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Study on the Future Role of Gas from a Regulatory Perspective

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Disclaimer:

This study was commissioned by CEER and prepared by DNV GL taking into account feedback from stakeholders and CEER members. The information and views set out in this paper are those of the author(s) and do not necessarily reflect the official opinion of CEER.

INFORMATION PAGE

Abstract

This document (C17-GPT-04-01) is titled "Future Role of Gas from a Regulatory Perspective" and was prepared in cooperation with DNV-GL.

The study discusses the potential future role of gas in a context of the COP21 decarbonisation targets, the growing share of renewable energy and price trends of carbon and other fossil fuels. Based on three demand scenarios (high, average, low), this paper evaluates the role of gas in the energy mix on a time horizon to 2040 including their respective impact on European infrastructure. A set of regulatory measures that may be required in each of the scenarios forms a further integral part of this study.

Target Audience

European Commission, energy suppliers, traders, gas/electricity customers, gas/electricity industry, consumer representative groups, network operators, Member States, academics and other interested parties.

Keywords

Decarbonisation; gas demand; gas infrastructure; renewable gas; CNG; LNG; power-to-gass; hydrogen; regulatory incentives for innovation; stranded assets.

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Background

The natural gas industry is undergoing a period of substantial uncertainty regarding its future role in the energy mix. In spite of its environmental advantages over other fossil fuels, the ambitious COP21[1] decarbonisation targets in combination with the ongoing rise of renewable energy as well as disadvantageous price trends of oil, coal and CO2 have brought natural gas in Europe in a position which currently appears rather questionable in the long term.

Without any doubt, the transition to a low carbon economy involves substantial changes along the entire gas value chain and requires a close and proper coordination between policy, regulation and industry in order to move towards decarbonisation in an economically-efficient way, which makes best use of existing assets instead of rendering them stranded, and attracts at the same time new necessary investments.

In order to start a deeper analysis of the above issues, CEER decided to commission DNV GL (hereinafter “the consultant”) to prepare a study aiming at evaluating the potential future role of gas, its infrastructures and the consequent regulatory measures that may be required.

Objectives of the Study

The aim of this study is to enable the regulatory community to:

- identify key issues deriving from the possible future development of the natural gas sector both from a commodity and infrastructure perspective; and
- develop proposals for potential future regulatory initiatives that may be needed to reflect these developments. A steering group (SG), made up of CEER Gas Working Group experts was set up in order to exchange views with the consultant on the possible future role of gas.

The consultant collected different views also through interviews with experts from industry associations, transmission system operators, power sector, institutes, governmental agencies, natural gas supplier. Several Workshops were also organised to ensure the maximum involvement of stakeholders in the process.

Next steps

This document offers a broader vision of the different roles that gas could assume in the coming years and of their possible consequences. At the last Madrid Forum (19-20 October 2017) the presentation on the main findings of this document received a positive support by stakeholders.

Against this background, in 2018 CEER will continue working on selected aspects of the future role of gas from a regulatory prospective taking advantage of the work already carried out by this study as well as of the outcomes of other relevant studies. In this work, the interaction and synergies between gas and electricity sector will be further analysed and a transparent debate with stakeholders will be launched.

[1] For further information see: http://unfccc.int/paris_agreement/items/9485.php.

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1 EXECUTIVE SUMMARY

In the last years, the natural gas industry has been undergoing a period of uncertainty regarding its future role in the energy mix. Despite its friendly environmental properties compared with other fossil fuels, its performance has been negatively influenced. These have been caused by the low prices of coal and oil, low carbon prices resulting from ETS, and large increase in RES generation mainly driven by various policy support schemes.

Considering these developments, DNV GL has been commissioned by CEER to prepare a study aiming to evaluate the potential future role of gas, its infrastructure and the consequent regulatory implications and measures that may be required. In our work, we have considered the discussion points raised during the dedicated workshops.

The work has been divided into three parts. Firstly, three gas demand scenarios (high, average and low) are constructed. These scenarios define the range of possible evolutions of natural gas demand from a 2040 perspective for the EU-28. For the selected scenarios, certain assumptions are considered in terms of achieving EU environmental targets and key sectors driving structural change in gas demand.

Subsequently, we look at the gas commodity markets, focusing on the traditional use of natural gas (for example for electricity generation and heat); use of other gas forms (LNG /CNG) in the transportation sector and renewable gases that can substitute natural gas such as biomethane and hydrogen. We assess the competitive position of gas in these areas and highlight the need of regulatory measures in the context of the gas demand scenarios.

Lastly, we explore the regulatory implications in the infrastructure area. We start with the traditional natural gas infrastructure, particularly in the context of the low gas demand scenario. Consequently, we address the infrastructure for new uses of natural gas such as the use of CNG/LNG in the transportation. Such infrastructure comprises the refuelling stations which also can include compression equipment to convert natural gas in CNG or LNG, and storage facilities. Finally, we turn to the regulatory measures needed for infrastructure for renewable gases and incentives for innovation and decarbonisation.

Gas Demand Scenarios

To account for future uncertainties, existing natural gas demand scenarios (high, average and low) have been selected in order to define the range of possible evolutions of natural gas demand in a 2040 perspective for the EU-28. The scenarios imply certain assumptions in terms of achieving EU environmental targets and key sectors driving change in gas demand. Despite the existing challenges, natural gas traditionally supplied via pipelines or other forms such as LNG and CNG plays a substantial role in meeting EU future energy demand in all three scenarios. Beyond that the substitution of natural gas by renewable gases using the existing gas infrastructure could support the cost-efficient decarbonisation.

Such developments on the commodity markets will require adequate consideration of the associated infrastructure. The existing gas infrastructure may not only be dedicated to the commodity natural gas in its current form but may also be facilitating the penetration of other technologies, and the increasing use of renewable gases. As a substantial part of renewable gases will likely be generated locally and therefore also injected directly into to the gas distribution networks, these networks will be important to maintain the benefits of the integral gas system. Furthermore, the increasing use of CNG/ LNG in transportation determines the important role of the infrastructure for these emerging markets. Finally, there might be changing requirements for regulation in other non-gas infrastructure areas such as district heating.

The overall transition process involves substantial changes along the entire value chain and requires adequate policy and regulatory attention and effective coordination between policy makers, regulators and industry as well. The overall objective should be to manage the transition of natural gas industry in the most cost-efficient way and maximise social welfare.

Commodity Markets

In commodity markets, natural gas has been traditionally used mainly to produce electricity and heat, and in industrial applications. In the last few years, gas has become increasingly important in the land and maritime transportation sector, in both LNG and CNG forms. It is utilised in either dedicated natural gas engines or dual-fuel engines. Furthermore, renewable gases (biomethane, hydrogen and synthetic gas) have emerged and are expected to grow in the future, and contribute to decarbonise various sector of the economy.

Commodity markets are in most cases competitive markets and there is no scope for a direct regulation. Therefore, regulation should continue to focus on the further enhancement of competition including inter alia removal of market distortions, improvement of market design, improvement of tariff setting/ access arrangements of relevant related infrastructures.

For example, with respect to gas wholesale markets regulators can think of a series of regulatory initiatives to further develop the necessary tools for market integration across Europe. A new mechanism should be defined to achieve the merger of trading hubs or markets currently managed by different TSOs. The coordination between the electricity and gas sectors should improve in terms of operational decisions, time alignment but also implementing a coordinated approach to plan new infrastructure. Furthermore, regulators may consider revisiting network tariff design, particularly in the case of declining gas demand and excess transportation capacity. Tariff design must ensure, among others, that gas-fired plants and storages do not close prematurely due to transportation tariffs, as they could provide a valuable contribution to the energy system. On an overall policy level, measures may be necessary to further address the effectiveness of the emission trading scheme and improve the steering role of a carbon price towards the achievement of decarbonization objectives.

With respect to gas retail markets, national regulators should continue to focus on the further enhancement of retail competition (e.g. facilitating market entry and improving switching procedures) and consumer empowerment and protection. The gradual abolishment of price regulation in EU countries controlling end-user prices must follow the establishment of functional retail competition, while ensuring the effective and targeted protection of vulnerable consumers. Where retail prices remain to be regulated, they should reflect the underlying cost of gas supply and should not hamper the development of a competitive retail energy market.

The markets for use of CNG / LNG in transportation are contestable. There are multiple means of transport services, fuels, and different suppliers and buyers of both fuels and vehicles. There is no evident need of regulation of such contestable businesses. However, measures appear necessary for refuelling infrastructure as it is still fragmented and partly limited in Europe.

On a policy level, there are multiple measures that can be considered to promote the development of certain new technologies with favourable environmental impact. For example, the development of renewable gases can be encouraged, typically at national level, by various incentive schemes ranging from feed-in tariffs, tax breaks and investment support for investments etc. Similar measures can be used for the purchase of gas-fuelled vehicles. For renewable gases, tradable green certificates could be used to support the establishment of regional markets.

Infrastructure

Natural Gas Infrastructure

The development of future gas demand affects the traditional natural gas infrastructure. While a stable and high gas demand requires to maintain and extend the networks, a continuous decline of gas demand could potentially lead to under-utilisation and stranding of network assets. Regulators could apply different approaches to address stranded assets such as depreciation policy (accelerated depreciation), asset valuation, adjustment of cost of capital and explicit compensation outside of network tariffs.

Consideration of some flexibility in depreciation policy would e.g. permit recovery of charges over the short to medium term when user demand is more certain, and relieve the allowed revenue/tariffs on the longer term when user demand is less certain. Adjustment of depreciation allowance should be set in a way not leading to unbalanced tariff increases in the short to medium term that may discourage network users to book capacity.

In addition and without prejudice, any decommissioning of gas assets should be considered in a coordinated way and to the extent possible, based on existing infrastructure planning/coordination procedures such as the TYNDP or the process defined in Regulation (EU, Euratom) No 617/2010 concerning the notification to the Commission of investment projects in energy infrastructure. Cooperation between the stakeholders (TSOs, national energy regulators) is essential for a smooth and coordinated effort. Regarding cost allocation for decommissioning, if the asset stretches over one or more countries, each respective TSO would be responsible for and bear the cost of decommissioning the asset in its own country. However, additional considerations, i.e. cost / benefits caused by decommissioning reflecting cross-border impact would be also required. Moreover, the possibility to maintain an asset should also be addressed if a neighbouring TSO might demonstrate that there are benefits such as security of supply. Therefore, cost allocation in this respect is related to compensation payments between the TSOs in the respective countries. The regulatory treatment of such compensation payments would fall under the decision of the national energy regulators and the respective regulatory framework in which the TSOs operate.

In any case the application of such approaches should be based on an individual assessment and take into account the interrelation and compliance with regulatory goals such as cost-reflectiveness, tariff stability, energy affordability, etc.

CNG/LNG in transportation

The increased use of CNG/LNG in transportation determines the important role of the infrastructure for these emerging markets. Such infrastructure comprises the CNG/ LNG refuelling stations which also include the compression equipment to convert natural gas in CNG or LNG. Regulators should not intervene where contestable provision of services is possible and effectively leads to sufficient geographical coverage and competitively priced offers. For example, the provision of refuelling station services and CNG/LNG transportation are contestable activities and can be provided in a competitive environment. The competitive provision of other potentially contestable services such as storage and bunkering may be limited due to operational or physical constraints (at ports or other locations) or requirements of the permission rules. In such circumstances, these activities will require regulation.

Operators of natural gas networks may seek involvement in contestable activities as the ownership, development, management and/or operation of LNG/CNG refuelling infrastructure, power-to-gas (P2G) infrastructure and other new technologies. Where a combined provision of regulated and contestable services is possible, the regulatory framework should ensure that customers and market participants benefit to the largest extent possible from the range of services. However, regulation must prevent unintended interactions between the regulated and contestable sectors in terms of cost and revenue allocation, and information advantages. Without regulatory control, including also the analysis of contractual relations, companies may be able to benefit from this by allocating costs to regulated activities, or by using information held by the regulated business. This could increase the cost of regulated services and distort competition in the contestable part of the sector.

One way to address this issue is to apply an approach similar to the one recently suggested in the Clean Energy Package for electricity DSOs. The Clean Energy Package (Article 33 of the draft Electricity Directive) states that Member States may allow DSOs to own, develop, manage or operate recharging points for electric vehicles if and for as long as there is no market interest from other parties to engage in these activities. The market interest should be tested in a tender process reviewed and approved by national regulators. Alternatively, regulators may consider using a more flexible approach in the gas industry by attributing a proactive role to gas network operators. Such an approach would recognise explicitly the specific circumstances and benefits of involvement of the gas network operators in contestable activities e.g. potentially contributing to the resolution of the "chicken and egg"[2] problem that challenges the use of new fuels. Nevertheless, the fundamental principles of unbundling related to cost and revenue allocation, and use of information must remain valid and appropriate.

Furthermore, LNG transported via trucks can in fact be used to supply remote areas and to secure gas deliveries to consumers. In addition, the use of LNG in the transportation sector also contributes to increase competition in the market for transportation fuels by adding a new product and opening a new market segment for suppliers.

Policy decision makers and regulators can apply additional supporting schemes such as tax breaks and investment subsidies for e.g. CNG/LNG refuelling stations, funding research and development, pilot and innovation projects.

Finally, a common coordinated approach in the establishment of national/regional plans may bring benefits in terms of alignment and synergies, and contribute to the integration of CNG/LNG transportation infrastructure in these plans. While the primary planning responsibility is with regional governments, municipalities and other competent authorities, energy regulators can provide valuable input in this process.

Infrastructure for Renewable Gases

The transport of hydrogen via pipelines of natural gas network should be a regulated activity. It is likely that new hydrogen pipelines will have similar economic characteristics to the existing natural gas networks and therefore should be regulated.

Since the hydrogen production process cannot efficiently change production to match demand there is a need of storage capacity to allow system flexibility for both intraday and inter-seasonal variations in demand. Storage is a potentially contestable area. However, there could be a case for regulation if geological or other constraints limit supply of storage capacity. Limitations may also appear due to the limited market size of the relevant market that may hinder the establishment of functional competition.

Regulators should accompany and steer the transition towards higher hydrogen quantities blended in the gas networks. There will be the need to adjust the technical specifications for the blended natural gas and regularly amend the relevant regulation. On the transmission level, there may be a need to revisit the Interoperability Network Code (INC) and the CEN provisions on gas quality. Moreover, regulators should steer the technology roll-out in terms of time and targeted penetration zones where the hydrogen quantities will gradually grow. They will need to develop the design of the commercial and access arrangements of such a system.

With respect to biomethane, regulators should set clear connection rules including connection charges, technical connection requirements, responsibilities for setting and maintaining the relevant product quality norms, and metering and compression. Regulators may consider

[2] The infrastructure for the distribution of the fuel should be available before the demand for the fuel materialises, while at the same time market participants would not invest in infrastructure before sufficient demand is in place to ensure utilisation of the infrastructure and recovery of the related costs.

providing explicit incentives in national regulation to the parties injecting biomethane into the natural gas networks via the reduction of network tariffs/connection charges.

Regulatory Innovation Incentives

Overall we support the idea of innovation and decarbonisation incentives as part of the regulatory framework as this facilitates development and drives improvement in processes and technology application in the gas sector. National regulators should set clear objectives and qualification criteria for what projects would be subject to innovation incentives. For example, innovation incentives can be provided for a new or unproven technology or operational practice directly related to the gas network. The innovation project should relate to the development, and research in a field, or technology that could help achieve certain targets such as decarbonisation by the possibility of using biogas, CNG/LNG or hydrogen. Innovation and decarbonisation incentives can be incorporated into the regulatory framework by using a special allowance. The allowance would be based on a proportion of the allowed revenues. In addition, regulators can apply special arrangements to specific investments in decarbonization/innovation initiatives such as accelerated depreciation allowances or/and WACC premium.

2 INTRODUCTION

The European natural gas industry is currently being exposed to substantial degree of uncertainty regarding its future role in the energy mix. The main reasons of this uncertainty stem from the ambitious COP21 decarbonisation targets in combination with the continuing rise in renewable energy, as well as disadvantageous price trends of oil, coal and CO2.

To this effect, natural gas is witnessing some significant challenges regardless of its environmental advantages over other fossil fuels. Despite the existing challenges, the natural gas sector can still play a substantial role in meeting EU future energy demand. In the commodity markets this can be achieved by using natural gas in its current form, other forms like LNG and CNG and penetration of substitutes such as renewable gases.

The development on the commodity markets will require adequate consideration of the associated infrastructure. For example, the existing gas infrastructure may not only be dedicated to the commodity gas in its current form but may also be facilitating the penetration of other technologies, and particularly of renewable gases. Furthermore, the potential use of CNG/ LNG in transportation determines the important role of the infrastructure for these emerging markets. Finally, there might be changing requirements and role in other non-gas infrastructure such as district heating.

The complex transition process involves substantial changes along the entire value chain and requires adequate policy and regulatory attention, and effective coordination between policy makers, regulators and industry as well. The overall objective should be to manage the transition to a widely decarbonized energy sector as required by policy until 2050, in the most effective and cost-efficient way. Within this process the (natural) gas industry may play an important role and act as facilitator for the integration of energy from renewable sources in the energy infrastructure. This, in turn, could support sectorial integration and maximise social welfare.

CEER Gas Working Group commissioned DNV GL to prepare this study aiming to evaluate the potential future role of gas, its infrastructure and the consequent regulatory measures that may be required. In our work, we consider the discussion points with the CEER working group raised during the workshops as well as the feedback from the responses of the expert interviews and from the advisory panel.

The work has been divided into three parts. Firstly, we construct three gas demand scenarios (high, average and low), see Chapter 3. These scenarios define the range of possible evolutions of natural gas demand in a 2040 perspective for the EU-28. For the selected scenarios, certain assumptions are considered in terms of achieving EU environmental targets and key sectors driving structural change in gas demand.

Subsequently, we look at the gas commodity markets, focusing on the traditional use of natural gas (for example for electricity generation and heat); use of other gas forms (LNG /CNG) in the transportation sector and renewable gases that can substitute natural gas such as biomethane and hydrogen further described in Chapter 4. We assess the competitive position of gas in these areas and highlight the need of regulatory measures or remove regulatory barriers in the context of the gas demand scenarios. Building on the outcome we address the need to amend or further develop the existing regulation. This might, for example, be in terms of removing market distortions, improving market design, enhancing competition or proving explicit incentives for new technologies.

In chapter 5 we turn to infrastructure. We explore the regulatory implications for the traditional natural gas infrastructure, particularly in the context of the low gas demand scenario where the utilisation of the existing natural gas infrastructure may decrease. Furthermore, we assess the role of renewable gases, these include biogas and biomethane as well as P2G technology and hydrogen production. The analysis also covers the possible conversion of the existing pipelines for the transportation of hydrogen. Then, we explore the infrastructure for the use of CNG/LNG in transportation sector. Lastly, we address the potential regulatory measures in infrastructure areas for renewable gases and incentives for innovation and decarbonisation.

The study includes annexes describing the demand scenarios (Annex 1), cost of heat supply (Annex 2), technologies value chain (Annex 3), selected national examples for application of new technologies (Annex 4) examples with regulatory innovation incentives (Annex 5) and summary table of the conclusions (Annex 6).

3 CHARACTERISTICS OF DEMAND SCENARIOS

3.1 Demand Scenarios Description

Three gas demand scenarios (high, average and low) have been constructed which define the range of possible evolutions of natural gas demand in a 2040 perspective for the EU-28 (see also Annex 1). The selection is based on the review of several representative sources agreed with the CEER Working Group. The sources include the Ten-Year Network Development Plan (TYNDP 2017) from ENTSOG, the World Energy Outlook (WEO) from the IEA for 2016, and the EU Reference Scenario (2016) from the European Commission. The study does not aim to validate the underlying assumptions of these scenarios in terms of achieving EU environmental targets and key sectors driving structural change in gas demand, but rather to use these scenarios to illustrate the magnitude of potential developments of gas demand in the future.

The high demand scenario assumes that the EU is on track to meet the 2050 environmental targets. Gas-fired power plants are expected to increase their market share as they are the main back-up source for RES power generation and generate electricity in the base-load part of the market. Demand for natural gas in the residential sector will remain stable due to the lack of significant improvements in energy efficiency, i.e. gas remains to be the main fuel for heating. The transportation sector represents the main sector where the demand for natural gas will increase. This assumption is consistent within the three gas demand scenarios. Industrial demand remains stable in the period up to 2040, being supported by economic growth and lack of competitive substitutes for natural gas in industrial processes.

The average demand scenario presents different dynamics than those seen in the high demand scenario with the EU still being on track to achieve the 2050 targets. In the power sector, the main source of electricity generation is from RES sources in combination with a decrease in the use of natural gas and coal. Gas-fired plants represent the main source of back-up for renewable power generation. The residential sector experiences a decrease in demand for natural gas due to improvements in efficiency of buildings and alternative sources of heat increasing their market share (district heating and heat pumps). The transportation sector remains the main area where natural gas demand increases both for land and maritime transportation. In the industry sector, demand for natural gas slightly declines due to the substitution of natural gas with other sources as a feedstock or energy source for industrial processes.

In the low demand scenario, the EU achieves higher environmental targets compared to the 2050 and COP21 targets already set. Power generation is provided primarily by renewable energy sources with natural gas decreasing its share post-2030 to achieve environmental targets. Demand for natural gas in the residential sector decreases due to the improvement of energy efficiency and decarbonisation targets (e.g. zero-carbon footprint in new buildings). The transportation sector is again the sector where demand for natural gas increases. In the industry sector, demand for natural gas declines due to the substitution of natural gas with other sources as a feedstock or energy source for industrial processes.

The following table summarizes the main characteristics of the gas demand scenarios against different sectors of the economy.

Sector	High	Average	Low
Power Generation	The use of gas for electricity generation increases, gas-fired plants used for based-load generation and as a main source of back-up for RES	The use of gas for electricity generation decreases, overall decrease of conventional generation (gas and coal), gas-fired plants used as a main source of back-up for RES	The use of gas for electricity generation decreases, electricity generation mainly from RES, gas-fired plants used as a main source of back-up for RES
Heating	Stable demand due to a lack of significant improvements in energy efficiency and keeping the status quo of the heat supply	Decrease of demand due to increase in energy efficiency, penetration of new technologies (e.g. heat pumps, biomass) and better access to district heating	Significant decrease of demand due to radical efficiency improvements, penetration of new technologies (e.g. heat pumps, biomass) and better access to district heating
Transportation	The use of natural gas (CNG and LNG) increases in the land transportation sector and natural gas becomes the primary fuel in the maritime transportation	The use of natural gas increases in the heavy-duty vehicles sector of land transportation and natural gas becomes the primary fuel in maritime transportation	The use of natural gas increases slightly in both land and maritime transportation
Industrial	Industrial gas demand remains stable mainly due to keeping demand for industrial goods and no substitutes of natural gas for industrial use	Industrial gas demand slightly declines due to substitution of natural gas for industrial use	Industrial gas demand declines due to partial substitution of natural gas for industrial use

Table 1 – Main Characteristics of Gas Demand Scenarios

3.2 Renewable Gases

Renewable gases have been gradually emerging in the European energy market as possible alternatives to natural gas in several applications. Renewable gases primarily include biogas, biomethane and hydrogen as well as synthetic gas. Biomethane and biogas represent the main source of renewable gases in Europe at present. Descriptions of the value chain options for biogas/biomethane and hydrogen are provided in Annex 3 and addressed in the dedicated sections of the commodity and infrastructure perspective.

The possibility of renewable gases to substitute natural gas is not however explicitly acknowledged in the gas demand scenarios presented above. In general, long-term gas demand scenarios still lack the recognition of renewable gases[3] and their potential contribution to decarbonize some sectors of the economy. Renewable gases may be produced and consumed locally without the need of large transportation infrastructure. They may also become a direct substitute of natural gas, for example use of natural gas as feedstock in industrial processes for heating. Furthermore, in the transport sector renewable gases may foster gas demand on its own.

The growth of renewable gases will change the gas fuel mix however it is still difficult to provide an accurate estimation of the future role of renewable gases. In the recent analysis by ENTSO-G & ENTSO-E, transmission system operators categorize the supply sources and indicate the potential share of renewable gases. They conservatively estimate, depending on scenario assumptions, that 7-12% of gas demand in 2040 may be covered by renewable gases.[4] Other sources from industry and academia point to an even faster development and a larger share of renewable gases towards 2050.

With such a potential growth, renewable gases could increasingly contribute to meet future gas consumption and overall bring new opportunities for gas to decarbonise the economy. We address their role later as an integral part of this this study.

3.3 Peak Demand

In addition to the total annual demand, we also look at peak-day demand. When comparing the future patterns of the peak-day demand and yearly average daily demand[5], there does not seem to be large contrasting tendencies on an aggregated level. However, a single country analysis might show different figures. The different change of the peak-day demand and yearly average daily demand could point to changing demand patterns of specific consumer groups. For example, a gas-fired plant may be dispatched for less operating hours, however at its maximal capacity.

As part of the analysis we also looked at the future development of natural gas infrastructure. We reviewed several recent and previous studies (EWI, OIES, REKK) and the information from TYNDP prepared by ENTSO-G.[6] Based on this review it appears that some redundancy potential exists and may rise depending on the future gas demand patterns. In the TYNDP assessment, ENTSO-G confirms that the gas infrastructure can accommodate gas supply mixes on a European level on an annual basis and is resilient to a peak demand situation with a comfortable level of flexibility.

[3] Out of all the sources, used for this study, only ENTSOG provides some consideration of renewable gases as part of its gas demand forecast.
[4] See ENTSO-G and ENTSOE 2018 Global Climate Action and Distributed Generation scenarios
[5] The aggregated peak day demand is the arithmetic sum of the peak day demand values per country provided by ENTSO-G in its 2017 TYNDP with 100% coincidence. It is acknowledged that it is unlikely to register the peak day demand values coincidently across Europe.
[6] ENTSO-G focusses on supply adequacy outlook and assessment of the resilience of the gas system, including identification of the investment gaps and future needs. In this regard, it looks at the supply infrastructure (transmission pipeline, LNG terminals and gas storage) assuming different scenarios

4 COMMODITY MARKETS

In this chapter, we look at the gas commodity markets, focusing on the traditional use of natural gas (for example for electricity generation and heat); use of other gas forms (LNG /CNG) in the transportation sector[7] and the role of renewable gases. We assess the competitive position of gas in these areas and highlight the need to amend or further develop the existing regulation. This might, for example, be in terms of removing market distortions, improving market design, enhancing competition or proving explicit incentives for new technologies.

4.1 Use of Natural Gas for Electricity Generation

4.1.1 Role of Natural Gas

Natural gas is used for electricity production, mainly in open and combined cycle turbines. Due to their technical flexibility, gas-fired power plants can quickly be started and stopped, and can be used both as base-load and peak-load plants. They can also be used as back-up generation for intermittent RES sources. In respect of coal, gas is a cleaner source of energy.

In the electricity market, natural gas competes with other generation technologies. In the last few years, natural gas has under-performed when compared to RES and coal. These developments were largely driven by the huge promotion of RES. The increase in RES generation in the EU was mainly the result of various support schemes that were implemented by Member States, such as feed-in tariffs, feed-in premiums, auction/tender systems, quotas, tax credits and grants. Shrinking production costs due to the scaling up of global production volumes and technological advances have also played an important role. The impact of the growth of renewable power with low marginal costs, has forced down wholesale electricity prices and displaced conventional generation, including gas, out of the merit order.

Further factors posing challenges to gas-fired power generation were the price competitiveness of coal supply together with low carbon prices resulting from the European emission trading scheme (ETS). The competitive coal supply was largely driven by coal imports from the USA due to coal displacement with shale gas. Low carbon price has also affected the use of gas-fired generation. Since its establishment, the price of carbon in the emission trading scheme has plummeted. It was mainly due to the surplus of trade allowances allocated to companies who were the largest emitters of CO2 and therefore did not need to buy additional certificates.

Recently the performance of gas power plants has started to improve which indicates a possible change leading to gas overtaking coal as the primary fuel for power generation. This can be largely attributed to falling gas prices and favourable electricity prices driven inter-alia

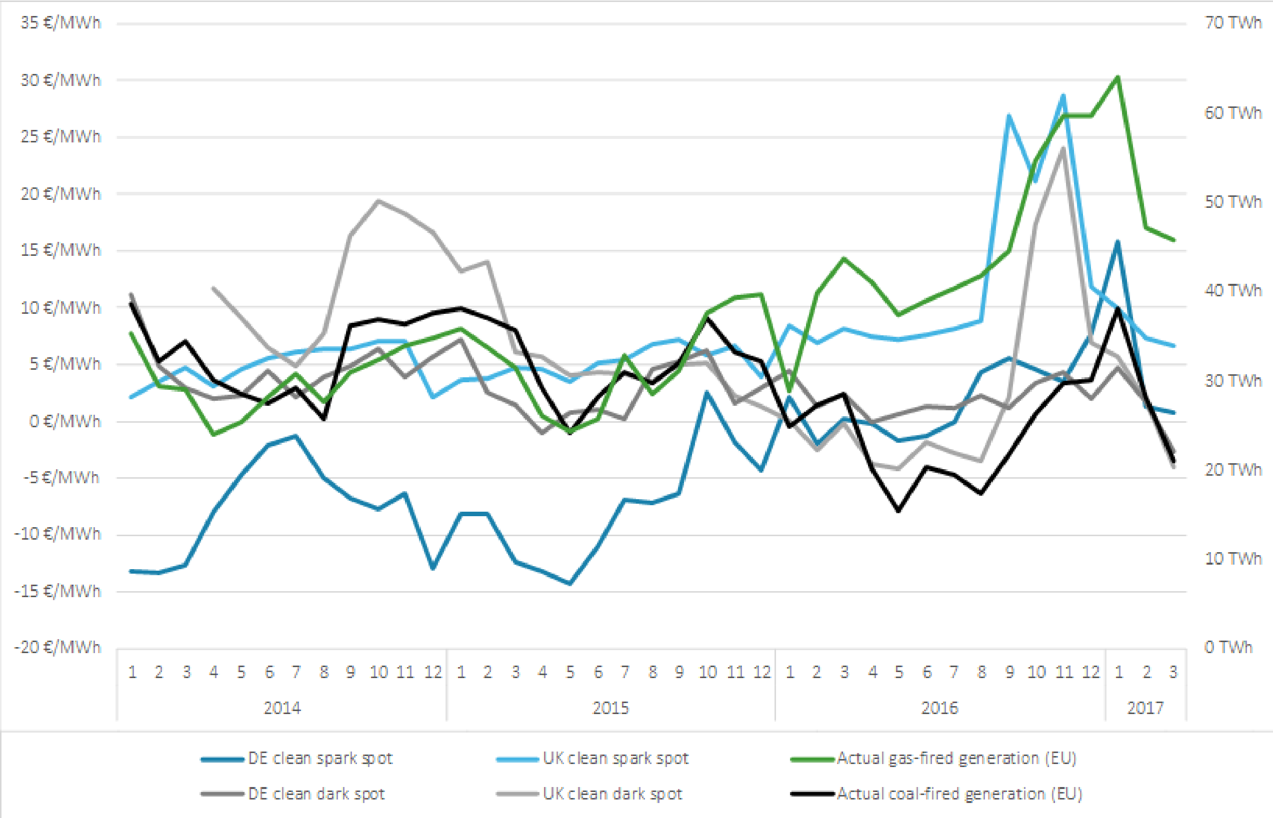
[7] Natural gas finds large use in industry applications. It is used inter alia in metal, chemical, oil refinery, glass & ceramics, pulp and paper, and fuel industries. Furthermore, it is used in multiple processes such as waste treatment, incineration, metal preheating, and as feedstock for manufacturing chemicals and products (e.g. plastics and polymers, textiles).

by the closure of coal-fired power plants[8]. The closures will continue also in the future[9] as a new set of environmental standards[10] have required power producers to re-visit their strategies of using their coal assets. The producers have been confronted with the need of large investments in new technology to refurbish the polluting plants. The alternative is to limit the annual operating hours and ultimately shut down the generation facilities by 2021. More than 2.900 most polluting generation plants are expected to shut down in the EU.

The challenges in the performance of gas-fired power plants in the last years have been reflected in the development of clean versus dark spark spreads. The figure below displays the contribution margins for gas- (clean spark spreads) and coal-fired (dark spark spreads) generators in the respective periods that best reflect the competitiveness of gas-fired plants.[11] Higher clean dark spreads relative to clean spark spreads indicate that coal generation has been more profitable than gas in the last years. This has resulted in coal generation running more intensively. The figure demonstrates a recent change and the realised UK spark spreads as well as recent data from Germany shows recovery of gas-fired generation.

[8] Coal-fired power plants of 8 GW were shut down in 2016.
[9] Coal-fired power plants of 7 GW are expected to shut down in the period 2017-2020.
[10] Directive 2010/75/EU on industrial emissions; Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants.
[11] Clean dark spreads measure the profitability of coal-fired power plants and are defined as the average difference between the cost of coal and carbon emission (at a specified level of plant efficiency) and the corresponding price of electricity. Clean spark spreads measure the profitability of gas -fired power plants and are defined as the average difference between the cost of gas and carbon emission (at a specified level of plant efficiency) and the corresponding price of electricity. If the level of the spreads is above 0, power plant operators earn positive contribution margins in the observed period.

Figure 1: Evolution of clean spread and dark spreads (Euro/MWh) in selected markets and electricity generation from coal in the EU (TWh)



Source: Platts and ENTSO-E Data based on the European Commission's Market Observatory for electricity markets (2017)

Furthermore, the increasing liquidity in LNG markets worldwide may have a positive direct or indirect impact on gas market prices also in Europe putting downward pressure on prices, and consequently on the cost of gas-fired generation. Another favourable factor is the review of the emission trading scheme and introduction of more effective mechanisms on carbon price[12]. Under the proposed changes, the number of allowances will be gradually reduced to raise their prices and provide effective incentives to adopt environmental friendly technologies.

The expected positive development is reflected in the gas demand scenarios. In the high and average gas demand scenarios, gas is expected to continue to play a substantial role in electricity generation. In the high demand scenario, gas-fired power plants are expected to increase their market share due to their back-up function for RES and in the base-load part of the market. In the average demand scenario, the main source of electricity generation is expected to be from RES sources in combination with a decrease in the use of coal and natural gas for power generation.

[12] Reference is made in this case to the United Kingdom where the introduction of a floor to the carbon price contributed to the increase in gas-fired power generation. Recently France has also proposed to establish a floor for carbon prices in European emission trading scheme. In addition, it suggests imposing a carbon tax at EU borders to ensure a level playing field for non-EU competitors.

Natural gas will also continue to be important in the low demand scenario as gas-fired generation is still necessary to back-up RES and to ensure system stability. It is however predicted to decline in the period after 2030 as the power sector reaches full decarbonisation. Notwithstanding the decrease of energy demand, sufficient network capacity may need to be maintained because gas-fired power plants will frequently be called on as a back-up for intermittent RES during times of peak demand.[13]

4.1.2 Regulatory Implications

With respect to the gas commodity market, regulation should aim to enhance competition in this market. Direct interventions such as subsidies for gas generation, do not appear adequate and will cause distortive effects. In our view, regulatory measures appear necessary in the following areas:

- Wholesale gas markets
- Gas transportation tariffs
- Sector coordination
- Carbon market prices

In addition, a well-functioning carbon market is an essential factor to progress towards low-carbon electricity generation.

Effective Wholesale Gas Markets

The existence of effective wholesale gas markets is relevant not only for use of gas for electricity production but also for all markets for goods using gas input.

The focus of the current EU regulatory framework in gas markets has been to ensure effective competition and non-discriminatory access to natural gas pipelines. However, the targets set by the EU have not been completely met as originally designed by the Gas Target Model (GTM). Although progress has been made, market integration has not materialised as originally aimed for in terms of upstream concentration and limited liquidity. ACER revisited the GTM and developed a “Bridge to 2025”. This revolved around the key aspects of wholesale market functioning, upstream competition and new developments in the gas supply chain.

The GTM advocates larger markets and trading areas to pool liquidity and promote competition in upstream supply. Market mergers that have happened within member states or trading zones indicate that a merger of zones are possible and can be attractive. However, not all zonal mergers would be beneficial. Some mergers would not have a substantial impact on competition and could be unfavourable in other ways. For example, a zonal merger may result in a disproportionately high share of interruptible transport contracts or inefficient investment

[13] Depending on the connection level of the gas-fired power plants, the need to maintain capacity is referred to the transmission or distribution networks.

decisions. Zonal mergers would therefore need to be carefully evaluated using CBA (cost-benefit-analysis) and only those beneficial zonal mergers should proceed. In practice, even zonal mergers with positive CBA results can be hampered by national considerations related to changes of wholesale prices and tariffs.

Regulators may think of a series of regulatory initiatives to further develop the necessary tools for market integration across Europe. A new mechanism should be defined to achieve the merger of trading hubs or markets currently managed by different TSOs. This new mechanism could even take the form of a network code defining the procedures for achieving a merger of trading zones.

Gas Transportation Tariffs (TSO)

The design of network tariffs for transmission system operators plays a substantial role in facilitating the use of natural gas in the power sector. Such use will become increasingly important in virtually all demand scenarios selected as gas fired generation represents the main back-up source of power for intermittent RES. The transmission tariff design is set out in the Network Code Tariffs (TAR NC)[14] which was adopted in March 2017 and now is being implemented. The code deals with tariff design at interconnection points, and not at domestic network points. The implementation of the code may change the current transmission tariff structure in some European countries.

The current design of network tariffs in fact discourage the efficient use of gas-fired power plants in some cases by creating excessive costs for such plants in accessing the gas network and gas supplies. With a decreasing annual utilisation, transport tariffs may become a significant part of the cost of operating a plant. The gas transport tariff may affect the balance between further operation, mothballing or even closure of a power plant.

Regulators should review existing arrangements with a view to minimising the extent to which, given existing infrastructure, gas users, most notably power plants, are dis-incentivised from operating when it would be efficient to do so. There is also a risk of creating a vicious cycle by which the revenues lost from the power plants will be charged via higher tariffs to other market participants and may discourage them to use the network.

Gas transportation tariffs are dominated by capacity charges differentiated by capacity products. Capacity products are sold for different durations, for example long-term products are generally defined as contracts of one year or longer and short-term products are shorter than one year and can be down to one day and intra-day. While capacity products with diverse duration can be available at interconnection points, they may not be however offered at connection points of gas-fired power plants. Offering short-term products at these connection points would allow greater flexibility in reserving capacity for short term periods to better match the capacity booking with the gas demand profiles. Confronted with a lower utilisation, gas-fired power plants will need to use network capacity for short periods of time. Regulators should consider using a short-term multiplier that will not excessively increase the short-term capacity

[14] The network code on rules regarding harmonised transmission tariff structures for gas

charges and at the same time not discourage network users to book short-term capacity. Such an approach would help mitigate the cost exposure of power plants to book transport capacities and may also support the revenue position of the network operator.

Furthermore, from a broader context, the declining demand and excess transportation capacity in the low demand scenario may necessitate a basic re-thinking of the network tariff design. This would address not only gas-fired generation but also gas imports & exports / entry-exit and gas storage. In the case of competing import routes the tariff structure and tariff levels may determine the preferred routing and affect the network use. Gas storage is important for supply security and the tariff design should contribute to the efficient use of storage and should also ensure that storage facilities do not close prematurely due to unreasonable cost burdens.

Where there is surplus transport capacity, auctions are an efficient instrument to allocate that capacity. With decreasing gas demand in some regions/routes, the auction prices would fall. Auctions can play a role to allocate uncongested capacity, however auction revenues may not be sufficient to recover the cost. The auctions are based on reserve prices which constitute the minimum prices below which no capacity allocation will take place. The setting of reserve prices in systematically and structurally under-utilized systems, would need a stronger orientation to short-run marginal cost. However, the revenue based upon marginal cost tariffs will threaten the cost recovery. Ramsey pricing has been often proposed to adjust marginal cost tariffs and to resolve the cost recovery. Ramsey pricing also suggests to charge the remaining costs on those users who are less price sensitive, i.e. network users that are less able to change supply sources and/or transport routes and should therefore contribute more to the recovery of the remaining cost. The application of Ramsey pricing may lead to higher mark-ups for cost recovery on (within country) domestic entry points than on entry points into the EU system or exit points to neighbouring systems. There may be a need to consider harmonizing the reservation prices (in terms of structure and level) within wider regions in Europe to avoid potential distortions.

Improve coordination of power and gas sectors

We believe that additional measures should be implemented to ensure that regulatory and market arrangements allow for more efficient use of gas-fired power plants. As indicated in the scenarios a significant gas-fired generating capacity is likely to be needed to provide flexible back up to RES generation. This will require an improvement of the coordination between the electricity and gas sectors in terms of operational decisions, time alignment but also a coordinated approach to plan new infrastructure, for gas to continue to be a back-up or storage facilitator for RES. Such coordination should be driven by more intensive cooperation between gas and electricity TSOs.

Carbon Market Prices

A well-functioning carbon market will importantly support the progress towards a low-carbon energy system. On overall policy level, measures may be necessary to further address the effectiveness of emission trading scheme and improve its steering role. As mentioned above the European emission trading scheme has contributed to small and disproportioned emissions reductions between different types of conventional generation. It has had limited impact on investment decisions and innovation towards low-carbon electricity generation.

4.2 Use of Natural Gas for Heating

4.2.1 Role of Natural Gas

Natural gas is used to heat (and cool) residential and commercial buildings. It competes with other sources inter alia such as district heating[15], fuel oil in the heat market and increasingly heat pumps especially for new buildings. Competition means that consumers can receive heat from difference sources.

In the case of district heating, the consumers purchase heat directly while in the case of heating with natural gas or oil they receive the fuel which then needs to be converted into heat via the boilers in their home. Similarly, in the case of heat pumps they receive electricity which is converted into heat.

The competitive position[16] of the different concepts is influenced by the transport cost, i.e. heat network, natural gas network and oil delivery by road transport.[17] The cost depends on the configuration of the networks / transport services and the specific local consumption conditions,[18] The second important factor is the cost of heat generation which is characterised by generation technology and fuel procurement cost. For example, in the case of district heating, generation based on waste heat from local industry or CHPs may improve competitiveness due to the efficiency advantages of the joint production process.[19] In the case of natural gas and oil supply the heat generation cost depends on the cost and efficiency of the boiler and the respective fuel prices.

The competitiveness of gas in the future will depend to a significant extent on the underlying policy framework, development of technologies and fuel prices. This is also implied in the specification of the demand scenarios.

In the high gas demand scenario, future heat demand remains stable due to the lack of significant improvements in energy efficiency and natural gas will continue to be the main fuel for heating purposes. In the average and low demand scenarios heat demand declines if EU

[15] In district heating systems, heat is generated centrally or derived from an existing heat source, and distributed by pipelines, mostly in the form of hot water. In addition to heat plant and distribution networks, the system also contains heat substations that deliver the heat to customer premises. Heat has been traditionally generated in large power stations and in cogeneration plants, different types of heat-only boilers (burning gas, oil, electricity), waste incinerators and industrial facilities producing waste heat. In the last years, the share of renewable heat production technologies (biomass, geothermal, solar thermal, heat pumps) has been increasing.

[16] See also Annex 2.

[17] For heat pumps these will be electricity networks.

[18] For example, short distribution networks with high consumption densities, typically urban areas with high population density, would reduce distribution costs.

[19] The improvement will depend on the extent to which these advantages are allocated to heat supply whereas the advantages will be influenced by the electricity market prices and regulatory rules on joint production pricing.

energy efficiency requirements are successfully implemented. This is because new buildings will exhibit high energy performance and existing buildings will be upgraded to meet the minimum energy efficiency requirements. On the supply side, natural gas will continue to be used in heating systems. While its market share will decline, natural gas can be substituted by renewable gases. In addition, the share of district heating and heat pumps will increase.

4.2.2 Regulatory Implications

The principal objective should be to ensure effective competition between the available heating solutions, however in the light of the specific environmental targets and the underlying policy framework meeting environmental targets in Europe has been significantly supported by multiple policy incentives in the different member states. Examples of such policy incentives include inter alia fuel taxes, co-generation support schemes, subsidies and funding facilities or energy efficiency promotion tools. There have also been incentive schemes specifically targeting renewable energies and efficiency in the heating sector.

In respect to the gas market, gas wholesale and retail supply are competitive areas. Drawing on the underlying concept of competitive markets and the requirements of EU Directives, there is no scope for a direct price regulation of gas supply to consumers except for the targeted protection of vulnerable consumers. ACER's market monitoring results show that many markets remain highly concentrated, with low switching activity from consumers. Furthermore, in practice, price regulation of end-user prices, particularly household consumers, is still widely applied in EU countries. Regulated prices for household consumers are often justified by policy makers for protecting vulnerable consumers.

National regulators should continue to focus on the further enhancement of the framework for retail competition (e.g. facilitating market entry and improving switching procedures) and consumer empowerment and protection. The gradual abolishment of price regulation must follow the establishment of functional retail competition, while ensuring the effective and targeted protection of vulnerable consumers. Where retail prices remain to be regulated, they should reflect the underlying cost of gas supply and should not hamper the development of a competitive retail energy market. Departing from such principles may discourage market entry and innovation, increase suppliers' uncertainty regarding their return on investment in the long term and consequently hinder competition in retail energy markets.

4.3 Use of CNG and LNG in Transportation

4.3.1 Role of CNG and LNG in Transportation

In the last few years, gas has become increasingly important in the transportation sector, in both LNG and CNG forms. It is utilised in either dedicated natural gas engines or dual-fuel engines, used to burn petrol or diesel.

CNG and LNG present similar characteristics that make them a fuel suitable for use in different parts of the transportation sector. In order to produce CNG, natural gas is compressed between 200 and 250 bar. Internal combustion engines powering most land and maritime transportation vehicles can generally be converted or built to operate on both on regular gasoline and oil-based fuels, as well as CNG. CNG is therefore used in several applications including cars, buses, vans, trucks, tractors with an increasing number of vehicles being available on the market from multiple suppliers.

Natural gas is compressed by 600 times its volume to be converted to LNG. This is in turn used in various applications from regasification for injection of the gas into transmission networks, to fuel to be used in land and maritime transportation. The use of LNG in land and maritime transportation represents the most innovative development in the use of LNG. In the land transportation sector, LNG is used as a fuel for heavy duty vehicles due to its ability to substitute diesel fuels and the possibility to be stored in volumes sufficient to ensure adequate travelling ranges to meet the requirements of heavy duty vehicles. In the maritime sector, LNG has experienced an increase in use in the last few years as a fuel for bunkering activities and fuel for ships. Multiple value chains options are possible both in the CNG and LNG business (see Annex 3).

Demand for natural gas in transportation is expected to increase under the three scenarios. The extensive deployment of LNG and CNG technologies in the road and maritime transportation plays a substantial role in realising this increase. This is line with our analysis of the competitiveness of natural gas in the transportation sector indicating that natural gas can generally be considered as a competitive fuel both in land and maritime transportation.

In the land transportation sector, we have assessed competitiveness in both light duty (LDVs) and heavy duty (HDVs) vehicles sub-sectors. Three factors have been considered, cost competitiveness (capital and operating costs), fuel availability (sufficient refuelling stations for vehicles or bunkering facilities for ships), and emission reduction potential. Natural gas-fuelled vehicles and traditional diesel fuelled are included in the analysis for HDV. Natural gas-fuelled vehicles, gasoline, diesel and electric vehicles (EVs) are compared in the analysis for LDV[20].

In the maritime transportation sector, we have assessed competitiveness for different types of ships fuelled by marine gasoil, fuel oil and LNG.

In the land transportation sector (HDV and LDV), natural gas-fuelled vehicles exhibit competitive advantages in terms of operating cost. This counterbalances the higher capital investments (however decreasing over time) to purchase them compared to regular gasoline and diesel vehicles. In terms of environmental impact, natural gas vehicles generally have lower emissions compared to other types of vehicles, and are typically well positioned to support the achievement of environmental targets in the transportation sector.

[20] Fuel cell electric vehicles (FCEV) have not been considered in our assessment of the competitiveness of various types of vehicles and fuels in the transportation sector, as they have not reached a level of market penetration similar to that of natural gas fuelled vehicles and EVs. We however provide an assessment of FCEV in Annex 4, section Hydrogen Used as a Fuel in the Transportation Sector.

In the maritime sector, LNG-fuelled ships still represent a minority of the total fleet but the ability of LNG to reduce emissions of ships and its potential cost competitiveness are the main driver behind its use as a fuel in maritime transportation.

Heavy-duty vehicles

In the HDV sector, natural gas-fuelled vehicles appear rather competitive under current market conditions. The major reasons are the comparable (and often higher) operating efficiency of gas-fuelled HDVs compared to diesel equivalents and the ability to ensure a competitive range coverage. Currently gas-fuelled HDVs still sell at a premium price compared to diesel HDVs equivalents.

In the future, it is realistic to see a reduction of purchase and operating cost due to sales enlargement. The potential to increase efficiencies and reducing the cost of purchase of gas-fuelled HDVs are the main elements that can further increase the competitiveness of gas as fuel in the transportation sector. The possible travelling range without refuelling for gas-fuelled HDVs is comparable or potentially exceeding the one of regular diesel-fuelled HDVs[21].

In relation to emission reductions, gas-fuelled HDVs exhibit favourable characteristics in terms of greenhouse gas emission reductions compared to diesel HDVs. However, a precise estimation of the emission reduction potential achievable with gas-fuelled HDVs remains difficult due to different use and load patterns of such HDVs. Several studies have been conducted indicating figures of emissions reduction between 6 % and 20% compared to diesel HDVs[22]. However, the generally lower efficiency of most heavy-duty engines as well as issues of methane leakage[23] may limit to some extent the potential benefits of lower CO2 emissions from natural gas. It is worth noting that the engines can reduce other types of emissions (particle pollution and sulphur emissions) which receive increasing public attention especially in urban areas.

The limited number of LNG refuelling stations currently available is a factor that has negatively affected the competitiveness of the LNG-fuelled HDV. Recently, there are various developments leading to an improvement of the situation.[24]

[21] This is due to the dual-fuel capabilities of gas fuelled HDVs, using both diesel and natural gas.
[22] The assessment of the emission potential reduction of natural gas fuelled HDVs is generally done in the studies assessed using a “well-to-wheel” (WTW) approach. A WTW approach takes into consideration the entire life-cycle of the fuel from production to combustion including extraction, separation and treatment, transportation, refining and distribution to the tank of the vehicle. It therefore provides a more comprehensive and precise approach of the total emissions released by the vehicle during its lifetime. An alternative approach that can be used is the “tank-to-wheel” (TTW) approach which focuses on the measurement of the different tailpipe emissions of vehicles
[23] Some LNG is passed through the engine without being burned and therefore released in the atmosphere.
[24] See e.g. http://www.gaz-mobilite.fr/actus/jacky-perrenot-vise-1000-camions-gaz-gnv-2020-1776.html or http://www.gaz-mobilite.fr/actus/transport-routier-groupe-jost-35-pourcent-flotte-gaz-naturel-gnl-gnv-1744.html

Light-duty vehicles

In the LDV sector, the competitiveness of natural gas is partially challenged by EV[25]. In comparison to natural gas-fuelled vehicles EVs exhibit higher operating cost efficiency but also higher purchase cost. Beyond that also the limited autonomy in terms of range compared to conventional or natural gas-fuelled vehicles and the longer charging times are typical considerations of potential buyers.

In relation to the emission reduction potential, EVs present a higher emission reduction potential being virtually emission free. This is based on assessment using a tank-to-wheel approach (TTW). It is important to highlight, however, that an assessment of LDVs emissions using a well-to-wheel (WTW) approach presumably arrive at higher emissions of EVs, i.e. lower emission reduction potential of such vehicles compared to alternative technological concepts. The production cost of EVs, and primarily batteries[26], have rapidly decreased during the last decade. A similar trend is likely to occur in relation to the cost of charging points[27]. It is therefore realistic to expect that the share of EVs will continue to grow driven by lower cost and environmental regulation favouring zero emission vehicles. Current projections indicate that the share of EVs is expected to increase in the future with EVs reaching as much as 50% of the total market share for LDVs by 2030-2040[28]. However, no complete substitution of regular gasoline vehicles with EVs or natural gas vehicles is expected. The competitiveness of EVs is affected by the limited number of charging points available across Europe. In addition, the growing charging points in the future would likely require substantial investments in distribution networks.

Despite the above-mentioned challenges, natural gas-fuelled vehicles and EVs exhibit advantages over regular gasoline and diesel vehicles, especially in relation to operating efficiency and environmental performance. Consequently, their market share in the LDV segment will likely increase.

[25] The subsequent assessment of electric vehicles (EV) applies to battery electric vehicles, being due to their more advanced level of market penetration compared to fuel cell electric vehicles, etc. However, stated disadvantages of battery electric vehicles may be partially offset by fuel cell electric vehicles in the future.

[26] For example, the cost of batteries has been decreasing constantly in the last 7 years with a year-on-year drop of on average 19% between 2010 and 2016. Batteries represent a substantial cost component of EVs. In addition, their design and capacity affect the range possible for EVs. Contrary to CNG vehicles, whose engines' design is based on conventional gasoline engines, EV electric engines still have a large potential to further improve their efficiencies of their engines and costs. The increase in the capacity of batteries for EVs will also impact the charging times needed for such batteries. Increasing battery capacity will likely reduce charging times which in turn is expected to increase the competitiveness of EVs. Charging times now vary from 6-7 hours for batteries with a capacity of 3,3 kW to 10-30 minutes for newer batteries with a capacity between 50 and 120 kW.

[27] The flexibility in the location of charging stations given their relatively small size is a competitive advantage of EVs charging infrastructure. In some European countries, EVs charging infrastructure has also received support in terms of investments subsidies or financial support for R&D of such stations.

[28] Bloomberg New Energy Finance, Electric Vehicle, Bloomberg, 2017, available at: https://about.bnef.com/electric-vehicle-outlook/

Maritime Transportation

In the maritime sector, natural gas competitiveness seems to stem from higher cost efficiency and effectiveness in reducing the emissions of various types in the face of increasingly strict emission standards for ships. The overall number of ships running on LNG remains however small compared to the total number of ships registered in Europe. The principal driver for the increasing use of LNG in transportation can be identified in the need to reduce emissions. The main challenge is related to the infrastructure investments, mainly in bunkering facilities required to meet the increasing fuel demand. The situation resembles the one in the LNG fuelling infrastructure in road transportation where the number of refuelling stations is considerably lower than the ones of diesel.

4.3.2 Regulatory Implications

The transportation business can be considered as contestable[29] due to the presence of multiple means of transportation, fuels and different suppliers and buyers both of fuels and vehicles. There is no evident need of price regulation in such contestable business. These are competitive markets and should be monitored by competition authorities to prevent market abuse and correct market failures or irregularities.

The competition of natural gas against other fuels is, however, strongly affected by environmental regulation. Environmental regulation seems to be a significant factor that influences the overall competitiveness of fuels in the transportation sector in general. Moreover, it is an important factor that steers vehicle manufacturers in determining the type of vehicles that they will offer to the market. Emissions targets have already been set for vehicle manufacturers.

Measures appear necessary for fuel availability and fuelling infrastructure. Such infrastructure is still fragmented and partly limited in Europe, which can impede the growth in use of natural gas in transportation across the sub-sectors assessed. The major reason for such limitations is the presence of the "chicken and egg" problem. On the one hand, users of CNG and LNG expect to have the fuel infrastructure available before committing to purchasing the vehicles running on such fuels. On the other hand, CNG and LNG infrastructure developers expect to have a sufficient demand in place to ensure cost recovery for the infrastructure to provide such fuel. We address infrastructure issues in Chapter 5.

On policy level, there are multiple measures that can be considered to support the use of natural gas. These measures aim to promote the development of certain new technologies

[29] The contestability of a certain economic activity is a key criterion used throughout the analysis in this study. The contestability of a certain activity is defined by the existence of multiple providers of services or products in that activity. The presence of multiple competing providers requires three elements to be in place. First, entrance should be free and entrants may enter the market. Secondly, exit should also be free so that any firm may leave without impediments to the recovery of cost of entry. Finally, no company operating in the market could be able to prevent new firms from entering or forcing them to leave by temporarily cutting its price.

with favourable environmental impact (positive externalities and innovation). Examples for the types of such measures have been observed in the initiatives taken to support EVs. These initiatives include, typically on a national level, tax breaks, incentives for the purchase of EVs, subsidies for charging points, etc. However, gas fuelled vehicles and infrastructure for their fuelling have not yet received a level of policy support like the ones provided to EVs. Indeed, some policy support for the use of natural gas in transportation has been provided on the infrastructure side (CNG/LNG refuelling stations)[30]. However, policy makers may consider additional measures, such as tax breaks and incentives for their purchase that can also be applied to the gas-fuelled vehicles. Specific tax incentives on CNG and LNG as a fuel for transportation would also help to support the increasing use of natural gas in this sector.

Finally, licensing requirements for the supply of natural gas (and in broader context also LNG and CNG) differ across member states. To facilitate the supply of LNG and CNG by different market participants across Europe, a harmonization of licensing requirements for natural gas supply may be beneficial. Such harmonisation would require a thorough review of the national licensing requirements to achieve a common European licensing approach. Having a coherent and unambiguous regulatory approach would remove uncertainties, establish a level playing field for the competing fuel and facilitate the cross-border development of new activities.

4.4 Renewable Gases

4.4.1 Role of Renewable Gases

Renewable gases are gases produced from renewable sources. They represent alternative gases with the ability to substitute natural gas and include biogas upgraded to biomethane and synthetic natural gas (SNG) produced in methanation process. In addition, we explore hydrogen produced in power-to-gas (P2G) applications via electrolysis or steam gas reforming, with further involvement of CCS technology. See the figure below and Annex 3).

Biogas/Biomethane

Biogas can be used to produce electricity and heat, or upgrading to biomethane used as a fuel in the transportation sector or injected into the natural gas grids. The main technology used for production of biogas is generally called anaerobic digestion (AD) and is based on breakdown of organic material in the absence of oxygen. Plants carrying out AD allow microorganisms to digest the feedstock used in a controlled reactor in the absence of oxygen.

The proportion of methane contained in the biogas produced is in the range of 50%-65%. The source of feedstock for biogas production includes organic waste, industrial waste, agricultural waste (manure) and energy crops. It depends on the region and location of the production

[30] Reference here is made to the Blue Corridors Initiative. Support to the development of infrastructure for the use of natural gas in transportation (HDVs) has been provided in the form of support for the development of minimum infrastructure in strategic locations (see Annex 4 for more details).

plant. The plant can be located at landfill sites, municipal and industrial wastewater treatment plants or other places. A pre-treatment of the feedstock is also carried out in certain circumstances before using the feedstock in the AD plant. Such pre-treatment is aimed at enhancing the ability of feedstock to generate biogas by eliminating chemicals that inhibit the growth of micro-organisms that can disturb the production process. Once biogas has been produced, a cost-effective option is to use it near the production point to meet local demand for heat and/or power. Where there is insufficient local demand, upgrading to biomethane for injection into the gas network can be a useful alternative. Gas injected in this way displaces traditional natural gas giving savings in greenhouse gas emissions. The upgrading to biomethane can be achieved using different methods, these include adsorption, membrane filtration or cryogenic separation. These methods aim to increase the proportion of methane in biogas to 95% (biomethane).

Biogas production and use has found momentum in many countries across Europe. Its primary drivers are the availability of waste that can be effectively collected as well as regulatory incentives given to biogas and biomethane production. Multiple types of waste can in fact be used to produce biogas and biomethane contributing to its overall production flexibility. Biogas and biomethane can contribute to decarbonisation targets and to reduce the carbon footprint of the activities in which it is used. However, this also depends on the policy and regulatory support due to the high production and treatment cost of biogas compared to natural gas.

According to data from 2015, Europe has 17.376 biogas and 459 biomethane plants.[31] On the forefront of this development stand Germany and Italy as countries that for long had practiced favourable support schemes and incentives. Consequently, the biogas industry in some Member States have reached a matured level, mainly reflected in reduced feed-in tariffs or even their phase out. Nevertheless, biogas plants are being further upgraded to biomethane units which can inject directly into the natural gas network and this sector is experiencing steady growth. For example, in 2016 France recorded the largest increase of biomethane injected into the national gas grid—of about 160% compared to 2015, with other Member States following this trend.

[31] Source: European Biogas Association (EBA), 2015

Power-to-gas (P2G) and Hydrogen

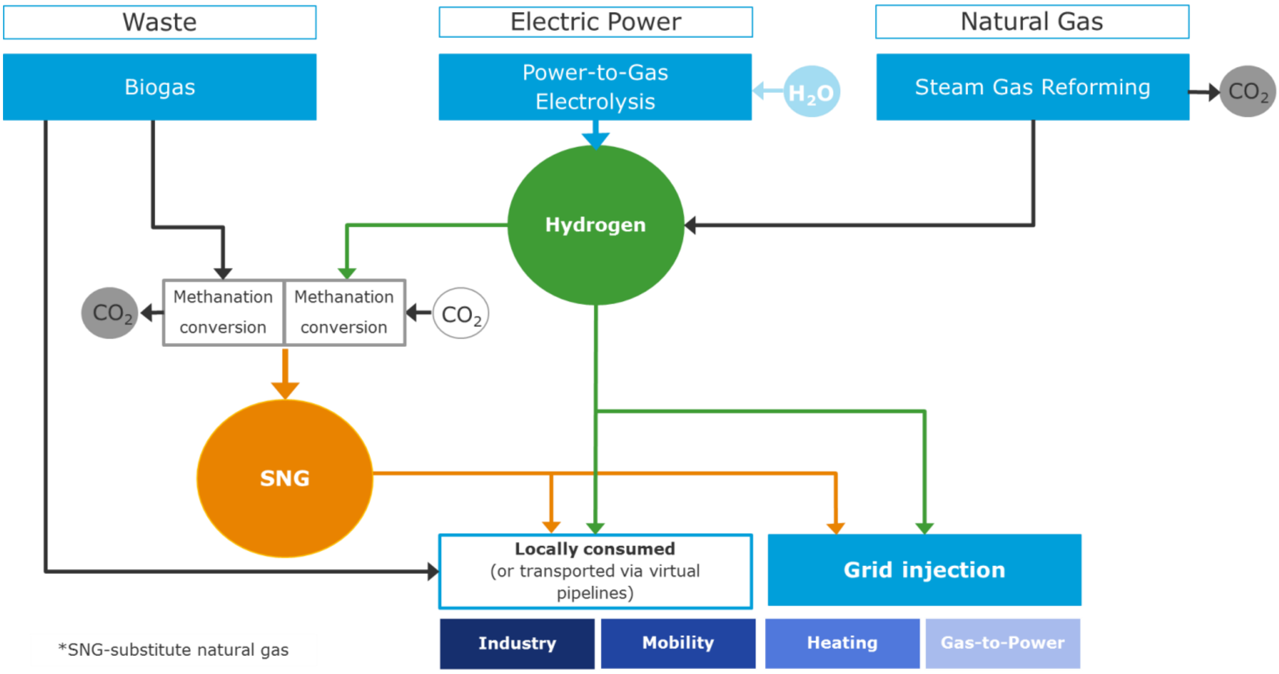
Power-to-gas is the functional description of the conversion of electrical power into a gaseous energy carrier like e.g. hydrogen or methane. Hydrogen can be transported by trucks or rail cars, or through pipelines. The latter can use hydrogen blend, i.e. a certain proportion of hydrogen is mixed with natural gas into natural gas network, where the existing network transports natural gas but with a changed energy content. Alternatively, it can be based on a full conversion, i.e. transportation of pure hydrogen via the network, where the network becomes essentially a hydrogen network.

Hydrogen is expected to become an important future energy carrier. Hydrogen produced via P2G and combined with renewable electricity could positively contribute to security of supply by reducing the dependence of fossil fuel import. For example, P2G can be used to absorb and store electricity by converting it into hydrogen in case of surplus renewable electricity. This is of a particular interest for Europe where the combined generating capacity of offshore wind farms could reach around 100 GW by the year 2030, while the PV capacity installed is expected to increase from 35 GW in 2012 to almost 60 GW in 2020 where P2G could help to accommodate these quantities.[32] Later the hydrogen can be used as a transport fuel, converted back to electricity or injected into the natural gas network. Hydrogen itself represents an alternative source of gas that can help meet environmental targets and reduce overall carbon emissions. While hydrogen would play a role in all three demand scenarios, its role may become substantial in the low demand scenario when electricity generation relies for the most part on RES (wind and solar).

Hydrogen is already used as a gas and liquid in the petroleum industry and in manufacturing processes for producing chemicals, foods and electronics. There are also examples for use of hydrogen for electricity and heat generation, and as a fuel in the transportation sector.[33] However, these are still at early implementation stages or demonstration level (see the examples in Annex 4). Production costs are still high compared to other fuels used. Further challenges exist in transporting the gas.

[32] See European Power to Gas Platform—chaired by DNV GL.
[33] Hydrogen could be burnt in an engine in a similar way to petrol, the gas burning in air to release energy. Although there is an advantage as there is no carbon dioxide produced, harmful nitrogen oxides would still be formed in the engine. However, in a fuel cell, hydrogen can react with oxygen without burning. The energy released can be used to generate electricity, which is used to drive an electric motor.

Figure 2: Different Forms of Supplies of Renewable Gases (Simplified Representation)



Source: DNV GL

4.4.2 Regulatory implications

With respect to regulation one should distinguish between production and supply of gas (hydrogen or biomethane) and the use (or conversion) of infrastructure to transport the renewable gases. We address the regulation of the infrastructure in Chapter 5. In this chapter, we also address the regulatory incentives for innovation and decarbonisation in the context of renewable gases.

Production of hydrogen and biogas production are potentially contestable activities[34] and there is no normative need for regulation if functional markets exist. However, policy interventions to address positive externalities related to renewables gases are common and often used in practice. They aim to support commercial viability and to encourage supply of such gases as environmental benefits resulting from their use are not adequately reflected in in the respective output prices.[35] They should treat renewable gases and other renewable energy sources equally in the respective areas of intervention (e.g. building policy, emission regimes etc).

[34] There are up-front investments required however costs are not substantial. The production plants can be scaled to meet demand and there are multiple production units controlled by multiple providers.
[35] Positive externalities mean that renewables gases have fewer carbon emissions than fossil energy sources for example in the fields of transport, electricity production and heating. However, this carbon saving is not adequately reflected in the respective output prices.

The policy interventions can be implemented through methods ranging from feed-in tariffs, to tax breaks and investment support, etc. The tariffs can be set for the biomethane injected into the natural gas network or for the biogas used to produce heat and electricity.

Biomethane is in most cases injected in distribution networks. However, injection at the transmission level is also technically possible. Network tariff incentives should therefore be adequately designed in the context of the specific situation in the respective country.

Promotional tariff schemes can also be used for hydrogen production at the distribution and transmission level. Fiscal measures based on tax incentives and investment grants can also encourage production of hydrogen. Further support can be provided through the reduction or abolishment of duties or levies on the use of hydrogen as a fuel in transportation.[36]

Green certificates can be used to support the establishment of regional markets for biomethane. Certificates similar to the ones used in the power sector for renewable energy can also be used to certify the renewable nature of the gas being purchased[37]. Producers can consequently trade such certificates on the market and consumers can receive guaranteed for the purchased gas.[38] These certificates can therefore support cross-border trading of biomethane.

It is worth noting that regulators in some jurisdictions (for example UK, Ireland, France) have provided funds to support the research and development of these new technologies. This has included pilot projects for possible injection of biogas and hydrogen into the gas network and exploring gas quality specification of biogas, hydrogen blend for example. In Annex 4 we provide example of projects in new technologies.

[36] Hydrogen finds in fact application in the transportation sector although to a limited extent compared to natural gas. Some car manufacturers are however investing in fuel-cell hydrogen vehicles.

[37] In this respect, the project CertifHy represents one example of the potential use of certificates to support renewable gases and in this case specifically hydrogen. More information available at the following link: http://www.certifhy.eu/

[38] A similar solution could be implemented in the transportation sector, where vehicle manufacturers can benefit from the receipt of certificates of biogas to meet the emission requirements set by regulation for their fleet of vehicles. Member States would be responsible for certifying the amount of biogas used in transportation within their territory. A level of biogas certificates equivalent to the market share of the car manufacturer in the country could be then allocated to the manufacturer based on the total biogas used in the transportation sector within the country. This would help the manufacturer in meeting its emission target which is calculated every year.

5 Infrastructure

The section explores the regulatory implications in the infrastructure area. We start with the traditional natural gas infrastructure, particularly in the context of the low gas demand scenario. Consequently, we address the infrastructure for new uses of natural gas such as the use of CNG/LNG in the transportation. Such infrastructure comprises the refuelling stations which also can include compression equipment to convert natural gas in CNG or LNG, and storage facilities. Finally, we turned to the regulatory measures needed for infrastructure for renewable gases and incentives for innovation and decarbonisation. We also address district heating in terms of possible regulatory arrangements for district heating sector.

5.1 Natural Gas Infrastructure

5.1.1 Role of Natural Gas Infrastructure

The role of the natural gas infrastructure is to transport natural gas through the transmission and distribution grids in a safe, secure and efficient manner to its users. The natural gas infrastructure is made up pipelines, (small / network-related) storage facilities, pressure regulators, compressor stations (relevant for gas transmission) to ship or transport the natural gas through the network. The construction and route of a natural gas system depend on the geographical conditions, environmental considerations, the distance and the pressure level. As other energy infrastructure industries gas networks are also characterised by high initial and irreversible investments, and has a relatively long asset life (approximately 50-60 years). In the EU natural gas infrastructure is regulated, however member states may opt for negotiated or regulated access regime for storage facilities.[39]

This section explores the regulatory implications on the traditional natural gas infrastructure (primarily gas transmission), particularly in the context of the low gas demand scenario. The selected low gas demand is driven mainly by achieving the environmental targets and energy efficiency programs. Notwithstanding the potential of renewable gases to contribute to decarbonisation in a cost-efficient way, this would require collective commitment of policy, regulation and industry in order to be utilized within an enhanced concept of a widely decarbonized energy sector based on the continued use of the existing natural gas infrastructure. Without prejudice to that potential way forward and solely looking at the natural gas demand scenarios (excluding renewable gases), a decline in natural gas would lead to a reduced demand for natural gas network capacity over time.

This may lead to cases of stranding of assets in the natural gas networks.[40] We address this issue from a conceptual perspective in the following section.

[39] In addition, there are possibilities for exemptions from regulation for new infrastructure that are specified in the Gas Directive.

[40] We refer to potential stranding that may occur in some network areas. We realise that even if the future consumption is low, gas will be needed as back-up and many networks will continue transporting gas to gas fired power plants. Furthermore, even underutilised, networks may be required for security of supply reasons.

5.1.2 Regulatory Implications

We address a potential regulatory treatment of stranded assets by exploring the different options such as depreciation policy, asset valuation and adjustment of cost of capital.[41]

In any case the application of such regulatory instruments should be based on an individual assessment and take into account the interrelation and compliance with regulatory goals such as cost-reflectiveness, tariff stability, energy affordability, etc.

Beyond that we address from a theoretical/hypothetical point of view a coordinated decommissioning of stranded assets. As decommissioning could relate to an asset stretching over more than one country we adopt a broader approach focusing on the processes for cross-border decommissioning.

5.1.2.1 Stranded Assets

Factors/Criteria for the identification of Stranded Assets

There are different factors which may contribute to network assets being stranded. Based on the assumptions of the anticipated structural decline of natural gas demand in the low gas demand scenario, gas demand in the residential sector is falling due to energy efficiency programs in certain EU countries (e.g. UK and Germany). Furthermore, gas demand in the power sector declines in the period after the 2020s[42] as it is assumed that the power sector reaches full decarbonisation. It is assumed that the transportation sector sees an increase in natural gas demand due to phase-out of conventional vehicles and in parallel being replaced, besides others, by natural gas and hydrogen vehicles. However, the total demand for natural gas declines gradually in the period post-2020 with a sharper decrease post-2030 even with the increase of demand in the transportation sector.

From a regulator's viewpoint, regulated gas assets classified as "stranded" need to be treated on a case-by-case basis to consider the specific circumstances. In most regulatory frameworks, there is no defined regulatory treatment for stranded assets, therefore in this context it can be considered that the regulator's role is more of a reactive one based on observations and expectations of future gas demand decline. In other cases, there may already be a consideration of the potential risk of stranded assets in the regulatory framework.

The drivers of regulatory measures related to stranded assets can be based on the following assumptions:

Finally, as long the substitution of industrial gas remains limited, industry consumers will need to be supplied too.

[41] The regulated company can also be compensated for stranded costs outside of the regulated tariffs of the stranded assets, for example from the public budget or through special charges / levies.

[42] Gas demand in the power sector is needed in order to back-up RES and to ensure system stability.

Based on gas demand scenarios and the underlying drivers behind the scenarios, there is reasonable certainty that gas demand will sustainably decline leading to excess transportation capacity and network underutilisation,

Based on the assumptions of low gas demand, it is expected that the regulated companies cannot recover its allowed revenues under the current conditions of the regulatory framework,

An increase in tariff to off-set the low gas demand will not be sustainable leading to a possible spiral effect of further future reduction in gas demand -existing users will exit the market and therefore making it unattractive for new users to enter.

Regulatory approaches typically presume future consumers will meet a substantial proportion of the capital costs of investments made today in the gas infrastructure. Yet changes in demand, technological innovations and decarbonisation targets have made this presumption less certain resulting in potential stranded assets. This means the effective economic life of the asset is reduced and/or its residual value is less than originally assumed.

Consequently, the appropriate way to address stranded assets will be to consider adjustments of cash flow earned by the assets to maintain their profitability. As gas infrastructure is largely a regulated activity, the three main components making up the allowed revenues in a regulatory framework, i.e. the depreciation allowance, the regulatory asset base (RAB) and the cost of capital (i.e. the rate of return on the RAB). Therefore, these components could be subject to change under conditions of stranding. In the following we explain the different potential options for the regulatory treatment of stranded assets.

Regulatory Depreciation Policy

The recovery of the cost of the initial capital investment of an asset over its life is known as depreciation. The key rationale for the dominant straight-line depreciation approach used widely in regulation has been the promotion of stable network prices over time, and provides for all users of an asset to contribute to the capital costs which support their services.

Depreciation based on short asset life and front-loaded depreciation[43] can be used when it is considered that in the long-term future there is a risk of demand decline or technical obsolescence. These two methods assume that current customers will use the transmission/distribution network more heavily than future customers are likely to. If the asset life is reduced the depreciation allowance will increase which in turn is passed onto network users. This will lead to an overall tariff increase during the shorter (residual) asset life. However, during the shorter residual asset life, the depreciation effect will compensate the effect of the reduction of the return on the asset base in this case, i.e. the allowed revenue based on depreciation with shorter asset life will increase.

As these methods, as mentioned above assume that customers in the short to medium term use the network more intensively than customers in the long-term are likely to, therefore under

[43] Front loaded depreciation means the asset is depreciated more in the beginning and a smaller amount in the later years. The allowed revenue will therefore increase by adopting a change in depreciation profile using front-loaded depreciation.

this assumption they should pay relatively more than the customer in the long-term. This depreciation policy appears suitable if the expected future demand reduction forecast exhibits a high degree of certainty. However, in the case of significant uncertainty of the predictions about the future demand, it may result in an asset which was expected to be stranded – in not being stranded. This would have brought forward depreciation costs unnecessarily. Furthermore, the application of such a depreciation policy will result in tariff increases in the short to medium term to reflect the increase of the allowed revenue. Depending on the price elasticity of the demand reaction for network capacity, the network operators can earn the allowed higher revenue from the higher tariffs or encounter lower demand for network capacity.

Overall, changes in depreciation policy affect the rate and timing of depreciation but does not change the total depreciation allowance. The decisions to change the depreciation policy will impact the network charges and depending on the price elasticity of the demand reaction for network capacity may result in future reduction of capacity bookings. Furthermore, the difference is the time-period in which the depreciation is recognised in the allowed revenue based on the different depreciation policy options and the resulting differences in the RAB will also affect the net present value of the asset (future discounted cash flow earned for continued use of the assets).

One argument for allowing more flexible approaches to depreciation is to permit recovery of charges over the short to medium term when user demand is more certain, rather than pushing back a significant element of depreciation to the longer term when user demand is less certain due to changes to technology and other factors e.g. decarbonisation / environmental targets. Our analysis of conceptual discussions and practices related to treatment of stranded assets by other regulatory bodies, for example Office of Gas and Electricity Markets (Ofgem)[44] shows that there seems to be a tendency towards a more flexible depreciation policy. The change of depreciation policy either by reducing the asset life implies the asset is depreciated quicker (accelerated), i.e. the asset life is reduced, or changing the depreciation profile (e.g. adopting front-loaded). Allowing for accelerated depreciation for network assets would contribute to reducing the risk of the future cash-flows, by making the un-depreciated component of the RAB smaller, and therefore a lower risk of being economically non-recoverable.

Furthermore, a higher flexibility in depreciation policy would also provide network investors greater confidence around the regulatory treatment of new and existing assets. This would mitigate potential incentives for underinvestment compared to circumstances where alternative higher risk or investment deferral approaches were adopted.

Asset Valuation for Regulatory Purposes

A range of methods has been used by regulators to value assets mainly for setting the initial RAB. These methods include historic cost (original purchase price), indexation (values assets at their historic cost for the effect of inflation), replacement value and deprival value. In the

[44] For gas distribution, the 2011 decision document for RIIO-GD1 decided to allow front-loaded depreciation for all post 2002 assets and not just for new assets (i.e. post 2013) to reflect the lower utilisation of the network that is likely to occur under the various scenarios for the future of the energy networks in GB.

context of stranded assets and asset valuation of these assets we address the replacement value and deprival value methods respectively.

Replacement value method calculates the cost of replacing an asset with another asset (not necessarily the same) that will provide the same services (may be using more efficient technology) and capacity as the existing asset. The assets are valued based on what it would cost to replace them today. This method has the advantage that assets are valued in terms of today's prices and reflect technological changes. It can further consider components related to infrastructure optimisation, i.e. the functional combination of assets. From the perspective of the stranded asset this may be somewhat difficult as the cost of replacing an asset depends on how that asset is defined. Is it the physical item in question (e.g. a pipeline) or its future 'service potential' i.e. the asset may still be used but not to its full capacity (due to under-utilisation/limited demand for capacity). Replacement cost valuations entail a degree of estimation and judgment based on the knowledge at the time point which the assessment is carried out.

Deprival value can be defined as the minimum loss the business would suffer if it were deprived of the asset. Were the asset to be replaced, its value would equal the replacement cost. If the asset would not be replaced, then the deprival value would be the greater of the net present value of expected cash flows from the continued use of the asset or the net realisable value of disposing of the asset (exit value). The major merit of deprival value method is that it has a forward-looking component and considers explicitly the expected capacity demand and cash-flows to be generated by the regulated assets. In a regulatory context, the use of deprival values appears difficult due to circularity problem to establish the net present value of expected cash flows from the continued use of the asset (i.e. to set the asset value the regulator needs to know the future cash flows, which at the same time are based on future prices and capacity demand, however prices depend on the allowed revenue and the allowed revenue depends on the initial asset value).

Asset valuation methods are also usually applied in the context of setting the initial RAB for price control purposes i.e. before the start of a regulatory period. We are not aware of specific examples of regulatory precedents in explicitly adopting or amending asset valuation arrangements in the context of stranding. Indeed, one could argue that the future low demand and potential under-utilisation of assets would lead to adjustments of asset value, i.e. implying only partial recovery of the asset, to reflect the realistic expected revenues that regulated companies may earn. However, a technical challenge to apply such forward-looking technique is the estimation of the future revenue stream (and network tariffs) that can be generated by the regulated assets under uncertain future demand, and the circularity problems. Furthermore, the use of forward looking approaches and potential reduction of RAB to account for stranded assets is a legal question and would also have legal implications.

Regulated Rate of Return

The regulatory asset base (RAB) drives two of the fundamental building blocks that make up the company's revenue requirement, these are the cost of capital (i.e. the return on the RAB) and the depreciation allowance. We have addressed possible changes to the depreciation policy and asset valuation as possible options to mitigate the complete stranding of assets. Here we explore adjusting the cost of capital as an option for regulatory treatment of stranded assets.

The return on assets (allowed rate of return) comprises of a return on equity and a return on debt. While the two components can be set separately, the allowed rate of return on assets is often calculated as the Weighted Average Cost of Capital (WACC). WACC is a commonly used method for determining a return on the asset base.

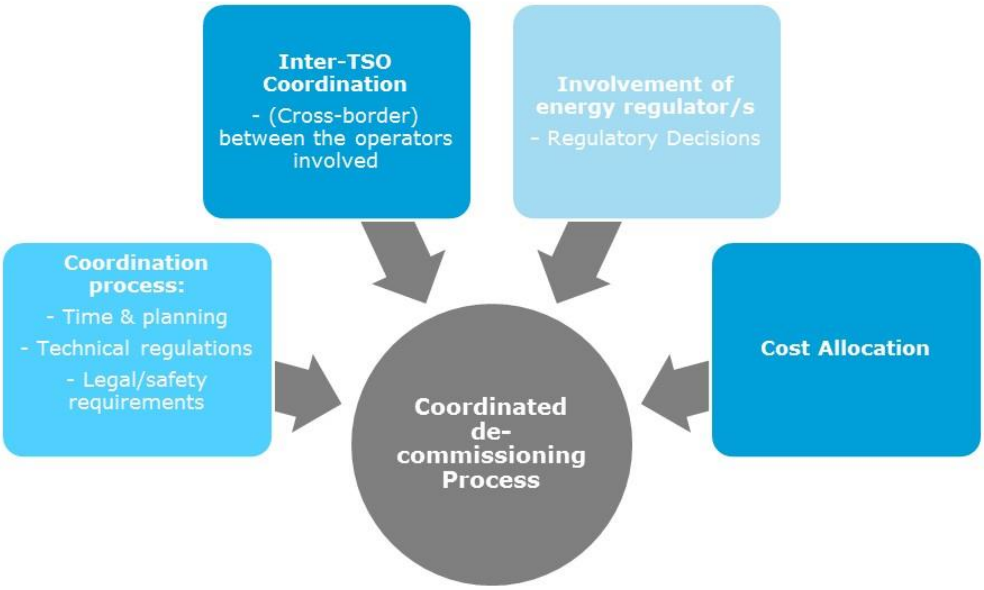
An example from Austria shows that the regulator allows a capacity risk premium on top of the calculated WACC. The volume (quantities) is determined based on existing contracted capacity from actual long-term contracts. The motivation for the premium is that the volume risk from revenue shortfall resulting from the expiry of existing contracts is absorbed by the TSO under the tariff methodology. The premium essentially accounts for the risk that the TSO has for not being able to market capacity after expiration of the long-term contracts and thus resulting in potential revenue shortfall. This also helps to avoid sharp increase in tariffs in long term in case that lower quantities will be contracted in future.

From another perspective and a possible option in the context of stranding is a downward adjustment of the allowed return. The motivation could be taken from a mitigation viewpoint to somehow account for the risk of stranded assets. A lower WACC therefore implies a lower return on RAB and subsequently lower allowed revenues / tariffs. It could be implemented as a one-off adjustment seeking a trade-off in terms of preserving the financial stability of the regulated companies and at the same time preventing a sharp increase in network tariffs that may discourage capacity bookings in the short to medium term.

From assessing the three different options, any decisions or changes to the existing regulatory framework should be adopted with a medium to long term view as frequent changes would undermine the regulatory framework. It is advisable that a public consultation to present and discuss the different options with the network operators is conducted. It is important to have a robust and consistent regulatory framework (including transparent and effective consultation process) that provides tariff stability and predictability for shippers using the gas infrastructure. On the other hand, regulated companies also require stability and recovery of their reasonable cost under the regulatory framework in which they operate.

5.1.2.2 Coordinated Cross-border Decommissioning

In the theoretical situation where an asset would have to be decommissioned because of stranding, several factors should be considered especially when there are various stakeholders involved. Decommissioning of gas infrastructure requires planning and coordination considering any legal, regulatory and especially technical and safety requirements. Decommissioning also becomes more complex if the decommissioning of an asset would impact more than one country (e.g. capacity level at interconnection point). This would therefore require a coordinated cross-border approach prior to and in relation to the actual decommissioning of the stranded asset. In this section, we deal primarily with cross-border decommissioning on a TSO level, however potential infrastructure decommissioning on distribution level could also occur.[45] It is essential that the processes and procedures in terms of inter-TSO interaction, roles and involvement of national energy regulator/s and other stakeholders are applied to ensure that the decommissioning process is conducted in a safe, secure and efficient manner.[46] We also look at cost allocation in the context where decommissioning is mitigated in the case when a neighbouring TSO demonstrates that keeping the asset has benefits such a security of supply, etc. Cost allocation would therefore be relevant in terms of compensation to the TSO where the asset was to be decommissioned due to under-utilisation for example. We discuss the necessary processes, involvement of the national energy regulators and regulatory implications.



Identification of Assets to be Decommissioned / Process and Procedure for Coordinated Decommissioning

It is the role of the TSOs as part of the asset management function to be able to identify which infrastructure assets should be decommissioned. Their technical assessment together with the own demand projections and network development plan will enable them in a structured way

[45] For example, a change of consumption in the residential sector caused by the transition to district heating from gas. In such cases where the distribution network is still being utilised, but in a limited way, the gas distribution company would still have to supply the last remaining customers whose systems have not yet transferred to district heating system

[46] The coordination process needs to be considered in terms of timing, planning, submission of relevant information, compliance with technical, safety and environmental regulations.

to determine which assets shall be decommissioned.[47] On a national (country) level, there already exists a coordinated approach between the TSO and regulators related to decommissioning. National decommissioning procedures already exist for when assets are at the end of their asset life and either needs to be decommissioned or replaced or upgraded. In this context cross-border infrastructure, coordination is required between the stakeholders in the respective countries. On a European level the Council Regulation (EU, Euratom) No 617/2010[48] serves as a framework for data exchange. Information submitted includes planned and under-construction projects, transformation of existing infrastructure and decommissioning projects of a certain size, on a five-year horizon. Regarding decommissioning, the Commission shall receive information on the character and the capacity of the infrastructure concerned, and the probable year of decommissioning. This information is discussed in coordination with ENTSOG, and the Gas Coordination Group for example. The information from member states facilitates the analysis of investment projects and development perspectives for the European energy system. This information could also be used in in the context of coordinated decommissioning procedures between the Member States involved.

Inter-TSO Coordination / Roles and Involvement of National Energy Regulators

As part of the coordination process regarding notification of information on planned decommissioning as part of the TYNDP of the respective TSOs. Additional information providing detailed technical information on the asset, and rationale behind the decommissioning should also be provided. This could be documented as part of a market analysis assessment justifying the lack of current and future need of asset resulting in decommissioning of the asset. This assessment could be a joint effort between the relevant TSOs if the assets stretches over more than one country. This is like the Regulation (EU) 347/2013 Guidelines for trans-European energy infrastructure for submission of PCI as a joint investment requests by the respective TSOs together. Other relevant details would include the technical description of the assets, clear timeline on the steps for the planned decommissioning, and the cost of the decommissioning[49]. This information should be sent to the leading energy authority for coordination purposes.[50]

[47] Such identification could be made from risk assessments studies, taking into account both gas and electricity supply needs on short, mid and long term horizons. The regulated network companies as part of their planning process, consider future demand scenarios, trends and developments in new technology, climate change policies and the like. They are well positioned to build their case and identify which assets will likely be to be decommissioned. This is also part of the requirement to inform and submit plans on investment and decommissioning to the national energy regulators which also feeds into the ENTSOG TYNDP.

[48] The regulation concerns the notification to the Commission of investment projects in energy infrastructure.

[49] In this regard the cost is only for cost items such as material disposal costs, site clearance, dismantling cost etc. that is related to the physical decommissioning of the asset.

[50] The energy authority in consultation with their counterparts shall assess and approve this decommissioning request/plan / cost within a certain time frame (e.g. 6 months) upon receipt of decommissioning request. The TSOs shall also be responsible for submitting regular progress reports (e.g. every 6 months) to the coordinating energy regulator once the decommissioning has started.

There may be situations where decommissioning could be avoided when a TSO in a neighbouring country can demonstrate that by maintaining the asset can contribute to benefits in its country such as security of supply. In such cases the process would involve the TSOs in both countries entering formal discussions. The TSO in the neighbouring country would need to provide justification for the necessity of not decommissioning the asset and the associated benefits. If the motivation for keeping the assets is supported by the neighbouring country, the relevant national energy authorities would need to be informed. The regulatory implications such as the treatment of the cost allocation between the TSO (asset holder) and the TSO of the neighbouring country would need be to be formalised on a country level (see below the section on cost allocation).

It is a necessity that there is strong cooperation and coordination between the energy regulatory authorities. It is advisable to nominate a single point of contact that serves to coordinate the decommissioning project. As there will be many stakeholders involved a central contact point would ensure clear communication channels. Similar to ACER recommendations for PCI projects, the national energy regulator in which the longest part of the infrastructure is located could be the best choice for the role of the central point of contact for the TSOs and the other national energy regulators. They will also be responsible for among others circulation of relevant document to all other involved energy regulators, TSOs, request / seek further information form necessary parties, organise meeting, consultation and coordinate with other national energy regulators. These tasks are also in line with the ACER recommendation[51]. The coordination effort shall be proportionate to the complexity of the decommissioning of the asset.

Cost Allocation

We discuss cost allocation from two perspectives, (1) decommissioning of an asset and (2) decommissioning is avoided due to the potential benefits that the asset could provide to a neighbouring country.

In the situation where decommissioning has been decided, the cost of decommissioning will depend on the asset in question[52]. Specific decommissioning plans and associated cost estimates for decommissioning should be clearly defined as a joint TSO effort if the asset stretches over one or more countries. Regarding cost allocation in this aspect, each respective TSO can be responsible for and bear the cost of decommissioning the asset in its own country. From a practicability and administrative burden perspective this can be regarded as simple and easy to implement. However, it would assume that the cost of decommissioning is arguably caused by the TSOs in their respective country. Therefore, additional considerations, i.e. cost / benefits caused by decommissioning reflecting cross-border impact will be also required.

[51] ACER recommendation no 5/2015 on good practices for the treatment of investment request, including cross border cost allocation request for electricity and gas projects of common interest.

[52] As mentioned previously this is related to material disposal costs, dismantling cost etc. that is related to the physical decommissioning of the asset.

We turn now to the case where decommissioning could be avoided. For example, if the asset to be decommissioned in country A could bring potential benefits to a neighbouring country B. Therefore, cost allocation in this respect is related to compensation payments between the TSOs in the respective countries.

This process would first start by the TSO (in country A) identifying the assets to be decommissioned as explained in the above section. This intention is then discussed with the neighbouring TSO (in country B). The TSO in country B would then need to demonstrate that by keeping the asset it would facilitate for example security of supply requirements in its region/country. As the benefits are attributed to the TSO in country B, the TSO in this country shall be responsible for the compensation payments to the TSO in country A, who would have otherwise decommissioned the asset. In terms of the regulatory treatment the compensation payments will fall under the decision of the national energy regulator and the respective regulatory framework in which the TSOs operates. While the compensation payment made by the TSO in country B will be included as a cost item in its allowed revenue, the compensation received by the TSO in country A should be deducted from the allowed revenue and not passed into its network tariffs.[53]

5.2 CNG/LNG Infrastructure in the Transportation Sector

5.2.1 Role of CNG/LNG Infrastructure in the Transportation Sector

The role of CNG and LNG infrastructure in the transportation sector is primarily to make CNG and LNG available for use as a fuel in transportation.

Such infrastructure comprises the CNG and LNG refuelling stations which can include compression equipment to convert natural gas in CNG or LNG, and storage tanks. In addition, the infrastructure includes the LNG trailers used for the delivery of CNG or LNG via virtual pipelines[54] to the refuelling stations (see Annex 3).

Additionally, LNG transported via trucks may also be used to supply remote areas and to secure gas deliveries to consumers.

[53] On broader terms, similar ideas (e.g. fall-back capacity contracts) in the context of keeping security of supply capacity available in one market zone (e.g. country A) different from other market zone (e.g. country B) needing SoS requirements have been discussed in the Vision of Gas Target Model Paper (2011)

[54] The term here refers to the movement of CNG or LNG via trucks /rail cars through routes that can vary over time or that can be flexibly arranged. The virtual nature of the pipeline is related to the fact that there is no physical pipeline involved in the transportation of the gas. Although used the term is imperfect as the transport of CNG via trucks or rails is based on individual operations and not on continuous flow of gas, as it happens in a pipeline.

5.2.2 Regulatory Implications

The regulatory analysis for CNG/LNG infrastructure in the transportation sector looks at the contestability potential of the activities in the value chain options. Non-contestable activities or activities with limited contestability potential typically require some form of regulation. For example, specific parts of the value chain may constitute a natural monopoly and as such require regulation. We then look at the involvement of regulated network operators in contestable businesses and the role of regulation. The analysis also addresses aspects related to the planning and development of new infrastructure, as well as aspects how to encourage this development.

Contestable and Non-contestable LNG/CNG Infrastructure

Specific parts of the value chain like physical networks to transport gas to the CNG refuelling stations constitute a natural monopoly[55] and should be regulated.[56] Other activities like gas storage, which may not be natural monopolies, can become de-facto monopolies due to various limitations. For example, the provision of storage and bunkering services for LNG is potentially contestable given the presence of multiple providers in the specific relevant market. However, the competitive provision of such services in response to market demand may be limited due to operational or physical constraints (at ports or other locations) or requirements of the permission rules. Limitations may also appear due to the limited market size of the relevant market that may hinder the establishment of functional competition. In such circumstances, these activities will require regulation including access and capacity allocation rules.

Regulators should not intervene where contestable provision of services is possible and effectively leads to sufficient geographical coverage and competitively priced offers. For example, transportation via virtual pipelines (LNG/CNG) or provision of refuelling station services are contestable activities and can be provided in a competitive environment. However, competition authorities will need to monitor specific segments to prevent from distortion of competition and abusive use of market power (for example refuelling LNG and CNG stations).

Involvement of Network Operators in Contestable Businesses

Under the current European legal framework (3rd package), provision of services in contestable sectors by gas TSOs/DSOs (except for production and supply of natural gas) is not explicitly forbidden. Network operators may decide to diversify their business and seek involvement in contestable activities as the ownership, development, management and/or operation of CNG/LNG refuelling infrastructure, but also P2G infrastructure and other new technologies.

[55] Natural monopolies generally exist when due to the existence of economies of scale, i.e. declining average costs as production expands, a single firm is able to provide services or products more efficiently than multiple entities.
[56] Connections between the core gas network and refuelling station can arguably have contestable elements. In practical terms however, they can be considered as a logical expansion of the regulated natural gas network and treated as regulated activity.

The motivation of network operators to enter such contestable businesses may be primarily linked to the need to further re-shape their business models. They can seek expanding their activities in new contestable areas which are complementary to the traditional gas transportation (diversification and scope effects) and contribute to the commodity demand which in turn affects the demand for transport capacity (scale effects).

Where a combined provision of regulated and contestable services is possible, the regulatory framework should ensure that customers and market participants benefit to the largest extent possible from the range of services. However, regulation must prevent unintended interactions between the regulated and contestable sectors in terms of cost and revenue allocation, and information advantages. Without regulatory control, including also the analysis of contractual relations, companies may be able to benefit from this by allocating costs to regulated activities, or by using information held by the regulated business. This could increase the cost of regulated services and distort competition in the contestable part of the sector.

In terms of unbundling, different degrees of unbundling apply to TSOs and DSOs. The models range from ownership unbundling applied in a number of Member States for TSOs to a simple unbundling of accounts for some integrated distribution and supply companies serving less than 100,000 connected customers, if so decided by the relevant Member States. The stricter the unbundling regime applied, the less issues with discrimination, particularly in favour of related companies, are likely to arise and should be considered by regulators when deciding on the involvement of network operators in contestable activities such as the operation of CNG/LNG refuelling infrastructure and P2G infrastructure.

One way to address this issue is to apply an approach similar to the one recently suggested in the Clean Energy Package for electricity DSOs. The Clean Energy Package (Article 33 of the draft Electricity Directive) states that Member States may allow DSOs to own, develop, manage or operate recharging points for electric vehicles if and for as long as there is no market interest from other parties to engage in these activities. The market interested should be tested in a tender process reviewed and approved by national regulators.

Alternatively, regulators may consider using a more flexible approach in the gas industry by attributing a proactive role to the gas network operators. Such an approach would recognise explicitly the specific circumstances and benefits of involvement of the gas network operators in contestable activities. The involvement of gas network operators in e.g. the construction of CNG/LNG refuelling stations could contribute to the resolution of the “chicken and egg”[57] problem that challenges the use of new fuels.

The fundamental principles of unbundling related to cost and revenue allocation, and use of information must remain valid and appropriate. Nevertheless and against the background of decarbonization implications for the gas sector, a more detailed specification and application of these principles could help to mitigate the risks of having uncoordinated national initiatives that may hinder the deployment of new technologies on a European scale. Otherwise, the

[57] The infrastructure for the distribution of the fuel should be available before the demand for the fuel materialises, while at the same time market participants would not invest in infrastructure before sufficient demand is in place to ensure utilisation of the infrastructure and recovery of the related costs.

useful potential of new technologies could be undermined and the achievement of EU environmental targets compromised.

Establishment of Coordinated National / Regional Plans for CNG/ LNG Infrastructure

In some countries, the construction of CNG and LNG fuelling infrastructure is part of national or regional plans that define the overall number and in some cases location of such infrastructure for urban planning and other public policy reasons. A common approach in the definition of these plans across member states, as well as coordination of these plans with the requirements of the Directive 2014/94/EU, should be ensured. While national/regional infrastructure planning is not necessarily a task of national energy regulators, they can provide relevant information and support the activities of regional governments or municipalities as well as other institutions mandated to develop these plans.

Policy Schemes for Infrastructure Promotion

Legal framework can support the implementation of the infrastructure for the new technologies (CNG/LNG refuelling stations) through specific concession regimes. Concessions are particularly suitable to encourage the infrastructure development in early stages by granting exclusive rights to the concession holder in a certain geographical area. Concessions could be granted at national or at the European level, for example for pre-defined cross-border corridors like the corridors defined by the Blue Corridors initiative for LNG refuelling stations. Such a coordinated European approach to concessions would be beneficial for the development of the new infrastructure and would support the gas demand in the transportation sector.

Additional Regulatory and Policy Incentives

Policy makers and regulators can provide additional incentives to support the development of CNG and LNG infrastructure. These incentives can include investment subsidies for construction of refuelling stations and incentives to encourage demand of CNG or LNG vehicles through their use in their own fleet of vehicles. Moreover, financial support to research and development activities and tax incentives for could be considered. Funding industry pilot projects for LNG and CNG infrastructure, including also projects initiated and implemented by TSOs and DSOs, can also encourage the infrastructure development.

5.3 Renewable Gas Infrastructure

P2G and Hydrogen

Hydrogen can be transported via trucks/rail cars or pipelines. The transport by trucks or rail cars is relatively new across European markets, mostly involving a large industry partner participating in pilot projects. While small hydrogen pipeline networks already existing (e.g. Germany, the Netherlands), the technical feasibility of hydrogen transport through natural gas networks is still under research. The current research indicates[58] that hydrogen of up to 10 % of the total transported natural gas volume can be injected into natural gas networks without large technical constraints, i.e. without a major effect on the existing gas infrastructure or end-use equipment. To specify an upper limit for the hydrogen blend with a universal validity (harmonization) for the European gas networks remains challenging at this stage of development.[59]

The transport of hydrogen via pipelines of natural gas network should be a regulated activity. It is likely that new hydrogen pipelines will have similar economic characteristics to the existing natural gas networks and therefore should be regulated.[60]

Since the hydrogen production process cannot efficiently change production to match demand there is a need of storage capacity to allow for system flexibility for both intra-day and inter-seasonal variations in demand. Storage is a potentially contestable area. However, there could be a case for regulation if geological or other constraints limit supply of storage capacity. Limitations may also appear due to the limited market size of the relevant market that may hinder the establishment of functional competition.

Regulators should accompany and steer the transition towards higher hydrogen quantities blended in the gas networks. In the initial stage of development, hydrogen transportation via physical pipelines will be likely provided by blending a small proportion of hydrogen with natural gas. Blending small hydrogen proportion does not change substantially the specification of natural gas as it already contains hydrogen. However, with larger quantities of hydrogen being blended into networks, eventually targeting a full conversion, regulators will need to adjust the technical specifications for the blended natural gas and amend the relevant regulation.

There is no immediate need to align such regulation across Europe. However, clear technical specifications on the proportion of hydrogen that can be injected in the natural gas networks would be necessary to support the increase in use of hydrogen. On the transmission level, there may be a need to revisit the Interoperability Network Code and the CEN provisions on gas quality.

[58] Dmitri Bessarabov, Haijiang Wang, Hui Li, Nana Zhao, “PEM Electrolysis for Hydrogen Production: Principles and Applications”, 2017.

[59] Member States apply own norms and regulations with respect to maximal hydrogen blend, for example Belgium 2 %, France 6 %, Germany 2 %, Austria 2% - 4 %. In addition, current research emphasises importance of assessing every pipeline system individually based on its technical specifications.

[60] Regulators may consider also alternative models based on tenders for designated operators to construct and own hydrogen pipelines.

Regulators should steer the technology roll-out in terms of time and targeted penetration zones where the hydrogen quantities will gradually grow. In such a system, the product characteristics will change and customers would not anymore purchase natural gas but its blend with a different energy content. Regulators will need to develop the design of the commercial and access arrangements of the new system. Natural gas suppliers may be obliged with every unit of natural gas they deliver into the network to purchase a unit of hydrogen, and sell a hydrogen blend as the only allowed product. Alternatively, network operators may be given the responsibility of purchasing hydrogen. Overall, if it is feasible to have multiple production sites with a variety of owners, each of which has access to markets for trade with retail suppliers, then the market structure may resemble the existing natural gas markets.

Specific issues may emerge in relation to the involvement of the regulated network operators in contestable activities, for example P2G infrastructure for hydrogen production. While the involvement of such regulated entities may not be necessarily denied, it should reflect the requirements of the unbundling provisions, i.e. network operators may get involved in the operation of such infrastructure but may not get involved in any way in the production or supply of natural gas. There might be individual cases where regulators will need to look at the potential benefits from integration of P2G installations in the regulated network assets, particularly when the installations and their direct control have an essential role for the secure network operation. For example, in areas with large RES generation P2G installations could allow electricity network operators to avoid curtailment of RES installations in times of excess supply. Similarly, natural gas network operators could make use of the methanation part of P2G installation to convert hydrogen into synthetic gas and to ensure secure support of larger green gas volumes.

Biogas and Biomethane

Biogas can effectively be a substitute for natural gas once it is further refined and converted to biomethane. A great advantage of biogas-biomethane supply chain is the fact that the existing infrastructure for transport and distribution of natural gas can also be used to bring biomethane to the final consumer. The transport of biomethane via pipelines of natural gas network should be a regulated activity.

In the transportation process, the network operator must follow gas quality standards and only allow biomethane that satisfies these standards into their network. The possibility to inject the bio-methane as a replacement or additional gas in transport and distribution networks comes from the implementation of the European Directives 28/2009/EC[61]. Biomethane, is for example defined by legislation for example as "gas produced from renewable sources having

[61] The Renewable Energy Directive (RED) is currently under-going a revision and it supposed to strengthen the position of biogas and biomethane. The deployment of biomethane shall be eased through new provisions and changing some elements which in the previous RED version were limited.

characteristics and conditions that correspond to those of natural gas and eligible to enter into the natural gas network".[62]

This Directive requires Member States to ensure that the gas resulting from biogas production and as well as from other renewable gas origins (for example by methanation of hydrogen), is in compliance with the requirements of quality standards and have, consequently, non-discriminatory access to the transmission and distribution networks of natural gas.

In this regard, national energy regulators should set clear connection rules including connection charges, technical connection requirements, responsibilities for setting and maintaining the relevant product quality norms, metering and compression. They may consider providing explicit incentives in national regulation to the parties injecting biomethane into the natural gas networks via favourable network tariffs and connection charges. Furthermore, regulators may also consider setting additional commercial quality standards to network operators, for example maximal time to connect biogas plants after connection application. The suggested amendments would take place on a national level as the respective rules are country specific.

5.4 District Heating

In the low and average gas demand scenarios, heat demand declines under the assumption that EU energy efficiency requirements are successfully implemented. Consequently, the share of district heating and renewable heat in the heating of buildings increases.

District heating plays a major role in several EU countries' heating markets. Several member states have implemented incentive schemes targeting the environmental benefits of district systems. Examples of such policy incentives include inter alia fuel taxes, co-generation support schemes, subsidies and funding facilities or energy efficiency promotion tools. There have also been incentive schemes specifically targeting renewable energies and efficiency in the heating sector.[63]

Unlike natural gas and electricity networks, district heating systems are commonly not subject to direct economic regulation, particularly with regards to prices. There are some countries with district heating regulation in place for example in Denmark, Poland, Bulgaria, Hungary. The outlook of potential regulatory arrangements for district heating based on the European

[62] Article 2 of Legislative Decree 28/2011 of Renewable Energy Law of Italy.

[63] For example, the market incentive program in Germany (Marktanreizprogramm) is a central tool to support renewable energies and efficiency in heating sector. The program was launched in 90s and was amended several times, the last one in 2015 (BMWi March 2015). The program consists of several schemes to promote investments in renewable energy including direct investment subsidies for specific technologies (e.g. solar facilities, heat pumps of residential consumers) or providing loans with favourable conditions. The program covers further measures in energy efficiency improvement, refurbishment of buildings and construction / purchase of low-consumption or passive houses. These measures are also connected with the funding facilities of the Kreditanstalt für Wiederaufbau (KfW), Germany's federal state bank for funding and subsidies.

examples studied indicate that there is not a strict need to explicitly (ex-ante) regulate district heating when competition exists from other fuels such as gas, electricity, oil, biomass.

The role of authorities (energy regulators or competition authorities) should therefore focus on monitoring competition and preventing market abuse. The threat of ex-post investigations and subsequent proceedings prevents companies from exploiting their market power, either through excessive pricing or poor quality of service to consumers.

In some cases, there might be a need of ex-ante regulation when the potential competition for district heat from other fuels is limited. This could be due to the limited availability of competitive substitutes, for example a heat distribution networks to supply commercial and domestic customers is practically/technically not developed, or consumer site specific issues.[64] Furthermore, competition may be restricted on purpose by policy measures. For example, to support heat demand and mitigate uncertainties, policy makers may define geographical zones that should be supplied exclusively by district heating.

In terms of coordinating and planning of district heating this can be done on a central (national) or local level (municipality) level. Based on practice in different countries, there are different approaches although positive experience has shown that that district heating planning led by local municipals and local government have been successfully implemented. The local government are deemed in a better position to steer the coordination and support the integrated urban planning in their own district. Involvement of the energy regulator would be limited in this planning stage as this is related to design, construct and building. The establishment district heating zones (for example in Denmark) would require coordination between building owners, heat network developers and public authorities to agree on long-term plan for district heating development.

5.5 Regulatory Incentives for Innovation and Decarbonisation

Investment in innovation and decarbonisation is happening in Europe, irrespective whether the funding is part of the regulatory framework and/or on a national policy level. We looked at the current development of new technologies including the use of compressed natural gas (CNG) and liquefied natural gas (LNG) in transportation, hydrogen /power to gas (P2G), biogas (see also Annex 3). We found that certain areas are considered relevant by policy makers and regulators and the increased need for research and development which have been recognised by studies and pilot projects. Examples for such areas include:

- Possibility to supply bio-methane through existing gas networks
- Supplying low-carbon hydrogen through the existing gas distribution network and conversion of the low-pressure gas networks to supply hydrogen to homes, buildings and industry instead of natural gas

[64] For example, existing buildings have been constructed in such a way that any on site heat generation is either technically complicated or impossible.

- Using Power to Gas technology to turn renewable electricity to gas for use in existing gas networks

Investments in such areas targeted to decarbonise the gas network combine both infrastructure type innovation and use of alternative commodities (e.g. hydrogen, biogas). In many cases the treatment of decarbonisation type investments are included as part of the innovation type investments. For example, the objectives of certain 'decarbonisation' type projects include overall environmental targets not just a low carbon reduction.

Decarbonisation could provide gas with a much longer life in the power sector, and also in the heat sector. Furthermore, gas could have a much longer life transporting and distributing hydrogen manufactured either from decarbonised gas or from renewable energy via electrolysis, or biogas/biomethane (from low carbon sources) or (in the case of distribution) district heat.[65] The gas infrastructure could in this case be maintained in the long-run but applied to a different extent on the various infrastructure elements, for example use of distribution networks for the conversion of hydrogen.

Regulation often applies specific arrangements to promote and encourage decarbonisation investments. Decarbonisation investments may be part of innovation projects or a category subject to broader environmental targets and not just carbon reduction. The examples for UK, Ireland and Norway (see Annex 5) show that funding is granted upon approval process and the proposed projects must qualify certain criteria. Innovation depending on the regulatory framework may include innovation for infrastructure projects (e.g. hydrogen transport, or LNG and LNG transport) or commodity types projects (e.g. hydrogen or biogas production).[66]

Overall, we support the idea of innovation and decarbonisation incentives as part of the regulatory framework as this facilitates development and drives improvement in processes and technology application in the gas sector. National energy regulators should set clear objectives and qualification criteria for what projects would be subject to innovation incentives. For example, innovation incentives can be provided for a new or unproven technology or operational practice directly related to the gas network. The innovation project should relate to the development, and research in a field, or technology that could help achieve certain targets such as decarbonisation by the possibility of using biogas, CNG/LNG or hydrogen.

Innovation and decarbonisation incentives can be incorporated into the regulatory framework by using a special allowance. The allowance would be based on a proportion of the allowed revenues. This could be applied for smaller scale research and development projects that qualify for the allowance. The regulated companies would need to apply formally to use the allowance and present their projects and the potential benefits to their respective energy regulator. The innovation/decarbonisation allowance based on the examples provided in Annex 5 indicates that a certain budget (e.g. a certain percentage of the allowed revenue) is allocated to the network companies for investments in innovation/decarbonisation type projects subject to regulatory approval and qualification criteria. The regulatory treatment of the assets

[65] Oxford Institute for Energy Studies (Jan 2017) The Future of Gas in Decarbonising European Energy Markets: the need for a new approach
[66] For example, the Irish regulator has specified key areas for innovation including CNG and biogas technologies.

would enter in the RAB, be subject to depreciation allowance based on the specified asset life and regulatory return under the conditions set out in the overall regulatory framework.

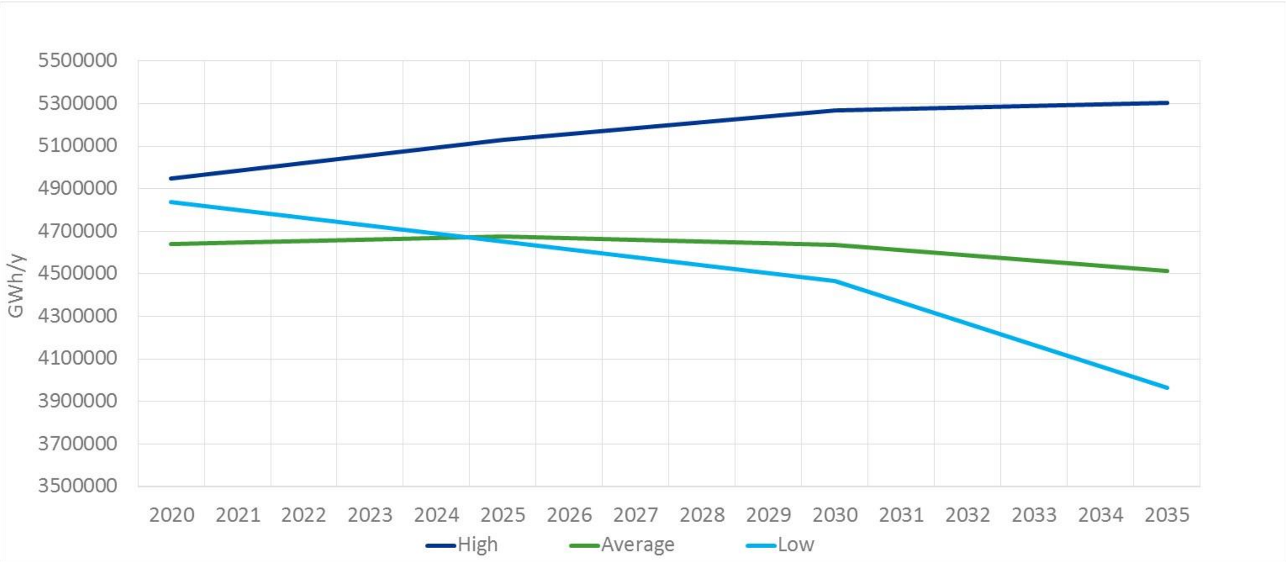
In a second step, national energy regulators may consider in addition a depreciation policy different to its regular treatment of the RAB for innovation and decarbonisation projects. This option would only be applicable for projects that are considered innovative and supports the development of a low carbon energy sector and/or deliver environmental benefits for example. To encourage innovation for decarbonisation investment projects where the asset or technology is still under development, it may be reasonable to adopt a shorter depreciation period for these investments. The applicability of this approach would also depend on the scale of the investment cost as shorter depreciation period would mean a faster recovery of the investment via the depreciation allowance in the allowed revenues. For example, accelerated depreciation allowance (front-loaded profile, shorter asset life) would allow the regulated companies to recover the cost of the investment quicker. It also provides higher certainty that there is some recovery in case the technology does not materialise. By considering a shorter depreciation period for certain projects this could be an incentive to promote investment. We are however not aware of practical use of this approach to encourage innovation type projects.

Further, an additional option could be to allow an additional return (WACC premium) for such investments. Italy and France have used additional return (WACC premium) to support investments in the gas transmission network. However, the application of the WACC premium cannot be directly linked to investments specifically related to innovation and or decarbonisation type projects. Nevertheless, we believe this could also be applicable in this context nevertheless. The premium would be set by the energy regulator for a certain number of years to encourage innovation/decarbonisation type investments as adopted in France and Italy for example.

Annex 1 – Demand scenarios

Three gas demand scenarios (high, average and low) have been constructed which define the range of possible evolutions of natural gas demand in a 2040 perspective for the EU-28. For the selected scenarios, certain assumptions have been considered in terms of achieving EU environmental targets and key sectors driving structural change in gas demand. The selection is based on the review of several representative sources agreed with the CEER Working Group. The sources include the Ten-Year Network Development Plan (TYNDP 2017) by ENTSOG, the World Energy Outlook (WEO) by the IEA for 2016, and the EU Reference Scenario (2016) by the European Commission.

Figure 3: Overview Demand Scenarios



Source: ENTSOG (2017) TYNDP, IEA WEO 2016 (ENTSOG conversion of data to GWh/y and interpolation of data for the creation of intermediate values (e.g. 2025 for the low demand scenario) when not originally available). All sectors are included in the calculations

Below we present a summary of the main assumptions and characteristics of these scenarios.

High Demand Scenario

Under this scenario, EU environmental targets (2050 targets) are achieved while natural gas demand is driven primarily by the increased use of gas in the power sector. This is also characterised by the increase in RES development and moderate CO2 prices. Gas-fired power plants are the main source of back-up for RES while nuclear power production remains at the same level of today. Demand for natural gas in the residential sector remains stable due to the lack of significant improvements in energy efficiency with gas remaining the main fuel for heating purposes. The transportation sector represents the main area of the economy in which demand for natural gas is increasing with LNG becoming the primary fuel for maritime transportation.

Average Demand Scenario

In the average demand scenario, EU is on track with the achievement of 2050 environmental targets. In the power sector, the main source of generation will be coming from RES sources in combination with a decrease in the use of coal and natural gas for power generation. Back-up generation for intermittent RES sources is however still provided by natural gas fired capacity. In the residential sector, new technological solutions such as heat pumps and energy from biomass as well as increases in energy efficiency and carbon-neutral buildings, access to district heating and heat pumps all contribute in reducing the demand for natural gas and overall energy intensity of this sector. The transportation sector represents the main area where natural gas demand is increasing on the back of LNG becoming the main fuel for maritime transportation and heavy good vehicles (HGV) / heavy duty vehicles (HDVs).

Low Demand Scenario

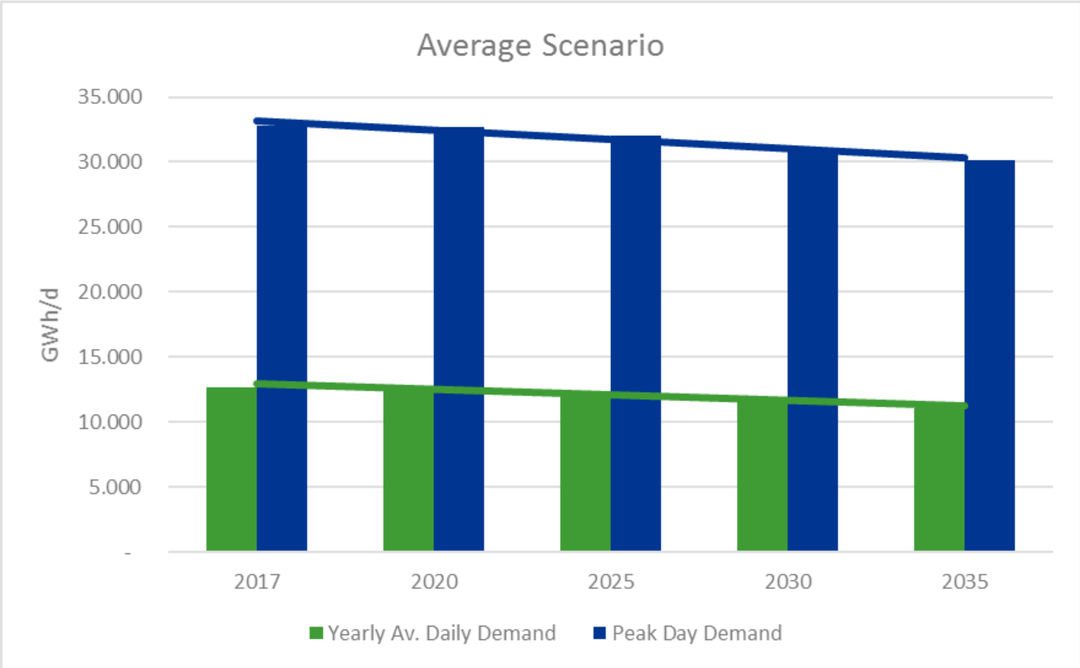
In the low demand scenario, the EU achieves environmental targets even more stringent than the 2050 targets and COP21 targets (including the possibility to maintain average world temperature increase below the 2 degrees' Celsius target). In the power sector, generation relies for the most part on RES including wind and solar. Demand for natural gas declines gradually in the period post 2020 with a sharper decrease past 2030 as this fuel remains too carbon intensive to achieve the environmental targets assumed under this scenario. In the residential sector, energy efficiency improvements are gradually assumed to converge towards the maximum efficiency improvement potentials but also experience a time delay. Hence gas demand follows similar patterns by reaching maximum demand levels in the 2030s and then decline. The transportation and industrial sectors are the only areas where an increase in natural gas demand materialises due to phase-out of conventional vehicles and in parallel being replaced, besides others, by hydrogen and natural gas vehicles.

Peak Day Demand

In addition to the total annual demand, we also looked at peak-day demand[67]. When comparing the future patterns of the peak day demand and yearly average daily demand, there do not seem to be largely contrasting tendencies on the aggregated level. However, a single country analysis might show different figures. The different change of the peak day demand and yearly average daily demand could point to changing demand patterns of specific consumer groups. For example, a gas-fired plant may be dispatched for less operating hours, however at its maximal capacity.

[67] The aggregated peak day demand is the arithmetic sum of the peak day demand values per country provided by ENTSOG in its 2017 TYNDP with 100% coincidence. It is acknowledged that it is unlikely to register the peak day demand values coincidently across Europe.

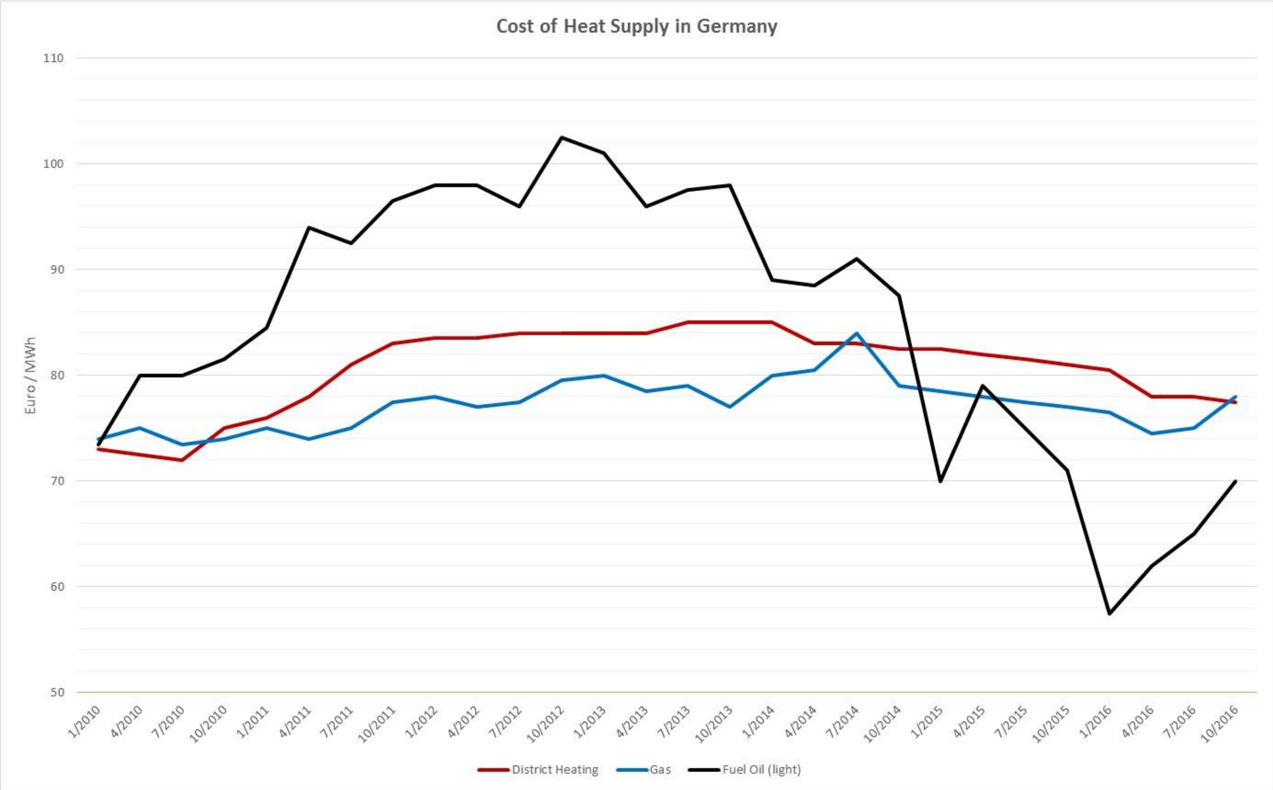
Figure 4: Peak Daily Demand vs. Yearly Average Daily Demand under the Average Scenario



Annex 2 – Cost of heat supply

The example below compares the full cost of supply of residential heat by using district heating, individual gas boilers burning gas from the gas supply system and individual oil boilers burning fuel oil. In the first case, the consumers purchase heat directly, while in the latter they receive gas or fuel oil which then needs to be converted into heat via the boilers in their home. The analysis is assembled for illustrative purposes and aims to reveal the full cost of heat supply, excluding taxes / levies for a building in urban areas with a surface of 2000 m2, annual heat demand of 280 MWh and peak demand of 156 kW. The example is based on data for Germany and relies on VDI's practical guidelines (Association of German Engineers) for cost comparison of space heating.[68]

Figure 5: Cost of Urban Heat Supply in Germany (VDI 2067), Peak Demand -160 kW, Energy Demand – 288 MWh



Source: Heizkostenvergleich nach VDI 2067, Vergleich der Vollkosten, Oktober 2016.

[68] Based on VDI's practical guidelines (Association of German Engineers) for cost comparison of space heating Heizkostenvergleich nach VDI 2067, Oct. 2016.

Annex 3 – Value chain options

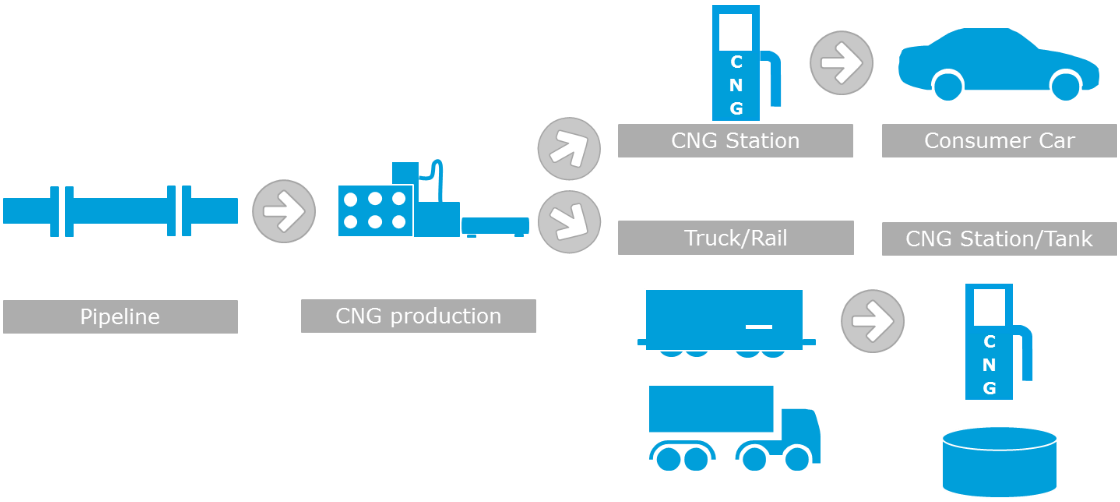
Several new technologies have been explored in our study including CNG, LNG, biogas, P2G, hydrogen and CCS. Each of the technologies and of the respective value chain options are presented below.

Compressed natural gas (CNG)

The CNG value chain is generally composed by a pipeline connection to a compression station where the CNG is produced. The pipeline connection may be a connection to a distribution or transmission gas network. The compression station can either be a stand-alone unit or located together with a CNG refuelling station used to distribute CNG as a fuel for vehicles. The latter combination seems to be the most common configuration of the CNG value chain that can be found across Europe.

There may be cases however when the compression station operates as a stand-alone unit. The CNG produced at compression station is consequently loaded on trucks or train cars for delivery at CNG refuelling stations. The transportation of CNG via trucks or train cars is generally referred to as a “virtual pipeline” that provides flexibility in the end delivery of CNG.

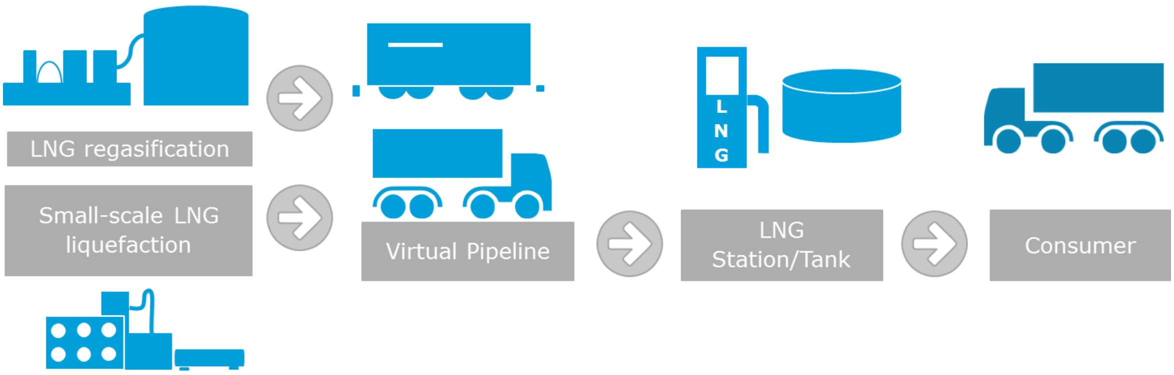
Figure 6: CNG Value Chain Options



Liquefied Natural Gas (LNG) in land transportation

The LNG value chain includes two possible options. In the first case, LNG is off-loaded from a ship at an LNG regassification terminal and consequently loaded on trucks or train cars (virtual pipelines) for delivery at LNG refuelling stations. In the second case, LNG is produced at a liquefaction plant connected to a natural gas transmission or distribution grid. The LNG produced at the plant is consequently loaded on trucks or train cars for delivery at LNG refuelling stations.

Figure 7: LNG Value Chain Options in Land Transportation



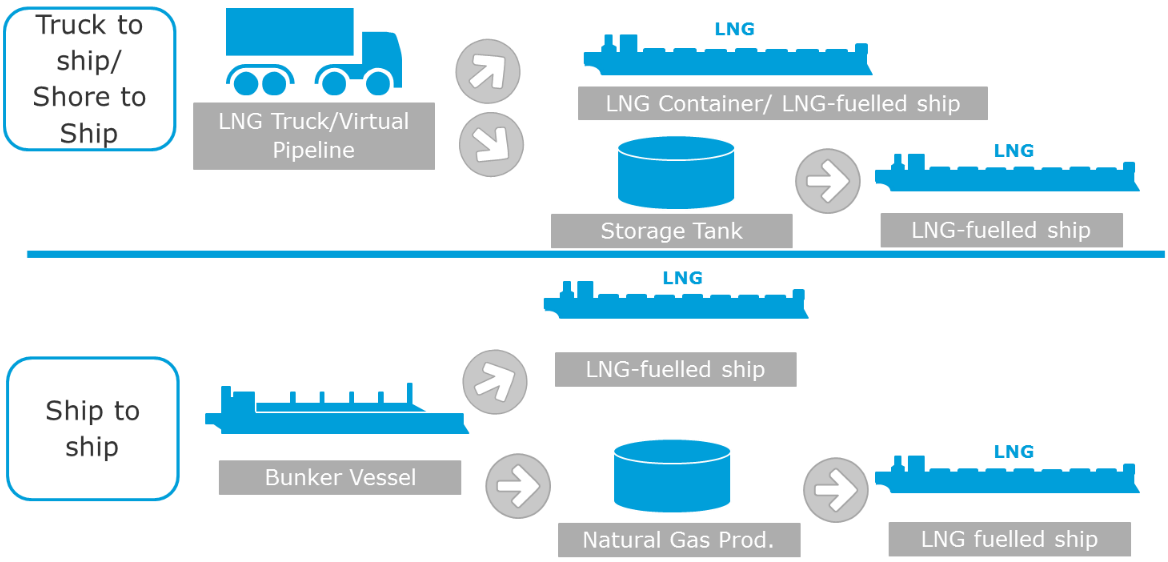
Liquefied Natural Gas (LNG) in maritime transportation

The components of its value chain include LNG trailers, LNG bunker ships, ships fuelled by LNG, storage tanks for LNG bunkering purposes. Multiple value chain options are possible when assessing the multiple use of LNG as a fuel in maritime transportation.

The value chain for use of LNG in maritime transportation includes four options. A "truck to ship" option foresees the delivery of LNG from LNG trucks directly to LNG fuelled ships at ports. A "shore to ship" option foresees a delivery of LNG loaded on trucks to ships fuelled with LNG. The LNG can be delivered either directly to the ships or by using intermediate storage tanks.

In addition, LNG can be delivered from bunker vessels either directly to ships fuelled with LNG or by using intermediate storage tanks for bunkering purposes.

Figure 8: LNG Value Chain Options in Maritime Transportation



Biogas/Biomethane

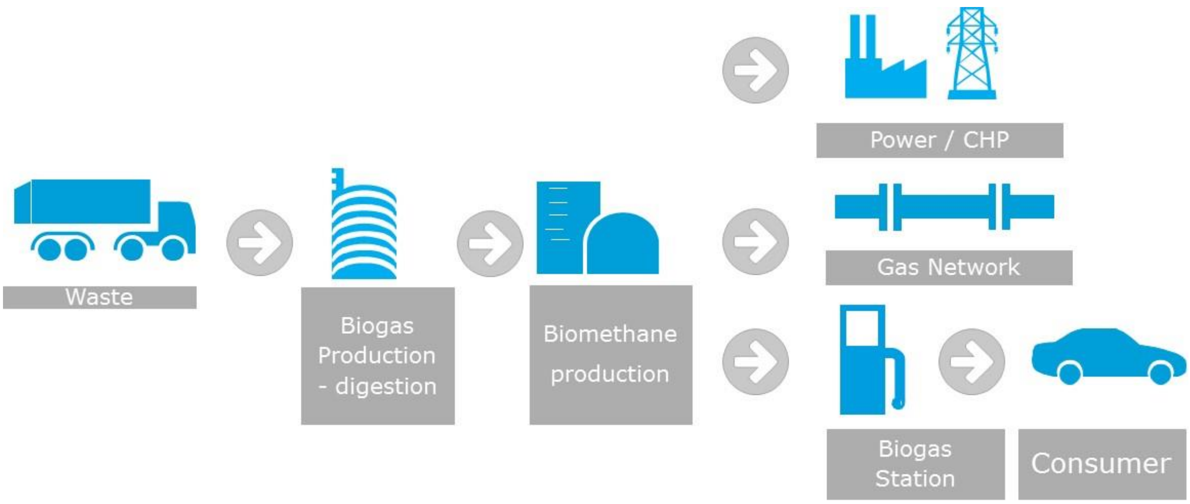
Biogas is produced through anaerobic or other type of "digestion" processes that allow to turn waste of different origin into a gas which further refined and converted in biomethane can be injected into natural gas grids. Biogas production has shown increasing trends in the last few years. The number of biogas and biomethane plants connected to the natural gas grid has doubled in Europe between 2011 and 2014.[69] Biogas markets have however developed mainly on a national rather than on European scale.

The biogas/biomethane value chain exhibits multiple options. They always include the source of waste, and the biogas and biomethane production plants. The final use of biomethane can be different in the different value chain options. Biomethane can in fact be used either as a fuel for power and heat production,[70] it can be injected in natural gas networks, or it can be used at refuelling stations delivering biomethane as a fuel for transportation (land).

[69] According to Eurogas in 2050 around 70% of the gas used in Europe could be renewable gas (biogas/biomethane, hydrogen and synthetic gas. Frederic Simon, Eurogas, available at: http://www.euractiv.com/section/energy/interview/gas-lobby-chief-in-2050-76-of-gas-could-be-renewable/.

[70] In practice biogas, not upgraded to biomethane, is used to produce electricity and heat.

Figure 9: Biogas/Biomethane Value Chain Options



Hydrogen and P2G

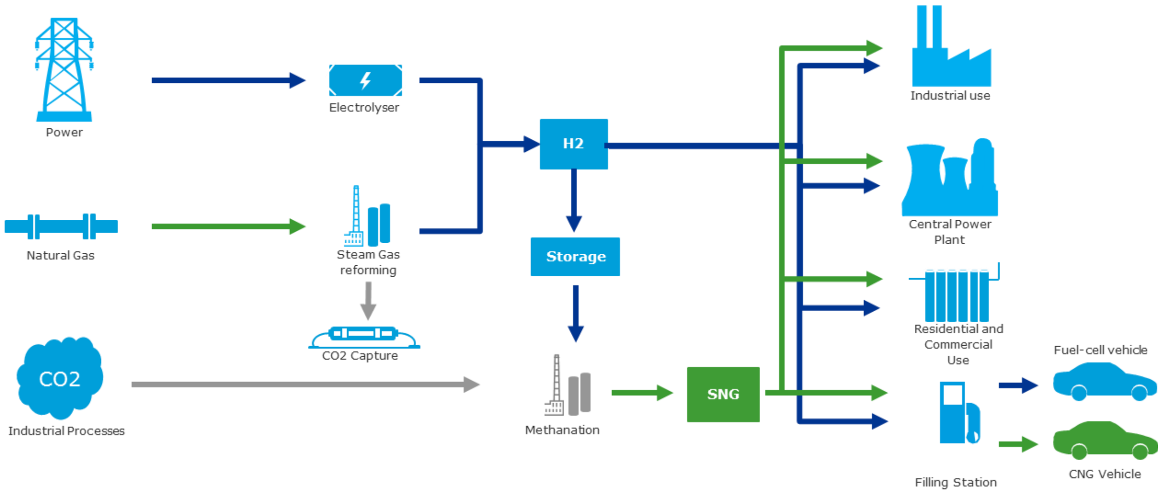
P2G and hydrogen production value chain are closely connected through multiple combinations. The main components in the value chain include the input sources hydrogen production (electricity, natural gas, CO2), the production process and the end-users of hydrogen (industrial, power production, residential or transportation).

Hydrogen can be produced through electrolysis. Electrolysis splits water into hydrogen and oxygen by using electricity. There are different electrolysis technologies ranging from small-size equipment suitable for small-scale distributed hydrogen production to large-scale production facilities that could be connected to production plants of renewable electricity.

Alternatively, hydrogen can be produced from natural gas through a steam gas reforming process. Under steam gas reforming methane reacts with steam under 3–25 bar pressure in the presence of a catalyst to produce hydrogen, carbon monoxide, and a relatively small amount of carbon dioxide.

Finally, CO2 can be treated through a methanation process to produce synthetic natural gas (SNG) which can also find application across the power, industrial, residential and transportation sectors. Given that the CO2 is retained from other sources in the production process, CNG can be effectively carbon neutral.

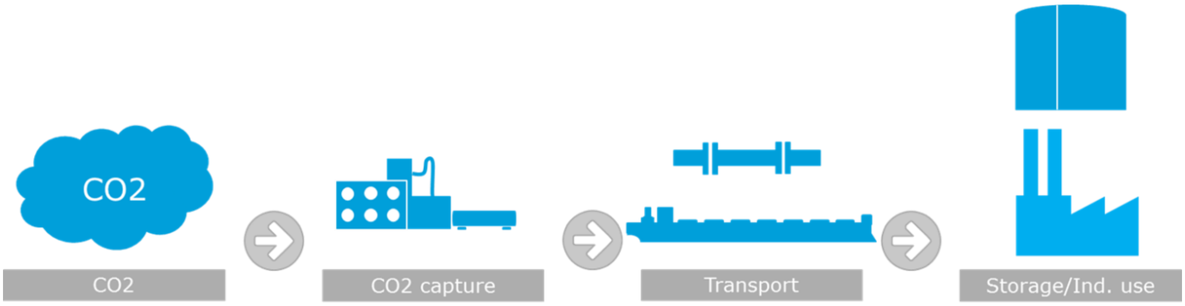
Figure 10: P2G and Hydrogen Value Chain Options



Carbon Capture and Storage (CCS)

The CCS value chain includes the capture, the transportation and the storage of CO2. There are different methods to separate and capture CO2 in industrial and power generation process (pre-combustion capture, post-combustion capture and oxy-fuel combustion). The transportation can be organised either via dedicated pipelines or via loading of CO2 on ships. The storage of CO2 can be organised in multiple ways including in depleted oil and gas fields, un-minable coal seams and deep saline formations.

Figure 11: CCS Value Chain Options



Annex 4 – Best practice examples of new technologies

The following annex presents a series of national examples for use of new technologies and the associated regulatory measures. It supports the regulatory analysis and conclusions that have been drawn in the study.

Compressed Natural Gas (CNG) in Transportation

Ireland

In Ireland, two developments stand out in the direction of increasing the use of CNG in the transportation sector. The first development relates to the publication and consequent implementation of a national policy framework on alternative fuels infrastructure for transport in the period 2017-2030 which covers CNG among other fuels[71]. The second development relates to the lead that the national gas TSO Gas Network Ireland (GNI) has taken in this respect and to the regulatory analysis carried out in parallel by the Commission for Energy Regulation (CER).

The national policy framework provides a long-term view on how the transportation sector in Ireland should evolve towards a more sustainable future. Several benefits have been linked with the use of natural gas in the transportation sector including but not limited to lower carbon emissions per unit of energy compared to other fuels, greater long-term competitiveness of the freight sector, lower fuel prices for consumers, etc. CNG in the transportation sector in Ireland is in fact still in a demonstration phase. GNI has constructed one CNG refuelling station in Cork and another temporary station in Dublin. GNI has therefore established an innovation fund to promote and accommodate innovations in the gas industry with a focus on increased utilisation of the gas network through innovative applications of natural gas, such as in the transportation sector. The fund was approved (under Price Control 3) by the national regulator CER and has been used for several innovation projects ranging from natural gas in transportation to marine and agricultural feedstock. GNI is also supported by an advisory group (Gas Innovation Group) consisting of members from government agencies, research institutes and academia advising GNI on wider policy, industry and market views.

In 2016 GNI requested CER to fund a project assessing the impact of the construction 13 CNG stations on the gas network. The total project cost amounts to 23.47 Million Euro of which 5.96 Million Euro will be provided by the Connecting Europe Facility and 4.68 Million Euro will be available via the innovation fund approved under Price Control 3 decision by CER. The remaining 12.83 million Euro were requested for approval to CER under Price Control 4. The regulator examined the investments proposed by GNI. Despite the risk of potentially negative net present value in some scenarios due to the uncertainty of CNG demand, CER approved the residual project funding under the innovation fund as part of the Price Control 4 decision. The costs will be recovered through network tariffs. GNI should submit to the regulator detailed progress reports on the pilot projects on an annual basis, prepare and publish a final report on

[71] This framework is required under Directive 2014/94/EU on the deployment of alternative fuels infrastructure.

the benefits for gas consumers. Furthermore, GNI should install infrastructure in line with safety requirements and in such a way so that assets can be sold once the pilot project is completed.

Additional regulatory analysis has been carried out by CER on the overall regulatory approach to be taken in relation to CNG refuelling stations and the contestability of this business. The fundamental question investigated by CER is whether the CNG refuelling stations should be a regulated or contestable economic activity. If such an activity is deemed to be a contestable one, then CER would not regulate the price and this would be set by market forces. CER initial understanding indicated no barriers to different market players to install CNG station equipment. Consequently, GNI entering the CNG refuelling station business would not provide a regulated monopoly service and the investments in such activities would not normally be added to GNI's regulatory asset base (RAB)[72].

CER confirmed this approach in its latest decisions[73] indicating that the market can operate freely in relation to the installation of compression and buffer tank equipment required for a CNG installation. There are several international companies that have experience in installing CNG equipment across Europe and that may be interested in entering the Irish market. Therefore, CER did not approve the initial request from GNI to include the installation of compression and buffer-tank equipment in the RAB.[74] GNI involvement in the CNG refuelling station business should therefore be limited to the pilot project described above.

The assessment of CER also covered licensing arrangements in relation to the CNG refuelling station business. The 2002 Gas (Interim Regulation) Act states that the activity of supply of natural gas, includes the delivery and supply (including liquefied gas) to customers. Supply of natural gas in Ireland requires a supply licence to be granted by CER. Every licensed supplier should also have a shipping licence. CER held a consultation in 2015 requesting stakeholders view on the need to have a license for the supply of CNG. Most respondents indicated that such licence would be required, although in a simplified version compared to the one currently required for the supply of natural gas. Some respondents indicated that such supply licence requirement should not be in place not to create an additional barrier to entry for players in this market. CER ultimately decided that any entity that supplies CNG to final customers should have a natural gas supply licence. Moreover, any entity that intends on shipping natural gas will require shipping license for natural gas. CNG retail suppliers would not however be required to have a license for natural gas shipping if they have no interaction with the GNI network (i.e. it is only acting as a retail supplier).

Finally, CER has underlined the importance to review and amend the existing safety regulations to address specific CNG aspects.

[72] Information paper D/15/050
[73] Decision paper CER/15/227
[74] GNI initially requested such inclusion based on the argument that for CNG to develop in Ireland, an entity needs to act as the promoter or "champion" of such business.

Italy

Natural gas vehicles have been used in Italy for many years and a CNG distribution network has developed over time. Various regulatory regimes have been in place for the distribution of fuels. CNG (and generally natural gas used as a fuel in transportation) is included in the regulatory definition of "fuels". A regulatory regime based on the authorisation of distribution of fuels has been in place since 1998 and subject to several amendments until today.

The authorisation to build a CNG station is provided by the respective municipality and its location is subject to compliance checks with inter alia the local and regional plans and safety requirements.[75] The plans may include definitions of areas for the stations location, potential users, services to be offered, decommissioning, opening times, etc. The plans may be accompanied by monitoring programs to assess the evolution of the local distribution of fuels and to collect data, for example distributed fuel volumes and technical data on station service conditions.

Municipalities set a maximum timeframe to process applications for the authorisation of refuelling stations (120 days). Upon the expiry of such timeframe, regions have another 60 days to approve the refuelling station. The municipality can select the investors by using tenders providing non-discriminatory conditions to the participants.

In relation to fuel supply to refuelling stations, stations can procure fuels from any supplier on the market. Any clause including exclusive supply rights to specific existing stations in place have no longer effect for the part exceeding 50% of the supply agreed and in any case for 50% of the total supply provided to customers by the station during the previous year.

Recently, SNAM (national gas TSO) and ENI signed a framework agreement for the development of up to 300 new CNG (and LNG stations) within ENI's national network of stations. The investment share of SNAM equals 150 million Euro by 2021. The investment is also aimed at creating a more balanced and homogenous network of CNG stations across the country.

Liquefied Natural Gas (LNG) in Transportation

Several initiatives have been taken both at the European and national level to foster the use of LNG in land transportation. In the following we provide some examples:

LNG Blue Corridors Initiative

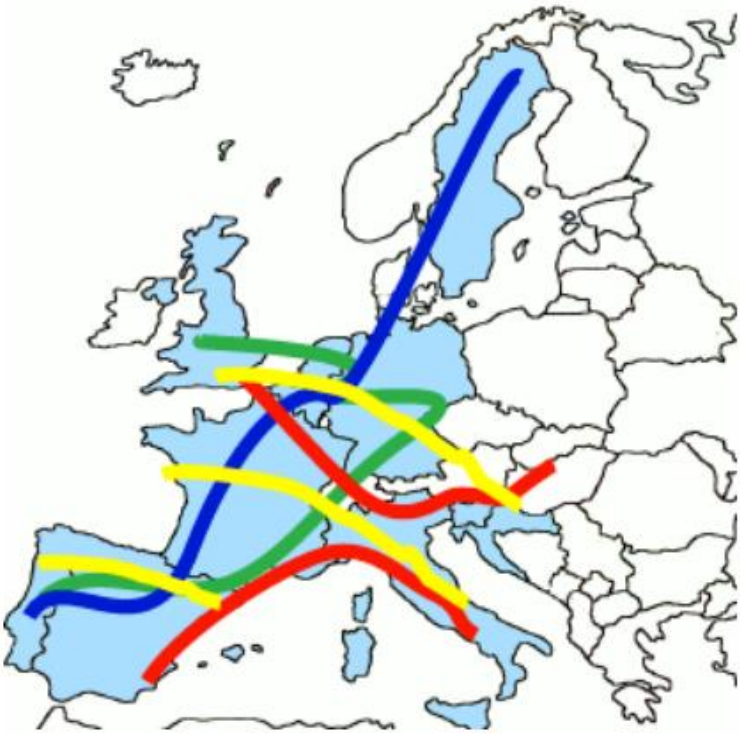
The Blue Corridors initiative has been taken at EU-level to support the use of LNG in transportation. It is therefore aimed at demonstrating the use of LNG for trucks and to define a roadmap for a future large-scale development of the market for LNG in transportation as an alternative to diesel fuel. The initiative identifies four corridors that are necessary to implement

[75] Previous regulation on minimum distances between refuelling stations have been abolished following disputes and decisions of the European Court of Justice that such minimum distance requirements are contrary to European rules. The presence of minimum requirements on distance between refuelling stations may discourage or impede new entrants and favour existing operators.

LNG transport network across Europe: Atlantic area (green line), Mediterranean region (red line), Europe's South with the North (blue line) and West and East (yellow line). The project is set to build around 14 LNG refuelling stations, both permanent and mobile, in specific locations along the route of each corridor which should support a fleet of approximately 100 LNG fuelled trucks. The project is financed under the European Seventh Framework Programme with a total amount of 7.96 Million Euro including 27 partners from 11 countries which include LNG fuel suppliers, distributors, fleet operators as well as research centres. The project started in 2013 and it is currently ongoing. Several partners participate to the project including vehicle manufacturers, natural gas supplies, operators of natural gas fuelled vehicles and at least one TSO (Fluxys). Below we summarise the findings achieved so far:

The different progress reached in the implementation of the stations planned under the Blue Corridors initiative mirrors the different stages of development of the LNG use in transportation across the different countries. Confirming the location of stations has proven problematic in countries which do not have a pre-existing policy framework for use of LNG in transportation.

In addition, market conditions have proven unfavourable with weak demand for alternative fuels for transportation and limited availability of vehicles offering, combined with uncertain long-term cost savings linked to taxation policies.



Source: LNG Blue Corridors

The overall cost for LNG refuelling stations can considerably across Europe and depend on the specific project environment. Companies often favour to install LNG stations at already existing stations to realise cost savings and use available ancillary services. Consequently, the deficit of larger available spaces for tanks and related equipment may become a factor limiting the development of LNG stations.

The slow development of LNG refuelling stations has been also caused by several standardisation and technical issues. Examples of such issues include LNG nozzles and receptacles compatibility, drivers training, weights and dimensions for LNG vehicles, maintenance facilities, parking structure, fuel quality etc. Possible solutions have been studied within the framework of the initiative.

The Netherlands

The Dutch government has taken a series of initiatives towards the increase in the use of natural gas in the transportation business. The primary driver for such initiatives is related to the need to reduce greenhouse gas emissions in line with the 2050 targets that the governments has set (80% reduction by 2050 compared to 1990 level). An additional driver is represented by the reduction of noise from road transport in cities. The policy actions taken in the Netherlands in relation to LNG in transportation include the reduction of the energy tax for LNG compared to diesel, PEAK (peak noise levels) programme and strategic initiatives that bring together stakeholders.

The PEAK programme is a joint initiative of three ministries to achieve low-noise emission in the distribution of goods. Under the PEAK, trucks are allowed in the inner cities for distribution of goods in the early morning hours. Lower noise emissions of LNG trucks constitute a comparative advantage to diesel fuelled trucks. However, several remaining barriers for the development of LNG refuelling station network have also been identified including inter alia the availability and prices of LNG fuelled trucks; and the lack of functional rules and standards for construction and use of refuelling stations.

The latter has been approached by establishing a first national regulation concerning the construction and operation of LNG refuelling stations in 2013. Furthermore, a series of procedures and guidelines have also been adopted[76]. They set standards for a variety of aspects related to LNG refuelling stations including the construction and design, operation of the stations, testing, maintenance, registration and inspection, safety measures, and procedures in case of incidents. A national LNG platform has also been established with the aim to publish information on the LNG business including information on the location of LNG refuelling stations[77].

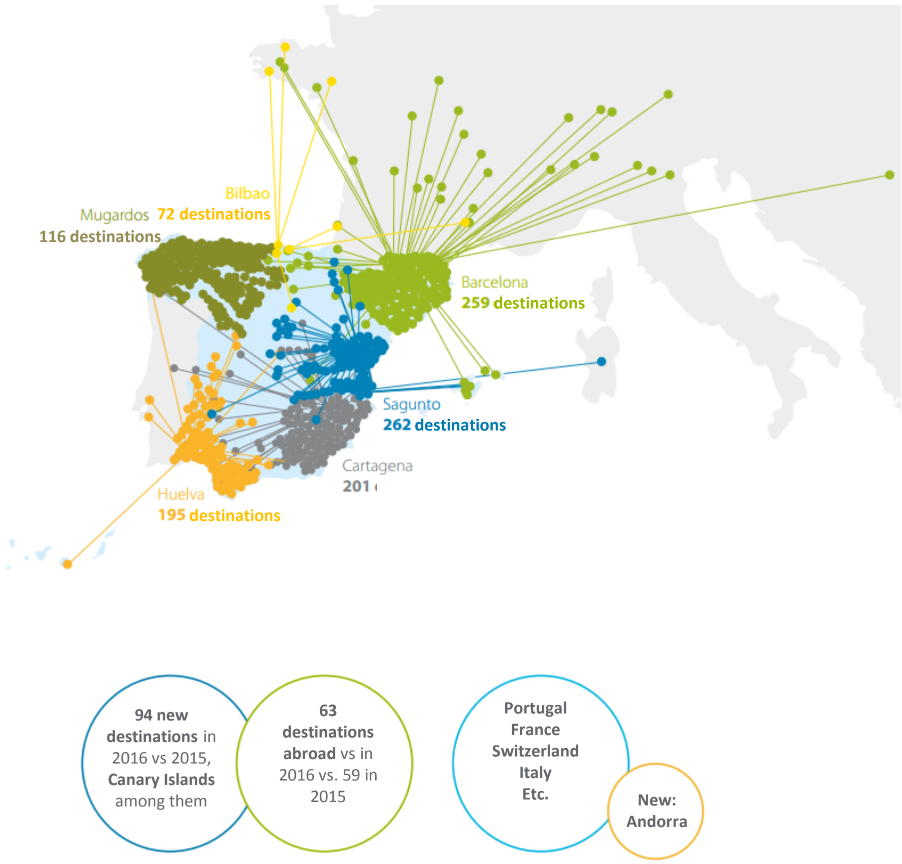
Spain

In Spain, the first truck was loaded in 1970 at the Barcelona LNG terminal, since then up to 45,000 trucks/year have been transporting LNG, not only in Spain, but also abroad through

[76] PGS33 guidelines, available at the following link: http://www.publicatiereeksgevaarlijkestoffen.nl/publicaties/PGS33-1.html
[77] The National LNG Platform is available at the following link: http://www.nationaallngplatform.nl/

different European countries. The truck loading market of LNG in Spain represented 11,232 GWh/y in 2016, around 3,5% of the conventional annual demand in Spain.

Figure 12: Destinations of LNG truck loadings by LNG regasification terminal in 2016



Source: Enagas

LNG in Maritime Transport

The use of LNG in maritime transportation for both fuel and bunkering purposes is a relatively new development in the maritime sector. Several initiatives have been taken and project launched at the national level in Europe to support the use of this new fuel. These initiatives include the Baltic States, the Netherlands, Germany, France and Italy. The examples from these initiatives highlight two measures that appear relevant for policy makers and regulators to support the use of LNG in the maritime sector.

The first one relates to the integration of LNG infrastructure for both land and maritime use at ports. Such integration would support the use of LNG in both areas and would mobilise the potential synergies in land and maritime transportation. LNG in land transportation is generally used for freight transport over long distances. Containers loaded on freight trucks are often delivered via ports. Having LNG fuelling facilities for trucks at ports is therefore necessary to ensure interoperability between different types of infrastructure.

The second measure relates to the involvement of affected stakeholders including permitting authorities in the project execution process. Such involvement will ensure timely coordination, knowledge exchange and adequate actions with respect to the main issues to be solved. For example, the involvement of permitting authorities in the early stage would help them to obtain sufficient information on the LNG bunkering business in order to adapt the existing permits and procedures and to accommodate the new business specifics.

Finally, given the relative early stages of this business, it is sensible for the national frameworks / planning to identify key ports and regions where LNG bunkering infrastructure will be developed. This will provide clarity and predictability to investors and facilitate the initial infrastructure development when fuel demand is not yet extensive[78].

Baltics

The HEKLA (Helsingborg & Klaipeda LNG Infrastructure Facility Development) represents the second phase of a project aimed at developing a LNG network within the Baltic Sea region. Main sponsors of the project (funded under the CEF initiative) include the port authorities of Helsingborg and Klaipedos. The project focuses on investments in LNG bunkering infrastructure in the two ports of Helsingborg & Klaipeda. These two ports have a central function in the port network between Scandinavian and Mediterranean as well as in the North-Baltic sea port networks. The project objective inter alia is to increase the availability of LNG as a fuel in the western and eastern parts of the Baltic Sea. In addition to the investments, the HEKLA project foresees several events to disseminate the project outcome to stakeholders (industry participants, authorities), particularly aspects concerning issuing permits for investments and procedures related to LNG bunkering. Stakeholders will be given the opportunity to have face-to-face meetings and gather direct know-how from the parties involved in the project.

The Netherlands

A project for the development of bunkering vessels and related infrastructure in the port of Rotterdam and Lubeck has been ongoing since 2014 (REALNG). The project aimed at designing, building and operating a maritime LNG bunker vessel as well as necessary related port investments for bunkering. Additional deliverables include the implementation of the SECA and MARPOL regulations[79]. As part of the project, one of the stakeholders, the STC-Group launched a course open to the public related to the LNG as a fuel in shipping.

Germany

The main aim of the Rhine-Alpine project is to increase the use of LNG as a fuel for inland navigation in the German market. The study will assess customer demand analysis for logistics and transportation hubs including the definition of appropriate locations for LNG distribution

[78] Such planning could be done by building upon the experience and plans of the Blue Corridors initiative.
[79] Sulphur Emission Control Areas (SECAs) and International Convention for the Prevention of Pollution from Ships.

infrastructure, an outline for a wide-scale roll-out of the concept in Germany as well as other European countries, and the real-life trial construction of two water-side small-scale terminals in the harbour areas of Mannheim and Duisburg. The outcome of the project would be to increase the use of LNG as a clean fuel along the corridor and to guarantee sufficient access to LNG for inland waterway routes in the area. Among the projects included there is a plan for LNG for heavy-duty vehicle transport in the Rhine-Alpine Corridor.

France

The objective of the North Sea-Mediterranean corridor is to develop a European LNG distribution network for inland waterways with new solutions for transportation and storage of LNG. The project lasts from 2016 to 2018 and investigates the economic viability of the potential investments. Furthermore, it aims to develop a business plan intended to demonstrate the competitiveness of the solutions presented in comparison to classic road distribution networks.

Italy

The project GAINN-IT aims to define, prototype, test, validate and deploy a network of infrastructures of alternative fuels for surface transport in the period 2017 - 2030. It explores the use of LNG as an alternative fuel for both maritime and road transport. Each of the ports considered under this initiative will include an LNG receiving system and related ancillary facilities. It will further include LNG storage and local distribution system, LNG ship refuelling system and related ancillary facilities as well as LNG vehicles (non-ship) bunkering system and related services. Two LNG grids will be enhanced by the project: the Thyrrenic-Ligurian and Adriatic-Ionic grids (ports involved include Genoa, La Spezia, Livorno, Ravenna and Venice). The project is managed by the Italian ministry for infrastructure and transportation. It is expected that the project outcome will largely determine the national legal framework for the supply of alternative fuels to ships. One of the core project aspects is the merging of port and LNG refuelling station infrastructure for vehicles (not ships) in one solution that would foster the synergies between different types of transportation (land and maritime) and possibly improve the overall economics of LNG as a fuel for transport purposes.

Biogas / Biomethane

Biogas and biomethane production has gained momentum in Europe and in some of the member states specific initiatives have been taken to support the production and use of biogas/ biomethane. Denmark and Sweden represent two examples of explicit policy schemes and regulation developed to support biogas and biomethane. Biogas/ biomethane is used mainly district heating and transportation. The use of biogas biomethane in these two countries is encouraged by several financial incentives including feed-in tariffs, subsidies, tax measures. Given the relatively high production costs, the economic feasibility of biogas/biomethane depends to large extent on these measures and this dependence may remain for the foreseeable future.[80]

Denmark is the country in Europe with some of the most ambitious targets in relation to biogas/ biomethane use in a 2050 perspective. Biogas/ biomethane is used in a number of applications including electricity production, heat and vehicle fuel with a constant increase over the years. The support to the use of biogas/ biomethane is set out in the framework of the national energy policy. The framework has set a target to achieve a fossil free economy by 2050 with greenhouse gas emissions to be reduced by 40% by 2020 compared to 1990 levels. The framework foresees that 60% of the organic waste from restaurants, food shops and other activities will be collected and used for biogas by 2018. Climate change and environmental reasons are therefore the drivers behind this support for biogas formalised in the energy policy framework 2050 and renewable energy act.

The policy framework is supported by a set of financial incentives. The first one is based a feed-in tariff paid for use of biogas/biomethane to produce electricity in CHP. The feed-in tariff varies in relation to the methane percentage included. Further there are subsidies for plants delivering biomethane to the natural gas networks. Additional incentives are provided in the form of financial support that cover part of the investment or operating cost of biogas/biomethane plants. Producers can apply for investment grants for plants digesting manure. A subsidy is foreseen for biogas used for heat production delivered for district heating purposes. In the transportation sector, the renewable energy act provides for subsidies of biomethane used as a fuel for vehicles. The subsidy is given to suppliers of biomethane to end users or suppliers at refuelling stations.

The major objective of the policy incentives is to ensure that only sustainable gas is included in the gas network past 2050. The substitution of natural gas with biogas/biomethane is also seen as an important tool to achieve other policy goals such as security of supply (declining North Sea production and indigenous production), flexibility and balancing needs of the energy system, and to ensure that sustainable gas into the network makes the reduction of the use of gas for heating purposes not necessary.

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80 There are several other measures that support the use of biogas. In the CHP sector, CHP plants using biogas can connect and deliver heat to district heating networks. In the transportation sector, synergies between the CNG and the biogas/biomethane production are exploited to raise the use in transportation.

The main challenges concerning the development of biogas/biomethane include the availability of biomass feedstock, its utilisation in CHP plants, network related issues (specific standards and contracts), burdensome approval procedures and sustainability of the financial incentives. While the location of available feedstock may substantially affect production costs[81], in general these costs remain high and above natural gas prices.

Sweden

The Swedish case exhibits similar characteristics to the Danish one, focusing however in particular on the use of biomethane in transportation. The policy target set by Sweden is to substitute all natural gas used in the country with biogas/biomethane over the long-term. This push is supported by the domestic capability for biogas/biomethane production, as well as by the presence of a well-developed industry revolving around biogas/biomethane production and use.

Sweden has put in place a variety of policy support schemes for biogas/biomethane production including tax exemptions, tax reduction of 40% for the use of a company gas vehicle, zero vehicle tax for green cars for the first five years, grants for investments that reduce greenhouse gas emissions, public procurement rules favouring gas for transport etc.

In relation to biogas/biomethane plants, regional subsidies are available to encourage investments with high environmental benefits including specific subsidies for innovative biomethane production which is not able to compete in the market yet. Subsidies are capped at 45% or 30% of the investment costs depending on the associated benefits of the investments. The cap can increase for small or medium scale plants.

Furthermore, electricity producers using biomethane can obtain tradeable green certificates. There is regulation supporting small heat producers to deliver heat into existing heat networks including production of heat from biogas. CHP plants using biogas are allowed to connect to district heating networks if there are no technical risks. However, they should pay for their network connections. Taxes are imposed on energy, CO2 and sulphur but they are not applicable to renewable energy fuels.

Refuelling stations with capacity greater than 1500 m^3 are required to have at least one type of renewable fuel. Quality standards apply for the biomethane used in vehicles and injected into the natural gas networks.[82] Reporting obligations are in place in case production of biogas exceeds 1 Million m3 a year or if storage of more than 50 tons of biomethane is kept. A permit is needed for storing more than 200 tons of biogas.

Similar challenges have emerged to the use of biogas/biomethane in Sweden as those found in Denmark.

[81] For example, biomass collected across several small farms faraway from biogas plants would increase cost of feedstock transport and ultimately and production cost.
[82] Subject to the gas specification of the natural gas network company propane is generally added to the biogas to enhance its calorific value to match the one of natural gas.

Hydrogen

Several initiatives have been undertaken at national and European level to support the development of hydrogen as an alternative energy fuel. Currently the development of hydrogen is not widespread and is often limited to pilot projects or studies.

In the following we address first the question of transporting hydrogen through the natural gas pipelines. Then we provide examples of infrastructure incentives where hydrogen is used as a fuel for vehicles (refuelling stations).

Conversion of Natural Gas Networks to Transport Hydrogen

There are several on-going pilot projects/ studies focusing on the future use of hydrogen. Below we describe two of them: a study on a full pipelines conversion to hydrogen (UK) and a pilot project of Power2Gas facility (France). Both studies are acknowledged and supported by the corresponding regulatory authorities.

The first initiative (H21 Leeds City Study) investigates a possibility for a full hydrogen conversion of the gas system of the city Leeds in the United Kingdom. It is executed by a consortium led by the gas distribution operator Norther Gas Networks. The study is being financed through the Ofgem's innovation scheme and is one of the most ambitious project in Europe with cost estimates around £2 Billion.

The second initiative is the Jupiter1000 pilot project in the south of France. The project aims to store surplus electricity by electrolyses conversion to hydrogen. The hydrogen is then blended in a small proportion with natural gas in the natural gas network. Currently in France the maximal hydrogen proportion allowed to be injected into the natural gas networks is equal to 6%. Nevertheless, both GRTgaz and TIGF consider that hydrogen and P2G technology could reach 100 installations in 2030 able to manage surplus electricity production of 2.5 to 3 TWh per year.

The project cost is equal to €30 million and is funded 40% by GRTgaz and 30% by subsidies from the European Union (FEDER), the French state (ADEME future investment programme) and the Provence-Alpes-Cote d'Azur regional authority. The remainder is financed by the partners. Correspondingly, the regulator CRE has allowed to include the capital cost of the investments funded by GRTgaz and TIGF in their transmission charges.[83]

[83] Public consultation of 27 July 2016 by the French Energy Regulatory Commission on the next tariff for use of the GRTgaz and TIGF natural gas transmission networks.

H21 Leeds City Gate —Full Network Conversion Study

The H21 Leeds City Gate research project is a study that envisages the conversion strategy for the Leeds City area including proposals to supply the local grid with 100% low-carbon hydrogen produced at four steam methane reformers on the cost by the North See utilising carbon capture and storage.

- **The project estimates to build steam reforming facility (incl. CCS) by the coast, hydrogen storage and a new TSO network connecting these to the city gate**
- **Existing DSO network to be used— no need for new DSO pipelines or further investment**
- **Investment for conversion of the network and appliances and ongoing costs for CCS, steam methane reforming, storage and efficiency losses**

Cost Estimates for Leeds H21 Study

Project Area	Capex (£ Million)	Opex (£ Million)
Steam Reformer develop. (incl. CCS)	395	
Development of H2 storage (intra-day & inter-session)	366	
Appliance Conversion (incl. all users)	1,053	
New Hydrogen Transmission System	230	
CCS		60
Storage management		31
Additional energy used for H2 production		48

Table 2 – Leeds H21 City Gate Project and Overview of Estimated Costs

Jupiter 1000 P2 Gas Pilot Project
GRTgaz with partners is involved in the pilot Jupiter 1000 project at the Fos sur Mer harbour nearby Marseille (Department of Bouches-du-Rhône in France). The project is located at the intersection of gas and electrical networks and close to an industrial source of CO2. With a power of 1MWe, the JUPITER unit demonstrates the practical appl**ication of P2G technology.** • **The project implements two technologies of electrolysis: PEM (Proton Exchange Membrane) and Alkaline** • **The CO2 is captured from industrial flue gas** • **The electricity is generated from renewable sources** • **The hydrogen blending complies satisfies the quality specifications of the natural gas network, the upper limit of hydrogen concentration in France is 6%.** • **The project cost is estimated at €30 millions**

Table 3 – Jupiter 1000 P2G Pilot Project

Hydrogen Used as a Fuel in the Transportation Sector

The use of hydrogen in transportation is so far more "national". Consequently, policy actions undertaken so far remain more country specific rather than looking for European solutions (except H2ME Project described below). The regulatory framework at national and European level has been developing recently and it revolves in many cases more around issues of transportation policy rather than energy regulation. Given the status of relative "infancy" of the hydrogen use in transportation, there have been several initiatives focusing on pilot projects and financial support.

Hydrogen mobility Europe (H2ME) is a flagship project giving fuel cell electric vehicle (FCEV)[84] access to the first pan-European network of hydrogen refuelling stations. The total project costs amount to €170 million (€67 million funded by Fuel Cells and Hydrogen Joint Undertaking, FCHJU[85]) and more than 40 organisations (car manufacturers, energy companies, hydrogen industry, academia) participate. The first project stage (H2ME1) started in 2015 and will continue to the middle of 2020. It aims to increase the number of fuel cell electric vehicles (FCEVs) driving on Europe's roads and to support the development of a pan-

[84] The average time needed to fill up a tank of a hydrogen fuel cell electric vehicle is just three minutes; modern refuelling systems operate at 700 bar. The range of a fuel cell vehicle is the range of 500 to 700 kilometres. Also from a safety point of view, hydrogen vehicles are claimed to be not different from conventional cars. Germany's independent safety certification and inspection agency–TÜV–came to this conclusion in its series of crash tests.

[85] The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) is a public private partnership supporting research, technological development and demonstration (RTD) activities in fuel cell and hydrogen energy technologies in Europe. The three members of the FCH JU are the European Commission, fuel cell and hydrogen industries represented by Hydrogen Europe and the research community represented by the Research Grouping N.ERGHY.

European network of hydrogen refuelling stations. With over 300 vehicles (cars, vans and trucks) and 29 refuelling stations being deployed, the project is one of the most ambitious coordinated projects for hydrogen deployment in Europe to date. There is a second project stage (H2ME2) planning to deploy further more than 1100 vehicles and 20 stations. In addition, it aims to remove barriers that may hinder infrastructure development and to provide recommendations how to support future investments and overcome barriers.

Carbon Capture and Storage (CCS)

We provide examples of CCS technology that have found application in two European countries, namely the UK and Norway. Both cases indicate that policy support and legal/regulatory framework is required to encourage the development of commercial-scale CCS. Furthermore, carbon price policy and emissions performance standard are important factors to ensure the right incentives are in place for the adoption of CCS.

The United Kingdom

In 2012, the UK has announced a CCS Roadmap in order to support the commercialisation of CCS technology by 2020. The program was funded with £1 billion including additional operational support as part of the UK electricity market reform to support the design, construction and operation of commercial-scale CCS. The aim of the program is in particular to generate learning that will reduce the cost of CCS in the future, test and build familiarity of industry with the CCS regulatory framework, support the development of suitable CCS business models, contribute to the development of early infrastructure for CO2 transportation and storage.

A bidding process established to select CCS projects to be financed was established. Two projects were selected for financing. The first one is Shell/SSE Peterheard Project in Scotland for the collection of CO2 at a gas-fired power station for injection in an offshore depleted gas field. The second one is the North Sea and Alstom/Drax While Rose Project in England for the collection of CO2 from a new coal-fired power station for storage in a saline aquifer beneath the North Sea. In addition, the UK government has set in place a £125 million research, development and innovation programme for CCS which has funded around 100 projects.

The funding for the two projects and CCS program was however scrapped in the fall of 2015 following discussions with the project promoters and a reset of the UK energy policy including a focus on new gas fired power stations and a closing of coal fired power plants by 2025.

Regardless of this setback, other regulatory measures taken in the UK represent suitable examples of regulatory action taken to support CCS. These relate for example to the introduction of a “Triple Lock” of policies to ensure that the UK has only new coal-fired power stations that have CCS. Conditions on the consent given to coal power stations including the requirement for all new stations above 300 MW to be carbon capture ready, and that new coal-fired power stations must have at least 300 MWe of their generating capacity equipped with CCS, represent the first element of the lock.

Price signals are also considered as an important factor to ensure the right incentives are in place for the adoption of CCS. This represent the second part of the lock. Price signals from the EU ETS have been deemed not consistent with this objective. The government has therefore moved towards providing the right incentive in the ETS mechanism by introducing a carbon price floor topping up the EU ETS price to provide the necessary stable incentive. The 2016 budget by the UK government capped this floor at £18 GBP per tonne of CO2 until 2021 in order to limit the competitive disadvantage faced by businesses and reduce their energy bills.

The third element of the triple lock is constituted by the emissions performance standard (EPS) introduced in the framework of the energy market reform setting a level of 450g/kWh in order to backstop the requirement that new coal plans are equipped with CCS. The policy message given is that the role of any new coal fired plant will be dependent on the successful development of cost-competitive CCS. The EPS was introduced by the energy act of 2013 and subsequent regulations.

Norway

In a similar fashion to the UK case, Norway has established state funding for a large-scale CCS programme with increasing budget allocated to these from the overall state budget[86]. The two specific large-scale CCS projects are Sleipner and Snohvit. The Norwegian government is also supporting the full-chain development of ongoing CCS projects through specific studies, with the aim to facilitate the achievement of a final investment decision in 2018 and to have at least one project operational in 2022. To this end, the Norwegian government has proposed to allocate additional funding to study the full-scale deployment of CCS. Ongoing projects include multiple applications of CO2 capture including application at cement factory, ammonia plant, waste recovery plant, ship transport of CO2 and injection in reservoirs on the continental shelf.

In the case of Norway, the regulation governing CCS is part of the laws and regulations on petroleum activities either for the purposes of enhanced oil recovery or permanent storage on the continental shelf. The Norwegian government has developed a strategy for CCS. A feasibility study report has been produced indicating that realising a full-scale CCS chain in Norway by 2022 is possible at lower costs than those considered earlier.

A detailed regulatory and legal framework has been put in place in relation to permitting requirements for exploration and CO2 storage and suitable storage locations, permits for CO2 storage, access by third parties to storage facilities and transportation pipelines, and liabilities of the CO2 storage operator and public participation.

[86] Budget allocated to CCS activities in 2016 was set at NOK 1314 million including funding for technology research, further studies on full-scale demonstration for CO2 capture, and other financing for administration of grants.

Annex 5 – Regulatory innovation incentives

In this annex, we provide case studies showing examples of specific funding for innovation as part of the regulatory framework. In recent years, energy regulators have recognised the need for promoting innovation and incorporated specific innovation mechanisms as part of the regulatory framework.

We must also add that in many cases the treatment of decarbonisation type investments are included as part of the innovation type investments

Great Britain

A notable feature in Great Britain already having a long tradition in energy regulation is its continuous enhancement of its regulatory approaches to consider the changes and development of the energy sector.

As part of its current framework - RIIO (Revenues = Incentives + Innovation + Outputs), Ofgem introduced specific incentives for innovation as part of an 'innovation stimulus'. The aim of this approach is to provide incentives to drive innovation that are needed to deliver a sustainable energy network. There are two mechanisms provided under the innovation stimulus. These are the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). The Network Innovation Allowance (NIA) is a set annual allowance that allows the regulated network operators a funding opportunity of 0.5-1% of revenue to be spent on innovation projects, 90% of which can be recovered through the incentive mechanism. The NIA funds smaller scale research, development and demonstration projects and can cover all types of innovation, including commercial, technological and operational. Unlike the NIC (see below), the NIA is not focussed solely on innovative projects with potential low carbon and environmental benefits.

The regulated network company must present in a supporting innovation strategy an application to Ofgem. The application must include that the proposed innovation project meets eligibility criteria. Projects must have a direct impact on the Gas Network and include one of the following:[87]

- A specific new (unproven) piece of equipment (including control and/or communications systems and/or software)
- A specific novel arrangement or application of existing equipment including control and/or communications systems and/or software)
- A specific novel operational practice directly related to the operation of the gas transportation system
- A specific novel commercial arrangement

The projects must also ensure that they offer

- Potential to develop new learning
- Potential to deliver net financial benefits to the customer
- Without leading to unnecessary duplication

[87] http://www2.nationalgrid.com/UK/Our-company/Innovation/NIA/

The Network Innovation Competition (NIC) is an annual competition to fund innovative projects which could deliver carbon or environmental benefits for gas customers, and that would not otherwise be funded without this additional funding. A total of £20M/year is available for gas transmission and distribution.

Ireland

The current price control from 2013-2017 an allowance of €8 million was allowed for innovation opex funding, of which €7.2 million was allocated to gas transmission and €0.8 million to distribution. Innovation funding has focused on the roll out of CNG for use in the transport sector, renewable gas and research grants. In its most recent decision for the upcoming price control (Oct 2017-2023), an innovation allowance of up to €20.0 million approximately 1% of allowed revenue has been allocated. Innovation funds were allocated to five principal areas CNG[88], biogas, research, business/ technical[89] and programme management services. This innovation funding is treated as a pass-through cost item and is not part of the efficiency requirement.

It is the responsibility of both Gas Networks Ireland (TSO) and the Gas Innovation Group to determine the best possible use of the innovation funding. Applications for funding submitted to the Gas Innovation Group will demonstrate the potential to achieve the following -will deliver significant carbon savings; increase throughput through the gas system; assists in the transition to a low carbon economy; and provide measurable value to all gas customers.

France

The French Energy Regulatory Commission (Commission de régulation de l'énergie - CRE) introduced in its current gas transmission price control (started 2017)[90] an incentive scheme for research and development (R&D) cost. In the consultation process it was considered necessary to study new possible uses of the gas transmission networks. All stakeholders were in favour of this proposal. A budget is allocated by CRE to the TSOs for R&D expenditure which are subject to monitoring. The TSOs on a yearly basis must report to CRE on the actual spending, list of current and upcoming R&D related projects with expected results. At the end of the price control period, any underspending on the allocated R&D amount is accumulated in an account and reimbursed back to the network users.

For electricity distribution, costs for R&D and pilot projects are covered within the distribution network tariff. These costs are not subject to efficiency increase requirements and are treated as a pass-through item in setting the allowed revenues.

[88] A decision from CER was published in November 2016 regarding the request of TSO Gas Network Ireland (GNI) to fund the impact assessment of the introduction of CNG on the gas network through the introduction of 13 CNG stations (CER/16/313). Part of the project cost was approved via the innovation fund.

[89] Decision on October 2017 to September 2022 Transmission Revenue for Gas Networks Ireland, 30.08.2017

[90] The Determination of the French Energy Regulatory Commission of 15 December 2016, for the price control known as "ATRT6", took effect on 1st April 2017 for a period of four years.

Norway

The Norwegian Energy Regulator (NVE) applies an innovation incentive scheme for (R&D) cost in electricity distribution. Cost of R&D and pilot projects are added to the allowed revenues if the regulator approves the project proposals. The network operators are allowed to recover maximally 0.3% of their regulated assed base. This allowance is explicitly added to the allowed revenues and is not subject to efficiency targets. There is an official approval process and the network operators need to first apply for project approval from a grant institution[91] such as the Research Council of Norway, Innovation Norway, Enova or EU's different funding bodies. The proposed project must bring socio- economic benefits, such as more efficient operation or other efficiency gains for the network company. The grant institution would assess the projects if a project proposal is found feasible, the grant institution approves the project. Only if the network company receives an approval from the grant institution, it can apply to the regulator to include the project cost in the allowed revenues through the incentive scheme. Furthermore, the regulator has the final decision whether to apply the incentive scheme for the respective project.

[91] Depending on the grant institution and the complexity of the project (typically the number of partners involved), the approval process takes between two and twelve months.

Annex 6 – Conclusions summary tables

Table 2: Summary Table: Commodity Perspective

Commodity Perspective – Regulatory Implications			
Scenario			**Category**
High	**Average**	**Low**	**Use of Natural Gas in Electricity Generation**
✓	✓	✓	• Wholesale gas markets (regulators) ○ Regulatory initiatives to further develop the necessary tools for market integration ○ New mechanism for market mergers
–	–	✓	• Gas transportation tariffs (regulators) ○ Redesign of tariffs to encourage the use of gas-fired power plants (multipliers for short-term capacity, specific short-term products) ○ Basic rethinking of the tariff design (in cases of sustainable surplus transport capacity) ○ Redesign of reserve prices in capacity auctions (in cases of sustainable surplus transport capacity)
✓	✓	✓	• Carbon market prices (policy makers) ○ Review of the ETS scheme to ensure a proper functioning carbon market and related price ○ Use a carbon price floor
✓	✓	✓	• Coordination between the power and gas sectors (regulators and network operators) ○ Improvement of coordination in terms of operational decisions, time alignment, planning of infrastructure via more intensive cooperation between gas and power TSOs

High Average Low	**Use of CNG and LNG in Transportation**
✓ ✓ ✓	• Ensure effective competition / Monitoring of commodity markets to prevent market abuse and correct market failures (competition authorities) ○ Effective environmental regulation (environmental authorities)
✓ ✓ ✓	• Measures supporting the infrastructure development, see the table on CNG/LNG infrastructure in the transportation sector (policy makers and regulators) ○ Although directed to the infrastructure development, such measures would indirectly support commodity demand to a significant extent
✓ ✓ ✓	• Commodity-based policy incentives to support the use of natural gas in transportation (policy makers) ○ Tax breaks on CNG and LNG as a fuel for transportation ○ Tax breaks for gas-fuelled vehicles ○ Grants and other incentives on purchase of gas-fuelled vehicles
✓ ✓ ✓	• Review and alignment of licensing requirements for supply of natural gas, CNG and LNG across member states (regulators)

Scenario	
High / **Average** / **Low**	**Use of Renewable Gases**
✓ / ✓ / ✓	• Feed-in tariffs for injection of renewable gasses into the natural gas network (policy makers and regulators)
✓ / ✓ / ✓	• Use of green certificates to support the establishment of markets for biomethane (policy makers and regulators)
✓ / ✓ / ✓	• Commodity-based policy incentives to support the development of renewables gases (policy makers) ○ Tax breaks /investment grants for production of renewable gasses ○ Tax breaks for RES gas-fuelled vehicles ○ Grants and other incentives on purchase of RES gas-fuelled vehicles
✓ / ✓ / ✓	• Funding research and development / pilot projects, innovation incentives (policy makers or regulators)

High Average Low	**Use of Gas for Heating**

✓
✓
✓
✓
✓
	• Focus on further enhancement of retail competition (regulators)
	  ○ Facilitating market entry
	  ○ Switching procedures
	• Gradual abolishment of price regulation following the establishment of functioning retail competition (regulators)
	• Retail prices should reflect the cost of gas supply (regulators)

Table 3: Summary Table: Infrastructure Perspective

Infrastructure Perspective – Regulatory Implications			
Scenario			**Category**
High	**Average**	**Low**	**Natural Gas Infrastructure**
–	–	✓	• Potential stranded assets and regulatory compensation schemes (regulators) ○ depreciation schemes ○ asset valuation ○ adjustment of cost of capital
–	–	✓	• Coordinated cross-border decommissioning (regulators and TSOs) ○ Identification of assets to be decommissioned by TSOs ○ Procedures for cross-border decommissioning ○ Inter-TSO coordination, considering also options for deferring decommissioning if benefits from keeping the asset can be demonstrated ○ Role and coordination of national regulators ○ Cost allocation, in case of decommissioning based on asset location, may include additional considerations, i.e. cost / benefits caused by decommissioning and reflecting cross-border impact ○ Decommissioning can be deferred if TSO in neighbouring can demonstrate benefits from keeping the asset. This TSO should provide compensation to the TSO keeping the asset. The inter-TSOs compensation should be properly considered by the respective NRAs in the revenue setting of the TSOs.

High Average Low	**CNG/LNG Infrastructure in the Transportation Sector**
✓ ✓ ✓	• CNG/LNG infrastructure (refuelling stations and services) and the commodity transport are contestable activities and can be provided in a competitive environment • Monitor specific segments to prevent from distortion of competition and abusive use of market power, for example LNG/ CNG refuelling stations (competition authorities and regulators) • Regulation of non-contestable infrastructure (regulators) ○ Competitive provision of storage/bunkering services may not be possible due to various limitations

✓
✓
✓
	• Involvement of regulated entities (TSOs and DSOs) in contestable activities related to the CNG/LNG infrastructure (regulators)
	  ○ The regulatory framework should not create a barrier and should ensure that customers and market participants benefit to the largest extent possible from the range of services
	  ○ Regulators may consider adapting the existing unbundling rules, by recognising explicitly the specific circumstances and the motivation for such involvement of the regulated business into contestable activities.
	  ○ Regulation should prevent (unintended) interactions between the regulated and contestable sectors
	  ○ Regulators may consider adapting the existing unbundling rules, by recognising explicitly the specific circumstances and the motivation for such involvement of the regulated business into contestable activities. Nevertheless, the fundamental principles of unbundling will remain appropriate and any adaptation of the unbundling rules should not dismiss their validity.

✓	• Establishment of coordinated national/regional plans (policy makers and competent authorities) ○ The construction of CNG and LNG infrastructure may be defined in national or regional plans

✓ ✓	○ A common approach in the definition of these plans in line with Directive 2014/94/EU may bring benefits in terms of alignment and synergies (regulators can provide relevant information and support the activities of regional governments/ municipalities and other competent authorities)
✓ ✓ ✓	• Infrastructure promotion schemes (policy makers and regulators) ○ Specific concession regimes for the construction of CNG/LNG infrastructure may help to support its development ○ Concessions could be granted at the national or European level
✓ ✓ ✓	• Additional regulatory and policy incentives (policy makers and regulators) ○ Tax breaks for CNG / LNG refuelling stations ○ Investment subsidies for CNG / LNG refuelling stations ○ Funding research and development / pilot projects, innovation incentives

High	Average	Low	Renewable Gas Infrastructure
-	✓	✓	• Alignment of national technical specifications for hydrogen blending in distribution networks for natural gas (regulators) • On transmission level, there may be a need to revisit the Interoperability Network Code and the CEN provisions on gas quality (regulators) • Steering the technology roll-out in terms of time and targeted penetration zones where the hydrogen quantities will gradually grow (regulators) • Design of the commercial and access arrangements of a hydrogen system, long-term (regulators) • Involvement of regulated entities in operation of P2G/hydrogen/SNG production infrastructure / unbundling requirements (see the points to CNG/LNG infrastructure in the transportation sector) (regulators)

✓	✓	✓	• Clear arrangements on the connection rules of biomethane plants to the natural gas network (regulators)
			    ○ connection charges, technical requirements, responsibilities for quality, metering, compression
			• Explicit incentives for the injection of biomethane in the network (regulators)
			    ○ Favourable connection charges / network tariffs

Scenario	
High / Average / Low	**District Heating**
High: ✓ Average: ✓ Low: ✓	• Monitoring of competition and market abuse in the heating sector (competition authorities or regulators) • Use of ex-ante regulation when potential competition to district heating is limited (regulators) • Development of district heating networks may be defined in national or regional plans (policy makers and competent authorities)

High / Average / Low	**Innovation Incentives**

High: -
Average: ✓
Low: ✓
	• Regulatory incentives for innovation and decarbonisation (regulators)
	  ○ Definition of criteria for funding eligibility
	  ○ Explicit budgets for funding decarbonization/innovation initiatives by using special allowances
	  ○ Integration of the project cost in the allowed revenue
	• Potential use of accelerated depreciation allowance and WACC premium for investments in decarbonization/innovation initiatives

Annex 7 – List of abbreviations

Term	Definition
ACER	Agency for the Cooperation of Energy Regulators
AD	Anaerobic digestion
BEV	Battery electric vehicles
CAPM	Capital Asset Pricing Model
CCS	Carbon Capture Storage
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO2	Carbon Dioxide
DSO	Distribution system operator
EBA	European Biogas Association
EC	European Commission
EU	European Union
EAFO	European Alternative Fuels Observatory EAFO
EEA	European Environment Agency
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	Emissions Trading Scheme
EV	Electric Vehicle
FCEV	Fuel cell electric vehicles
GTM	Gas Target Model
HDV	Heavy Duty Vehicles
HEV	Hybrid electric vehicles
IEA	International Energy Agency
LDV	Light Duty Vehicles

Term	Definition
LNG	Liquefied Natural Gas
NGVA	Natural gas vehicle association
NPV	Net present value
NRA	National Regulatory Authority
TAR NC	Network Code Tariffs
OECD	Organization for Economic Cooperation and Development
Ofgem	Office of gas and electricity markets
PCI	Projects of Common Interest
PEV	Plug-in electric
PHEV	Plug-in hybrid electric vehicles
REEV	Range extended electric vehicle
RAB	Regulatory asset base
RES	Renewable Energy Sources
RIIO	Revenue, Incentives, Innovation, Output
SoS	Security of Supply
TTW	Tank-to-wheel
TSO	Transmission system operator
TTS	Truck-to-Ship
TYNDP	Ten Year Network Development Plan
PTS	Shore-to-ship
SNG	Substitute natural gas
STS	Ship-to-ship
WACC	Weighted Average Cost of Capital
WTW	Well to Wheel

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One of CEER's key objectives is to facilitate the creation of a single, competitive, efficient and sustainable EU internal energy market that works in the public interest. CEER actively promotes an investment-friendly and harmonised regulatory environment, and consistent application of existing EU legislation. Moreover, CEER champions consumer issues in our belief that a competitive and secure EU single energy market is not a goal in itself, but should deliver benefits for energy consumers.

CEER, based in Brussels, deals with a broad range of energy issues including retail markets and consumers; distribution networks; smart grids; flexibility; sustainability; and international cooperation. European energy regulators are committed to a holistic approach to energy regulation in Europe. Through CEER, NRAs cooperate and develop common position papers, advice and forward-thinking recommendations to improve the electricity and gas markets for the benefit of consumers and businesses.

The work of CEER is structured according to a number of working groups and task forces, composed of staff members of the national energy regulatory authorities, and supported by the CEER Secretariat.

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