogen's relationship to renewables can be very strong and hydrogen with a low-carbon footprint has the potential to facilitate significant reductions in energy-related CO_2 emissions. See: 2015 IEA Technology Roadmap for Hydrogen and Fuel Cells

2 Steam Methane Reforming: fossil fuels or bio energy can be processed with steam and /or oxygen to produce a gaseous mixture (reforming or gasification) separated from CO_2. This leads to low carbon hydrogen produced by natural gas with CO_2 capture.

3 Methane pyrolysis is a process that separates natural gas into hydrogen and solid carbon. Methane pyrolysis is another CO_2 abatement technology and it's a form of direct decarbonisation of natural gas, a process that obtains solid carbon ("carbon black") and hydrogen (CH4 → C + 2H2). The separated carbon can then be stored or used in production of other materials (e.g. graphite), while the hydrogen can be used as energy. See: IOGP, The potential for CCS and CCU in Europe. Report to the 32 meeting of European Gas Regulatory Forum, June 2019, p15.

4 See Marcogaz infographic at the 33rd Madrid Forum.

5 Ibid.

6 An electronic control system that regulates the combustion process and constantly optimises it.

considered as a long-term, cost-efficient solution for cases where the potential for biomethane/abated methane is high.

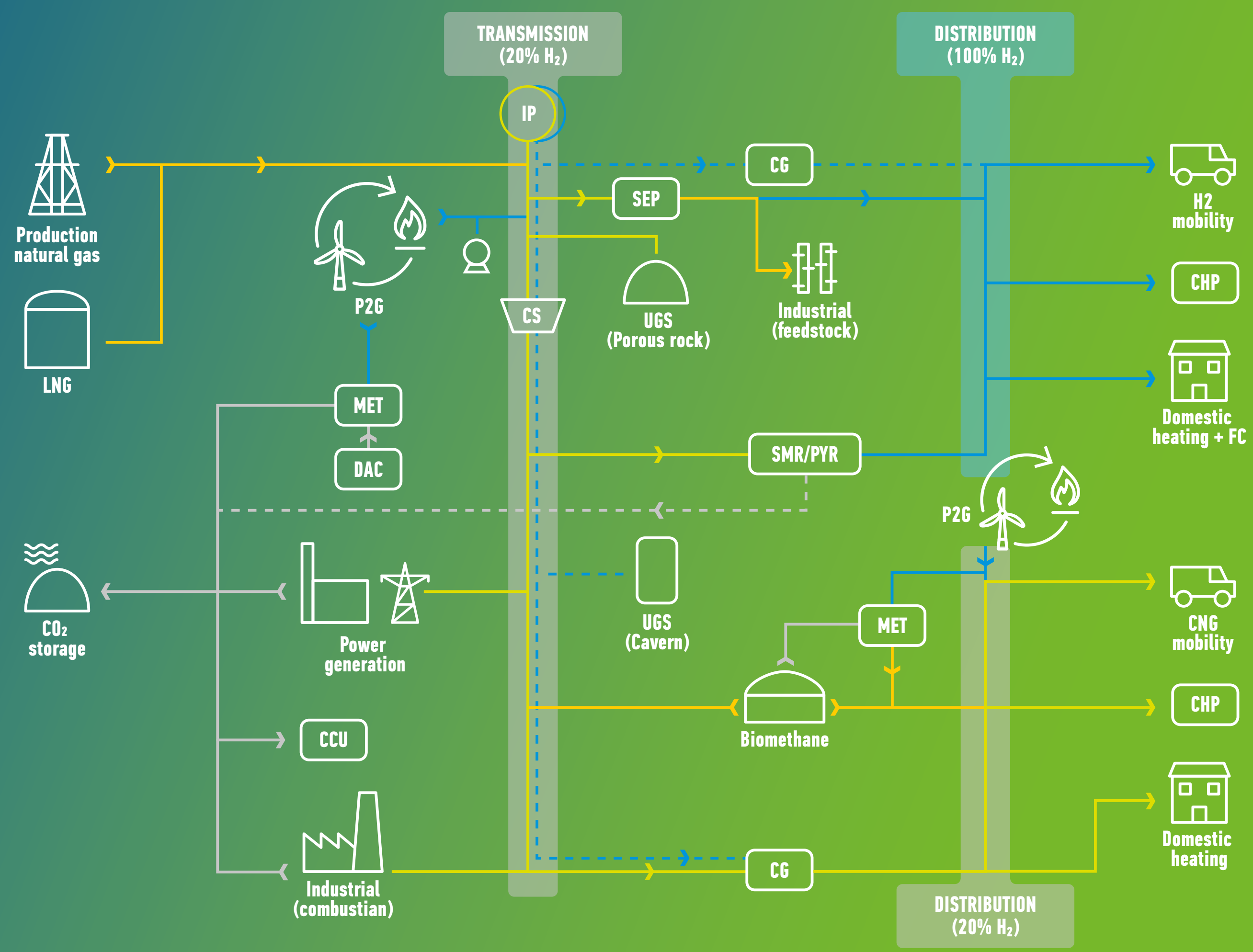
Especially in the transition phase, there might not be enough biomethane and hydrogen to satisfy the demand which will need to be met by conventional production. Therefore, some form of CCUS will be required to achieve carbon neutrality already in the short run and to aim for negative emissions in the long run. Where access to CO_2 transport and storage is limited, CO_2 could be combined with renewable hydrogen to produce synthetic methane, especially when the foreseen injection rate would exceed the maximum hydrogen threshold of the local network. Alternatively, CO_2 could be used outside the gas network in different CCUS applications (e.g. construction material).

To realise the potential of hydrogen integration in distribution networks, it might be possible to allocate some pipelines to pure hydrogen transport, which could be distributed to the hydrogen using sectors or blended with biomethane/methane at city gate where there is no such demand for pure hydrogen.

In addition, low-carbon hydrogen could be produced at city gate level (e.g. by pyrolysis). Further development of P2G, methane pyrolysis, direct air capture, and methanation technologies will bring this configuration closer to carbon neutrality and offer a significant potential for negative emissions. GOs and an EU-wide certification system covering biomethane and hydrogen in place on the markets side is one of the key assumptions in this configuration (see chapter 3).

FIGURE 10:
SCHEMATIC CONFIGURATION OF THE GAS GRID FOR BLENDING HYDROGEN AND METHANE (ENTSOG, 2019)

CH_4 | H_2 | CHP = Combined Heat and Power | LNG = Liquified natural gas
CH_4H_2 | CO_2 | CNG = Compressed Natural Gas | MET = Methanation
CS = Compressor station | P2G = Power to Gas
CC = Carbon Capture | DAC = Direct Air Capture | PYR = Pyrolysis
CCU = Carbon Capture Utilisation | FC: Fuel Cell | SMR = Steam Methane Reforming
CG = City Gate | IP = Interconnection Point | UGS = Underground Gas Storage



2.4 GRID CONFIGURATION 3: HYDROGEN

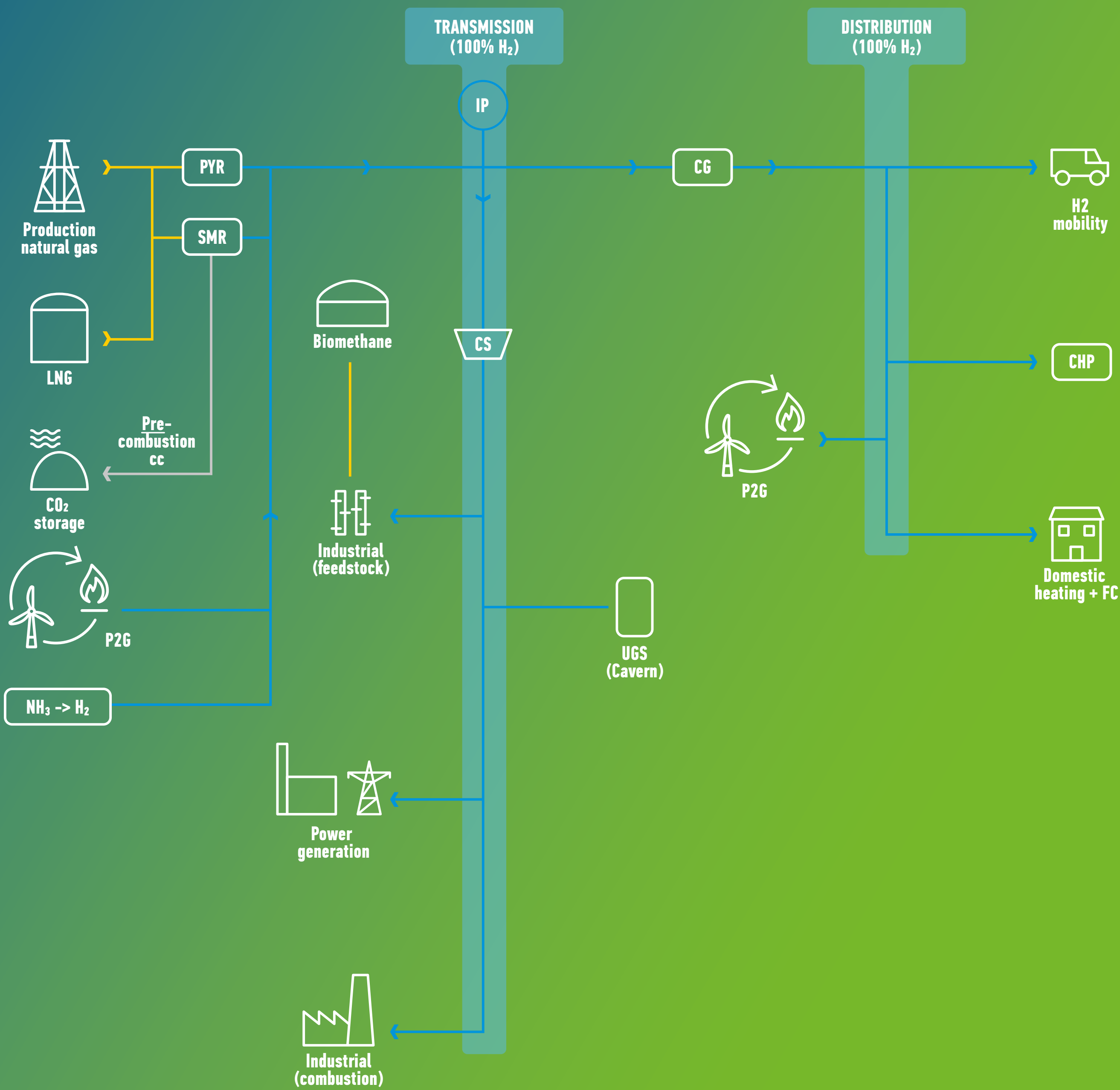
This network configuration (shown in figure 11) is based on repurposing the transmission networks to transport 100% hydrogen. This network configuration assumes all end-user technologies, except for some very specific cases in the chemical industry, are available for 100 % hydrogen.

In this configuration hydrogen will be produced through a diverse range of sources and routes, including: from methane (natural gas, LNG, biomethane) using pyrolysis and/or SMR/ATR with CCS; from renewable electricity using electrolysis (P2G); or imported hydrogen (either renewable or from natural gas with CCUS). Where SMR/ATR is utilised, the released carbon dioxide will be captured and transported via dedicated CO_2 pipeline infrastructure and stored off-shore. While this network configuration is well suited to centralised hydrogen production, it will be important to allow grid injection for decentralised energy producers (e.g. from localised P2G plants attached to wind parks).

Where this configuration has been adopted, the transmission network has been entirely repurposed for the transport of hydrogen - infrastructure elements such as compressor stations and gas storage facilities have also been converted for hydrogen use. Salt cavern storage is accepted as a means of storing hydrogen, however, further work is required to consider the suitability of storing hydrogen in porous rock storage sites. Industrial and domestic end use applications are adapted or replaced by hydrogen ready ones. Those end users connected to the transmission system whose applications cannot be converted to hydrogen (e.g. certain chemical industry consumers) will need to be supplied with biomethane or synthetic methane.

FIGURE 11:
SCHEMATIC CONFIGURATION OF THE GAS GRID FOR HYDROGEN (ENTSOG, 2019)

CH_4	H_2	CHP = Combined Heat and Power	LNG = Liquified natural gas
CH_4H_2	CO_2	CNG = Compressed Natural Gas	P2G = Power to Gas
CC = Carbon Capture		CS = Compressor station	PYR = Pyrolysis
CCU = Carbon Capture Utilisation		FC = Fuel Cell	SMR = Steam Methane Reforming
CG = City Gate		IP = Interconnection Point	UGS = Underground Gas Storage



2.5 POTENTIAL HYDROGEN INJECTION STRATEGIES

Three possible hydrogen injection strategies could be envisaged. However, a combination of all three may seem as the most viable option.

1. HYDROGEN IMPORTED FROM THIRD COUNTRY

Countries producing natural gas connected to the EU such as Norway, Russia or Algeria have the possibility to convert natural gas into hydrogen, would own the methane reforming facilities and would be responsible for the CCUS process (and related certification). Member States producing natural gas would require converting natural gas into hydrogen to be able to connect to the hydrogen network. CO_2 network and storage facilities (outside the EU or off-shore) would be required for this CCUS process.

2. HYDROGEN PRODUCED AT OR CLOSE TO EU BORDERS

EU would continue to import natural gas from external producers. This natural gas, after entering European borders, would be converted to hydrogen. There is a need for SMR/ATR facilities or other technologies, possibly owned and operated by TSOs (or others) in a regulated or commercial way, taking the unbundling rules into account, and with enough capacity to convert large amounts of hydrogen. In addition, CCUS is needed to capture CO_2 and transport it to storage facilities inside or outside EU borders (e.g. offshore gas depleted fields or aquifers). Lastly, there is a need for a hydrogen or hydrogen ready (blend) network for transport and distribution. Most likely CO_2 storage liability will remain within EU Member State under this strategy. Links between all infrastructures need to be properly addressed.

3. HYDROGEN PRODUCED AT INTERFACE BETWEEN MAIN TRANSMISSION AND REGIONAL NETWORK OR AT CITY GATE

The conversion facility location requires a transmission network for natural gas and a distribution network for hydrogen before and after conversion respectively. Natural gas conversion units' capacity, smaller than in scenario 2, needs to be adjusted to the point of delivery's demand. CO_2 networks need to be developed to transport the carbon captured to storage that may be far from the natural gas reforming unit.

4. A MIX OF THE THREE STRATEGIES ALSO POSSIBLE

A one-size-fits-all solution might not be ideal for a pan-European energy market so diverse, with so many different requirements, political drivers, stages of maturity and geographical distribution of resources (e.g. potential Hydrogen and CO_2 storage sites). That is the reason why the TSOs will most certainly assist developments that will include parts of the three scenarios described above, to combine all available solutions while maintaining the benefit of the integration of the European energy market that was already achieved.

The role of hydrogen storage will be important to ensure the full dispatchability of hydrogen. Especially, the importance of geographically favourable geologic formations will matter to match the location of big hydrogen industrial consumption.

2.6 FUTURE ROLE OF THE TSOs AND INTEROPERABILITY ACROSS CONFIGURATIONS

These configurations are likely to evolve over time and may co-exist, interoperate and complement each other in a given territory where local conditions so advise. Additionally, many other configurations might be possible depending on the development of new technologies.

The three configurations described above are based on simplified models and serve analytical purposes only. These can give the impression of strongly diverging pathways endangering the European integration.

In fact, configurations will certainly be combined within each Member State over due course while the gas system will have to ensure market integration. As underlined above, the pathways will build on the technological achievements of one another. The optimal network configuration will be determined by national or local conditions. In any case, technologies need to scale up.

Member States should cooperate and coordinate their plans to ensure a safe and reliable cross-border flow of gas and gas-hydrogen mixtures. As different regions may follow their pathways into different directions it will be key to preserve interoperability between the different energy carriers and markets. Physically there are possibilities to couple the three network configurations and leverage the current level of interconnection to maintain security of supply, and competitiveness. Interoperability can be preserved in the following ways:

— From hydrogen only networks to methane networks, flows can be realised either through a methanation process or ability of the system to withstand hydrogen blends.

— From methane network to hydrogen network, flows can be realised through conversion to hydrogen via SMR combined with CCUS, and pyrolysis separation membranes may be a suitable option to separate hydrogen from hydrogen and methane blend.

Despite the potential complexity of the configurations, the gas system can be adapted in different ways depending, among other factors, on the natural resources in each member state or region. The flexibility that the three configurations offer will be key for successfully advancing decarbonisation.

TSOs can play a role in integrating and facilitating the gradual adoption of these technologies in a consistent and coordinated manner (shown in Figure 9). **TSOs will manage diversity of technological choices while ensuring that achievements of the internal energy market are not diminished in the progression towards 2050. TSOs can**

actively contribute to an overall energy market by providing conversion services between energy carriers (electricity, methane, hydrogen). TSOs can also manage the transmission of CO_2 between emission points and carbon storage/utilisation facilities or at least the on-shore segment. Roll out of the conversion services will maximise integration of renewable technologies and preserve the integrity of the markets. Regional and Member State coordination will be required to optimise investment in conversion facilities by identifying where those are needed to preserve security of supply and interconnection, as grids adopt different configurations.

SPECIFIC CONSIDERATIONS FOR HYDROGEN-METHANE BLENDS:

a. To further enable the use of hydrogen-methane blends, standards for newly sold gas end-use applications should be revised. An EU roadmap setting minimum hydrogen readiness targets for commercial/residential applications – including CNG – by 2030, 2040 and 2050 would be beneficial in this respect.[1] This would not interfere with Member State discretion to opt for methane or hydrogen only networks rather than blends. The adoption of such EU hydrogen readiness targets for gas networks should only be decided on the national or regional level. For industrial and power generation customers, specific case by case assessments will be required, with NRA involvement.

b. As discussed above, hydrogen-methane grids may switch to a hydrogen only configuration after reaching a certain tipping point (current research estimates this for around 20 %)[2].

c. In the shorter-term, a minimum EU-wide hydrogen tolerance is needed to preserve security of supply in case of crisis situations management.

IN THE TRANSITION TOWARDS CARBON-NEUTRAL GAS SYSTEMS, IT IS IMPORTANT TO CONSIDER HOW TO DEAL WITH ISOLATED PARTS OF THE SYSTEM DEVIATING FROM THE MAINSTREAM CONFIGURATION. THE SO-CALLED 'ISLANDS' MAY APPEAR AS A RESULT OF:

a. Off-grid projects (off-grid P2G, raw-biogas direct links) being developed outside the gas system. In the mid-term, they should be connected to the gas market depending on their size and number of customers.

b. Sections of the network being converted to another carrier and disconnected from the network but remaining in the gas market (e. g. H21, North of England). In these situations, it should be investigated whether a physical connection to the existing infrastructure via a conversion facility is required to preserve security of supply.

Digitalisation and data sharing are required as enablers for enhanced network management (e. g. network modelling and planning, billing, gas quality services) and end-use adaptation to varying gas qualities. However, there might be situations where software-based solutions are not sufficient and investment in gas treatment or end-user equipment is needed. In such a case, it is necessary to decide if costs should be shared among all users or borne by the concerned customer. ENTSOG sees the need for preserving market integrity and discusses the relevance of these costs for transition.

1 Referring to the readiness targets for end-use appliances.

2 See Marcogaz infographic at the 33rd Madrid Forum.

CONCLUSIONS OF CHAPTER 2

The future EU energy system will have to combine the specificities and potential of each Member State or region whilst achieving the decarbonisation targets in a cost-effective manner.

While many other options may be possible, ENTSOG identified the following possible grid configurations that are likely to evolve over time and co-exist, interoperate and complement each other in a given territory depending on local conditions:

- **Methane**
- **Blending hydrogen and methane**
- **Hydrogen**

There are 3 possible hydrogen injection strategies:

1. Hydrogen is converted and imported from third country;
2. Hydrogen is converted at or close to EU borders;
3. Hydrogen is converted at the interface between the main transmission network and the regional network or at city gate. However, a combination of all three is the realistic option.

The interoperability for security of supply and market integrity are key principles. The role of European TSOs will be to manage diversity of technological choices while ensuring that achievements of the internal energy market are not diminished. Besides gas transmission, another key role of TSOs and DSOs will be the provision of technical services enabling quality management, conversion and interoperability of different gases, with the view to preserving and facilitating cross border trade in a single market for the benefit of all consumers.

3.

MARKET DESIGN CONSEQUENCES

3.1 INTRODUCTION

For network operators, market integrity is a core value for network operators to preserve. ENTSOG continues to work for streamlining the principles of this Roadmap, such as maximised integration of renewables, work for maintaining market integration and ensuring security of supply and interoperability.

The three gas decarbonisation pathways[1] or combination thereof will develop depending on the decisions made by the EU, the Member States and markets. It is clear that the EU's decarbonisation agenda will have a significant influence on the energy markets, regardless on the pathway taken. Any premature lock-in will have negative effects and may result in much higher costs than necessary to achieve decarbonisation goals.

ENTSOG supports the EU's decarbonisation agenda. The gas grids will have to be ready for, and able to adapt to the EU decarbonisation process – and ENTSOG and the gas TSOs will actively be supporting such development to reach the EU climate goals. Timely discussion on possible gas grid decarbonisation pathways and value created based on gas assets is necessary to identify the most suitable solutions for our customers. This discussion would need to cover carbon accountability of different technologies now based only on energy value. Therefore, the establishment of GOs and certificates is a must to ensure the functioning of the energy market. The growing importance of flexibility aspects, backup, storage and bulk energy transmission capacities (sector coupling) also needs to be reflected.

Without entering into policy debate on ETS and Climate Law[2] ENTSOG assumes that the markets will follow price signals from enhanced CO_2 pricing or taxation. This leads to progress in development of CO_2 abatement technologies and to proliferation of renewable generated electricity that influences the hydrogen production in dedicated regions.

For ENTSOG and TSOs, our customers and their needs are the central issues when talking about markets and market design. The EU energy market is huge with more than 510 million private energy consumers plus around 27 million commercial and industrial consumers.[3] On the top of encompassing necessary energy value, the gas market design will need to address consumers' daily life as well as the profitability and competitiveness of businesses.

Current EU decarbonisation targets, or even more ambitious agreed ones will have massive consequences on the existing gas market and its functioning. Decarbonisation of the gas sector will require substantial adjustment of the gas market design to ensure the deployment of all promising technologies in the EU in a coordinated manner, taking Member States specifications into account.

Without adjustments to **gas market design**, a fragmentation of markets could possibly occur, with detrimental and unintended consequences for competition and security of supply. Therefore, a **cooperative value chain**[4] supporting investments in natural gas grid adaptations for biomethane and hydrogen-based technologies needs to be established. Only cooperation of the full value chain may scale up the industrial usage of new gases.

1 As proposed in chapter 2: 1. increasingly renewable and low carbon methane, 2. blends of methane and hydrogen and 3. pure hydrogen pathway.

2 ENTSOG chooses to keep policy debate on ETS outside the scope of the Roadmap. Adequate carbon pricing will be subject of the Green Deal Debate.

3 Eurostat 2016, https://ec.europa.eu/eurostat/statistics-explained/index.php/Business_demography_statistics.

4 Jonathan Stern, OIES, Narratives for Natural Gas in Decarbonising European Energy Markets, Oxford 2019; https://www.oxfordenergy.org/publications/narratives-natural-gas-decarbonising-european-energy-markets/?v=3a52f3c22ed6.

However, on the gas side, the commercial market players are only investing in decarbonisation facilities to a limited extent. To make sure that investment in decarbonisation happens, the framework for both regulated and commercial players should be updated: if not made by commercial market players, the investments can be made by infrastructure operators with a revision of "old roles and responsibilities".[5]

The regulatory challenge is to ensure that the whole set of technologies can contribute to decarbonisation. Projects (within a regulatory sandbox framework) could apply for exemptions and be developed under certain conditions and their results should contribute to gas decarbonisation. A trial period, for example five years, could be allowed and the evaluation for a possible extension for the next cycle should be assessed depending on the achieved technical and commercial results. The specific regulatory oversight should encourage as a first step the R&D and pilot projects by the TSOs (amongst others) to test and roll out new technologies. For this controlled development of pilot projects, NRAs would be asked to take such costs into account as necessary infrastructure investment and justifiable cost of decarbonisation. R&D plan should be consulted with appropriate stakeholders to ensure its efficiency.

Therefore, the concept of regulatory sandboxes should be applied for supporting scalability. Facilities enabling decarbonisation may be limited in their number and/or capacity due to external constraints[6] and/or not yet profitable. In such cases support is needed and regulation may be a suitable mechanism to incentivise investment in decarbonisation facilities spurring green gases production as well as to ensure fair TPA access.

THE ENERGY MARKET DESIGN SHOULD:

— be the enabler of a path towards decarbonising gas

— support all possible decarbonisation pathways, especially the different implementation speeds required by individual Member States as wells as other regional factors and technological progress.

— be flexible enough so it can be adapted to alternative or adjusted pathways if needed, as it can be expected that there might be different priorities in different Member States.

WILL THE MARKETS ENSURE THE NECESSARY SPEED OF INVESTMENT IN DEVELOPMENT OF GAS DECARBONISATION TECHNOLOGIES:

— **What is the future gas market? What is the commodity traded?**

— **What market features are missing in current market design to support all the decarbonisation technologies?**

— **What will be the role of the TSOs?**

5 ACER, Public consultations on The Bridge beyond 2025, July 2019: As highlighted by ACER: "It seems clear that a sustainable future needs decarbonised gases and new technologies (such as P2G), but the current regulatory framework was not designed with these activities in mind and the lack of regulation for these areas may have unintended consequences, acting as a barrier or hindrance to their development. In this sustainable future, the old roles and responsibilities may no longer be fully appropriate."

6 For example, limited suitable locations to reasonably connect the power and gas systems with P2G facilities or inadequate numbers of biomethane plants in comparison to the potential supply.

3.2 METHANE PATHWAY: INCLUDING BIOMETHANE AND POST-COMBUSTION CCUS

3.2.1 WHAT IS THE MARKET? WHAT IS THE COMMODITY TRADED?

Under this methane pathway, we start with analysis of a market based on:

- **increasing shares of biomethane in the energy mix and in the gas systems**
- **methane as a commodity** assuming the development of a **CO_2 chain**.

Methane, especially after coal-to-gas switch, will continue to play an important role in this pathway. Methane levels will need to be paired with CO_2 abatement via CCUS. Gradually the shares of biomethane will grow, up to high pressure transmission levels. In this pathway we assume only early local production of hydrogen: based on natural gas from SMR or pyrolysis – and then distributed locally (production site or city gate). Therefore, the commodity remains relatively homogeneous, methane and biomethane (CH_4) molecules with its traditional energy content are still traded, based on natural gas market's design. Two new features arise:

A) SCALING UP OF THE BIOMETHANE PRODUCTION

Given the significant growth potential[1] for biomethane in Europe and the inherent decarbonisation effect,[2] it is important to:

- encourage biomethane injection into the gas network,
- provide access to a large customer base,
- promote the removals of barriers to its production,
- increase the value of this resource,
- establish and EU wide framework for trading GOs/certificates.

To facilitate biomethane market development it is necessary to enable locally produced biogas to access the distribution and transmission grid via bidirectional reverse flows between TSOs and DSOs systems, specifically for seasonal biomethane oversupply management, as well as the upgrading/odorisation/ treatment facilities to produce biomethane ready for injection into the gas grids in a cross border context. Mechanisms for attributing costs of those services respectively to TSOs and DSOs levels as well as financial support schemes are to be designed in a way to efficiently support biomethane roll-out.

Biomethane production and injection into the gas network is still in its early stage but has grown significantly in recent years. While in 2011 fewer than 200 plants produced less than 0.8 TWh of biomethane, there are now around 500 plants in the EU, having produced more than 17 TWh of biomethane in 2016. Accordingly, biomethane production in biogas plants with upgrading facilities has boosted production more than 20-fold in only five years. Still, growing the share of biomethane production to contribute to fulfilment of the EU-wide RES targets, as per RED II directive, requires support. Biomethane injected into the gas network and mixed with natural gas provides savings in greenhouse gas emissions without any adaptation cost for end-users. The use of biomethane for electricity production in Combined Cycle Gas Turbines (CCGT) or Open Cycle Gas Turbine (OCGT) facilities, together with CCUS technologies can even count as a negative emissions energy source. All these effects are reflected, traced and monitored under **European GOs/certificates**.

1 Biogas has been exploited for energy usage for decades. In the EU-28 (plus Switzerland), more than 190 TWh of biogas was produced in 2016 of which more than 90 % is used for on-site electricity production. Gas for Climate study points to 1,170 TWh potential for renewable methane in 2050, https://www.gasforclimate2050.eu/files/images/original/GfC_infographic.png. Example of FR biomethane progress: 0.7 GWh injected in 2018. By end June 2019 projects representing an injection capacity of 19 TWh awaiting to be connected to the gas network (that is registered on the French biomethane capacity registry).

2 Biomethane has an emission factor of 23.4 kg CO2 eq/MWh NCV (according to a recent update of the French carbon public database administrated by French agency ADEME), roughly 10 % of the one of natural gas (227 kg CO_2eq/MWh NCV).

B) LARGE SCALE CCUS[3] DEVELOPMENT

The capture phase of CCUS can be one of two different cases:

— pre-combustion (including pyrolysis)
— post-combustion (including oxyfuel combustion).

In this pathway we assume that the choice by the markets will favour post-combustion CCS (as methane remains the energy carrier in gas networks) case and support biomethane developments. It is being applied to existing installation as it avoids a massive process revamping by the industrial consumer. To prove the CO_2 abatement, the management and the strict EU-wide carbon accounting and management system would need to be established. The rules, processes and responsibilities for cooperation across the whole gas value chain, industry and CO_2 operators would be embedded in CO_2 Transportation system in regions where needed.

The EC's communication 'EU's Energy Roadmap 2050' sees CCS as an important technology contributing to low carbon transition in the EU, with 7 % to 32 % of power generation using CCS by 2050. The EC Long Term Strategy scenarios that achieve climate neutrality rely on CCUS for mitigating 281–606 Mt of CO_2 in 2050 meaning that the CCUS capacity needs to significantly increase. This implies a rapid scale-up of CCUS deployment, from around 30 Mt of CO_2 currently captured worldwide each year to more than 2,000 Mt per year by 2050. According to IOGP, Geological storage potential for CO_2 in Europe is around 134 $GtCO_2$ (taking into account storage restrictions in some Member States). This is equivalent to 446 years' worth of CO_2 storage at the rate suggested necessary by the EC in 2050.[4]

3.2.2 WHAT MARKET FEATURES ARE MISSING IN CURRENT MARKET DESIGN TO SUPPORT ALL THE DECARBONISATION TECHNOLOGIES?

To ensure consistent roll-out of the decarbonisation under the methane pathway, the markets would need to positively respond to the stronger CO_2 price signals from redesigned ETS or to other incentives, designed to stimulate the scale-up of both (post-combustion) CCUS and well organised cross-border tracking of biomethane development.

Under this methane pathway, ENTSOG sees the need for development of:

A) European GOs/certificates

B) Principles for CO_2 Transportation

A) EUROPEAN GUARANTEES OF ORIGIN (GOS)AND CERTIFICATES

Under the methane pathway, the cross-border scale up and tradability of biomethane can be achieved via GOs certification scheme, as initiated by RED II.[5] ENTSOG welcomes the development of national registers and the cross-border trade of biomethane certificates among the member registries. ENTSOG also supports the use of EU schemes for cross-border tradability of GOs for renewable gas, such as the one promoted by the European Renewable Gas Registry (ERGaR) or CertifHy. However, what is missing is a trustworthy GOs and Certification Scheme recognised by all Member States. Cross-energy trade should also be recognised so that green gas burned in a CCGT results in green electricity. To ensure the cross-border dispatch of biomethane, the producers and consumers need to document the origin and climate value under a robust certificate system, recognised under the RED II framework, also in the cross-border context. The same would need to be achieved for hydrogen from all feedstock.

3 CCS and CO_2 emissions reduction technology would need to be applied in the industrial sector and in power generation via: - capture of CO_2 form industrial processes, - transport of CO_2 via pipelines, road or maritime transport - storage deep underground in geological formations. CCU follows similar process but the CO_2 captured is - after transported - used as a resource for valuable CO_2-based product or service applications.

4 IOGP, http://www.iogp.org/wp-content/wp-content/uploads/2019/10/IOGP_slides.pdf.

5 For promotion of renewable and low carbon gases, including biomethane, one option could be to have binding targets for renewable and low carbon gases based on national gas consumption (i.e. at Member State level). Another element is to link the GO value to the ETS to better link the be consistent with CO_2 quota system. ENTSOG-GIE recommendations on GOs for Madrid Forum, June 2019.

B) PRINCIPLES FOR CO_2 TRANSPORTATION

Market design needs to create conditions for safe, reliable and permanent storage of CO_2 with clear liabilities and clear CO_2 accounting rules, that could be linked to ETS. Under methane pathway we assume that a high[6] value of the CO_2 abatement for society results in the choice of the locations of CCUS facilities. This pathway ensures decarbonisation through large scale CCUS projects in Europe, mainly focused on offshore storage - but also possibly on production CCU-derived fuels or construction products.

ENTSOG agrees with IOGP to promote market framework for decarbonised products and services, including their GOs or accreditation schemes to incentivise new business models for CCUS technologies. Considering CCUS, especially for post-combustion processes, a cluster approach shows great advantages. The development of clusters (i.e. regional groupings where several CCS facilities share infrastructure) can help drive lower cost CCS, unlock value for local economies, and foster continuous technical innovation. Sharing transport and storage infrastructure, and the re-use of existing oil and gas assets are considered important steps that can enable potential cost reduction in CCS.[7]

If the market does not take up these activities, another possible option is for the gas TSOs to assume the role of CO_2 operators, facilitating the EU set-up for capturing emissions from clusters of industry, power and waste emitters and their cooperation with the governments. CO_2 transport and storage are activities which could be undertaken by TSOs, DSOs and Storage System Operators (SSO), subject to the TPA access rules that apply to natural gas infrastructure and subject to regulatory oversight of the NRAs and ACER.

Possibly an EU CO_2 agency/operator formula,[8] makes CCUS activity a service of pan European interest, eligible for PCI and public funding. This would serve to clarify the liabilities of CO_2 storage facility operators (state entities, gas infrastructure, companies or exploration and production companies).[9] NRAs powers are limited when it comes to the offshore environment and for that option to be available for TSOs, some legislation changes need to be assessed.

3.2.3 WHAT WILL BE THE ROLE OF THE TSOs?[10]

In the context of biogas, the TSOs role could be to invest in connection of biomethane production plants,[11] to invest on reverse flows from distribution to transmission grids or to invest in biogas upgrade to biomethane in combination (or not) with methanation. TSOs can promote biomethane with at least a capacity tariff discount and could be investor in connections of biomethane plants. Proper recognition of these roles and coverage in tariffs by NRAs would need to be allowed in order to promote the development of these decarbonisation developments.

In the context of CCUS: TSOs should be allowed, but not obliged to invest, own and/or operate CCUS facilities and CO_2 networks as a regulated business and/or to be a player in a commercial environment taking the unbundling rules into account. There is also a potential to use existing gas pipelines, e.g. those connected to depleted gas fields. TSOs involvement in repurposing of the existing natural gas-based infrastructures, building and managing CO_2 infrastructure would be highly beneficial in terms of infrastructure optimisation and cost savings[12] (coordinated planning, use of land, accumulated know-how, synergies in procurement and grids management etc., especially when CO_2 networks would generally be close to methane networks).

Regulation being one solution for promoting the deployment of CCUS systems can be applied in these three ways: Natural monopoly position, TPA or Regulated tariffs.

6 The necessity of such signal to influence market and consumers behavior is out of scope of ENTSOG own economic analysis. The convincing recommendations on ways for market uptake and ensuring that CCUS are economic activities recognized as economic activities contributing to climate mitigation and on possible deployment strategies for Member States, are presented by IOGP report on The potential for CCS and CCU in Europe. Report to the 32 meeting of European Gas Regulatory Forum, June 2019.

7 IOGP, The potential for CCS and CCU in Europe. Report to the 32 meeting of European Gas Regulatory Forum p.33, June 2019.

8 The EU Directive 2009/31/EC establishes a legal framework for the environmentally safe geological storage of CO_2 to contribute to the fight against climate change. Member States that want to mitigate any financial risk associated with CO_2 storage should be able to designate a (public) body to operate the CO_2 storage facility and assume liability for the stored CO_2 until this liability is transferred to the competent authority.

9 IOGP, The potential for CCS and CCU in Europe. Report to the 32 meeting of European Gas Regulatory Forum, p.28 onwards, June 2019.

10 Under the Methane Pathway we did not include the full development of hydrogen the that will occur based on: the development of P2G facilities; the choice of pre-combustion technologies (pyrolysis) as CO_2 avoidance method; the evolution of local SMR facilities; How to deal with the hydrogen production from P2G? What market design: Point to point as it is or included in the gas market design? This is analysed in the next pathway.

11 For Example, in France biomethane producers have a "right to inject" under which network operators should invest to connect them, as long as the investments comply with a given economical and technical criteria). In Denmark 15%, while in Sweden 10%.

12 Especially when CO_2 networks would generally be close to methane networks as methane consumers produce CO_2.

3.3 BLENDING OF METHANE AND HYDROGEN PATHWAY

3.3.1 WHAT IS THE MARKET? WHAT IS THE COMMODITY TRADED?

To preserve the market integrity, ENTSOG assumes that the commodity is no longer homogeneous anymore, but market participants can continue to trade energy value (kWh), and not methane or hydrogen separately. The trading consists of:

- sell and purchase of the documented energy content.
- sell and purchase of GOs/certificates documenting the "climate values"
- physical conversion and gas quality services – relevant interfaces between methane and hydrogen to ensure liquidity on one common gas market.[1]

With diverse gas quality, the importance of the TSOs gas quality services will increase. Conversion services like methanation (conversion H_2 ->CH_4) or methane reformer, (CH_4 -> H_2, via SMR/pyrolysis), blending or separation (via membranes), supported by large-scale roll-out of smart meters and chromatographs, will help to increase the flexibility of supplies and increase acceptability for end use.[2]

ENTSOG also assumes the greater integration of gas infrastructure with the electricity sector via P2G facilities, along with important variability of supply of renewable hydrogen coming from electrolysis. The variable weather patterns can influence availability of renewable electricity (wind or solar-based) and electricity TSOs' ability to inject this electricity into the power grid. These factors, together with market choices, are key to determining the amounts of hydrogen supplied from electrolysis. In this regard specifically, a regulatory framework for P2G facilities should be established to ensure necessary cooperation mechanisms for electricity and gas operators.

What market design features are missing in current market design to support all the decarbonisation technologies?

Under the Blending pathway there are crucial elements/tasks for the cooperative value chain:

A) European Gas Quality Services (cross border management between Member States) and communication (e.g. TSOs' protocols)

B) Principles for Sector Coupling

C) Principles for CO_2 Transportation (discussed previously under the methane pathway, Chapter 3.2)

1 French, Dutch, Polish examples as an explanation shows that such a market design could be built in a similar way to the High Calorific Value (H-gas) and Low Calorific Value (L-gas) zones management. Providing gas quality management, the TSOs would ensure access to European energy gas hubs and security of supplies for those zones, as the physical delivery occurs in the dedicated areas with differing gas qualities.

2 See Marcogaz infographic at the 33rd Madrid Forum.

A) EUROPEAN GAS QUALITY SERVICES[3]

With an increasing concentration of hydrogen, there will be a need for inventory, adaptation and/or replacement of gas infrastructure and end-use appliances. In addition, the variability of the functioning of end-users' appliances could complicate the billing process, although digitalisation may offer robust solutions in this regard. Therefore, market participants should coordinate changes in their regional/cross border/local concentrations of hydrogen coming with next production facilities being operational. There will be a tendency for higher concentrations of hydrogen around production or conversion facilities (especially in summer, when gas demand is lower).

Market functioning is facilitated by TSOs and DSOs engagement in conversions between hydrogen and methane and by smart gas quality services. Therefore, measurement or determination of the hydrogen content in the distribution and transmission grids will be required to ensure an accurate billing, which can be facilitated by IT solutions. Blending may also require standardisation of national and cross-border communication e.g. between sections of the EU grids operating with different concentration of biomethane, blending, pure hydrogen. Digitalisation could potentially offer robust solutions for it.

B) PRINCIPLES FOR SECTOR COUPLING

Inter-sectoral use of technologies that link and convert energy vectors can optimise the need for investment and in total contribute to the speed of the EU's energy transition. Sector coupling integrates renewable energy sources through integration of the energy networks (electricity, gas and heating networks) and energy storage. A P2G electrolyser could be operated like a transformer between the electricity and the gas system, which injects gas into the gas system. Since gas TSOs will not own the energy commodity, TSOs will manage the output in terms of grid injection and gas quality – they act only as operators of the conversion facility. As of today, only small P2G plants are in operation (up to 10 MW) and accordingly, the production of synthetic gases is currently expensive. Costs reductions could be expected when learning curve effects materialise.[4] Given that the current framework of regulations, market incentives, tariffs, etc. has not taken into account the opportunity of P2G, seasonal storage and other technologies. There is a need for further development and existing hurdles have to be addressed to make it possible.

Clearly, the products and services of the electricity and gas TSOs would need to be updated. Also, to avoid suboptimal investment, structured planning of electrolysis capacity and locations at national and EU level is necessary.

3.3.2 WHAT WILL BE THE ROLE OF THE TSOs?

The injection of hydrogen and the interaction with the electricity system via renewable electricity will make the gas TSOs role more complex. This will require a more flexible and robust gas system to allow TSOs to respond to these challenges. Firstly, gas TSOs will address the intermittence and decentralisation of operations due to renewable electricity production/renewable hydrogen. In some scenarios, TSOs will also have to manage the relatively high import rates of hydrogen from third countries. Secondly, on the top of managing the dispatch of the fuel, the TSOs will also manage the consumer gas quality requirements via gas quality conversion services necessary for cross-border flows to always maintain security of supply and market integration.

TSOs are also ready to take this more active role in enabling decarbonisation. TSOs will make efforts of mapping the exact needs and tolerances of their customers. TSOs would be well-placed to co-shape the hydrogen injection strategies and invest in conversion facilities under two coexisting possible models: in competition with commercial investors or in non-commercial business cases, where TSOs invest in a regulated framework (e.g. under the framework of regulatory sandbox).

3 Despite the intense efforts of the standardisation community, today there is not a clear EU technical agreement on the gas quality standards that should be delivered to and accepted by end us applications. ENTSOG will continue the dialogue with CEN to achieve further clarity on Eu level on provision of information by gas/hydrogen users and on the margin of flexibility/robustness in the application of gas quality standards. TSOs are facing competing requests form producers and end users and at the same times assessing the readiness of their system to increase renewable gases share. For ENTSOG's specific recommendation what should be done at European level go to: ENTSOG Position Paper on flexible approaches for gas quality, Brussels September 2018; page 3 onwards. https://www.entsog.eu/sites/default/files/2018-12/INT1359_180913_PositionPaper_Gas_Quality_website.pdf.

4 This is necessary to have much higher installed capacity in the GW region available by 2030. Electrolysis manufacturing capacity needs to develop for the upscaling challenges. – The production costs of synthetic gases are mainly determined by capital costs and thus high utilisation rates reduce the costs per kWh; in addition, cost reductions are expected due to up-scaling and learning effects.

3.4 HYDROGEN PATHWAY

3.4.1 WHAT IS THE MARKET? WHAT IS THE COMMODITY TRADED?

Based on assessment of the needs of customers and after reaching the tipping point[1] in specific areas, economic rationale may lead to a move from blends to pure hydrogen deliveries. TSOs will need to assess the readiness of the existing transmission system to accommodate 100% hydrogen. This work has already started with significant levels of investment aiming to accelerate hydrogen commercialisation. TSOs cooperate with the rest of the value chain to determine the optimal refurbished and hydrogen-ready transmission network sections: first, most likely industrial, and afterwards, to users connected to the to the hydrogen ready distribution areas. Once hydrogen becomes available in large, cross-border dispatchable volumes and is produced from renewable electricity using electrolysis, from natural gas/biomethane/LNG using pyrolysis or SMR[2], as well as imported via pipelines or maritime routes in the form of ammonia. Therefore, the commodity becomes homogenous again and is traded on energy content level and on its climate value via pan-European Certificate system based on GOs from renewable, decarbonised or low-carbon processes.

3.4.2 WHAT MARKET FEATURES ARE MISSING IN CURRENT MARKET DESIGN TO SUPPORT THE DECARBONISATION TECHNOLOGIES UNDER THE HYDROGEN PATHWAY?

A) A DEDICATED HYDROGEN NETWORK TO TRANSPORT AND STORE HYDROGEN MOLECULES

The economics of hydrogen networks would be similar to the ones of natural gas pipelines.[3] Regulation of hydrogen networks and the role of gas TSOs will need to be further discussed. EU hydrogen networks connecting diverse production and demand sites could be regarded as natural monopolies. Since building parallel network structures would not be cost-efficient, specifically starting with a blending scenario for larger scale of hydrogen-ready infrastructure, it will make sense to use existing natural gas networks and market design.

B) MARKET DESIGN ENSURING NON-DISCRIMINATORY THIRD-PARTY ACCESS TO HYDROGEN INFRASTRUCTURES

Non-discriminatory TPA to hydrogen networks should be considered, as it is essential to preserve the integrity and further develop the Internal European Energy Market. A hydrogen network could be managed by gas TSOs since they already have the experience and knowledge in developing and operating transmission networks as well as ensuring non-discriminatory access to the networks. TSOs would also be able to use the advantages provided by the existing gas infrastructure by retrofitting the assets, having access to rights–of-way, building and operational know-how and synergies.

1 Tipping points may differ based on national and consumer choices driven by e.g. appliances readiness.

2 Steam methane reforming related CO2 is treated under the CCUS management scheme, see pathway 1.

3 *ACER Bridge Beyond 2025.*

3.4.3 WHAT WILL BE THE ROLE OF THE TSOs?

Benefits of TSOs managing hydrogen pipelines would be as follows:

— Infrastructure optimisation and cost savings as a result of coordinated planning reflecting the development needs of the sector (e.g. blending and/or dedicated pipelines; full/partial conversion to hydrogen of existing pipelines, etc.);

— TSOs may own and operate P2G as conversion facilities without ownership of commodity on a TPA basis according to market nominations, such as for basic transportation services. It would show that ultimately it is the market which manages the facility, avoiding energy market distortion.

— Ensuring non-discriminatory TPA regime for market players to the hydrogen network. "Large" gas producers using methane reforming would have access as well as "small" users of a P2G facilities. On the consumer side, establishing a level playing field between consumers with large demand and more modest needs will also be beneficial for competition.

— Guaranteeing viability of pipelines in the development stage, as load factor progressively increases.

— To allow potential integration of hydrogen and (bio/synthetic) methane markets to deliver one price signal for gaseous energy, in a manner similar to the integration of H gas and L gas in some EU markets (e.g. France). This integration will prevent market fragmentation as hydrogen usage develops alongside (bio)methane usage.

CONCLUSIONS OF CHAPTER 3

The three possible pathways for decarbonising the gas sector from the market perspective are the Methane Pathway, Blending of Hydrogen and Methane Pathway, and Hydrogen Pathway. These pathways have different market design features that need to be compatible. There are a substantial number of market design features that are to be redesigned or are missing for these pathways to develop.

For the **Methane Pathway** to develop it requires a trustworthy European GOs and Certificates for biomethane that needs to be recognised by all Member States. In addition, a market design should create conditions for safe, reliable and permanent storage of CO_2 with clear liabilities and clear CO_2 accounting rules linked to ETS. There is also a need for incentives for biomethane production and injection into the grid.

For the **Blending of Methane and Hydrogen Pathway** the development of European Gas Quality Services is required to ensure cross border trade of hydrogen certificates between Member States. In addition, European Sector Coupling principles are needed for a proper assessment of the gas and electricity system value for capturing the renewable energy.

For the **Hydrogen Pathway** to develop there is a need for a dedicated hydrogen network to transport and store hydrogen and also a market design ensuring non-discriminatory third party access to hydrogen infrastructure.

ENTSOG expects that the pathways can and will coexist and occur in different timescales in different regions. Therefore, the major principle that the European gas TSOs have chosen to work for is to ensure the continued and further developed functioning of the European gas market.

GLOSSARY

ACER	Agency for the Cooperation of Energy Regulators
ATR	Auto-Thermal Reforming
CCGT	Combined Cycle Gas Turbines
CCUS	Carbon Capture, Utilisation and Storage
CEE	Central-Eastern Europe
CEER	Council of European Energy Regulators
CEF	Connecting Europe Facility
DAC	Direct Air Capture
DSO	Distribution System Operator
EC	European Commission
EFET	European Federation of Energy Traders
EU	European Union
ETS	Emissions trading system
GIE	Gas Infrastructure Europe
GOs	Guarantees of Origin
IOGP	International Association of Oil & Gas Producers
IP	Interconnection Point
LNG	Liquefied natural gas
MET	Methanation
NRA	National Regulatory Authority
OCGT	Open Cycle Gas Turbine
P2G	Power to Gas
PV	Photovoltaic
RAB	Regulated Asset Base
R&D	Research and Development
SSO	Storage System Operator
TEN-E	Trans-European Networks Energy Regulation
TEN-T	Trans-European Transport Network
TPA	Third-party access
TSO	Transmission System Operator

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