The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets

Specific Tender under Framework Contract MOVE/ENER/SRD/2016-498 Lot 2

Revised Report Tasks 1 & 2

Trinomics

Contract details

European Commission, DG ENER

ENER/B1/2017-412 under framework contract MOVE/ENER/SRD/2016-498 Lot 2

The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets

Presented by

Consortium led by:

Trinomics B.V.

Westersingel 32a

3014 GS Rotterdam

The Netherlands

Contact person

Luc van Nuffel

T: +31 10 3414 592

E: Luc.vanNuffel@trinomics.eu

Date

19 June 2018

Disclaimer

Rotterdam, 19 June 2018

Client: European Commission, DG Energy

The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets - Revised report Tasks 1 & 2

ENER/B1/2017-412
under framework contract
MOVE/ENER/SRD/2016-498 Lot 2

In association with:

TABLE OF CONTENT

List of Figures

List of Tables

List of Abbreviations

BAU	Business-as-usual
BEV	Battery electric vehicle
CCGT	Combined cycle gas turbine
CCS	Carbon Capture & Storage
CCU	Carbon capture and utilization
CHP	Combined heat and power
CNG	Compressed Natural Gas
DC	Direct current
DII	Desertec Industrial Initiative
EC	European Commission
FC	Fuel cell
FCEV	Fuel cell electric vehicle
GHG	Greenhouse gases
H_2	Hydrogen
HRS	Hydrogen Refuelling Station
ICE	Internal combustion engine
LH_2	Liquid Hydrogen
LNG	Liquefied Natural Gas
MENA	Middle East and North Africa
NDC	Nationally Determined Contribution
NG	Natural Gas
NGO	Non-Governmental Organisation
$PtCH_4$	Power-to-Methane
PtG	Power-to-Gas
PtH_2	Power-to-Hydrogen
PtL	Power-to-Liquids
PV	Photovoltaic
RES	Renewable energy sources
SMR	Steam methane reforming
SOEC	Solid oxide electrolyser cell
TRL	Technology Readiness Level
UNFCCC	United Nations Framework Convention on Climate Change

Types of gas

To set the scope of this study, the types of gases to be assessed have been defined as follows:

Types of gas

For the sake of this study, the term "gas" is not limited to natural gas, i.e. of fossil origin. Rather, the term "gas" is used for gaseous energy carriers, including

a) **Natural gas** (mainly CH_4) from fossil sources; in full decarbonisation by 2050 only relevant with CCS[1], e.g. NG power plant with pre- or post-combustion CCS,

b) **(Renewable) synthetic methane** (e-CH_4), synthetic methane produced from H_2 from (renewable) electricity through water electrolysis and CO_2 obtained from organic processes, or captured from air by elevated temperature processes

c) **Biomethane** (bio-CH_4), i.e. methane from organic matter (purified biogas), produced by anaerobic digestion or thermal gasification, and

d) **(Renewable) Hydrogen** (H_2): either fossil-based hydrogen in combination with CCS, e.g. from steam methane reforming of natural gas, or produced through water electrolysis from (renewable) electricity.

Mixtures of methane with hydrogen, often dubbed hythane are not addressed as a separate type of gas.

[1] CCS stands for Carbon Capture & Storage and describes a group of concepts which either capture CO_2 released during the combustion or extract the carbon contained in fossil energy carriers or the flue gas and, in both cases, stores it preferably for an unlimited period of time in underground structures at very large scale. In the first case, pure hydrogen is produced as energy carrier which burns without delivering CO_2 to the atmosphere (and it is equivalent to steam reforming described in point (d)).

1 Introduction

The European Union has set itself ambitious energy and climate policy goals that aim at, among others, protecting the global climate while ensuring security of supply at a reasonable cost to society. It is currently adopting targets for the year 2030 for reducing EU domestic greenhouse gas emissions by at least 40% compared to 1990, increasing the share of renewable energy to at least 27% of final energy consumption (proposal by European Commission) and improving the energy efficiency of the EU by at least 30% compared to a baseline scenario. This ambition is supported by the 2030 EU policy framework on climate and energy targets and the framework for an "Energy Union with a forward-looking climate policy". The 2030 targets regarding energy efficiency and renewable energy as proposed by the European Commission are currently being discussed in a trialogue concertation between the Council, Parliament and Commission. The Parliament has in January 2018 approved a proposal which includes a binding 35% target for both renewable energy and energy efficiency in 2030.

The long-term EU energy policy objectives include an 80% to 95% reduction of greenhouse gas emissions by 2050[2]. The 2015 Paris Agreement adopted by consensus by 195 UNFCCC members aims at holding the increase in the global average temperature to well below 2°C above pre-industrial levels or to pursue efforts to limit the temperature increase even further to 1.5°C[3]. The Paris Agreement acknowledges that the global action will require peaking of GHG emissions as soon as possible and achieving climate neutrality in the second half of the century.

This sharp decrease in CO_2 and other greenhouse gas emissions could drastically alter the role of natural gas in the European energy system. Therefore, the role of the European gas infrastructure may change substantially within the next thirty years. Taking into account the long lifetime of gas infrastructure assets, a forward-looking exercise is essential to take informed decisions and avoid devalued or even stranded assets when investing in new gas infrastructure.
In this context, the major objective of this study is to analyse the future role of the European gas infrastructure within a decarbonized energy system in Europe until 2050[4]. This report contains the results of the first two tasks of the study: review of existing storylines for future European gas infrastructure (Task 1) and development of well-reasoned qualitative generic 2050-storylines (Task 2).

The objective of Task 1 is to identify the potential developments in the gas sector and other sectors towards deep decarbonisation by 2050 on the basis of existing literature. To this end, the study identifies and assesses strategy papers and analyses results with wide European coverage, which provide plans, visions (= storylines) or scenarios (= quantified storylines) for the future European gas sector, or individual elements thereof, on the pathway to deep European decarbonisation in 2050. Whereas the focus is on European developments, the study also analyses five international storylines, in those regions where natural gas and other gases that can be transported via gas infrastructure to Europe or play an important role today or may play one in the future, or which are otherwise relevant

[2] In the context of necessary reductions according to the IPCC by developed countries as a group, to reduce emissions by 80-95% by 2050 compared to 1990 levels. In the Low Carbon Roadmap (2011), the Commission considered GHG reductions not only in energy system but also in other sectors, notably agriculture (but did not consider emissions from land use change (e.g. role of GHG sinks).
[3] See [https://ec.europa.eu/clima/policies/strategies/2050_en] and [http://unfccc.int/paris_agreement/items/9485.php]
[4] Simply and only as an *illustration* of deep decarbonisation, an objective of -95% GHG reductions by 2050 (compared to 1990) was chosen for this study. This objective was neither modelled nor does indicate the level of GHG reductions that the Commission will consider in the proposal for the Long Term Strategy.

for Europe. The international storylines can provide a better understanding of potential best practices and economies of scale. They cover Russia in connection with Ukraine and Belarus, Japan, Norway, China as well as the Middle East and North Africa (MENA) region. In order to compare the different storylines and to understand the ambitions behind them, a structured approach is employed already for the phase of collecting them. The methodology therefore comprises three sub-tasks, one to define the search and sorting criteria (Sub-task 1.1 in chapter 2.1), the second to collect relevant storylines in order to achieve a comprehensive overview (Sub-task 1.2 in chapter 2.2), and the third to assess their contents (Sub-task 1.3 in chapter 2.3).

The objective of Task 2 is to develop three (qualitative only) storylines, which result in different gas demand levels and gas infrastructure needs in Europe in 2050. To develop concise gas market storylines for Europe until 2050, a short outline of the European gas market is given in a first sub-task (Sub-task 2.1 in chapter 3.2). Regional differentiation is added by identifying and describing up to five regional market areas. In a second sub-task, three storylines are developed covering the timeframe up to 2050, using today's gas market as a starting point (Sub-task 2.2 in chapter 3.3). We outline meaningful developments of the five characteristic regions identified and described in the first sub-task, covering both the geographical and the time dimension for a structured storyline development. Task 2 is concluded with a sub-task focussing on ensuring compatibility of storyline elements with the requirements of the PRIMES and METIS models (Sub-task 2.3 in chapter 3.4). Finally, chapter 4 draws interim conclusions.

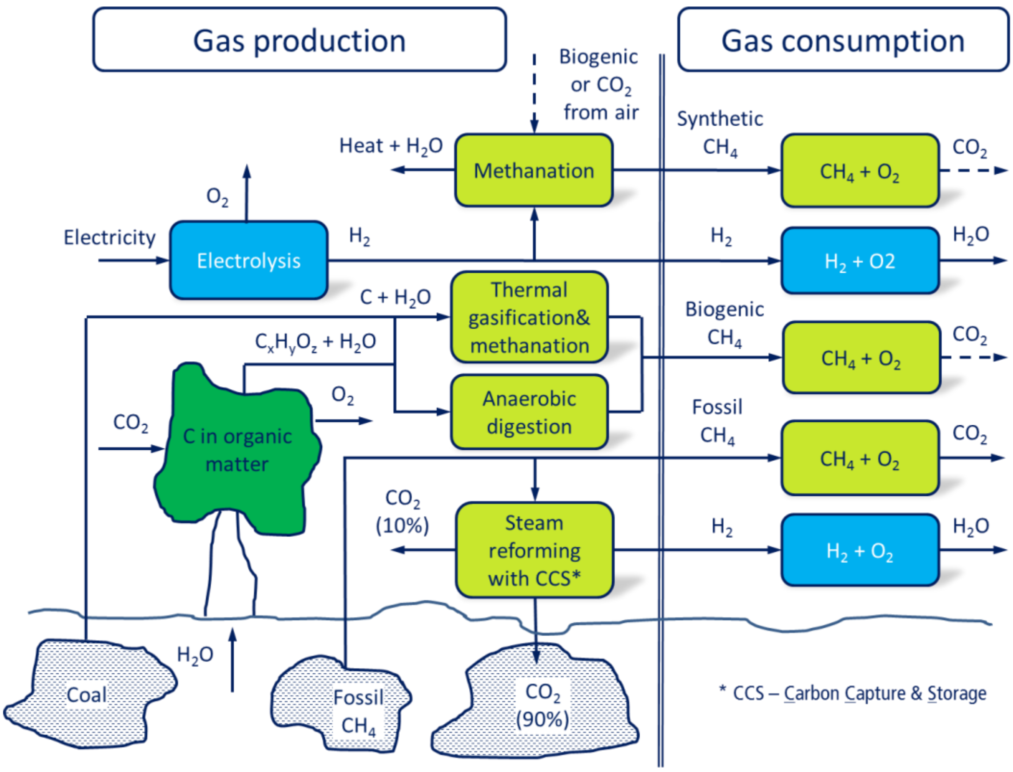
2 Review of existing 2050-storylines

2.1 Definition of search and sorting criteria

The major objective of the literature review in Task 1 is to understand and summarize different strategies, visions, plans or ideas for the development of a future gas infrastructure towards a clean energy system in Europe from the perspective of different stakeholders, markets and Member States. Therefore, a wide literature research has been carried out in order to arrive at a comprehensive overview and to develop a good understanding of storylines across Europe. In order to analyse a large number of documents in an efficient way, a structured approach based on well-defined search and sorting criteria has been followed. In this context, a list of criteria with growing level of detail has been developed and applied to both collection and sorting of storylines in sub-task 1.2. The results of the analysis are presented in sub-task 1.3.

The physical production pathways and their interdependencies are depicted in Figure 2-1. The figure shows the major processes and energy flows involved to produce the final gas types (from the above list) from the relevant primary energy sources (natural gas, biomass, electricity and coal). In addition, the major auxiliary media are presented. If fossil energies are applied, their use makes only sense in combination with decarbonization[5] technology (CCS & CCU) in an otherwise decarbonized world. Even though the use of CCS does not enable the production of fuels without GHG emissions, as in practical applications a share of up to 10% of the CO_2 still escapes into the atmosphere[6].

Figure 2-1: Types of energy gases assessed in this study and their interdependence



[5] Some prefer the term 'defossilization' as it denotes that fossil based carbon energy carriers should be phased out, allowing renewable carbon based fuels such as biomethane to be used beyond 2050, paying tribute to a sustainable and circular use of carbon.
[6] See e.g. for natural gas with CCS [RWE 2016] or for coal with CCS [2005].

The collection and sorting of storylines in sub-task 1.2 is based on the following main criteria:

- **General scope** of the study including regional coverage by EU regions (see chapter 3.2), time horizon, energy demand sectors considered (power, heating, mobility, industry) and study focus (demand, climate policy, supply resources, security of supply, infrastructure, technology);
- **Decarbonisation level** of the storyline to verify whether it is meeting the illustrative objective of -95% GHG reductions by 2050 (compared to 1990) selected for this study and thus being relevant for a more detailed assessment in sub-task 1.3 (a -95% reduction of GHG emissions (base year: 1990) was agreed with DG ENER as target for this study);
- **Future role of gas** in Europe in terms of expected development of gas demand and its share in different demand sectors (power, heating, mobility, industry);
- **Type of gas** (natural gas from fossil sources, power-based synthetic methane, biomethane and hydrogen);
- **Type of stakeholders** involved in the development of a specific storyline for the critical appraisal of its motivation (e.g. industry, policy, research, NGO, etc.).

The above list of criteria is further detailed and supplemented by additional aspects for the storyline assessment in sub-task 1.3:

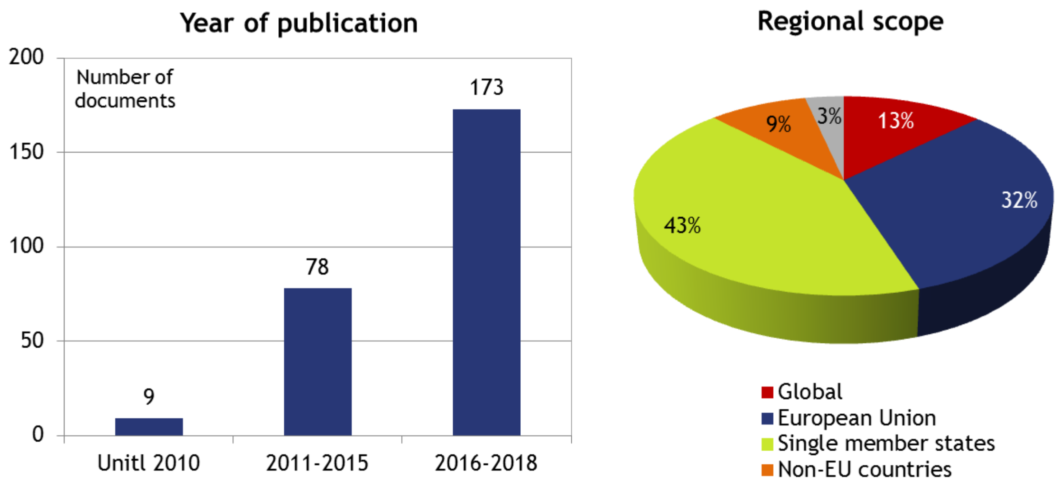
- **Role of gas and gas infrastructure:** more detailed description of the expected development of the overall gas demand, affected demand sectors, utilization of the gas infrastructure including the threat of devalued or stranded assets, impact on other non-gas energy supply infrastructures;
- **Potential environmental impact**: the climate impact of the storylines in terms of GHG reductions (CO_2 and other GHG including methane) until 2050, potential roadblocks from an unavoidable methane slip from infrastructure and production as well as potential societal issues related to achievement or non-achievement of a full decarbonisation
- **Technological aspects:** expected developments of the techno-economic parameters of the technologies involved in the storylines including technology and economic scaling and learning effects, classification of disruptive, isolated, innovative, etc. technologies and solutions, identification of potential roadblocks for relevant technologies as well as potential development of the market size for the respective technologies;
- **Regional aspects:** regional focus of the selected storyline, regional potentials for certain technologies and solutions taking into account Eastern versus Western European 'realities' and transferability/acceptability of the storyline to/by other European regions;
- **Political and economic aspects:** contributions of the storylines to the European energy policy goals (energy security / energy supply diversification, decarbonisation, competitiveness, value creation and employment within Europe) as well as impacts on current and future energy costs.

2.2 Selection of storylines

In order to conduct a comprehensive literature review on the future role of gas and gas infrastructure across Europe, a wide range of documents has been collected for a stepwise analysis. The search for adequate literature was mainly based on the joint expertise of the consortium, in-depth discussions with the client, personal interviews with selected experts from different European Member States and extensive desktop research[7]. In total, the literature collection comprises 260 documents, referred to as primary literature, with different scope, level of detailedness and overall results. At this point it is important to highlight that this primary literature containing storylines or storyline elements is a basis for the in-depth analysis in chapter 2.3 while secondary literature with a large number of additional documents has been used to better understand individual aspects of the various storylines, specifically in a regional context, and in the assessment of non-EU storylines in chapter 2.4.

As indicated in Figure 2-2 two-thirds of the documents from the primary literature identified based on the search criteria have been published in 2016 or later and are hence assumed to take into account the climate protection goals of the Paris Agreement of December 2015. Only 33% of the documents have been published before the Paris Agreement out of which only 9 documents are dated before the Fukushima nuclear disaster in March 2011. Since the focus of this study is on the role of the European gas infrastructure, most of the documents, in terms of regional scope, cover the European Union or individual Member States. Some selected studies take a global perspective (13%) or cover other non-EU countries (9%) mainly in line with the analysis of the non-EU storylines in chapter 2.4 whereas a small fraction of the literature (3%) is of a more general character without a specific geographic scope.

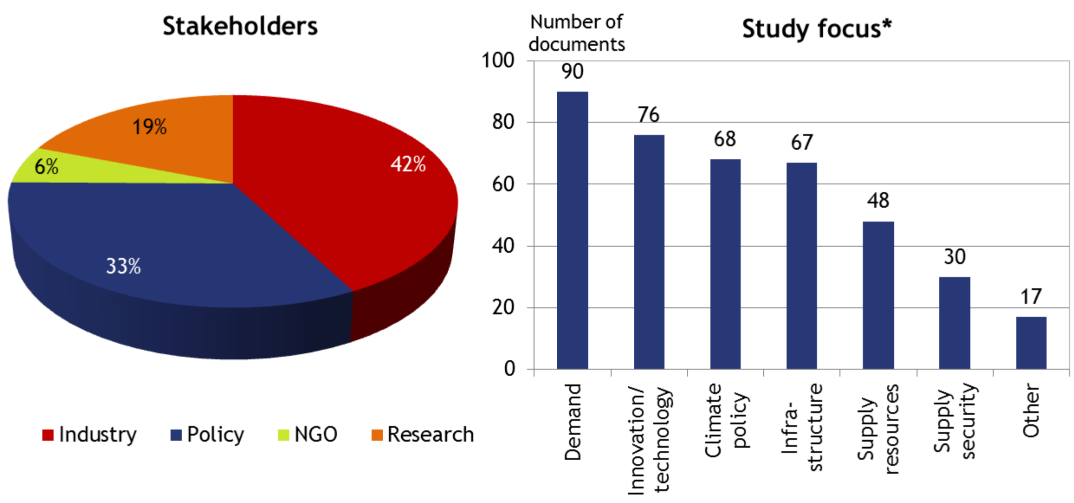
Figure 2-2: Year of publication (left) and regional scope (right) of collected documents



The distribution of the stakeholders involved in the preparation of the selected documents either as main author or as a client (see Figure 2-3) shows a good balance between industry (43% of all documents) and policy makers (33%). Analyses provided by research institutes account for around 18%. The comparatively low figure of 6% for studies motivated by non-profit / non-governmental organisations (NGO) is related to the fact that analyses conducted by a professional author for an NGO have been classified as 'industry work'. In this context, the balance between the stakeholders of the underlying studies ensures that the future role of European gas and gas infrastructures has been analysed from different perspectives and by taking into account the various stakeholder interests and points of view.

[7] The research was eased by a command of a wide set of language skills: English, German, French, Spanish, Polish, Nordic languages and Russian as some of the key documents were only available in the language of the individual country.

Figure 2-3: Distribution of stakeholders involved in study preparation (left) and study focus (right) of the primary literature identified (* Multiple study foci per document are possible)



Moreover, and as illustrated in Figure 2-3, the primary literature collected also covers a wide range of relevant topics. Most studies focus on research questions related to the future gas demand and potential innovative technologies for gas production, transportation and use.[8] This is followed by analyses addressing climate policy issues as well as by studies explicitly assessing the role of the gas infrastructure today and in the future. Supply resources and security of supply are less frequently covered topics in the literature collected as these play a major role for fossil natural gas, but typically a lesser role for new and clean gas technologies. It is worth mentioning that studies focusing on fossil natural gas without CCS or CCU were partially disregarded already during the collection process as a key aspect of this study is the deep decarbonisation of the future energy system. Although most studies are in English language, the literature review has also taken into account documents in other languages from different Member States, in particular in German, French, Spanish, Polish, Dutch, Danish, Norwegian, Russian and Ukrainian.

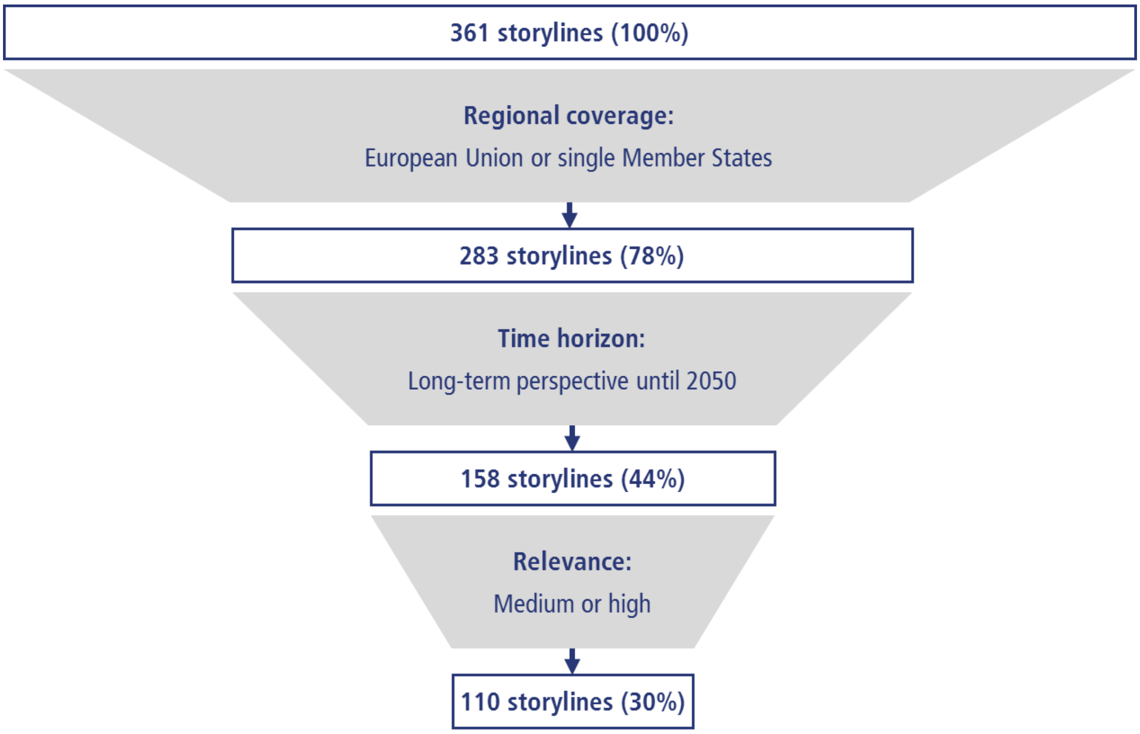
Furthermore, around half of the documents have been identified as containing in-depth analyses with multiple scenarios (with 3 scenarios on average and 5 scenarios as a maximum). Thus, the total number of storylines collected in the course of this literature review amounts to more than 360 individual storylines.

In order to narrow down such a large number of storylines for a more detailed analysis a selection process has been employed based on the following three steps (see Figure 2-4):

1. Regional coverage: The total number of 361 individual storylines was reduced to 283 (78% of all storylines) based on the regional scope by focusing on the European Union or single Member States;
2. Time horizon: Secondly, the collection was further narrowed down by filtering only those storylines covering a long-term perspective until 2050, resulting in 158 storylines (44%) matching both aforementioned criteria;
3. Finally, 110 storylines (30%) were selected as most relevant for a more detailed analysis based on the expert judgment of the researchers/scientists.

[8] In this context all types of gas are included as defined previously.

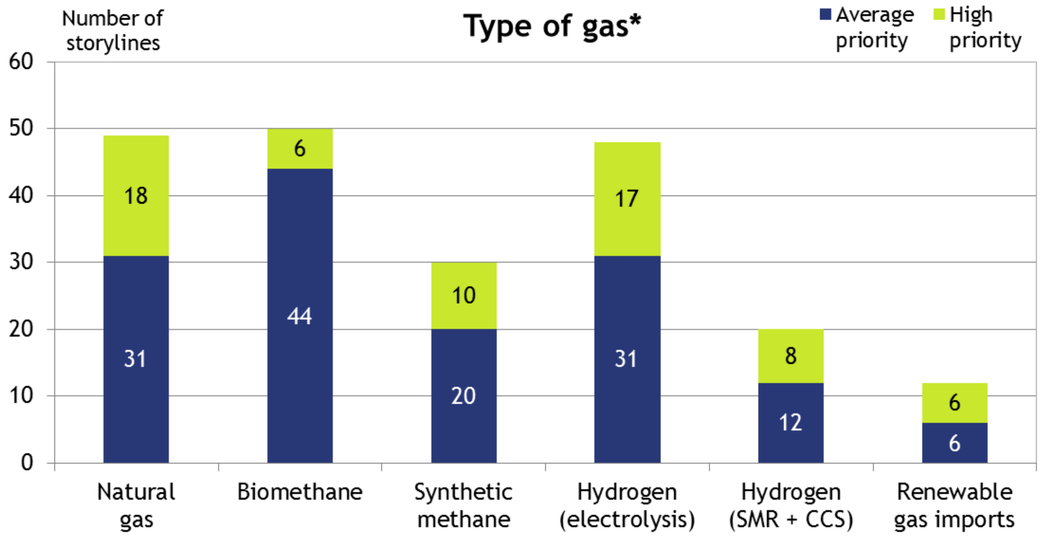
Figure 2-4: Down-selection of storylines from the primary literature for further analysis



The distribution of the relevant storylines in respect of the publication year and stakeholders is similar to the corresponding distribution of the entire primary literature with a slight shift towards more recent as well as industry and NGO-related studies. Also, the study focus is similar to the primary literature with major scope on demand, technological solutions and climate policy, and with a reduced coverage of supply resources and security of supply issues. However, the selected storylines tend to address infrastructure issues less frequently than the unfiltered document collection revealing a potential research gap in this area in the context of the decarbonisation of the gas sector. Furthermore, half of the selected studies include multi-sectoral analyses by taking into account all demand sectors for gas, namely power, heating, industry and mobility sectors. Thus, the focus of the storylines is well balanced across the different markets for gas.

Figure 2-5 shows the relevance of different types of gas covered by the selected storylines. Natural gas from fossil sources, biomethane and hydrogen provided by water electrolysis are covered most frequently as future types of gas. However, in comparison to the other two gases, biomethane is given a lower priority, i.e. only few studies put biomethane as an energy carrier at the forefront with high priority. Interestingly, power-based synthetic methane ("power-to-methane") is given high priority by a comparatively small number of storylines. In addition, few studies also consider hydrogen production from steam methane reforming with subsequent carbon capture and storage and usage (CCS or CCU) to ensure emission free energy use. However, this solution seems to be rather an isolated concept developed by individual stakeholders from only a few Member States. Finally, few storylines address renewable gas imports, and if they do then the issue is examined with a lower level of detail revealing a potential research gap.

Figure 2-5: Type of gas in the selected storylines with average and high priority (* Multiple gas type counts per storyline are possible)



As illustrated in Figure 2-6, the vast majority of the selected storylines (91%) expect GHG emission reductions in 2050 beyond 80% in line with the current EU goals (80% to 95% reduction) whereas only few storylines do not achieve this target. This is not surprising as the criterion of strong decarbonisation has been applied already during the literature collection process as well as for the expert judgment on the relevance of the corresponding documents. Almost half of the storylines (44% of the selected storylines) assume a very strong decarbonisation of the energy system with more than 95% GHG emission reduction by 2050.

A large number of the selected storylines assumes or projects a decreasing demand for gas until 2050 (76%; see Figure 2-6). This is further broken down into almost 20% of the selected storylines predicting a significantly decreasing gas demand (i.e. almost no gas demand) typically caused by the use of electricity as a major energy carrier (e.g. electrification of transport and/or heating) based on renewable sources, and 57% expecting a moderate decrease (i.e. lower gas demand than today). However, still a significant number of storylines (24%) expect a constant or even growing gas demand. This is mainly due to the strategy of switching from CO_2-intensive fuels such as coal or oil to comparatively less carbon-intensive natural gas within the power and mobility sectors. In general, more recent studies also examine deeper decarbonisation of the energy system than the older studies.

Figure 2-6: Share of selected storylines by expected gas demand until 2050 (left) and GHG emission reduction until 2050 (right)

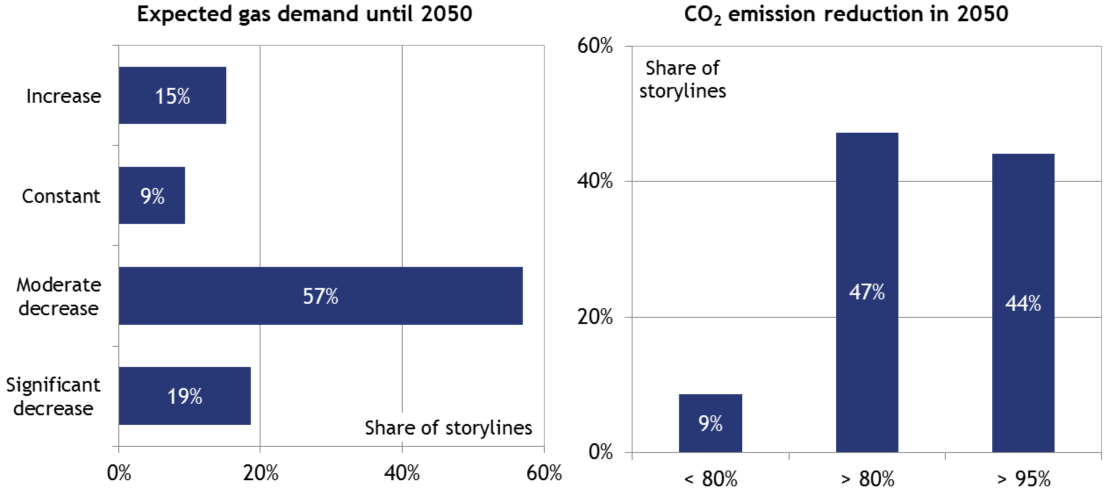
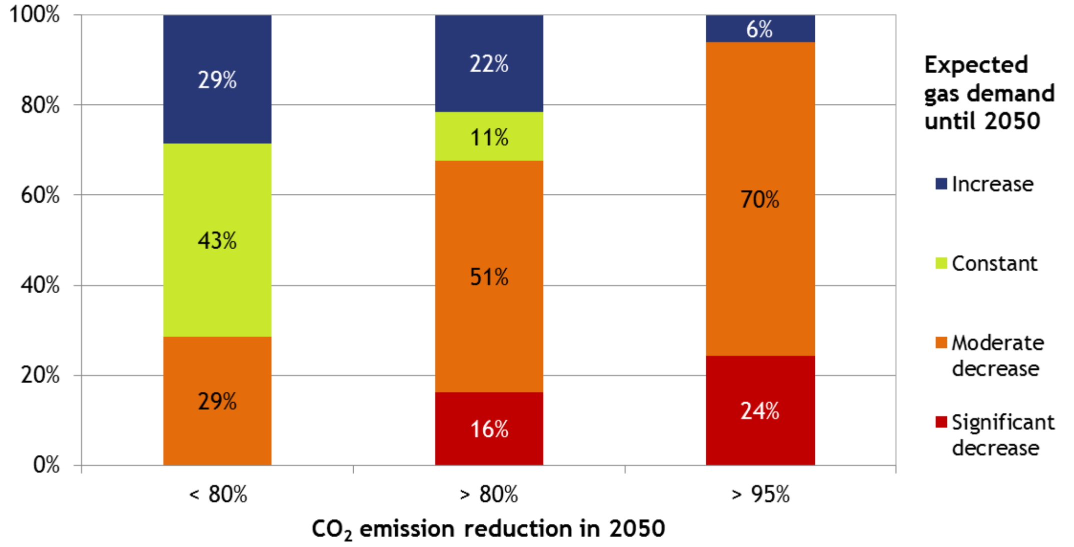


Figure 2-7 demonstrates a clear correlation between the GHG emission reduction until 2050 and the expected gas demand in 2050; and Figure 2-8 demonstrates a clear correlation between the GHG emission reduction until 2050 and the preferred type of gas. On the one hand, more than 70% of the storylines with a GHG emission target less ambitious than 80% reduction predict constant or increasing gas consumption in the future. In such storylines, (fossil) natural gas is the most important energy carrier (57% of the relevant storylines) followed by biomethane, both typically substituting coal in the power sector. Also, some storylines with a GHG reduction level between 80% and 95% allow for the use of (fossil) natural gas since it is valued as being comparatively clean and as an adequate option to balancing the intermittent feed-in of renewable power plants.

On the other hand, almost all storylines analysing strong decarbonisation of the energy system above the 95% target expect a decreasing role of gas in the future. Thus, increased or constant gas demand is mainly associated with less ambitious climate goals, while strong climate goals are generally associated with decreasing gas demand.

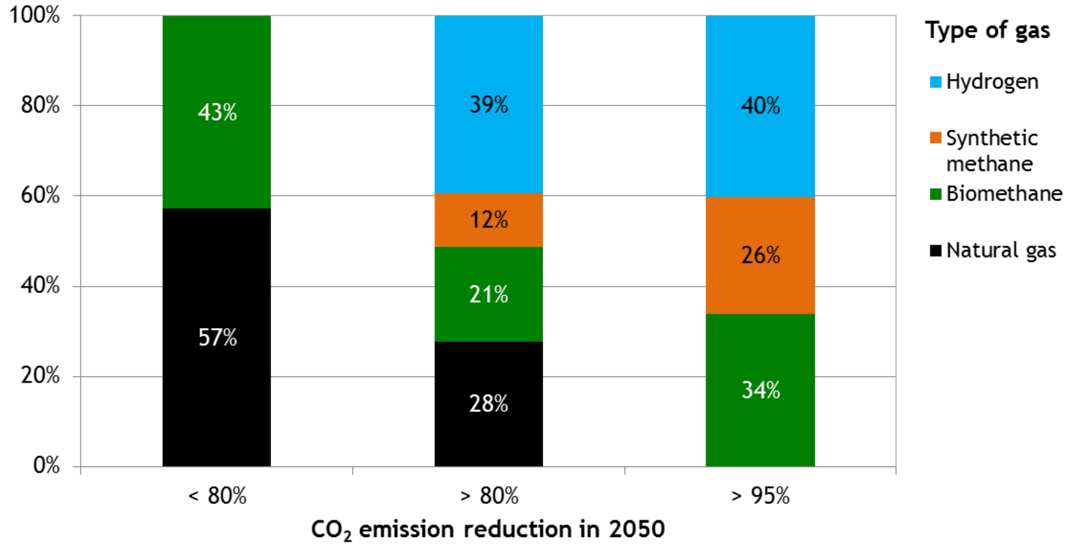
In this context it is relevant to note that some studies expect an increasing demand for gas in single sectors, in particular in the power sector to provide flexibility and in the transport sector. However, the overall gas consumption is typically falling based on strongly decreasing gas demand in the other sectors, e.g. in the heating sector through improved building insulation and switching to electricity for heating using high energy efficiency electrical heat pumps.

Figure 2-7: Correlation between GHG emission reduction and expected gas demand until 2050



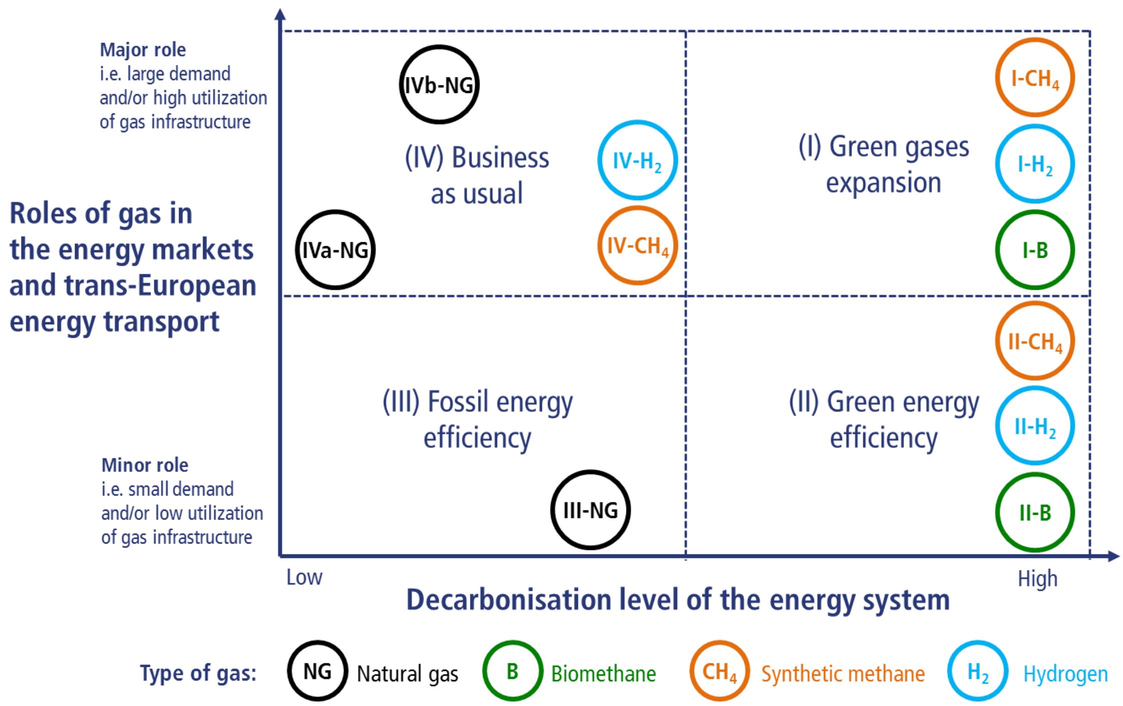
In the studies, such strong decarbonisation of the energy system does not allow for the use of natural gas from fossil sources and thus most storylines recommend using renewable electricity for the production of hydrogen or synthetic methane (66% of the storylines). This is mainly due to the fact that both gases are able to store large amounts of energy on a seasonal basis in an almost fully renewable energy system at comparatively low costs. 34% of the studies cover biomethane in strong decarbonisation storylines. In essence, the stronger the GHG reduction ambition, the higher the importance of synthetic methane and hydrogen and the lower the importance of natural gas; biomethane is rather covered independently of the GHG reduction ambition.

Figure 2-8: Correlation between GHG emission reduction until 2050 and type of gas



In general, and based on the literature review, the storylines on the future role of gas in the energy system can be classified and grouped according to three major criteria: (1) decarbonisation level of the energy system, (2) role of gas for energy supply and of gas infrastructure and (3) type of gas. Figure 2-9 provides an overview of potential storylines in a portfolio representation based on the first two criteria, which will be analysed in chapter 2.3.

Figure 2-9: Classification of the storylines according to the decarbonisation level of the energy system and the role of gas for energy supply and of gas infrastructure (roman number explained in the text)



The storylines have been grouped into four major categories as represented by the four quadrants of the portfolio:

I. **"Green gases expansion"**: this group of storylines is characterized by both strong decarbonisation and a major role of gas in the energy system and thus rather good utilization of the gas infrastructure. As described above, hydrogen is produced from renewable electricity through water electrolysis in these storylines. It can be either used directly by end customers in different markets **(I-H_2)** or it can be further processed to synthetic methane via a methanation process based on CO_2 from biogenic sources or from the air **(I-CH_4)**. In both cases, the gas serves for large-scale energy storage, whereas the electrolysers can also be used as flexible load in the power market. Since the production and use of synthetic methane suffer from lower efficiency the absolute gas demand figures and infrastructure needs are higher than in the direct hydrogen case (**I-H_2**). However, for hydrogen developing at a large scale, the existing pipeline system has to be re-furbished to be suitable for hydrogen operation[9]. In addition, green gas can be provided also from bioenergy as biomethane **(I-B)**. The in principle limited availability of bioenergy in Europe may require somewhat lower absolute gas demand figures and infrastructure needs than in the other two cases. In this context, biomethane combined with CCS or CCU would offer even negative carbon emissions.

II. **"Green energy efficiency"**: in this category green gases are needed only for back-up power generation within a strongly decarbonized energy system, and to a limited extent in transport growing from the currently very low levels. Electricity has become the major energy carrier supported by an extended power grid ('copperplate conditions'). Consequently, the gas infrastructure is typically underutilized, making it intrinsically more expensive since only

[9] Alternatively, for smaller or more concentrated (i.e. only big industrial users) penetration of H2, decentralised infrastructure could be envisaged (e.g. electrolysers located close to industrial customers).

limited amounts of gas are consumed, often at or close to the production site. Similar to "Green gases expansion" the green gases can be represented by hydrogen **(II-H_2)** or synthetic methane **(II-CH_4)**. In addition, in some storylines also biomethane **(II-B)** is either produced locally or imported from abroad. Again, combining biomethane with CCS or CCU could lead to negative carbon emissions.

III. **"Fossil energy efficiency"**: in this group of storylines fossil and renewable gas plays a minor role in the energy system. The decarbonisation level is higher than today but lower than in "Green gases expansion/Efficiency". As previously described, natural gas from fossil sources **(III-NG)** is mainly used in back-up power plants for balancing out intermittent renewable electricity feed-in. Depending on the actual decarbonisation level, natural gas can also substitute other more CO_2 intensive fossil fuels in power generation and other markets such as transport. However, the gas infrastructure will be underutilized, and gas transport and distribution will be specifically more expensive.

IV. **"Business as usual"**: in this class of storylines the decarbonisation level is comparatively low but the gas consumption in various markets rather high. Consequently, the gas infrastructure is well utilized. In some storylines within this group, natural gas is used in the future in the same way as today **(IVa-NG)** resulting in the lowest GHG emission reduction rate in comparison to all other storylines. In some other storylines, natural gas also substitutes other more GHG intensive fossil fuels, mainly coal in the power market and oil in the transport sector **(IVb-NG)**. Here, both the CO_2 emission reduction and the gas consumption are higher. In addition, natural gas can be used for hydrogen production via steam methane reforming or methane cracking **(IV-H_2)**. In order to avoid GHG emissions, the CCS and CCU technology becomes an intrinsic part of the production processes. Similarly, coal gasification and subsequent carbon capture and storage delivering either hydrogen **(IV-H_2)** or synthetic methane **(IV-CH_4)** is a relevant option here. However, since in both cases fossil fuels (natural gas and/or coal) need to be extracted and the processes involve fossil CO_2 they are not considered as fully sustainable.

In general, the abovementioned classification can be applied not only to gases domestically produced in the selected country but also to gas imports.

2.3 Analysis of European storylines

This chapter provides a detailed analysis of European storylines based on the selection of the previous chapter. The structure of this chapter covers the following topics for the storylines assessment: role of gas and gas infrastructure (chapter 2.3.1), potential environmental impact (chapter 2.3.2), technological aspects (chapter 2.3.3), regional aspects (chapter 2.3.4), as well as political and economic aspects (chapter 2.3.5). Chapter 2.3.6 contains a general appraisal regarding detailedness, methodology and reasonability of the selected storylines.

The measures proposed by all of the existing storylines assessed are focused on the fulfilment of major European energy policy goals, each one spiced by the individual authors' or customers' views. Important criteria for taking into consideration the contribution of individual storylines to this report were:

- **Topicality of the storyline:** Even though some storylines address singular technologies or concepts (e.g. focus is the residential heating sector [EEG; TU Wien 2018] or focus is the substitution of natural gas by biogas [Ecofys 2018]) they still contribute valuable insights which have been taken into consideration;

- **Inclusiveness of the methodology:** A specific storyline may comprise the simulation of a Member State's full energy system including all end-use sectors as well as energy production and infrastructures. Others may only address individual types of fuels, technologies or energy supply concepts. The relevance of these storyline types varies accordingly. An example for a full storyline with all relevant consequences for the European energy policy, i.e. in order to report the GHG emission reduction achievements is [FhG-ISI 2017a]. Holistic storylines have been given a wider consideration in this study;
- **Time perspective considered:** Due to stringent policy targets, a medium-termed only storyline, e.g. until 2030 or 2035, will not be able to address all consequences relevant to the 2050 European energy policy targets for the full energy system. Both backcasting and forecasting are needed to match the future vision for an energy system with the feasibility of measures planned for the next ten years or so. In this study, we have therefore given more attention to the storylines with time perspective 2050.

2.3.1 Role of gas and gas infrastructure

Changing role of gas in Europe

Next to utilizing its own production of natural gas or biogas, the current landscape of natural gas infrastructure in Europe is characterized by two basically different import options: (1) by pipeline: mainly from Russia and Norway, but also from Algeria and Libya, and (2) by LNG tankers from the world gas market (Middle East, Africa, and the USA).

In contrast, the future role of the gas infrastructure in Europe is poised to drastically change by 2050 as a consequence of the following major EU energy policy goals. As for any European gas supply by 2050 the gas sector needs to (1) be close to full decarbonisation, (2) contribute to security of energy supply including a growing supply diversification, (3) increase the share of renewable gas, (4) prioritise research and innovation in clean energy technologies and (5) keep the economic impact of the transition to a minimum (or even create additional value and employment in the EU) and improve Europe's competitiveness in energy costs. In addition, the gas infrastructure will need to (6) be compatible with the European electricity system (applications and infrastructures), (7) avoid massive structural breaks and guarantee a smooth transition from today's to the future gas infrastructure by the further utilization of existing installations in order to minimize the overall costs of energy supply taking into account the technical and environmental constraints and (8) serve the European regions characterized by a variety of energy strategies and related gas and electricity infrastructure developments.

Typical storyline categories have been collected in Table 1 representing the transition to different types of gases widely replacing natural gas, with examples illustrating their justification and selected implications. The storylines headlined "natural gas" are typically those focusing on the ≤ 2040 time horizon, with only a minority of storylines identified as "increased gas demand". Most of the storylines with "increased gas demand" originate from the (gas) industry. The insight that also the European gas supply needs to display virtually zero CO_2 by 2050 has gained momentum since the Paris Agreement in late 2015. This is one element explaining why only 18 out of 128 storylines/scenarios assessed here dating from 2016 to 2018 assume an increasing gas demand by 2050.

Storylines typically originate either from the interest of a stakeholder group or country with high focus on one specific gas type (e.g. biogas in [Ecofys 2018] or hydrogen in [NIB 2017]) or are anchored in the history of individual Members States' energy market developments. In Table 1, both an individual type of gas (e.g. hydrogen from natural gas with CCS [Northern Gas Networks, et al. 2016]) or a mixture of gas types can be in the focus. National storylines are of the latter type typically characterized by a wider scope. A specific case is the UK's energy networks (ENA – electricity and gas network association, i.e. industry) based study [KPMG 2016] which has framed the individual concept of the Leeds City Gate project [Northern Gas Networks, et al. 2016] adding a wider focus.
A minor share of the selected storylines/scenarios focuses on electricity dominated energy systems ('all-electric world') for the simple reason that this study's focus is on the future of Europe's gas infrastructure. Yet, it is our impression that these studies provide sufficient information for a balanced view, as some of the storylines' actors also represent the interest of the electricity network industry, e.g. [KPMG 2016] .

The following examples demonstrate the variety of approaches proposed by individual storylines for the four storyline categories defined in Figure 2-9:

Table 1: Future role of gas in the four storyline categories

Storyline	Justification/implication	Example storyline	
		MS of origin	Reference
I. Green gases expansion	With almost no fossil gas allowed in 2050 and gas playing an important role in the energy system, all gas needs either to be domestically produced from renewable energies, or imported from renewable sources. An approach for the important role of biogas (I-B) is presented in a number of Members States (BE, DE, ES, FR, IT, NL), based on agricultural and woody biomass as well as residues and applied to some end-use sectors with the highest societal cost savings expected. These sectors are residential heating and electricity generation (48 bcm/a), heavy duty transport (5 bcm/a) and industry (45 bcm/a). A total European potential of 122 bcm/a of renewable gas has been identified, which can be expanded by an additional 20 bcm/a of imported biomethane, e.g. from Ukraine and Belarus. This quantity of biogas is supplemented by synthetic methane from Power-to-Gas at a rate of 24 bcm/a. As the study focuses on the use of biogas and $PtCH_4$ in only 3 sectors, it does not provide statements on the total gas demand development.	Industry group: BE, DE, ES, FR, IT, NL (Southern/ central Europe)	[Ecofys 2018]
		DE FR	[Frontier Economics, et al. 2017] [ADEME 2018]
	Another example has been presented in several storylines, typically assessing several scenarios of mixtures of synthetic methane (I-CH_4), biogas (I-B) and/or hydrogen (I-H_2), which in addition to the use of gas for seasonal energy storage also supplies other direct gas end uses, often achieving operating cost reductions compared to an all-electric supply scenario (not FR).	UK NL	[Northern Gas Networks, et al. 2016] [NIB 2017]

Storyline	Justification/implication	Example storyline	
		MS of origin	Reference
	A third example is the Leeds City Gate project, where hydrogen is put in focus of a city-based gas infrastructure approach, but only materializing if becoming a national UK strategy and based on a switch to a 100% hydrogen gas grid. The H_2 is made from natural gas (I-H_2) with carbon capture & storage (SMR+CCS) and used in traditional appliances. In the case of an NL-based storyline, the hydrogen can also be produced from (offshore) wind energy (I-H_2), and used directly or admixed to methane in the gas infrastructure.		
II. Green energy efficiency	A good example is presented by Denmark and Sweden, where the gas infrastructures today are directly connected. Even though the gas demand is strongly decreasing by around 50% by 2050 due to its phasing out for space heating and electricity production, gas will provide an indispensable value also in the future. Its new role will be to collect biogas (II-B) at decentralized locations, enhanced by synthetic methane (II-CH_4) from Power-to-Gas, for consumption in industry. Also, some hydrogen (II-H_2) will be directly used for upgrading biomass and to be stored in decentral short-term energy storage on site.	DK, SE	[Energinet 2015] [Swedegas 2018]
III. Fossil energy efficiency	This storyline category can be synonymous with an 'all-electric world' with little innovation in the gas system. As the task of this project has been to identify storylines with a future focus on gas infrastructures 'all-electric' storylines have surfaced only incidentally. Among others, two storylines with "some" fossil natural gas (III-NG) in the energy system have been presented in the two scenarios "regional and national management", the ingredients of which are obvious: In the regional management case methane is used for low-temperature heat, for CHP and in mobility, in the national management case specifically more hydrogen is produced and also used for high temperature heat and as feedstock. Electricity is poised to become the dominant form of energy, also for use in industry, generated from solar and wind power centrally or decentrally and transported to industry via the electricity grid and partially converted into hydrogen for a parallel transport infrastructure. Extensive electrical grid extensions need to be foreseen.	NL	[Netbeheernederland 2017]
IV Business as usual	An example for this storyline category (IV-NG) is Italy with a high market share of gas today and in the future according to current energy and climate policies. On the contrary, considerations are directed towards diversifying the supply of natural gas away from Russian imports to biogas and increasing LNG imports. In addition to traditional uses of gas, the role of natural gas in transport	IT	[IEA 2016] [OIES 2014]

Storyline	Justification/implication	Example storyline	
		MS of origin	Reference
	(CNG in cars and LNG in heavy duty trucks and ships) is important today and anticipated to increase further. The biomethane strategy focussing on the river Po delta is typical for countries from Eastern and Southern Europe as the climate conditions allow for a two-annual crops approach.		
IV Business as usual	Ireland is extensively using NG in its energy system. In a business-as-usual (BAU) scenario it is foreseen that about one third of all energy continues to be NG based, with 50% out of this used for electrification and the remainder applied in residential and industry use. In a future -80% GHG scenario NG (with CCS) is predicted to continue its share of about 30% with another 10% added by biomethane from mostly imported biomass. No answer is provided which alternative energy supply options were to follow if both biomass imports will not materialize or the CCS option could not be applied.	IRL	[Gallachóir 2015]

In an energy system as described by "Green" storylines, all energy provision as well as application sectors need to be fully integrated in an economically optimized approach. Several detailed studies have been launched in Germany alone only last year, specifically pointing out the two sides of 'sectoral integration', (a) the interdependency of the natural gas and electricity grids as well as (b) of all energy end-use sectors [FhG-ISI 2017a], [FfE 2017], [Frontier Economics, et al. 2017], [Ontras 2017], [Schoof, R. 2017], [Wehling, A. 2017], [Dena 2017], [Prognos; BCG 2018], [DNV GL 2017].

The ambition in these storylines has been to assess in how far the application of synthetic methane and hydrogen can support the electricity system in absorbing increasing fluctuating electricity production from renewable energies. In the meantime it has become obvious that developing a near "copperplate" functionality of the electricity transport grid would have to solve the critical public acceptance issue [IIASA 2014], which could partially be managed by underground DC lines but would however require high capital investments[10].

In this respect the large scale high energy density transport and storage functionalities of gas grids are emphasized by several storylines as a cost-effective option to relieve the strain on the electricity infrastructure [DNV GL 2017], [E3G 2017]. The effect of increasing the level of public acceptance of the 'Energiewende' by replacing part of the additional highly visible overhead electricity lines through buried gas pipelines is interpreted as twofold, (1) the reduction of energy costs through a more efficient transport and storage of large quantities of renewable electricity and (2) the avoidance or

[10] In [Europacable 2011] the authors mention a cost increment of ca. 2-3 of HVDC underground versus aboveground cables, other literature [Energie-Forschungszentrum Niedersachsen; Leibnitz Universität Hannover; TU Clausthal; Georg-August-Universität Göttingen; OECOS 2011]states between factors of 2.12 (500 km) and 9.4 (50 km). This reference also mentions thermal effects of buried electricity cables on the adjacent surface which reduces agricultural use along a given line. Finally, the energy transport capacity along a given line is much higher for gas than for electricity, depending on a large number of parameters.

reduction of reinforcing and extending the electricity transport and distribution grids [Frontier Economics, et al. 2017], attributable to the “Efficiency” storylines in Figure 2-9.

Pipeline transport being the major focus of this study, LNG is using another complementary gas transport infrastructure. In the short- to medium-term it may be produced from natural gas, whereas in the future it would have to be based on biomethane or PtG inputs. Economic and political considerations will need to be taken into account for its competitiveness when e.g. considering the combination of (decentralised) biomethane with (central) LNG plants. It may specifically be applied in transport in the maritime sector and for heavy duty transport, where it will compete with the use of CNG.

We furthermore conclude from the storylines assessed that the gas industry will have to cope with the fact that gas distribution infrastructures will change with the change in gas sources from fossil to renewable. Gas today imported predominantly from Russia or Norway will in the future be substituted by gas originating from renewable electricity rich locations closer to the end users (e.g. in the case of the Netherlands) or when imported from renewable energy/electricity rich regions such as from North Africa. This will result in changing “centers of gravity”, both on the gas demand and supply side, most probably having an influence on the regional density and capacity, technical capabilities and flow direction in the grid.

Another infrastructure directly affected is the one for district heating. In some studies, district heating grids fed by heat from decentral CHP stations (or other sources) are suggested to be further extended, making the gas distribution grid dispensable [Energi Styrelsen 2014]. In general, for residential space heating, there is a clear competition between gas distribution grids (boilers), district heating grids, and electric grids (deep insulation combined with heat pumps). Electric grids, however, serve additional purposes and applications, and are thus more universal in character and hence generally required.

Sectoral gas demand

Concerning the future gas demand foci, the storylines allows drawing some trend like general conclusions which are summarized in Table 2. Given today’s gas demand by sector, which is high for heating and in industrial use (low temperature and process heat) and low for power and transport, the general trend is a demand reduction in the (residential and industrial) low temperature heating sector and a demand increase for power production and transport. In industry, the decreasing gas demand for low-temperature heating may be at least partially compensated by increasing gas demand for high-temperature process heat and as base chemical, thus keeping industrial gas demand roughly constant. “Partially” in this context refers to the regional differentiation and the view to Member States with a stronger steel and base chemical industry. Furthermore, new large scale uses of gas in industry to replace e.g. coal are the direct reduction (DRI) of iron ore in steel making[11] and in chemical industry for the production of fertilizers, methanol or polymers. Also, renewable hydrogen could replace biofuel admixture end of pipe by the replacement of fossil natural gas in refineries [Tuck Foundation 2016]. Obviously, individual storylines may divert significantly from this average representation, and thus Table 1 is only indicative, e.g. Austria being a Member State with an important steel industry sector.

[11] For Germany alone the gross potential of H_2 use for steel making by DRI was estimated to be in the order of 2.4 Mt or 26 bcm, comparing to a total industrial H_2 consumption of 10 to 20 bcm of H_2 today [Jakobs 2016]. Already today, AcelorMittal is the only German steel plant applying a DRI process based on an iron ore reduction with synthesis gas generated from natural gas [Hölling 2017].

Examples for emerging gas demand are the refuelling of large fuel cell trucks [UBA AT 2016] or the use of hydrogen for steelmaking in direct reduction smelters [UBA AT 2015b].

In principle, a growing competition for decarbonised gas could develop for the different market segments as the domestic sources for it are limited.

Table 2: Gas demand sectors today and in the future (explicit counts without "empties")

Gas demand by sector	Today	2050	
	Demand	Trend as compared to today	Storylines and contribution of gas types (Figure 2-9)
Power (e.g. coal today)	low	↑ increasing	DE (III-NG) [FfE 2017]
Power (e.g. gas or hydropower today)	high	↓ decreasing	AT (II-CH_4, II-B, I-H_2) [UBA-AT 2016]
Heating	high	↓ decreasing	DK (II-CH_4) ([Energi Styrelsen 2014]
Mobility	low	↑ increasing	NL (I-H_2) [NIB 2017]
Industry	high	↓ decreasing	AT (II-CH_4, II-B, I-H_2) [UBA-AT 2016]

Changing role of gas infrastructure in Europe

Another relevant issue is how the character of the gas infrastructure is anticipated to be changing and how the operation of infrastructure could be affected by the projected changes in scenarios/storylines with increasing or decreasing gas demands (see Table 3). Based on examples, some basic observations can be made. As these implications do not necessarily refer to the storylines as characterized in Figure 2-9, Table 3 provides selected existing storylines, all of which are specific to their Member State of origin, even though other storylines have been developed for the specific "Member State of origin". The assessment of storylines has also revealed that no single Member State has presented one monolithic gas infrastructure strategy as of today. To the contrary, the ideas for the future design of Member State energy markets diverge between ministries and industry groups which is reflected in the diverging statements and recommendations. Hence the column denoted by 'Member State of origin' should not be misinterpreted as 'Member State strategy'.

Independently from the storylines assessed it is worthwhile mentioning that the gas infrastructure will in the future need to specifically address different types of energy transport and storage fluctuations. Whereas today, the balancing of the gas system is mainly focusing on seasonal demand variations and short-term variations can adequately be addressed by the flexibility of the transport system (linepack), this may change in an energy system with a large share of fluctuating electricity supply such that the role of the gas grid will receive a stronger focus in balancing short- and medium-term variations. The need to consider both annual gas transport and storage volumes and short-term peak requirements will need to be assessed in more detail by future dynamic modelling. As domestic green gas will continue to be a scarce and hence precious good, further analysis will also need to address the issue of valuation of gas applied in different markets or different applications.

Table 3: Gas infrastructure implications of selected storylines

Changes	Gas infrastructure implications	Storyline	MS of origin Reference
Residential heating substituted by heat pumps and district heating, little belief in hydrogen and fuel cells for cars, except for large scale seasonal energy storage	• Bi-directional instead of top-down operation (collection of biogas and $PtCH_4$ gas from decentral installations, gas transport system to industry and mobility) • Short-term on site storage of energy in H_2 • Further development of district heating • Gas distribution grid dispensable • MWh spec. costs for gas transport and distribution to increase	I-B, I-CH_4 (I-H_2 for storage)	DK - [Energi Styrelsen 2014] (personal com.: LBST with gas development department energinet.dk, 21st Feb. 2018)
Gas transfer through Austria will decrease Gas use reduced by 20% (2030) and 60% (2050) (residential heating, electric gas compressor drives) Hydrogen applied for steelmaking and mobility (FC cars & trucks)	• Gas transport grid with reduced throughput • Gas compressor stations converted to electrical drives • Distribution grid becoming (partly) dispensable • Hydrogen infrastructure expansion for new applications, notably transport • MWh spec. costs for gas transport and distribution to increase	I-B. I-CH_4, (I-H_2 for emerging applicatio ns)	AT - [UBA-AT 2015b] [EEG; TU Wien 2018]
From gas exports to imports Renewable electricity partially converted by PtH_2 / $PtCH_4$ Reduced gas demand (improved building insulation, reduced district heating demand, EL-heat pumps) Seasonal electricity storage based on hydrogen	• PtG-capacity at renewable electricity generation locations (on- and offshore), artificial North Sea island • Norway pipelines to be re-furbished to hydrogen operation • Hydrogen storage in underground salt caverns (refurbished from NG operation) • MWh spec. costs for gas transport and distribution to increase	I-B, I-CH_4, I-H_2	NL - [WEC 2018]
Heating energy accounts for ~45% of UK's total energy needs (in terms of final consumption) Limited building insulation Gas grid and appliances conversion at minimum cost s CO_2-free hydrogen to be supplied by SMR&CCS for cost reasons Other energy sectors to be included (mobility, industry, power generation) Provide sufficient seasonal storage capacity	• Distribution grid to remain important • Conventional boilers converted to hydrogen operation • CCS technology concept to be established • Stepwise refurbishment of complete grids from NG to hydrogen • Refurbish grid to transport demand of new hydrogen applications (e.g. mobility) • supply all other energy sectors such as industry and mobility as well as add flexibility to the electricity sector • Develop RES hydrogen capacities over time • Develop hydrogen underground salt caverns	I-H_2 (based on NG-CCS)	UK [KPMG 2016] [Northern Gas Networks, et al. 2016]

Changes	Gas infrastructure implications	Storyline	MS of origin Reference
	• All challenges of hydrogen admixture to natural gas to be avoided		
Biomass-based methane (fermentation & gasification) and $PtCH_4$ introduced over time (not hydrogen) CH_4 consumption ~35% lower than in 2015	• Gas grid can remain essentially unchanged including general structure • Distribution grid to be extended to a limited extent to collect biogas from decentralized locations • Conversion to reverse flow planned • MWh-spec. costs for gas transport/ distribution assumed to remain stable	I-B, I-CH_4	FR [ADEME 2018]
Remaining concepts for 95% decarbonization: • REN electricity • Solar & geothermal energy • Biogenic fuels(with limited total potential) or • Chemical energy carriers from renewables (H_2, renewable CH_4, liquid fuels etc.).	• Strong focus on renewable electricity (energy efficiency driven) • Concession that also public acceptance will have an impact for strategic decisions • Electricity preferred up to -80% GHG emission reduction, 95% secondary energies kicking in thereafter • Biomass potentials seen as limited due to competition in import regions • Gas grid only for renewable gases, H_2 more compatible than CH_4 (efficiency[12])	II—H_2	DE [FhG-ISI 2017a]

Devalued or stranded assets in gas infrastructure and applications

The International Energy Agency has defined the term “stranded assets” as “those investments which are made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return, as a result of changes in the market and regulatory environment [WEO 2013]. In cases where we interpret the storylines assessed in the way that assets may suffer from a devaluation we have therefore avoided the term “stranded assets”. In fact, as the changing role of gas infrastructure over time will have to be dealt with, assets will not necessarily become stranded but may have to be revalued.

As explained e.g. by [Energinet 2017] or[EEG; TU Wien 2018] specifically the gas consumption for low temperature residential and industrial heating is set to decrease significantly whereas the decrease of gas consumption for industry will be less pronounced. In combination with the new task of collecting biogas decentrally this will emphasize the role of the transport grid and reduce the role of the gas distribution grid[13]. This will by definition have a more pronounced effect in the storylines of the two “Efficiency” categories. This development has been flagged by most of the existing storylines assessed in these categories even though the decrease in gas demand in some sectors (low temperature residential and industrial heating and power generation) is partially expected to be compensated for by a growing gas demand in other sectors (industry, transport). It can be concluded that from a view of

[12] The study is rather strict in its interpretation: in a -95% scenario renewable energy and efficiency will become dominant, which puts the gas grid in question in principle if no green gas is transported. With efficiency being the second driver, $PtCH_4$ is questioned as compared to the direct use of hydrogen.
[13] Some of the remaining distribution grid will also be used to collect biomethane.

balancing the changes from today's to the future tasks of the gas grid some of the existing assets in the gas segment of today's energy infrastructure, i.e. the distribution grid, will at least partially be lost.

The allocation of devalued or stranded assets to the storylines in Figure 2-9 is rather straightforward. The storylines with either the least overall gas consumption foreseen (II, III) or any diversification away from methane in the grid (all hydrogen-based concepts: I-H_2, II-H_2, IV-H_2) will result in the highest share of existing devalued or stranded assets. However, for a wide introduction of hydrogen in the energy system the assets will not be completely lost [Braaksma, A.; Jensen, N. 2018]. Instead, additional investments will be required in the refurbishment or replacement of the existing methane infrastructure and end-use technologies as mentioned by [Braaksma, A.; Jensen, N. 2018] and described e.g. in [Northern Gas Networks, et al. 2016] in detail. The investments for a hydrogen refurbishment (replacement or conversion have to be weighed against investments which are required for a continuous refurbishment of the existing gas infrastructure such that only a part of the investment needs to be considered as additional. In [Northern Gas Networks, et al. 2016] extensive considerations have been made to identify the net additional costs for a hydrogen upgrade taking the ongoing refurbishment costs into account (e.g. the exchange of old iron pipes by new ones from polyethylene). Challenges evolving from multiple delayed refurbishments of the gas infrastructure are described e.g. for the case of Ukraine [KPMG 2017].

Simultaneously, the specific gas transport and distribution costs are poised to increase which is explicitly pointed out in some of the storylines [UBA-AT 2015a], [UBA-AT 2015b], [Energi Styrelsen 2014], [EWI 2017]. This can lead to uncompetitive gas network costs for some of the remaining consumers possibly pushing them to also turn their back on the use of gas [EWI 2017]. However, as the gas infrastructure is believed to be indispensable from the view of the TSO Energinet.dk[14], some of these additional energy costs can be attributed to the development of the renewable energy-based electricity infrastructure. In such situations, there may be a need for changes in regulations in order to protect certain demand sectors or users from unfair burdens.

Reducing the use of gas across various end-use sectors will also have an impact on private assets on the gas application side, which may of course change from Member State to Member State. In the case of e.g. Denmark or Austria, boilers may have to be replaced by electric heat pumps or by heat exchangers for district heating, and in the case of the Leeds City Gate concept boilers would have to be retrofitted from natural gas to hydrogen operation. As it has already been experienced in the past, a gas system can be converted to another gas in a very well-planned scheme. In the 60/70s large portions of the UK but also the German city gas or town gas system (with a 50-60% share of hydrogen and up to 150 years old) had been converted to natural gas operation in a 'life trial' (40 million households in the UK in total at a peak conversion rate of 2.3 million households converted each year) [Northern Gas Networks, et al. 2016]. For the transition it is suggested to convert the gas distribution grid back to hydrogen in batches of around 2,500 households.

[14] E.g. [Energinet 2017] states for the case of Denmark: *"The gas system is thus a powerful energy source, and it is worth retaining it and seeking to maximize its utilization in a future with greatly fluctuating electricity generation. In the coming years, the gas system must transform to new usage patterns and ensure that it remains sustainable in terms of technology and economics, so it can contribute to the green transition. As an integrator of wind and solar power as well as a supply of fuel for the industry and transport sector, the value of the gas system is very high. In the shorter term, the gas system can reduce CO_2 and NO_x emissions from the transport sector, particularly within heavy transport and shipping."*

Finally, even though the issue of gas imports has been explicitly excluded from this study's scope, it should be mentioned here that the development of new pipelines (e.g. Nord Stream 2) or LNG terminals may threaten assets in existing pipelines or terminals which today serve to import natural gas from other regions. Also, the sectoral development of domestic LNG markets, such as e.g. for the refuelling of heavy-duty trucks will also eat away from the transport (and distribution) of natural gas to refuel CNG vehicles. This aspect needs to be seen in the light of recent insights that part of the heavy duty truck fleet could also be run on CNG and be served by a CNG refuelling station infrastructure [LBST 2016]. But as LNG is now only seen in the context of importing fossil natural gas, this infrastructure can be seen as future stranded assets itself unless schemes are developed to import LNG from renewable sources.

Pessimism or optimism concerning the future role of gas infrastructure?

Even though a decreasing gas demand is foreseen in most storylines assessed in this study, which can be interpreted as a negative message, the robustly positive message from our assessment is that the contribution of the gas infrastructure to a future, renewables-dominated energy system is indispensable, rendering an 'all-electric world' not the most appropriate option. However, a mere bipartisan role to the electricity infrastructure does not seem to be a fair analysis of the future role of the gas grid. The gas grid is believed to remain an asset in its own right, as some energy end use sectors require the delivery of chemical energy carriers, liquid or gaseous. In emerging applications such as for fuel cell trucks or gas in steel making the role of gas in the energy system goes beyond its role to support of the electricity infrastructure.

Even though this will have no direct impact on the gas grid infrastructure, the integrability of the charging infrastructure for battery electric vehicles (BEV) in addition to a potentially massive installation of electric heat pumps into the electricity distribution grid at large scale and in all consequence may have a larger effect than anticipated. If it turns out that the investments required to reinforce the distribution grids (cables, transformers and stationary batteries) for slow, medium and fast charging should a high two-digit percentage of BEVs be aspired, then the FCEV option may become accepted as the more economically and customer friendly benign option. With FCEVs being refuelled by hydrogen from the gas grid, this could enhance the role of the gas transport grid as well as parts of the gas distribution grid [FZJ 2018].

2.3.2 Potential environmental impact

CO_2 emission reduction

As presented in chapter 2.2 most storylines assessed in this study have a focus on GHG-emission reduction of 80% and beyond by 2050[15]. By 2030 natural gas could contribute to the global intermediate CO_2 reduction target of 40% or 6% above the target, through a coal-to-gas switch in European power production based on [E3G 2017]. At the lower end of this range (storyline category "Fossil energy efficiency", storyline III-NG) fossil natural gas is used as a back-up for intermittent renewable energy generation. Moreover, the fossil fuel is utilized as efficiently as possible, for example in combined heat and power units, which are then often operated based on the power market conditions thus avoiding

[15] In addressing the global -80%…-95%GHG emission targets, typically total GHG emissions are targeted, i.e. including other than energy related ones. As this study's focus is on the gas grid and mostly its role to supply gas as an energy carrier. As non-energy related GHG-emissions (e.g. land use change/deforestation, N_2O from soil, animal husbandry, fertilizer production, cement production) significantly contribute to total GHG emissions the real GHG emission target for energy use could be even higher than -100%. As it is not always clear which CO_2 emission origins are addressed by one or the other storyline we have not specifically separated one from the other source allowing for a systematic inaccuracy. This should however be considered in future more detailed energy system models.

must-run capacities [Forum Energii, et al. 2017], specifically if they can be combined with local thermal storage. At the upper end of the range (storyline categories "Green energy efficiency" and "Green gases expansion") no fossil energy carriers (without CCS) can be used in the energy sector in 2050. This is due to the fact that certain agricultural and industrial process GHG emissions can be considered as unavoidable. This means that all avoidable GHG emissions need to be eliminated to achieve a reduction of at least 95% [FhG-ISI 2017a].

Obviously, a dominant use of fossil natural gas in the future, i.e. in storyline III-NG and storylines IVa-NG and IVb-NG, will not allow for a sufficient reduction of GHG emissions as required by the goals of the Paris Agreement. In these storylines, a further use of fossil natural gas is typically explained either by the lack of climate ambition (storylines with -80% GHG emission reduction targets or below), the lack of economic advantages and/or missing regulatory incentives for greening the gas. In addition, some studies argue that already the switch from comparatively CO_2-intensive fossil energies such as coal to natural gas contributes to the reduction of GHG emissions in the short- and mid-term [OIES 2017], [Braaksma, A.; Jensen, N. 2018], which will, however, not be sufficient for the 2050 zero-CO_2-emission gas world (e.g. [Netbeheernederland 2017], scenario "international", most of which is decarbonized by CCS).

In this context, the most important conclusion from the assessment in this study is that storylines for 80% and 95% GHG-emission reduction provoke significantly different solutions for various aspects along the entire energy system. Reducing GHG emissions by 95% instead of 80% requires fundamentally different approaches, technologies and concepts. Pathways and strategies that would successfully achieve an 80% GHG emission reduction might not be able to also achieve a reduction of 95%. A prominent example for fundamentally different approaches raised by more than one storyline is the fact that the role of fossil-based gas in electricity production can be significant in the -80% scenarios, where natural gas is assigned the role of stabilizing the electricity grids dominated by renewable power. In a 95% GHG emission reduced world, however, fossil-based gas (without CCS[16]) cannot be used for electricity production at all. Thus, at an early stage it should be clear whether 80% or 95% emission reduction is the target. In fact, developments that aim for an 80% reduction might even hinder the achievement of a 95% reduction (lock-in effects). One example is the introduction of a low carbon technology with a long lifetime that cannot be replaced or converted to a carbon free technology in time (e.g. Diesel electric trains with a life expectancy of 25 years or more).

[FhG-ISI 2017a] comments the gap of a -80% to a -95% world: *"For an 80% reduction the direct use of electricity as preferred option is sufficient for efficiency reasons (technical, economical); hydrogen and electricity-based hydrocarbons will not yet be required, as for a few critical applications conventional fuels can be applied still fulfilling the GHG emissions obligations. However, this option is no longer available in case of a 95% reduction. The use of electricity cannot be further extended as required for various reasons; typical constraints are requirements for system flexibility as well as missing public acceptance of grid extension or limitations by technical requirements of individual industrial processes among others."*

The same consequence can be reported for the low temperature residential & industrial heating and transport sectors. For example, some studies come to the conclusion that in the building sector more

[16] Even some CCS concepts have limited, but unavoidable CO_2 emissions.

stringent energy savings measures and alternative heating systems have to be applied when advancing the energy strategy from a -80% target to a near fossil-free energy system by 2050 [UBA-AT 2015b] and [EEG; TU Wien 2018]. In the transport sector, more fuel cell vehicles (cars, trucks) come into play as on the hand one they allow to introduce electric mobility in more challenging sectors (heavy goods transport) and on the other hand hydrogen fuel in combination with energy storage can be used synergistically for load balancing of the renewable electricity generation.

In other words, an environmental policy setting a 95% target will have a significantly different impact on the gas infrastructure than a policy aiming at 80% reduction. In the 95% case, the gas infrastructure will not become obsolete in 2050 as such. However, the type of gas may change from methane to hydrogen, and the way it is used would change to back-up power generation, seasonal power storage and renewable transport fuel [Frontier Economics, et al. 2017]. Nevertheless, with the -95% target, the role of fossil gas will need to come to an end by 2050 at the latest.

Other GHG emissions - Methane leakage

As mentioned by [CAT 2017] methane slip from natural gas extraction and methane transport may be the cause for significant contributions to climate change. The authors in [Nature Communications 2017] published their findings from multiannual study efforts to trace global methane emissions which had risen sharply after 2006. Originally being attributed to natural and agricultural sources, the bulk portion of global methane emissions can robustly be accounted to the methane slip of unconventional[17] oil and gas extraction. This analysis is further backed up by studies from the U.S. Environmental Defense Fund (EDF) which had connected large methane gas clouds reported by NASA in 2014 with the shale gas operations in the area of New Mexico in quantities which had never been reported before [EDF 2017].

As a consequence for Europe, all domestic natural gas production or natural gas imports from regions which base their production on unconventional gas extraction need to be re-assessed in so far as they have to be evaluated against their much larger potential GHG emissions impact. Consequently, methane slip might become a serious environmental issue for all storylines with a large share of both fossil and synthetic methane (i.e. in storyline classes “Business as usual” and “Green gases expansion”, storylines I-CH_4, I-B, IVa-NG, IVb-NG, IV-CH_4). At this point it is important to emphasize that synthetic methane will have a lower environmental impact in the upstream part in comparison to fossil natural gas (e.g. lower impact of the storyline I-CH_4 in comparison to the storyline IVb-NG) due to the lack of methane emissions from the gas production process. Only in storylines with electricity as major energy carrier in the energy system (i.e. storylines classes “Fossil energy efficiency” and “Green energy efficiency”) or a hydrogen focus (I-H_2) the problem of methane slip can be limited as suggested by [CAT 2017].

In the light of the growing concerns about increasing methane emissions from natural gas production [Tollefson, J. 2013] also the level of potential methane emissions from synthetic PtCH_4 operations will need to be analysed further in the future.

Behavioural and societal aspects

A deep decarbonisation of 95% is not possible by technical solutions alone. Some storylines suggest that end customers will need to change their lifestyles and habits to some extent and will need to increase

[17] Shale gas, tight gas, coal-bed methane etc.

their acceptance towards new clean energy technologies. Acceptance and commitment of the society is a key prerequisite for the success of the renewable energy system [Riigikogu 2017]. Missing acceptance for one technology or technical solution can to some extent be compensated by applying other usually more costly options or technologies [FhG-ISI 2017a]. Recent examples are the planned high-voltage direct current (DC) power lines from Northern to Southern Germany. Due to strong opposition along the corridors, it was decided to invest in more costly underground cables [RSE 2011]. Concerning public opposition against the installation of new gas transport pipelines similar to the electricity grid has not been observed recently, one reason being that no new pipelines are in the planning. In addition, but without being underpinned by detailed studies yet, it is believed that the reduction in gas demand as predicted by the majority of studies frees sufficient gas transport, distribution or storage capacities to supply the gas transport, distribution and storage tasks for the new gas applications in the transport and/or industry sectors.

In addition, [WWF Österreich; Global 2000; Greenpeace 2015] point out that end customers will have to develop a higher sensitivity towards a more sustainable use of limited resources, energy and materials. In this context [FhG-ISI 2017a] mention shorter travel distances, the intensified use of bicycles and a more sustainable modal split in the transport sector as well as reduced consumption of meat and reduced intensity of fertilizer application in agriculture. [WWF Österreich; Global 2000; Greenpeace 2015] suggest behavioural measures in the heating sector such other ventilation routines or technologies, or fewer rooms heated. All these measures will directly or indirectly affect the gas infrastructure by a reduction of the general level of energy consumption. Moreover, [E3G 2017] emphasizes that switching to hydrogen as a new gas type in the gas network will require end-user acceptance as current devices will need to be exchanged in a future hydrogen network.

Probably the most prominent option for behavioural changes in the mobility sector is framed by the term “adaptation of modal split” or simply “modal shift”. By reducing the use of individual motorized transportation in favour of using a bicycle for short distances and public transport (buses, tramways and trains) for medium to long distances a significant reduction of GHG emissions connected with low cost measures will be possible. The behavioural changes may imply less privacy and more exhausting travelling efforts and may be difficult to communicate to the public. These more consequential measures typically come into play for the more aggressive GHG emission reduction targets of -95%. Two examples are an Austrian and a German based storyline implying both a shift in passenger and freight transport [UBA-AT 2016] and [FhG-ISI 2017a]. Again, we do not interpret any direct impact for the gas infrastructure evolving from these changes, except that a modal shift from individual to public transport will mean a general shift from fuels to electricity-based transport and as such will contribute to reduce the future gas demand if electric mobility is interpreted narrowly, i.e. as battery electric or catenary operated trucks only. If e-mobility is understood in its wider sense then fuel cells may be refuelled by hydrogen from the gas grid, the extent of which would have to be modelled later in more detail. E.g., strategies in some MS, such as Italy point at an important continuing role for ‘gas’ also in the future, i.e. when considering the use of CO_2-free gas such as biomethane. They could become even more relevant, if operated as hybrid gas-electric drive systems[18].

Even though this has not been flagged by any of the existing storylines assessed, it appears to us that public acceptance of alternative energy infrastructures and end-use technologies have not been in the

[18] See e.g. http://www.aerius-holding.com/language/en/2014/06/cng-natural-gas-the-real-alternative/.

focus of analysis yet. Understanding that the energy system will undergo significant changes in the near future to fulfil the CO_2 obligations touching on all end-use sectors, i.e. also transport and residential energy use, we believe that the citizens have to be better involved in or informed about the decision processes. As an example, it may not be known to the private customer that the choice of electric vehicle type may have an impact on his recharging/fuelling habits. Using a battery electric vehicle in an energy system with large share of renewable electricity might have the consequence of controlled charging to take peak burdens from the distribution grid. The authors would also like to point out that the availability of critical resources for battery but also other types of electric vehicles such as lithium, cobalt or manganese may pose a challenge for mass market coverage unless alternative materials will be identified[19]. This in turn would mean that BEVs can only be recharged for high costs or not at all in congestion periods (many customers charging simultaneously or in periods with low electricity production). Had a customer known, that her/his flexibility as a user is much greater with a fuel cell electric vehicle or green gas-powered hybrid vehicle, which is comparable to refuelling a gasoline or Diesel car today, this might (have) change(d) her/his purchase decision. More political activities will need to be directed at how to inform and involve the European citizen.

2.3.3 Technological aspects

Key technologies by type of gas

In line with the expected significantly changing role of gas and gas infrastructure in the future, the underlying technologies and concepts for gas production, infrastructure and application will need to be advanced or adapted. The assessment of existing storylines spans a wide scope of options within the Member States as well as from Member State to Member State. They do not only differ by region and different types of gas, but also by the GHG-emission reduction ambition. In a nutshell, Table 4 lists the relevant key technologies for each gas type in connection with the relevant current Technology Readiness Level (TRL, 1-9) and associated major risks (see also Figure 2-1 above).

Table 4: Future technology options by type of gas and value chain with TRL and risks

	Methane		Hydrogen	
Value chain	Biomethane	Synthetic methane ($PtCH_4$)	Power-to-Hydrogen (PtH_2)	Natural gas Steam Reforming with CCS
Production	Anaerobic digestion (TRL: 9) or thermal gasification (TRL: 7[20]) Risk: limited bioenergy potential, CH4 emissions from leakages	Water electrolysis (TRL: 8-9) Methanation (TRL: 8-9) CO_2 extraction from air (TRL: 6), Risk: expensive and energy intensive CO_2 extraction from biogenic sources	Water electrolysis (TRL 8-9)	Conventional NG production (TRL: 9) Unconventional gas: • shale gas/tight gas (TRL: 9) • coalbed methane (TRL: 9) Risks: CH_4 emissions from leakages, water contamination from fracking chemicals, fossil resources

[19] Recent studies offer a bandwidth of results concerning the availability of critical resources for battery and fuel cell electric vehicles, i.e. lithium. See e.g. [Öko-Institut 2017] assuming limited supply challenges and [2015] identifying major challenges with lithium resources as result of a meta study and a policy and management perspective.
[20] Following [Ludwig-Bölkow-Systemtechnik; Hinicio 2015] the TRL of biomass gasification is ‘7’ (2015), and is expected to be ‘8’ (2023) and ‘9’ (2030).

Value chain	Methane		Hydrogen	
	Biomethane	Synthetic methane ($PtCH_4$)	Power-to-Hydrogen (PtH_2)	Natural gas Steam Reforming with CCS
		(TRL: 9), Risk: limited potential		are finite, secured long-term enclosure, limited storage capacities, missing public acceptance CO_2 collection and transport (TRL: 9)
Transport **Conversion** **Storage**	As NG (TRL: 9)		Conversion of existing NG distribution and large scale storage H2 pipelines (TRL: 8-9), Risk: H_2 leakages H_2 compression (TRL: 9), Risk: H_2 leakages H_2 refuelling stations (TRL: 8-9), Risk: H_2 leakages Salt cavern underground storage (TRL: 9), Risk: as NG	
Application	As NG (TRL: 9)		Conversion of existing NG appliances and instrumentation: • Residential boiler (TRL: 8-9) • Residential Fuel Cell CHP (TRL: 8-9) • Large Fuel Cell CHP (TRL: 8-9) • Gas turbine CCGT (TRL: 8-9) • Fuel Cell Electric Vehicles (FCEV) (TRL 9) General Risk: possible hold-up of wide market introduction due to necessary further adaptation of regulations, regulatory hurdles	

A new aspect which has been flagged only recently is the development of hybrid gas-electric technologies which offer the chance to combine highest efficiency in an all-electric world on one side with the end user flexibility and comfort through gas based systems on the other side. An example in the transport sector are hydrogen (gas) operated fuel cell electric cars or trains/railcars with a large onboard battery (electricity), offering the short-distance high-efficiency driving of a battery vehicle with the brake energy recuperation (train/railcar) or long distance driving/fast refuelling capability of the hydrogen operated fuel cell. Examples are the Mercedes GLC FCell [21] or the Alstom fuel cell train[22]. On the stationary side, studies have revealed a potential interesting future of gas-hybrid heat pumps, combing the high efficiency of electric heat pump operation with a gas fired boiler. Both systems combined by an integrating control system can be operated at higher temperatures and low electricity prices in heat pump mode and in gas operation at lower temperatures[23]

The interpretation of Table 4 is that the NG&CCS option (from a natural gas perspective being an 'application technology' and from the hydrogen perspective a 'production or better conversion technology') is characterised by the need for further technical development on one side and several fundamental risks, which is also reflected by the fact that this option ranks low on many Member

[21] See e.g. https://www.mercedes-benz.com/en/mercedes-benz/vehicles/passenger-cars/glc/the-new-glc-f-cell/.
[22] See e.g. http://www.greencarcongress.com/2016/09/alstom-unveils-hydrogen-fuel-cell-regional-train-coradia-ilint.html
[23] See e.g. [energinet.dk 2018].

States' political and probably also on some industry's agendas. This fuel option relates to the storylines III – Fossil energy efficiency (III-NG) and IV – Business as usual (IVa-NG and IVb-NG).

The biogas option (storylines I – Green gases expansion (I-B) and II – Green energy efficiency (II-B)) is already developing today in some Member States based on regulatory incentives. Whereas anaerobic digestion is rated at TRL 9, biomass gasification has not yet reached full commercialization at a TRL 8. It is limited by available biomass potentials within Europe as well as imports if competition with the food and other industrial sectors and general sustainability criteria are taken into account [ADEME 2018]. In addition, direct electrification of biogas (partly in association with heat use) competes with biogas upgrading to biomethane and use or injection into the gas grid.

The $PtCH_4$ option (storylines I – Green gases expansion (I-CH_4), II – Green energy efficiency (II-CH_4) and IV – Business as usual (IV-CH_4)) is appreciated by industry for its advantage of using the existing transport and storage infrastructure for natural gas. On the other hand, it comes at higher costs than hydrogen for the additional process steps of CO_2 extraction from air or from biogenic sources, and of methanation. Furthermore, biogenic CO_2 sources are limited in availability.

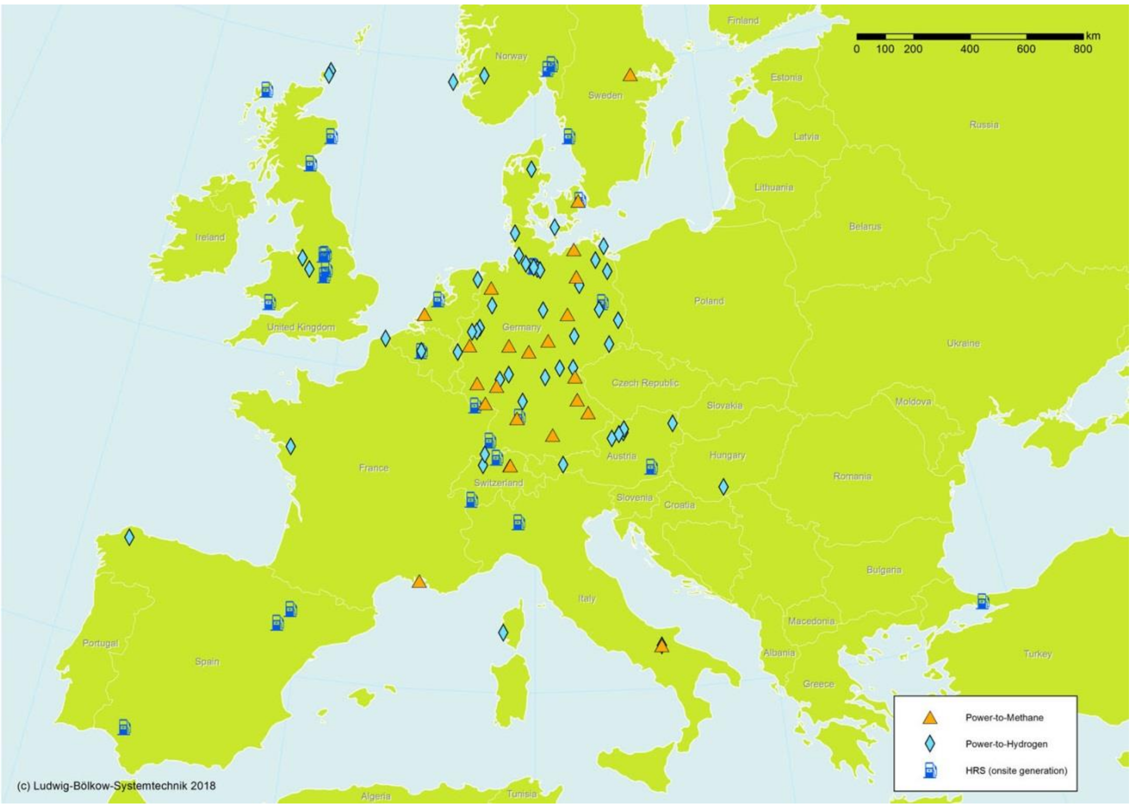
Finally, hydrogen (= PtH_2) gas (storylines I – Green gases expansion (I-H_2), II Green energy efficiency (II-H_2) and IV – Business as usual (IV-H_2)) is basically characterised by a high level of technology readiness and efficient as well as least complex value chain. From a 'well-to-wheels' (transport applications) or 'source-to-user' perspective (stationary applications) PtH_2 based end-uses typically rank in the middle between all-electric solutions on the high efficiency side and the $PtCH_4$ solutions on the low efficiency side[24]. However, it suffers from a time lag towards a wider integration into the energy system for overcoming the technology ramp-up in the gas market, including its anchoring in European gas grid related regulations. On the other hand industry has collected experience from the safe operation of hydrogen equipment including electrolysers, compressors, hydrogen pipelines and storage at large or very large scale. Hydrogen demand by volume comprised 15% of the volume of natural gas at world scale in 2010[25]. In a recent study [Hydrogen Council 2017] it is claimed that by 2050 hydrogen could contribute up to 18% of world's final energy demand (transport, electricity production, residential and industrial use), help to reduce ca. 6 Gt of CO_2 emissions annually, generate new business of 2.5 trillion U.S. $ with hydrogen and required equipment and provide 30 million jobs worldwide. Finally, some studies have assumed that the reduction in gas demand will free some pipeline transport and distribution capacity which could then – after conversion – be used for the transport/distribution of hydrogen. As even with significantly higher flow velocities larger pipelines will be required more detailed analysis needs to be undertaken for a more detailed capacity check.

Countless projects on the use of biogas and biomethane can be identified all across Europe whereas PtX technologies are still in their infancy. Figure 2-10 shows all concluded, ongoing or planned $PtCH_4$ and PtH_2 projects including those which provide hydrogen onsite by electrolysis at hydrogen vehicle refuelling stations. It is obvious that most plants have or are concentrating on central and Western Europe and more specific with a strong focus on Germany (DE: 59, UK: 13, AT: 9, CH: 7). Concerning

[24] For transport it has been shown that FCEVs (cars) are half as efficient as BEVs and 3 times as efficient as CNG-cars powered by $PtCH_4$. For trucks FCEVs are about double as efficient as CNG-trucks powered by $PtCH_4$ [Deutsches Zentrum für Luft- und Raumfahrt; Institut für Energie- und Umweltforschung Heidelberg; Ludwig-Bölkow-Systemtechnik; Deutsches Biomasseforschungszentrum 2014] and [2017; 2017]
[25] Assuming no hydrogen demand growth this number would have been reduced to 13.5% (Source: LBST 2018, based on [BP 2017b] and [CertifHy 2015])

the use of hydrogen in the energy sector, the Netherlands have proposed a number of related pilot projects, some of which are relevant to be mentioned here [WEC 2018]: (1) a 23 km, 4.500 t/a H_2 pipeline project connecting DOW Chemicals with Yara and ICL in the Zeeland region by 2018, (2) the hydrogen Magnum Power Plant in Eemshaven (to be operational by 2023) driven by a consortium of Nuon/ Vattenfall (NL, DE, NO), Dutch Gasunie and Norwegian Statoil to operate 3 CCGT multi-fuelled gas turbines with hydrogen from CCS delivered from Norway and (3) the North Sea Wind Power Hub (up to 3 islands to be operational by 2035) and planned by TenneT (Netherlands and Germany), Energinet (DK), Gasunie (NL) and the Port of Rotterdam (NL), on the Doggerbank north of Helgoland to collect wind energy (30 GW catchment area) as alternating current and either send through one central direct current transmission cable onshore to Denmark, the Netherlands, the UK and Germany, or via hydrogen from a PtH_2 electrolysis plant.

Figure 2-10: Overview of past, ongoing and planned pilot projects demonstrating the use of $PtCH_4$ and PtH_2 concept, including hydrogen vehicle refuelling stations with onsite hydrogen production by electrolysis (Source: LBST database, 2018)



About 4 large hydrogen underground storage facilities in salt caverns are currently in operation in the UK and the USA [Roads2HyCom 2007], one further hydrogen underground storage facility is planned by the HYPOS project in East Germany (research cavern Bad Lauchstädt, variable H_2 volume: 42 MNm^3, storage capacity 126 GWh (LHV), operation to commence by 2023/2024) [Hypos 2018]. Finally, the storage potential and possible business cases of hydrogen in underground salt caverns has been mapped as part of the EC-funded research project HyUNDER in 2012-2014 [HyUnder 2014]. A major result, covering 10 European Member States, was that the salt cavern potentials in Europe are mainly limited to Germany, the UK, the Netherlands, Denmark, and to a lesser extent in Spain, Portugal and Romania. To extend the underground storage potential further beyond these regional limitations, also the storage of hydrogen in pore storages has successfully been tested by admixture trials in Austria (Lehen, 1.15 MNm^3 @ 7.8 MPa with 10% H_2 admixture) [RAG 2014] and in Argentina [Hychico 2016].

Table 5 has been compiled with the purpose of presenting a set of data on the key technologies for the alternative gas options, biomethane and hydrogen. Therefore, this table does not show any specific technology data which are assumed to be common knowledge in the gas industry. Among these technologies, steam methane reforming and methane cracking of natural gas to produce hydrogen, CCS/CCU technologies including the use of biomethane and the conversion of biomethane to LNG (liquefaction) for import of renewable gases to Europe may play a more important role than today in the transition period until 2050.

From a systems perspective many detailed aspects could be commented here. Instead and given the limited scope of this study, one specific aspect for synthetic gas from $PtCH_4$ is addressed. In $PtCH_4$ plants an overall energy efficiency enhancement can be reached by improved thermal integration of the individual processes. Specifically, the utilization of heat generated in the methanation stage could be used to increase the total process efficiency by applying high temperature electrolysers (SOEC). For that purpose, the SOEC technology should be further promoted beyond today's ambitions.

So far, only the gas types methane and hydrogen have been addressed. Next to these single gas concepts of operating the gas grid and appliances on pure methane gas or hydrogen, it has also been discussed in detail to allow mixtures of both gases as a means to smoothen the transition from natural gas to CO_2-free gas for many years [Levinsky, H. B. 2004]. Also for use in internal combustion engines for transport methane/hydrogen mixtures of up to 20 vol% have been proposed with the advantage of low NOx-emissions and variable admixture to increasingly reduce CO_2 emissions [Swain, M. R. et al. 1993]. And finally, a 20/80 CH_4/H_2 blend of hythane has been tested in everyday driving of CNG-buses in the EC-funded research project AltHYTUDE [GDF SUEZ 2011] showcasing an efficient transition from natural gas to green gas in urban transport.

More recently the research activities have been intensified such as by [Altfeld, K.; Pinchbeck, D. 2013], [DVGW, et al. 2013] and [Judd, R.; Pinchbeck, D.].

As a conclusion, different interpretations claim realistically high allowable hydrogen admixture rates of 10 or 20 vol% of hydrogen in methane gas without jeopardizing the integrity of the gas infrastructure and with few technical changes [26]. On the other hand the detailed analysis and research work has also revealed a handful of weak spots which would have to be solved in order to allow admixture rates of more than 2 vol% hydrogen. They had been classified as either 'acceptable without further changes up to a H_2-admixture rate of x%', 'requiring technical modifications beyond a H_2-admixture rate of x%' and 'need of further research beyond a H_2-admixture rate of y%. As specifically critical for the low percentage admixture of hydrogen the use of gas chromatographs for gas analysis, the refuelling of CNG vehicles (internal combustion engine technology, composite fuel tanks) and other end-user appliances such gas turbines as boilers as well as the underground storage in pore storages had been identified to require further conversion/adaptation needs or further research.

An earlier EC-funded research project [Florisson, O. 2010] had claimed that from a safety perspective admixture rates of 30 vol% or even up to 50 vol% could be tolerated for pipeline operation, but that a limitation to 20 vol% in household appliances would be advisable. In conclusion, the operation of methane/hydrogen mixtures could turn out as a viable solution of gradually increasing the admixture of

[26] Others claim maximum H_2-admixture rates of only 2 vol% (DE) or of 5 vol% (FR) depending on the grid considered or the applications connected.

green gas to the gas grid. From a user perspective however the introduction of methane/hydrogen mixtures is remains ambiguous: with varying hydrogen admixture rates safety related, technical and economic operating conditions can vary over time, which could lead to operational challenges. Open questions remain how to e.g. adjust the energy prices with varying admixture rates or adjust burners or appliances stepwise or even dynamically.

However, in our assessment of existing storylines we have come across a hydrogen admixture assessment only twice (UK: HyDeploy assessing a 20 vol% hydrogen admixture to the natural gas grid [National Grid 2017] and NL: [CEF 2017]].

In order to support any future energy system modellers with specific technology and economic data on the advanced technologies relevant in the non-fossil based gas types we have prepared Table 5 with most data referenced by relevant literature. Not being comprehensive, it demonstrates the expected development potential of some of the technologies proposed by the existing storylines assessed by this report, pointing at both the predicted or expected efficiency improvements and cost reduction potentials which have been published in literature. As for the cases of $PtCH_4$ (= methanation) and steam methane reforming (SMR) also those technologies stick out which have already today reached a high development status with little further developments expected. However, it should be noted here that it is the view of the authors that this table provides indicative figures only. The past has shown that specifically long-term predictions appear to result in erroneous assumptions and should therefore only be used with great care and for orientation. E.g., the cost reduction potential of photovoltaics and wind energy has been massively underestimated in the late 80s and early 90s, always leading to pessimistic ramp-up curves for renewable electricity. The same can be said for advanced future systems such as batteries or fuel cells in mass production. In principle it has been the author's own learning that in the end energy systems and policy effects typically have a much bigger impact on the potential success of a technology or concept than shear efficiency or cost figures. This list has been compiled on specific request of the European Commission to support the modelling team with the latest numbers used in energy system modelling.

Table 5: Overview of selected performance data of key technologies for future gas infrastructure (LBST: literature will be condensed later)

Technology	Scale / Power rating (LHV)		Efficiency (LHV)		Specific investment		Remark
	today	long-term	Today	long-term	Today	long-term	
Production technologies							
Anaerobic digestion*	2 - 6 MW_{CH4}	2 - 6 MW_{CH4}	49%	49%	1,600 – 2,300 €/kW_{CH4}	1,600 – 2,300 €/kW_{CH4}	Incl. biogas upgrading (8), (9)
Biomass gasification	22 MW_{CH4}	380 MW_{CH4}		55%	1,800 €/kW_{CH4}	900 €/kW_{CH4}	(8)
$PtCH_4$ (LT ely)	1.2 – 6.2 MW_{CH4}	300 MW_{CH4}	51%	59%	3,200 – 5,100 €/kW_{CH4}	1,360 €/kW_{CH4}	Incl. ely, buffer storage & BoP, w/o CO_2 supply (18), (19), (20)
$PtCH_4$ (HT ely)	0.06 MW_{CH4}	300 MW_{CH4}	72%	73%			HELMETH project, HHV converted to LHV (17)
AEL, ambient	1.5 – 32 MW_{H2}		60% + heat (60°C)	67%	770 – 1,530 €/kW_{H2}		including BOP (2), (3)
AEL, pressurised	7 - 32 MW_{H2}		60% + heat (60°C)	67%	930 - 960 €/kW_{H2}		including BOP (2), (3)
PEMEL, pressurised	3 MW_{H2}		60% + heat (60°C)	71%	2,050 €/kW_{H2}		including BOP (2), (3)
PEMEL, pressurised		60 MW_{H2}	60% + heat (60°C)	71%		550 €/kW_{H2}	including BOP (2), (3)
SOEC	0.08 MW_{H2}	48 MW_{H2}	80% (electricity) 70% (electricity+heat)	87% (electricity) 78% (electricity+heat)	3,730 €/kW_{H2}	590 €/kW_{H2}	Incl. BoP, early R&D stage (4), (5)
SMR w CCS	840 MW_{H2}		76%	76%	540 €/kW_{H2}	540 €/kW_{H2}	Incl. CO_2 pipeline (6)
Energy conversion, transport and storage							
CO_2-pipeline							Similar as NG
H_2-compression	330 MW_{H2}	333 MW_{H2}			22 €/kW_{H2}	22 €/kW_{H2}	Large-scale for H_2-transport (16)
Salt cavern storage	125 GWh_{H2}	124 GWh_{H2}	95%	95%	0.75 €/kWh_{H2}	0.75 €/kWh_{H2}	Per kWh H_2-storage capacity, incl. below/aboveground equipment, compressors, efficiency from H_2-purification (7)
Energy application							
H_2 boilers					3,800 €/unit	3,800 €/unit	(10)
NG FC CHP (SFH)	0.7 kWe	0.7 kWe			13,000 €/unit	5,000 €/unit	Incl. fuel processor & backup boiler for LPG &NG (11)
NG FC CHP commercial	1.0 MWe	1.0 MWe	39%	39%	5,230 €/kWe	2,100 €/kWe	Incl. fuel processor & backup boiler (12)
H_2 FC CHP commercial	1.0 MWe	1.0 MWe	48%	51%	3,050 €/kWe	1,050 €/kWe	(12)
H_2 CCGT	270 MWe	270 MWe	55%	60%	800 €/kWe	800 €/kWe	Feasibility study (7)
FCEV			60%	60%	65,450 €/unit	25,000 €/unit	Hyundai iX35 FCEV (13), (14)
H_2 in steel production (DRI)							Pilot plant in Sweden (HYBRIT), start-up in 2020 (15)

* Biogas plants for CH_4 injection into NG grid

(1) [DLR, et al. 2015], (2) [E4tech; Element Energy 2014], (3) [Langås, H. G. 2015], (4) [Becker, W. et al. 2012], (5) [Mougin et al. 2014], (6) [Wheeler 1996], (7) [Miege et al. 2013], (8) [DBFZ 2009], (9) [KTBL 2012], (10) [Northern Gas Networks, et al. 2016], (11) [Maruta 2016], (12) [Roland Berger 2015], (13) [Hyundai 2014], (14) [Hyundai 2018], (15) [Hybrit 2018], (16) [FZJ 2012], (17) [Gruber 2017], (18) [Jauslin Stebler 2013], (19) [Gasefuels 2014], (20) [Schoeber 2012]

Associated risks and disruptive character of key technologies

The theory of disruptive technologies, and associated with these disruptive developments has been developed by [Christensen, C. M. 1997] and denotes innovations which are typically found at the lower end of current markets. New markets based on disruptive technologies may develop suddenly and without their relevance having been recognized by the established market participants. Reason typically is the small initial market size and the limited customer base and characterised by their potential to push competing established products out of the market. Often their potential impact on existing market structures to provide the same or even an advanced customer satisfaction is overlooked. In the "Innovator's Dilemma" Christensen has specifically pointed at fuel cells as one possible disruptive technology as they may not be the most obvious customer choice. For their application as alternative transport drive system, and from the perspective of the internal combustion engine they require a new fuel infrastructure (other than e.g. CNG vehicles). From the perspective of battery electric vehicles however, they are less efficient and cannot be comfortably refuelled from the garage base wall box. Their disruptive character is in combining both disadvantages into one bigger advantage for the vehicle customer: the advantage of simple refuelling ('as today') with double the energy efficiency of internal combustion engine drives.

Other disruptions may be caused by the introduction of hydrogen energy as compared to the use of biogas as alternative gas type. Whereas biogas and synthetic methane gas ($PtCH_4$) merely imply gradual measures towards decarbonising the gas sector by building on the identical gas infrastructure and applications, hydrogen will require a broad conversion of infrastructure and end-use equipment, but offer a smooth interface between electricity and gas sectors and allow a smooth transition from a fossil towards a renewable energy world.

As such, hydrogen and fuel cells viewed as disruptive technologies contribute to the three storylines I – Green gases expansion a, II – Green energy efficiency and IV – Business as usual, however unfold their full disruptive potential in storylines I as then their impact on the energy system is most significant.

In observation of the different gas applications, the disruptive effect of fuel cells for transport use is much higher than for stationary applications. In stationary uses, their contribution is reduced to an efficiency improvement as (a) they can be fuelled by hydrogen produced onsite today and (b) the transition can happen gradually by a region-by-region conversion such as proposed by the [Northern Gas Networks, et al. 2016] storyline. In contrast, for the transport sector the impact of a transition to fuel cells and hydrogen is much higher as without a wide regional coverage with hydrogen refuelling stations customers will be less willing to buy a fuel cell car. Therefore, fuel cells for fleet operation (city buses, garbage trucks, trains, taxis, …) are often suggested for the early transition phase such that the number of fuelling stations to be built is much lower and their utilization higher, slowly establishing a full refuelling network.

Taken the disruptive character into account, the decision for hydrogen and fuel cells will require the most courageous decisions of all gas types, but at the same time may promise the most rewarding long-term rewards. In addition, it needs to be emphasized that any investment into any of the long-lived gas infrastructures today will lead to long-term capital lockup and sets boundary conditions for achieving the 2050 GHG emission reduction targets.

The consequence is twofold

- On the one hand, any infrastructure related decision today might need to be taken top-down bearing a long-term view in mind and not being guided by short- or mid-term needs or interests, such that it does not lock into unsustainable pathways and block a potential shift to an infrastructure better suited to a carbon-free energy system; and
- On the other hand, the infrastructure development needs to pay attention to those concepts and technologies which offer the smoothest possible transition pathways from the existing to the future gas infrastructure in order to minimize the devaluation or stranded assets.

As several existing storylines have shown, they are still in need of a Europe-wide acceptance. In the sense of their disruptive character hydrogen and fuel cells may offer opportunities rather than risks which have apparently been identified by other world regions, as documented in the non-EU storylines chapter 2.4. I.e., a much higher appreciation of hydrogen and fuel cell technologies has been observed specifically for some Asian countries (Japan, China and South Korea). These developments may either become a risk for Europe if not embraced in time. However, they may also pose an opportunity if Europe's current technological leadership is exploited and is turned into a commercial success soon enough.

Global anticipation of gas types and key technologies

As any of the gas types is also assessed in other world regions, the introduction to European markets is not hampered by their still unconventional nature or would not put Europe or the relevant Member State(s) into the role of an outsider. In addition, any of the proposed gases and underlying technologies would profit from global technical and economic learning.

For the above reasons a regional grouping of visions, specifically with a view to providing an estimate for the extent to which individual technological concepts or types of gases will be introduced into the individual energy markets is a challenging, if not impossible, task. The spread becomes obvious by considering the U.S. at one end, representative for storyline category III, through its strong focus on fossil natural gas, and Japan (see also chapter 2.4.3) at the other end, the latter one being representative for storylines I-H_2, II-H_2 or IV-H_2 and putting much focus on a strong electrification in combination with a "hydrogen society" to provide fuel for power production, transport, households and industry.

Whereas no indications for any of our storylines from Figure 2-9 have been identified for Russia, Ukraine or Belarus (chapter 2.4.2) or the MENA countries (chapter 2.4.6), also China is showing vital signs of engaging in new gas infrastructures for different gases (chapter 2.4.5). It is developing a methane based pipeline infrastructure to collect domestic methane gas from shale gas, to import natural gas from Russia for substituting coal in power generation and (lately reduced as a result from the 30 year gas contract with Russia) also as LNG. At the same time, China has only recently started an introduction of hydrogen and fuel cell vehicles as a consequence of strong urban pollution to be enforced by stringent government policies [Zhixiang, L. 2018]. With 4 HRSs today, 100 by 2020, > 1,000 by 2030, and a full HRS grid by 2050 the Chinese plans to install a complete grid by 2050. The fuel cell electric vehicle roll-out will be in steps of 10,000 FC cars, FC trucks and buses and 50 trams by 2020 and 2 million FC cars, further FC trucks and buses, further FC trams by 2030.

What comes as a surprise of recent communication from China that also stationary FC applications (200 MW by 2020 and 100 GW by 2030) are planned, combined with the vision of 3,000 km hydrogen pipelines already by 2030 and a 'well-done' hydrogen infrastructure and distributed power by 2050. These data are even more dramatic understanding that most of the hydrogen infrastructure and equipment will be new and must not be integrated into an existing gas infrastructure. It almost goes without saying that this vision incorporates a full conversion to renewable energy by 2050 such as wind and solar energy.

Finally, also Norway plans to participate in the conversion strategies to a hydrogen-based energy system (see chapter 2.4.4). Even though further producing natural gas in the future, the plans are to exploit this by the use of CCS and produce hydrogen for the purpose of value creation. In concrete collaboration e.g. with the Netherlands [WEC 2018] Norwegian industry considers to transport hydrogen through dedicated pipelines to central Europe (see separate paragraph further up in this chapter). At the same time the vast onshore wind potentials with 3,800 average annual full load hours will allow to use vast quantities of electricity for the production of hydrogen in thinly populated regions in northern Norway, operating at an average annual full load hour period of e.g. 5,000 h [LBST 2014]. Instead of transporting this energy to central Europe by electricity, the alternative of gas transport (as liquefied hydrogen or by pipeline) have already been assessed [Stiller, C. et al. 2008].

Potential roadblocks

Potential roadblocks are those which may in the extreme case completely rule out a technical concept or a technology, and by that a whole storyline due to known challenges or unforeseen structural and external events. Often, roadblocks are connected with missing public acceptance or new insights from climate research. The following major roadblocks have been identified by this study (examples of affected storylines are provided in parenthesis):

- Missing public acceptance of CCS technology in most parts of Europe, meaning that the concept may still be applied in some countries such as e.g. the UK [KPMG 2016] (storyline category IV – Business as usual (IV-H_2));
- Re-evaluation of the GHG relevance of shale gas imports from the U.S., rendering the specific GHG-footprint higher due to the methane slip encountered, and thus intolerable from an EU policy perspective, which could have an impact on all Member States considering to import LNG from the U.S. in the future, such as e.g. Spain [Deloitte 2016];
- The unavailability of large biomass/biogas import quantities due to growing global pressure for the exploitation of these resources, such as indicated by [Ecofys 2018] and [Energi Styrelsen 2013].

With the use of other methane gases than natural gas, the gas infrastructure will experience new tasks. Not only that the distribution grid will be less utilized as compared to the transport grid due to expected savings in gas demand for room heating, both transport and distribution grid will need to be equipped for the decentral collection of biomethane [E3G 2017]. Also, the number of small $PtCH_4$ plants may grow, which – specifically in periods of low gas demand, i.e. in the summer period - will require a reversed flow from the distribution back to the transport grid. To avoid roadblocks in the gas grids and to safeguard a constant gas quality the admixture conditions of different gases need to be reworked for an adapted regulatory framework.

2.3.4 Regional aspects

The most striking observation with a view to the European diversity of future gas and gas infrastructure storylines is the distinctive discrepancy between Western and Eastern Europe in the level of strategy development especially towards 95% GHG reduction targets and practical activities such as technology development and launching of pilot projects.

It turned out to be difficult separating the Eastern from the south Eastern Member States as their approaches demonstrate little evidence of significantly changing storylines specifically with a view to the gas infrastructure. Even though focussing on the Eastern Member States the following interpretations can also be applied to the South East.

Energy strategy documents of Eastern European Member States mainly focus on short-term (2020 or 2030) European or national targets [Spiridonovs, J. 2015] (LV), (EE), [TEM 2017] (FI), [Ministerstwo Gospodarki 2009] and [Ministerstwo Energii 2017a] (PL), [MoE BG 2011] (BG), [MINGO 2009] (HR), [MoE RO 2016] (RO), [MND HU 2012] (HU). Strategies and visions towards 2050 are formulated rather vaguely and only consider a 80% GHG emission reduction target [Riigikogu 2017] (EE)), [Blumberga, D. et al. 2014] (LV), [MEAC 2016] (EE), [DLR, et al. 2013] and [LOCSEE 2014] (GR). They heavily build upon electrification of the demand sectors and on the use of biomass. In the evaluated documents, synthetic gases are not taken into account as possible relevant energy carrier in the future. As a consequence of the missing need to balance out renewable electricity at large scale also large-scale energy storage could not be identified as major development focus in Eastern Europe. The national strategies rather focus on security of supply and diversification of gas imports from Russia [OIES 2017]. When assessing different types of gases, Eastern European Member States suggest mostly a decentralized use of biogas to stretch the fossil methane gas basis or, as proposed in the Polish national energy strategy, production of synthetic methane via coal gasification with subsequent CCS or CCU as a possibility for diversification from Russian gas imports [Ministerstwo Energii 2017b]. Synthetic methane from electricity or hydrogen as a future gas alternative could not be identified in literature.

Summarising for the Eastern European Member States, there are no sophisticated long-term holistic scenarios available that describe a way forward to achieve a 95% GHG emission reduction by 2050. Thus, most of these countries rather follow the storylines classified as “IV - Business as usual”, where in comparison to the past fossil natural gas plays the same role (storyline IVa-NG) or even a larger role substituting other fossil fuels, notably coal, in the future (storyline IVb-NG). An isolated result can be reported for Poland with substantial resources of domestic coal which can potentially be used for methane production by coal gasification (IV-CH_4). Some countries in Eastern Europe with more ambitious GHG reduction goals rather expect fossil natural gas or biomethane as a back-up for renewable electricity (storyline categories “III – Fossil energy efficiency (III-NG)” or “II - Green energy efficiency (II-B)”, respectively).

For the Western European Member States a full variety of short- to long-term storylines can be identified in literature. From a bird’s perspective of the assessment of existing storylines, most studies covering Western Europe or individual Member States appear to address the deep decarbonisation of the future energy system with GHG emission reduction targets of at least 80%. Therefore we conclude that Western Member States are more concerned about the environmental issues of the gas sector rather than of security of supply and import diversification. The stronger environmental focus can also be attributed to the fact that Western Europe is less dependent from Russian gas imports (except of

Germany and Italy), and has the options to choose from gas imports via pipeline or as LNG from the world market. In fact, the possibility of LNG imports to Western Europe increases the diversity of NG supplies in spite of the dwindling domestic NG production and thus contributes to the competitiveness of the gas markets.

In this context, many studies for Western Europe expect a (partially significantly) decreasing gas demand due to the decarbonisation targets for the energy system and furthermore focus on potential options for substitution of fossil natural gas by renewable gases. Many of the studies predict a minor role of gas in the future energy system and can therefore be classified as “storyline category III - Fossil energy efficiency (III-NG)” or as “storyline category II - Green energy efficiency (II-CH_4, II-H_2 and II-B)”, the latter ones with more ambitious environmental targets of at least 95% GHG emission reduction. Some studies explicitly address the future role of the gas infrastructure and analyse energy systems implying a large share of renewable gas (i.e. “storyline I - Green gases expansion (I-CH_4, I-H_2 and I-B)”). In some cases the storylines include a further use of fossil natural gas which is then converted to hydrogen via steam methane reforming and combined with CCS or CCU (“storyline category IV - Business and Usual” (IV-H_2)”). This approach, however, can be viewed as an isolated result which is currently mainly promoted by actors from the UK and the NL.

All in all, the different storylines are typically based on the interest of individual groups or represent a vision of individual Member States’ public institutions. Hence, there is no definite indicator on a regional level of interest in the particular type of green gas. Some examples of storyline motivations are:

- **Political ambitions:** The depletion of Dutch natural gas resources in combination with the availability of large on- and offshore wind potentials can explain a fresh interest in the use of synthetic methane and hydrogen;
- **Industrial development:** The interest of a UK region in hydrogen (the North) to substitute natural gas in the gas grid for residential heating can be explained by the UK’s strong tradition in offshore oil and gas production, its dominance of natural gas for residential heating and public preferences for the use of boilers also in the future;
- **Natural resources:** The Danish energy policy interest in a combination of biomass and synthetic methane for substituting natural gas in the gas grid can be explained by the ample biomass and on- and offshore wind resources as well as underground storage capabilities;
- **NGO’s ambition:** Primary policy targets of NGOs are centred on the sustainability of energy supply. For the case of Austria a report has been presented comprising some far reaching consequences also addressing behavioural challenges.

Concluding, it is the opinion of the authors that the variation of interests, business cases, roles as well as technical or economic strategies across Europe’s individual member states as revealed by our assessment should be properly addressed in further studies and modelling approaches, specifically to take into account specific challenges and opportunities of the Eastern European and the Western European member states.

2.3.5 Political and economic aspects

Contribution to European policy goals

The major European policy goals for the future energy supply are (1) decarbonisation of the energy system and hence mitigation of the GHG effect as well as avoidance of local pollutants, (2) the security of supply by e.g. energy diversity and growing utilization of renewable energy and (3) European competitiveness by the growth of industry through the access to the cheapest possible energy.

Since European Council conclusions in 2009 and the Low Carbon and Energy Roadmaps in 2011, the objective of Greenhouse Gas emission reduction goal of -80-95% had been broadly accepted in the EU. The objectives of the Paris Agreement and recognition that it will achieving climate neutrality in the second half of the century kicked off a dynamic political debate in some Member States with the consequence of searching more stringent goal of GHG-emission reduction (especially if pursuing the goal of limiting the temperature rise to 1.5 °C). While no revised objectives for the EU have been put forward yet, this study focused on assess the existing storylines with an illustrative target of -95% GHG emissions reduction in mind. Even though we are lacking strategic evidence from our storyline assessment it is worthwhile mentioning that the gas sector could even contribute negative CO_2 emissions through the use of biomethane in combination with the CCS or CCU concept.

We have identified some studies consequentially addressing the implications of a -95% GHG emission reduction target by 2050. But only few of the studies have been as consequential as two recent studies from Germany on this matter, reflecting the industry view on one hand and the political perspective on the other. We have therefore decided to take the German positions as spearheading example, only recently defending both ends of the -80% to -95% bandwidth, one denying the reasonability of the -95% target and opting for the -80% target the other one admitting that the -95% target may have to be adhered to.

The study supporting the 80% target is [Prognos; BCG 2018]. Its major conclusion is that by taking today's policy measures as given, a reduction target of 61% is within reach, leaving a gap of 19-34% until 2050. The energy users then contribute by achieving the following sectoral goals: residential -70%, energy conversion -70%, industry -48% and transport -40%, requiring investments of about 530 B€ in total to achieve the -80% GHG target by 2050. The study concludes that the fulfilment of the -80% GHG target can be reached in principle, the 530 B€ translated into about 15 to 30 B€ of additional investments annually. Understanding that a close to 100% decarbonization of most energy sectors will be required for the case of fulfilling the -95% target makes the authors believe that reaching this target will be a burden unacceptable for the industry and society as a whole. Specifically, this target could only be reached in a perfect international consensus which the authors do not believe in and at very high additional investments. Furthermore drastic behavioural recesses would have to find public acceptance. PtX technologies are seen as a necessary and viable solution to supply all energy sectors, including large imports of renewable gas or liquids e.g. from regions with more favourable conditions for harvesting renewable energies, as Germany's domestic resources would not suffice. Other proposed measures are the drastic reduction of residential energy use and the application of electric heat pumps, more efficient transport modes with a trend to public mobility and the application of the CCS technology which has been strictly ruled by regulation[27]. By anticipating dire negative implications of the -95% GHG emission reduction target on stability and growth of German industry and society the authors advocate energy policy measures aiming at the less stringent target of -80% instead.

On the other side of the bandwidth, the Federal German Ministry for Economic Affairs and Energy is the client for a project assessing the future of the energy system in a holistic approach to better

[27] The EC Directive 2009/31/EC of the European Parliament and the Council of 23 April 2009 e.g. requires that monitoring after permanently sealing a storage site shall last for at least 30 years.

understand the implications and consequences of a -95% GHG emission reduction target. In module 10a of this project which is not yet finished [FhG-ISI 2017a] the modelling framework and fundamental considerations for the design of an energy systems implying the -95% target have been outlined. Without the results of the modelling having been published yet, the consequences for the energy system and society as a whole have been pinpointed. Major insight is that if agriculture and some critical industry sectors are allowed a CO_2 bonus all other sectors need to be virtually fully decarbonized by 2050, which will imply that all future energy infrastructures need to be considered bearing the 2050 goals in mind. As for the [Prognos; BCG 2018] study, it is concluded that the consequences of adhering to the -95% target are strong societal implications incurring that individual consumer behaviour will need to change, which is seen to become a major challenge. One obvious explanation is that even the reduced consumption of meat would have to be considered. As an apparent consequence for the gas infrastructure it is furthermore concluded that biomass, and hence biomethane, which is limited in potential, will – beyond food production - be restricted to specifically critical energy applications such as aviation.

Furthermore, wind and PV based electricity would become the major energy carrier, a major task raising the public acceptance for extending the electricity grids. Another implication were that buildings need to be much better insulated, heating habits adapted, industry would need a fundamentally new and decarbonized technology basis and CCS & CCU becoming other key technologies. It is also claimed that to avoid carbon leakage world regions would need to cooperate and that the economic impacts of such rigorous changes are unforeseeable yet. The study's conclusion in brief is that a new 'currency' needs to be developed, dubbed 'public acceptance'. Other than the study by [Prognos; BCG 2018] however, our interpretation of the study is that such paradigm shift should be explicitly taken into account by the future energy policy within the EU.

Interpreting the two studies for Germany, both perspectives seem to merge in their assessment of the drastic challenges which our energy systems will need to find answers for. However, the implications for the energy system are interpreted differently. The industry view as presented in [Prognos; BCG 2018] suggests to incorporate the use of PtG technologies and hence a significant contribution of gas infrastructure at large scale both for harvesting domestic renewable electricity in order to limit behavioural changes of the end users which will be necessary to achieve -95% GHG emission reduction target. The political and research perspective presented in [FhG-ISI 2017a] is more open concerning the necessity of societal/behavioural changes. Simultaneously, German politics (i.e. the Energy Ministry) seem to be determined that electricity will become the major energy carrier for which public acceptance must be developed. Also, biomass and likewise biogas will become rather limited and will not become available for energy transport and storage and neither for heating purposes at large scale. Having presented these specific examples for the case of Germany, it is our general interpretation that all other European Member States will sooner or later arrive at similar discussions of how to balance the behavioural against technological options as well as the role of the gas infrastructure against – or better in coordination with – the electricity infrastructure.

Diversification of energy supply – drivers and measures

Concerning the criterion of energy supply diversification, the following two major drivers should be mentioned:

- **Natural gas's reputation as clean fuel under threat:** One strong driver for the development of many gas infrastructure-related storylines has been the threat of devalued or stranded assets

by a significantly reduced appreciation of gaseous energy carriers in a renewable energy dominated world. This development has been specifically pronounced as only a few years ago natural gas had a rather positive reputation as 'the cleanest fossil fuel' [Bittmann, M. 2013]. Representative storylines are storyline II – Green energy efficiency and I - Green revolution, both of which suggest the growing substitution of fossil based by CO_2-free gases.
What is more, also methane leakage from shale gas operations specifically in the U.S. can significantly multiply the GHG-effect of the use of natural gas. This unexpected environmental threat has already been explained in chapter 2.3.3 in more detail. Even though this context only surfaced recently it may have an accelerating effect on the substitution of natural gas. In addition, methane leakage from piped and LNG imports should be taken into account as even a leakage of as small as 3 to 4% of methane from production to final user could render natural gas a less clean fuel than coal. Whereas new pipes and infrastructure in the EU are good in that respect, this cannot always be said for the long export routes, where jurisdictions might not deal with methane issue as done in the EU, and where the infrastructure is not sufficiently dense for cost-efficient reuse of any methane that could be caught. With the first evidence from literature and given the much higher GHG impact of methane, the extent and accountability of uncontrolled methane leakages, specifically from shale gas production needs to be validated by further research.

- **Geopolitical threats:** The future supply of natural gas has received a dent in 2014, when the Ukraine crises struck and the transmission from Russian gas fields to the European user was physically endangered for geopolitical reasons. The Russian geo-political interests have been assessed by e.g. a Ph.D. thesis before the Ukraine crises: [Buryk 2010]. Even though the perspective of alternative pipeline routes and LNG imports will compensate these threats to some extent, the level of gas imports continues to be a motivation to diversify away from a high import dependency. One example for a growing interest in domestic gas sources (biogas, Power-to-Gas) in order to avoid current and potential future energy import dependencies from outside EU is e.g. [WEC 2018]. This motivation is backing the two storylines I and II.

The following measures for a stronger diversification of gas supplies to Europe have been proposed by different storylines:

- **Substitute gas by other forms of energy:** Major focus has been on "all-electric" energy supply concepts. Even though they have not been searched for explicitly in this study, examples of individual scenarios are presented in [Ontras 2017], "Scenario all-electric", [Frontier Economics, et al. 2017], "Scenario Nur Strom", as well as [KPMG 2016], "Scenario 4 – Electric future" and a shift away for heavy goods road transport (option: CNG or LNG powered) to electrified trains by 2050 [Deloitte 2016]. Storylines II - Green energy efficiency and III - Fossil energy efficiency are the typical representatives of a strong electric focus;
- **Methane diversification - Substitute fossil methane (= natural gas) by synthetic methane (= $PtCH_4$) and biomethane**: Several storylines, originating from industry [Ecofys 2018] but also policymakers [Energi Styrelsen 2014] have presented scenarios in which the increased use of biomethane (the domestic production often being enhanced by biomass or biogas imports) and synthetic methane from Power-to-Gas are typically combined. E.g. in the case of [Ecofys 2018] 98 bcm of domestic biomethane production within Europe is combined with the annual production of 24 bcm synthetic methane (possibly to be enhanced by a further 20 bcm biomethane annual imports from Ukraine and Belarus) is foreseen as renewable gas potential. This can be topped by the production of hydrogen from natural gas with CCS. In the biomass

scenario assessed in [Energi Styrelsen 2014] for the case of Denmark the domestic biomass utilization (ca. 300 PJ/a) is topped by the use of biomethane and synthetic methane (ca. 40 PJ/a), the use of waste (ca. 40 PJ/a) and biomass imports (ca. 40 PJ/a) in 2050 rising to ca. 230 PJ/a of biomass imports in the enhanced biomass scenario; (annual primary energy consumption Denmark in 2015: 16.9 Mtoe [BP 2017a]).

- **Gas type diversification – Substitute methane by hydrogen:** This is the most robust solution for the long-term view but with investments required for the adaptation of the gas infrastructure from methane to hydrogen, based on existing technologies and highest efficiency as well as compatibility with the electricity infrastructure and was proposed by e.g. [KPMG 2016], [NIB 2017]. For the Evolution of Gas scenario in the case of the UK [KPMG 2016] suggests a 70% share of gases in the final energy demand by 2050, comprising a high share of 50% hydrogen, 47% natural gas and 3% biomethane which shrinks to a 27% gas share (only natural gas) in total energy demand in the Electric Future scenario by 2050.

The authors of this study have observed both the worsening positive environmental perception of natural gas as the cleanest fossil fuel in Europe as well as a threat of a growing dependency from single large gas exporters, namely Russia. On the other hand, a relevant number of alternative energy infrastructure solutions have been developed ranging from (a) the replacement of gaseous energy carriers by renewable electricity, (b) the use of green gases such as from domestic biogas sources or the production of synthetic methane from renewable electricity and finally (c) the full conversion of the gas infrastructure to a consequentially decarbonized gas infrastructure, i.e. to pure hydrogen. Exactly, these concrete proposals have been taken as blueprints for the definition of the generic storylines by this study in chapter 3.

Costs of energy supply

The competitiveness of industry throughout Europe, and hence also the affordability of the associated gas supply costs also for households, is one of the major EU energy policy goals. The observation made in the storyline assessment is that with the exception of some storylines with a primary focus on sustainability as the dominating study target such as [WWF Österreich; Global 2000; Greenpeace 2015] or [Greenpeace; GWEC; Solar Power Europe 2015] most modelling approaches in national energy strategies are based on economic optimization algorithms, e.g. [Frontier Economics, et al. 2017] or [FhG-ISI 2017a]. These types of simulation take the GHG emissions as ceiling and economically optimize the energy system meeting GHG emission reduction as secondary constraint. Resource availability or energy efficiency could be other criteria, but are generally left to be ruled by market forces.

In addition, some storylines assume that the reduction of GHG emissions is part of a global trend [FhG-ISI 2017a] indicating the relevance of internationally competitive (energy) costs. This is important from an economic as well as a climate point of view as GHG emissions could be transferred to other world regions (“carbon leakage”).

As a result individual interpretations can be drawn from the modelling exercises, typically based on a set of unique assumptions, such that their relevance can rarely be compared between the studies. Therefore, generalized results are difficult to draw; studies always need to be interpreted on their specific backgrounds. The following list presents some examples:

- In [Netbeheernederland 2017] and for the **Netherlands**, total future energy supply costs in 2050 are calculated to be about twice as high as they are now, whether an energy system dependent on fossil fuels (with CCS) or one heading towards a CO_2-neutral energy supply is assumed. It is also found that differences in total costs are insensitive to different scenarios, even though the trend is that *"climate-neutral scenarios, in terms of renewable sources, tend to be more expensive than the current cheap fossil fuel. In addition, more investment in plants, insulation and infrastructure is required."* The marginal total cost difference between a synthetic methane-based and an electricity-dominated energy supply is also supported by a modelling exercise for a limited gas supply region in Eastern Germany in [Ontras 2017] where 217.5 M€ total investments for the Green Gas scenario stand against 219.4 M€ for the All-Electric scenario in 2050, including costs for electric chargers, façade insulation, electric heat pumps, grid extension, gas boilers, electrolysis, methanation and wind power plants as well as battery storage.

- In [KPMG 2016] it is found for the **UK** that the measures to decarbonize the heating sector, whichever option is chosen, and the conversion of homes and businesses to new energy sources will require large capital investments. At the same time the result of this storyline analysis is that "*a continuation of using the British gas network offers significant savings versus alternative heating sources*" assuming the hydrogen conversion of residential heat supply. On top, it is specifically relevant to understand that an aligned build-up of a hydrogen infrastructure for transport helps to lower the specific infrastructure conversion and operating costs, again an important evidence of the need for sectoral integration;
- In [Energi Styrelsen 2013] four scenarios with a focus on (a) wind, (b) biomass, (c) enhanced biomass and (d) hydrogen have been assessed for **Denmark** by 2050. Concerning the total annual costs required to shift to these energy systems two observations are presented: One is that the costs are somewhat higher in 2050 than in 2035 as the industry and transport sectors have to be adapted to alternative fuels. The other one is that the costs for the four alternative approaches are almost equal in 2050 except the enhanced biomass scenario, which assumes a rather large share of biomass being imported with the consequence of a 15% cost increase. In a personal interview on 21 February 2018, the authors of energinet.dk indicate that the enhanced biomass scenario is now seen to be unrealistic due to the unsustainability, the uncertainties and the growing energy dependence connected with the import of large quantities of biomass. It had been anticipated in 2014 to directly substitute today's coal imports.
- In [Frontier Economics, et al. 2017] one assessment focus has been on a comparison of the expected costs of an all-electric and a gas enhanced energy infrastructure for **Germany**. One major conclusion is that the 'Energiewende' will not be manageable without the use of green gas for large scale energy transport and storage in principle. Furthermore, the analysis has shown that the continued use of the existing gas transport and distribution grids for green gas including the energy storage facilities will have significant cost advantages over an energy system without a gas grid. In total, cost savings in the order of 12 billion € annually are expected by 2050 (in real terms of 2015), specifically reflecting the avoided cumulative investments in the electricity grid and end-use technologies of approximately 268 billion € by 2050;
- In [Ecofys 2018] a group of industry partners from Belgium, Germany, France, Italy and the Netherlands have come to the conclusion for EU-28 that by applying 72 out of 122 bcm of biogas from the EU allocated to the residential heating and electricity generation sectors anticipate societal cost savings of around 138 billion € annually by 2050, compared to a decarbonized energy system without any role for renewable gas. Seeming rather high, these

savings will need to be validated by further studies. These cost savings are equivalent to approximately 600 € per EU household annually. They are achieved by avoiding costs to build and operate the electricity generation capacity to meet peaks in electricity demand and through savings on building insulation costs required for installing electric heat pumps[28]. Finally the study also found that the use of biomethane and hydrogen in existing gas infrastructure will be cost neutral as compared to biofuel for the use for heavy-duty transport. The view of these stakeholders from the gas industry supporting a strong future contribution of biomethane to Europe's energy supply by 2050 is noteworthy as it reflects the bandwidth of positions, understanding that a study called for by the Federal German Ministry for Energy and Economic Affairs completely denies the role of biomass based fuels for Germany by 2050 with the exception of some specifically critical applications such as for aviation [FhG-ISI 2017a];

- Concluding this list of examples, a politically motivated and fundamental statement by a research study team financed by the **German** Federal Economics Ministry [BMWi 2017] provides a different view on the associated costs for increasing the climate ambitions from -80% to -95% GHG reduction target: *"The economic consequences of a 95% scenario, i.e. the incremental costs to the 80% target, are hardly predictable, as some technologies to achieve the 95% target are still in the research stage. It is furthermore also impossible to assess the global societal costs and consequences as structural changes will be required. Future economic assessments will also have to qualify and quantify the costs for missing the global -95% policy targets."*

As can be seen from the above examples, the necessary investments for adapting the current gas infrastructures, transport and distribution grid, highly depend on assumptions and on regional frameworks. Therefore it is not possible to draw any general conclusion for the whole of Europe in this study. Further modelling is therefore required with a specific view to the economic impact. In these future modelling approaches the different technical, economic (costs) and societal (public acceptance) dimensions should be properly taken into account in view of an holistic understanding of the multiple contributions of the gas infrastructure to the energy system.

2.3.6 General appraisal of the selected storylines

Methodology and detailedness of the storylines

Literature differs widely in terms of methodology and detail of publications. Most important in the context of this study, however, is the fact that so far only very few storylines are using complex and powerful methodologies and present detailed results (and assumptions or input parameters). If full coverage of the European Union at country level granularity, an hourly time resolution, a timeline until 2050 and a climate ambition of 95% GHG reduction by 2050 were taken as additional criteria, the selection would go down to zero.

In order to showcase the variety of methodologies employed and the detail of the results published, two examples are pointed out in the following, the first describing a powerful methodology with detailed results published, and a simpler approach with generic results published. A number of storylines are in between these two examples, many focusing on an individual Member State.

[28] Heat pumps principally operate at low temperatures of e.g. 45°C and to avoid excessive heating surfaces require sound insulation systems.

Among the most powerful methodologies the ones by ENTSO-E and ENTSOG [Entsog 2018] are to be mentioned for the development of the TYNDP 2018 scenarios, currently available as draft edition. Input is generated in a scenario development process involving stakeholder consultations, electricity sector assumptions and results come from a mix of top-down (e.g. European targets on renewable energies) and bottom-up (e.g. country-level demand data, technology penetration, installed plant capacity, etc.) approaches, commercially available market modelling tools are used to determine how the power system will behave in each zone, for each hour of the year, and each of the three climate situations included (warmer or colder / dryer or wetter years), energy consumption is predicted, the penetration of electricity demand side technologies (including demand response, electric vehicles, heat pumps and home storage) is forecasted, gas demand data for scenarios include a sectoral breakdown for all countries. Results are published at country-level. However, the scenarios are only calculated until the year 2040 while GHG emissions are allegedly targeted at 80% to 95% reduction by 2050. Furthermore, only gas and electricity are covered while other fuels are not included, notably oil-based transport fuels, bio-energy other than biomethane, etc. GHG reductions are results of market forces and policy measures in the various scenarios, and result from different assumptions on fuel prices (coal, gas, oil) and on GHG emission allowances.

A simpler, but nonetheless scientifically sound, approach has been employed by [ADEME 2018] with the aim of refining the methodology in future steps by 2019 using global optimization models of all energy carriers and uses. It is a prospective techno-economic study and serves to analyse techno-economic conditions for achieving 100% renewable gas in 2050. Covering France, the approach is based on existing energy scenarios calculated in a previous study achieving a GHG reduction by 2050 above 70%, and aims at testing the techno-economic feasibility of achieving 100% renewable gas production by 2050. Three renewable gas production technologies are included: fermentation of wet biomass (incl. residues) producing methane; gasification of dry biomass (including residues) producing methane; Power-to-Gas producing methane (and hydrogen as long as it can be injected into the gas grid and mixed with methane without adaptations of the gas grid). Power-to-Hydrogen (PtH_2) has been excluded where it would require a dedicated hydrogen grid. The study focuses on 2050, no trajectory of the transition from today towards 2050 has been included. Electricity for Power-to-Gas is primarily 'excess' power; data are based on a detailed study with regional and hourly resolution. In 2050, the renewable gas is produced to 100% in France; no gas imports are assumed. Gas grid adaptations have been analysed and optimised for four typical regions (départements). The results are published in an 18-page extended summary report only; more detailed results are not available. However, the study is based on detailed previous energy-climate scenario work published in great detail in 2017.

Reasonability of the storylines

In general, the selected storylines apply reasonable approaches, and present plausible results compared to the input assumptions and parameters. However, some examples of issues meriting discussions and further research are highlighted in the following.

GHG reduction ambition by 2050

[Entsog 2018] targets GHG reductions of -80% to -95% by 2050. However, GHG reductions calculated until the year 2040 in the various scenarios on the one hand vary considerably between the scenarios, and on the other hand the share of fossil gas in the overall gas mix is still rather high in 2040. Unfortunately, the draft report does not discuss this issue, so it remains open which scenario would achieve the GHG reduction by 2050. In general, the selected storylines cover the full spectrum of -80%

to -95% GHG reduction by 2050, while less ambitious storylines have not been selected. It needs to be emphasized here that a number of studies specifically point to the fact that structural differences develop in the energy system between a -80% GHG reduction ambition and the -95% ambition. In other words, a solution for -80% may not be viable for a simple extrapolation to -95%.

Biomass potentials for biomethane production

Biomass availability is assumed to be much higher in 2050 than today requiring new practices and organisational changes in agriculture and forestry while sustainability requirements as well as food and primary materials competition is taken into account in [ADEME 2018]. This is based on previous studies, and is an important input assumption with a potentially significant impact on the overall study results. [Ecofys 2018] assumes biomethane production of around 100 bcm/a in 2050 compared to up to 30 bcm/a in 2040 assumed in [Entsog 2018]; however, this may be due to lower GHG reduction ambitions in the latter study. On the other end, a German study [FhG-ISI 2017a] rules out biomass for anything else than rather specific applications such as for aviation. Quantitative differences in bioenergy potentials assumed or calculated in storylines are based on different types of bioenergy included[29], different assumptions made on competitive uses of biomasses, different assumptions on agricultural regimes, practices and future increases in per hectare yields, and other assumptions (see also next paragraph). The allocation of bioenergy potentials to different energy and non-energy related uses strongly influences the bioenergy availability for biomethane production. Because of this complexity, comparisons of bioenergy potentials require detailed assessments, but may suffer from lack of transparency or detail provided by some storylines.

General appraisal of biomass and bioenergy potentials

Extensive discussions regarding the sustainability, availability and competition of land for the production of biomass for use as food, fodder, (construction) material, power, heat, or transport fuel have been led for many years. Important aspects concerning biomass and bioenergy potentials are:

- A meta-analysis by [Creutzig, F. et al. 2015] found high agreement among studies with sustainable technical bioenergy potential of up to 100 EJ/a worldwide. There is reduced agreement concerning global technical bioenergy potentials between 100 and 300 EJ/a. For potentials above 300 EJ/a, the scientific agreement is low.
- In early 2018 a study by Ecofys [Ecofys 2018], commissioned by a group of companies from the gas industry, resulted in the assumption of a high biogas share in the EU gas grid, summing up to 98 bm^3/a and additional biogas imports of another 20 bm^3/a mostly from Ukraine and Belarus (in total 118 bm^3/a of biogas represent an energy content of 4,150 PJ/a or 5,7% of Europe's primary energy consumption in 2011), almost dwarfing the additional use of 24 bm^3/a of renewable synthetic gas. Major biogas production processes are believed to be anaerobic digestion and thermal gasification.
- In its 2013 energy strategy paper [Energi Styrelsen 2013] Denmark had studied a bandwidth of scenarios with a specific focus on biomass and biogas, with a high import share of 31 out of 443 PJ/a in 2050 (scenario 'biomass') and 119 out 710 PJ/a (scenario 'enhanced biomass'). When discussing these assumptions in the framework of this study, the opinion by energinet.dk communicated in a personal telephone discussion with LBST on 21 February 2018 was that specifically the expectation of the 'enhanced biomass', based on the consideration that coal

[29] Including wet bioenergy crops, dry bioenergy crops such as short rotation forestry, different types of wood, different types of residues, aquatic biomass, etc.

imports needed to be substituted by biomass imports, was overly optimistic and is now believed to be unsustainable.

- Another, rather specific case is the one presented by [CIB 2017], where the Italian biogas potential is seen in the light of the adapted EC biomass policy[30], focussing future biomass utilization in the EU on 2nd generation crops, here dubbed 'biogas done right' (BDR). The authors define this concept by (a) a bioenergy to be produced at TWh-scale while keeping the farms' food output and improving their overall economics; (b) a bioenergy that contributes to a deep change in crop rotation and farming practices, soil usage and care ranging from conventional farming practices' GHGs emission mitigation to developing progressively more carbon efficient farming practices (organic fertilization, all year around soil covering, precision farming, water saving irrigation systems, etc.) toward 'carbon negative' agricultural systems; and (c) a bioenergy able to stepwise reduce both food/feed and energy production costs. By applying the BDR concept the authors of this study expect a biogas potential of 100 TWh/a by 2030 for Italy (out of a hydrocarbon need of 1,800 TWh/a, out of which 700-800 are contributed by natural gas today). By 2050 the potential could grow to 185 TWh/a biomethane. It should be noted, however, that efficient double cropping, which is assumed here, limits similar potentials to southern European Member States.
- Studies that come to the result of high biomass potentials for global bioenergy typically apply assumptions such as
    - re-allocation of established biomass feedstock and uses, such as 'first generation' biofuel for transport to lignocellulosic feedstock for combined heat and power (CHP) providing control power in a system with high shares of renewable power from fluctuating wind and photovoltaics;
    - further intensification of agricultural practices to increase yields of food and fodder e.g. through breeding/genetic modification, nutrients and pest control – the area thus freed is then dedicated to energy crop production;
    - use of so-called 'un-' or 'under-used' land that is supposed to be 'abandoned' or 'degraded' – often these lands are extensively used by small-holders or communities for subsistence farming, livestock, honey production or source of firewood and construction material [Fritz, S. et al. 2013];
    - impacts from climate change are often not taken into account in potential analyses. However, changing precipitation patterns, increasing extreme weathers and other impacts concerning land availability and soil quality from rising average global temperature will have an impact on the bioenergy availability [Gutsch, M. et al. 2015].
- Wastes and residues are a feedstock for bioenergy that can both be efficient and low-carbon. For woody residues, a closed nutrient cycle and the humus balance maintained are minimum environmental safeguards. Biogas produced from waste water should primarily serve treatment plants' internal energy needs for resilience reasons of critical infrastructure.
- Roundwood and short rotation forestry is considered a major feedstock for bioenergy. Using these resources for climate change mitigation first leads to high carbon emissions ('carbon debt') [Fargione, J. et al. 2008], [Withers, M. R.; Malina, R.; Barrett, S. R.H. 2015]. The massive release of biogenic carbon bound in wood is a matter to be considered in bioenergy strategies.

[30] Proposal for a directive of the European Parliament and of the council on the promotion of the use of energy from renewable sources (recast) COM (2016) 767 final 2016/0382 (COD)

- The land area and thus bioenergy potential is decreasing if the diet in transition countries is moving towards meat consumption levels of western countries. Furthermore, agriculture transition towards organic farming practices will be needed to achieve the Paris Agreement. Organic farming requires more land-area at short time-scales than high-intensive farming.

Bioenergy can play important roles in regions with high biomass availability. At regional-scale, environmental, social and economic safeguards can effectively address risks associated with intensive use of bioenergy. Ideally, biomass use is embedded in circular economy concepts. An optimum use of biomass for mitigating climate change is 'cascading use', i.e. fixing biomass-C e.g. in woody material for construction over long periods, followed by 2nd and nth use as far as possible, and eventually its energetic valorisation. Cascading use and similar concepts have been emphasised in various EU policy documents, such as the EU Bioeconomy Strategy, the EU Circular Economy Package and the EU Forest Strategy [IEA Bioenergy 2016]. All in all, the contributions from bioenergy in future energy systems is typically in the order of lower double-digit or single-digit percentage shares of primary/final energy consumption.

Biomethane focus versus synthetic methane and hydrogen

There is a slight tendency in the literature to study biomass-based gas production pathways in more detail than the renewable electricity-based pathways providing synthetic methane or hydrogen, e.g. in [Ecofys 2018] or [ADEME 2018]. Furthermore, Power-to-Hydrogen has been excluded in [ADEME 2018] where it would require a dedicated hydrogen grid or other dedicated infrastructure; only hydrogen admixture to methane in the gas grid is covered. As a consequence, hydrogen applications such as fuel cell electric vehicles are not covered. Similarly, [FhG-ISI 2017a] have excluded fuel cell electric vehicles from the very detailed cost optimization modelling approach for Germany because of alleged excessive technology costs.

Incumbent gas sector stakeholders seem to tend towards favouring methane in the development towards renewable gas because of the existing infrastructure rather than to fully explore new opportunities provided by hydrogen. The latter would require a refurbishment of the existing gas infrastructure to hydrogen, but on the other hand opens opportunities based on significantly higher efficiencies of fuel cells compared to conventional technologies, notably in transport. However, [Northern Gas Networks, et al. 2016] in the UK is either an exception to the rule, or is a forerunner just as the Dutch TSO2020 Synergy Action [CEF 2017] developing hydrogen for transport and its admixture to natural gas in the grid. Furthermore, incumbent gas sector stakeholders seem to favour the more traditional biomethane production over gas production using renewable power (synthetic methane, hydrogen) [Ecofys 2018].

How much electrification in the heating and transport sectors is possible and economically advantageous?

In general, relevant storylines agree qualitatively that future gas demand will come under pressure notably in the heating sector. On the one hand, heating energy demand will more or less strongly decrease based on improved insulation of buildings, and to a small extent by more efficient heating technologies. And on the other hand, electric heat pumps in buildings using ambient, low-temperature heat and electricity or district heating systems based on renewable heat or electric heat pumps[31] will compete with gas-based technologies probably reducing the share of gas in space heating. Both, assumptions and results on the share of gas-based technology versus electricity-based technologies in the heating sector vary widely.

In the transport sector, gas plays a very small role today, but is anticipated by many studies to gain a significant market share from the oil-based dominance of today. This may be based on commercially available internal combustion engine propulsion systems fuelled by methane, or increasingly on fuel cell electric vehicle technology currently in the commercial market entry phase fuelled by hydrogen. However, battery electric vehicles compete with gas vehicles. Current major competitive disadvantages of electric vehicles are higher (but falling) prices, a thin (but developing) electric recharging network and a growing hydrogen refuelling station infrastructure, while environmental advantages are strongly based on zero local emissions and full renewable potential. In passenger cars and light duty vehicles, all technologies compete, while long-distance freight traffic has demanding range requirements which can only be met by diesel or methane combustion engine trucks, and fuel cell electric or overhead line electric trucks. The latter concept is notably being developed in Germany and Sweden, and requires a new overhead line infrastructure on major traffic routes [FhG-ISI 2017b]. Available studies vary widely in their assumptions or results on the share of methane combustion engine vehicles versus battery electric vehicles versus hydrogen fuel cell electric vehicles in the passenger car, light and heavy duty vehicle segments.

Consistent scenario comparisons of these options in heating and transport within a unified, European methodologic framework would help better understand market opportunities for the different gas types, competitive strengths and weaknesses of the competing technologies, societal advantages, infrastructure requirements in both gas and electricity (as covered by [Entsog 2018], albeit with limited exploration of the above-mentioned transport aspects), necessary fuel supply infrastructures (electric charging, hydrogen refuelling, overhead lines, etc.)

Electricity prices for synthetic methane or hydrogen production

For Power-to-Gas, renewable electricity price assumptions seem high in some studies, and low in others. In [ADEME 2018] average electricity prices are assumed to be 67-82 €/MWh in 2050 (grid costs including adaptation and storage go on top), while [Ecofys 2018] calculates *hydrogen* production costs of 23 €/MWh for a hydrogen quantity of 24 bcm/a. As the latter price for hydrogen seems to be low even at marginal electricity costs of 0 €/kWh this example shows that further research is required to consolidate the assumptions at European level as it is well known that hydrogen production costs can vary significantly with the assumptions (i.e. electricity price and electrolyser specific investment) and local conditions (electrolyser utilization). The above mentioned figures typically do not take into account the game changing effect of China entering this market, both on technology cost and development, and upscaling potential. It is worth mentioning that solar and wind power production cost reductions continue to be faster than anticipated by experts. In this sense, most storylines may prove to be on the conservative side in terms of renewable electricity costs [FhG-ISE 2018], [McKinsey 2018].

[31] District heating system can rely on other heat sources as well, including gas-based technologies such as CHP systems, CCGT or fuel cells. Also, gas-based boilers or fuel cells for the combined production of heat and power are viable options for installation in buildings.

Emerging challenges have short-term impact on storylines

The literature review of storylines reveals changing development trends over the past years that coincide with concrete events or developments of historic nature (see Table 5 below). Cause and effect relationships may only be assumed here, but do not require rigorous scientific proof in the framework of this study. Rather, this illustrates that most storylines and scenarios developed before 2014 have been assessed as not providing value to the present study; in general, only more recent storylines provide relevant information and insights.

These changing trends notably relate to the level of ambition of protecting the global climate, to resource depletion issues and to local air quality, to list the most important in the context of this study. All stakeholders developing storylines seem to have become more and more aware in recent years of the urgency for action in view of ambitious climate targets for 2050, a timeframe only 32 years into the future. This is reflected in quickly developing parameter sets, sometimes significantly adjusted within short timeframes.

Table 6: Emerging challenges for the energy market evolution since 2011

Event/development	Impact Changing parameters
Nuclear disaster in Fukushima / Japan March 11, 2011	• Diminishing role of nuclear power (e.g. Germany) • Push for and strong focus on (fluctuating) renewable electricity • Need to develop large-scale, long-term next to small-scale, short-term energy storage technologies and concepts
Ukraine/Russia unrest begins in February 2014	• Security of supply considerations for natural gas • Push for PtG pathway as alternative gas source • Emerging importance of gas infrastructure
Paris Agreement signed at 21st Conference of the Parties of UNFCCC in Paris on 12 December 2015	• Wide acceptance of the 2°C goal • Gradual understanding that this requires full decarbonisation for the EU/-95% GHG emission reduction by 2050 • Sectoral integration becoming important issue • PtX gaining momentum
Volkswagen diesel pollutant emission scandal gradually emerging since September 2015	• Perception of underestimated role of mobility's contribution • Diesel technology's apparent failure as low CO_2 silver bullet • Push for e-mobility (BEVs and FCEVs across all transport modes)
Local pollution challenges in China's Megacities	• China's boom in renewable electricity, gas imports and alternative energy technologies in transport

2.4 Analysis of non-EU storylines

2.4.1 Selection of non-EU regions of interest

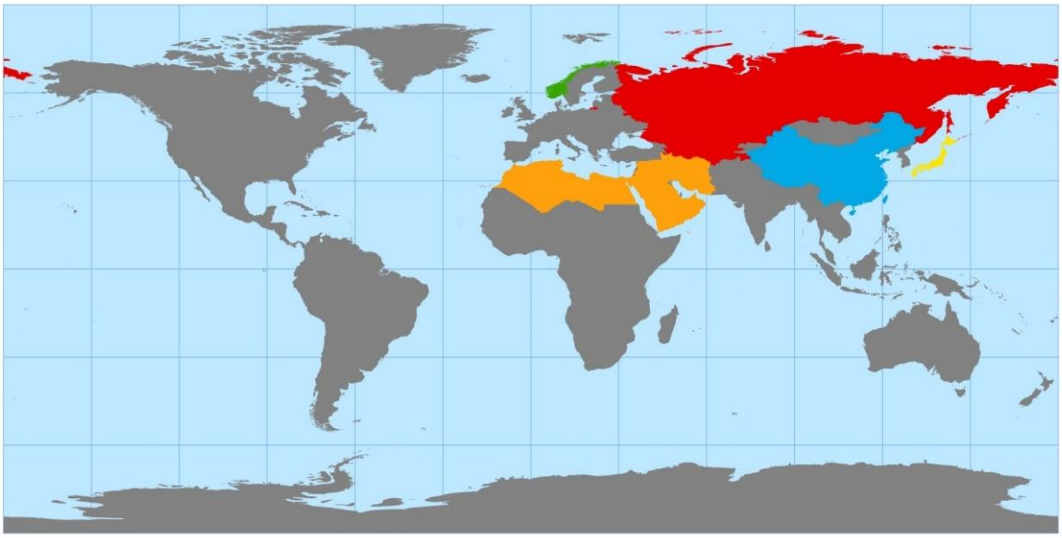
For the selection of non-EU storylines the highest priority was broad consistency with the climate goals as defined by the Paris Agreement. Furthermore the storylines should either:

- contain relevant experience for the EU to learn from; or
- provide the potential for technology and/or energy trade, e.g. gas import to the EU; or

- impact the cost reduction rates of technologies, and thereby the commercial viability, of these technologies in the EU.

The selected world regions are shown on the map in Figure 2-11. Three of the five regions (NO, MENA, Russia and Eastern Europe) are in direct proximity to Europe with major gas export potentials towards Europe, the other two (JP, CN) farther away and potential competitors to Europe in terms of renewable gas imports.

Figure 2-11: Selection of world regions for non-EU storyline assessment



2.4.2 *Russia/Ukraine/Belarus*

Large-scale energy exports are a major element of Russia's economy accounting for about a 70% of total exports, and 18-19% of GDP. The strategic and dominant role of oil and gas in the Russian economy and politics can be explained by the fact that in 2017 Russia has been one of world's largest producers of both fuels, ahead of the U.S. and Saudi Arabia as far as oil production is concerned [Länder Analysen 2018a]. Today, Germany, Italy and Turkey are the largest natural gas import markets for Russia, followed by the UK, France and Austria [Gazprom 2018]. Whereas domestic end-use has been stable, gas exports have been much more influenced by external developments. As Europe is reconsidering its natural gas supply strategy for various reasons[32] (security of supply, depletion of own gas resources, policy goal of -80…-95% GHG emission reduction by 2050, sectoral integration of electricity and gas) this also impacts the Russian gas export strategy. Ukraine's role has mostly been that of a gas transit country for Russian gas to Europe and Turkey, but it also produces from own production wells and is a large gas consumer. Transit pipelines through Ukraine have a total capacity of 183 bcm/a [Länder Analysen 2018b], rendering Ukraine the single most important transit country for Russian gas to Europe, a role diminishing more and more over time. About 90% of Belarus's total energy consumption is based on fossil energies such as oil and natural gas. As most oil and natural gas is imported from Russia, it is strongly depending on its direct neighbour. As Ukraine, Belarus is also a transit country for Russian gas to Poland and further on to Germany. In the early 90s Russia had been suspected to contribute significantly to methane emissions from its natural gas production and transport operations. Under

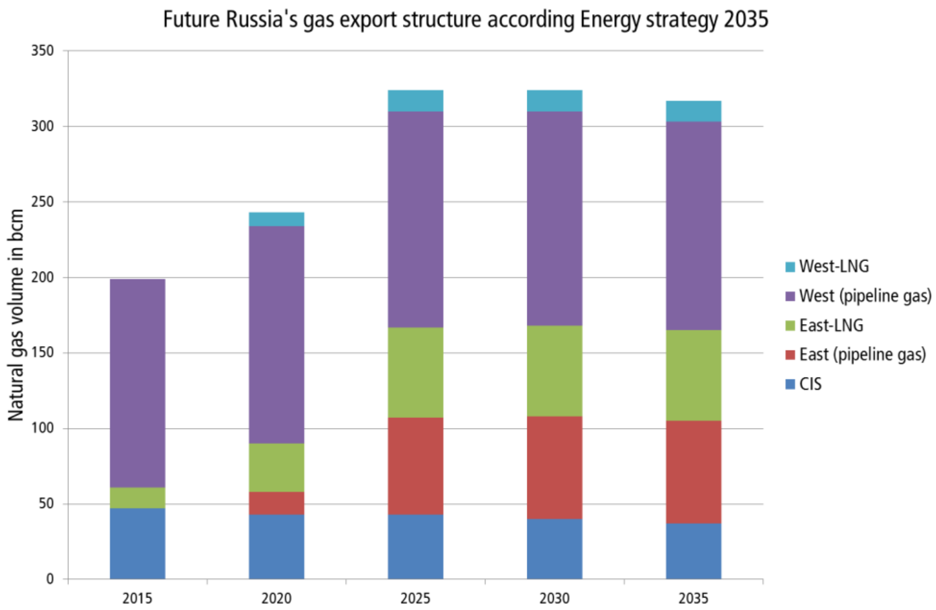
[32] The European 3rd Energy Package aims at a further diversification of gas supply and a further integration of a single European gas market, while European interest is to move gas trade away from the long-term oil-indexed contracts that dominate Russia's gas trade with the EU [Buryk 2010].

control of independent institutions, the methane emissions were then measured on-site and methane losses found to be less than 1% of all gas exported.[33]

The Russian Federation is one of the world's largest GHG emitters. The current Russian strategy in fulfilling its international climate policy obligations is dominated by strongly increasing energy efficiency and energy savings, while the production of green gas does not play an important role. As a consequence, Russia's strategy builds on substituting coal with natural gas contributing to a massive GHG emission reduction. As Russia can already fulfil its international GHG emission reduction obligations due to the economic downturn since the base year 1990, there is little need to change its focus, e.g. towards renewable energies. In fact, from the Russian perspective, the expected gas market development reflects the national policy goals of a strengthened national industry (value creation) as well as a diversification of exports to both the west and the east. In this context as depicted in Figure 2-12, the Russian gas production is targeted to increase to 785-842 bcm/a by 2025, and to 860-936 bcm/a after 2034[34] [EnergyPost 2015]. Moreover, the Russian government has developed a program for the "Development of the gas industry" in 2017 comprising the following elements:

- Increase production and exports of LNG (about 100 Mton/a by 2035);
- Growing volumes and increasing depth of processing raw gas in the framework of diversification and growing value creation for the Russian industry;
- Growing efficiency of existing gas fields and development of new gas fields with innovative technology.

Figure 2-12: Future Russian gas export structure (Source: LBST based on [MinEnergo 2017]



The Russian government has signed the Paris Agreement on April 22, 2016. However, the ratification of the agreement and thus the submission of the definitive Nationally Determined Contribution (NDC) are still pending, a final decision to be prepared by 2019-2020. Even though there is no official national document on CO_2 long-term targets by the Russian Federation a long-term development strategy with low GHG by 2050 is expected to be published in December 2019. Curbing GHG emissions in Russia will

[33] See [Zittel 1993].
[34] IEA assumes growth from a mere 660 bcm/a in 2020 to 800 bcm/a after 2035 assuming Russia will not have the economic power to develop the necessary production equipment.

rest on the following two main pillars: (1) increasing energy efficiency in all industry sectors and (2) development of renewable energy technologies, i.e. solar, wind and small hydropower plants with a total capacity of up to 9 GW by 2035 [MinEnergo 2017].[35] However, the development of the second goal has not become visible until now.

A thorough literature review reveals singular activities on the introduction of renewable energy technologies for electricity and gas or heat supply as well as for transport, some of them lacking the character of a public strategy. Even though the current Russian biogas-market is not well developed, the potential for biomethane production has been estimated to be between 72 bcm/a and 225 bcm/a. The techno-economic wind energy potential in Russia is estimated to be up to 16,500 TWh/a. However, according to [RAWI 2017], the Russian wind energy market is facing a number of serious barriers of financial, infrastructural and regulatory nature, and the role of biomethane is limited to decentralised utilization. The role of hydrogen as an energy carrier has not only been a topic for research until now. Power-to-Gas does not seem to be a relevant development topic, neither for the domestic energy market nor for export.

In August 2017, Ukraine updated its energy strategy towards 2035 to halve the country's energy intensity and to increase the electricity share. Other important elements of the energy strategy are to cut the natural gas end-use as well as to increase the national production of natural gas in order to improve security of supply [KPEKMU 2017]. However, due to the strong economic downturn, Ukraine has cut its GHG emissions by 50% compared to 1990 levels [Klimaretter 2015]. For Ukraine, a clear focus on the production and use of fossil fuels may remain [RadaKMU 2017], even though individual scenarios include an increase of renewable energy shares of up to 91% by 2050 (e.g. [HBS UA 2017]). According to the Bioenergy Association of Ukraine, the theoretical biogas and coalbed methane potential is around 3.2 bcm_{CH4}/a for the co-generation of heat and power. The potential role of biomethane use in Ukraine has drawn the attention of foreign investors, including Chinese power companies [Shanda 2017].

The Belarus government has ratified the Paris Agreement on 20. September 2016. As a diversification strategy, Belarus plans to reduce Russian gas imports until 2022. As of now, no alternative natural gas sourcing strategy has been developed, rendering energy savings the most important and cheapest diversification strategy. Other elements of the strategy are to build up nuclear energy (a new power plant rated at 2,400 MW shall start operation in 2020) and to increase renewable energies (around 6% of gross domestic demand by 2020). Biomass shall be used for the co-generation of electricity and heat (district heating) and shall serve as fuel for transport. Part of the strategy is to develop proprietary biogas technology. The national sustainability strategy 2030 furthermore mentions alternative fuels such as electricity for battery electric vehicles, biofuels as well as hydrogen.

In spite of Russia's role as the world's largest exporter of natural gas and the dominance of Ukraine's and Belarus's role as gas transport countries, little evidence can be found in literature for activities to reduce the carbon burden of the gas in the natural gas grid. The use of biogas has been assessed specifically in Russia, but with a clear focus on domestic and remote use disconnected from the gas grid, and excluding options for export at large scale. Also, hydrogen is only found in research literature with a clear technical focus, but is not covered by energy strategy documents as an energy carrier. However, the region has vast renewable energy potentials (biomass, hydropower, wind, solar), which

[35] Today only <1% of the total final energy end-use is contributed from renewable energies.

could be developed to supply CO_2-free energy to domestic and export markets, i.e. to Western Europe. The existing gas infrastructure is in principle well prepared to be used for, or adapted to, such concepts.

On the other side, a closer partnership between Europe and Russia could help to raise awareness of the urgency of Europe in seeking to reduce their GHG emission levels, and of Europe's reliance on importing energy with lowest CO_2 burdens. Vast biomass as well as wind energy potentials in Russia could be tapped to provide electricity, biomethane or synthetic methane generated from fluctuating renewables by means of Power-to-Gas plants, and transported through a well-established gas grid. Finally, a joint roadmap development between the European Commission and Russia in 2013 included a gas related action item on "further development of research and technology cooperation notably in the areas of production, transportation and utilization efficiency, CCS, unconventional and biogas etc." [EC 2013].

A first impression on Russia's active contribution to a CO_2-free gas provision to Europe was presented during an expert workshop in Berlin on 31 August 2018[36]. Here, Russian jointly with European experts met to discuss the state-of-the-art and perspectives of methane cracking, a technology which could provide CO_2-free hydrogen at large scale, made from Russian natural gas [Abánades 2013], [Romanov 2018]). Even though not being a sustainable option as natural gas reserves are limited this pathway could be used as a potential and cost efficient transition pathway for introducing renewable based hydrogen in the longer term. Rules for certifying that the carbon by-product from methane cracking is deposited without being released to the atmosphere as CO_2 would yet have to be developed.

2.4.3 *Japan*

Japan's energy policy is characterised by (a) the challenges of its strong industrial focus with high specific energy demand, (b) a limited domestic potential for renewable energies and (c) an infrastructure challenge (complex geography and earthquake risks). Therefore, Japan aims at securing renewable and CO_2-free energy imports in the long-term. With the nuclear electricity focused strategy having suffered from the Fukushima disaster in 2011, Japan has been experiencing an electricity supply challenge, which required to fundamentally reconsider the former energy supply strategy. After the Fukushima disaster, the Japanese government has developed a new 2014 Strategic Energy Plan, based on the following two principles: The first is the so called "3E + S" energy policy, emphasizing energy security (1E) while striving for greater economic efficiency (2E) and harmony with the environment (3E), with safety (S) as a basic premise. The second principle is 'building a diversified, flexible, 'multilayered' supply-and-demand structure.' The Strategic Energy Plan acknowledges the importance of renewable energy as a 'low-carbon domestic source of energy' [Hiranuma 2014].

Natural gas is one of the most important fuels in Japan's primary energy supply, accounting for 23% of Japan's total energy consumption in 2015, after oil (42%) and coal (27%). Japan relies on liquid natural gas (LNG) imports for virtually all of its natural gas supply and is also the world's largest LNG importer, accounting for 35% of the global market [BP 2016].

Japan has a long-standing hydrogen energy development. It has been among earliest developers of a full-fledged hydrogen economy as part of the WE-NET (= World Energy Network) programme in the early 1990s (three phases 1993-2020) [ENAA 2003]. In addition, Japanese automotive industry has been

[36] Technical Workshop "Carbon-free hydrogen production from natural gas, facilitated by Zukunft Erdgas e.V., Berlin, August 31, 2018.

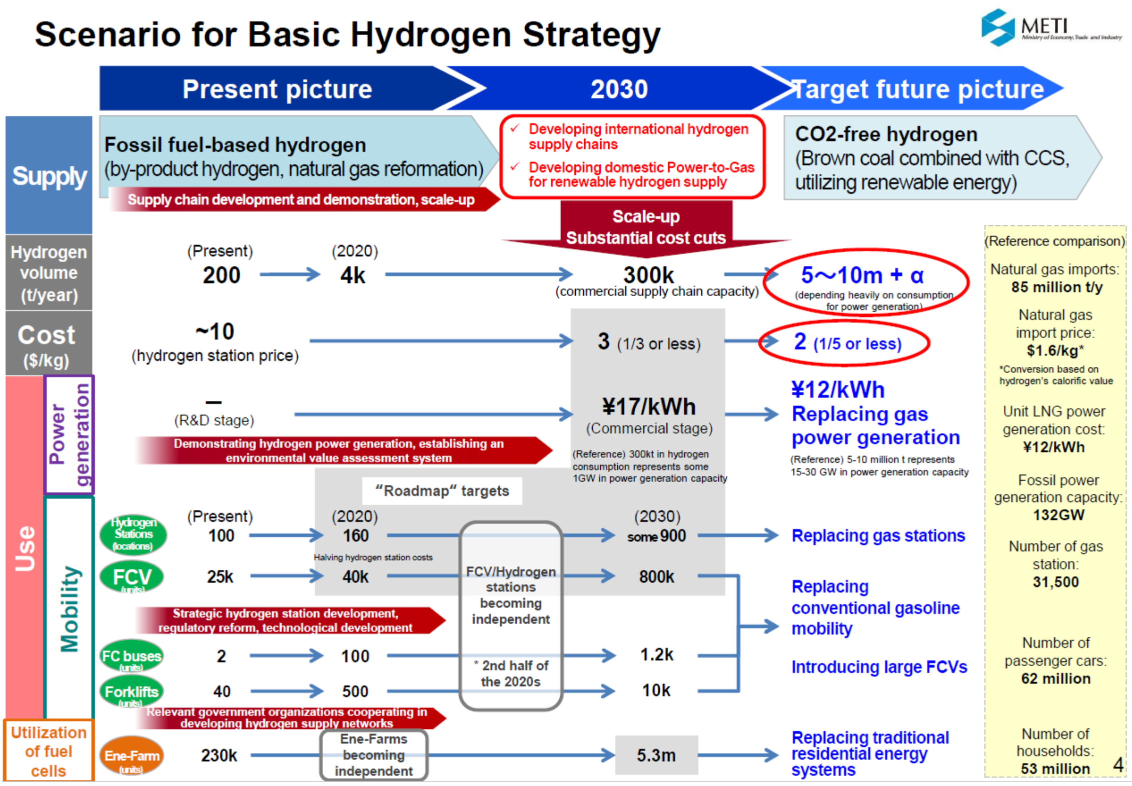
developing fuel cell electric cars since the mid-1990s [Netinform 2018]. As early as 2000, a pipeline system for natural gas was proposed by [APRC 2000], which was then also earmarked to be capable of collecting and distributing hydrogen from wind power in Siberia.

In March 2016, the Japanese Ministry of Economy, Trade and Environment (METI) set a target of 40,000 hydrogen fuel-cell vehicles on Japan's roads by 2020 together with 160 hydrogen refuelling stations, and is currently pushing to turn Japan into a 'hydrogen society' with plans for growth to 800,000 vehicles by 2030 (see Figure 2-13). In addition, hydrogen is expected to become a fuel for centralized zero carbon power generation in a future Japanese electricity market as well as for residential combined heat and decentralised (= emergency safe) power production [METI 2017] and [METI 2015]. The major targets of this strategy referred to as "Basic Hydrogen Strategy" to be achieved by developing a hydrogen economy in Japan are to:

- develop an energy supply vision for a carbon-free society for Japan by 2050 and an action plan for 2030;
- set a goal for reducing hydrogen costs to those of conventional energy (e.g. gasoline and LNG);
- provide an integrated policy from hydrogen production to utilization across ministries; and
- present hydrogen to the rest of the world as a new energy choice based on Japan's ambition to lead global efforts for establishing a carbon-free society, building on Japanese strengths and strengthening Japan's industry.

This strategy is also tied to a $100 million commitment to power the car fleet for the 2020 Tokyo Olympics with hydrogen. Also in the long-term energy outlook beyond 2030, METI foresees hydrogen to play an even more central role.

Figure 2-13: Japanese Hydrogen Energy Strategy (inofficial translation), December 26, 2017 [METI 2017]



In order to provide hydrogen to Japan, a group of companies led by Kawasaki Heavy Industries (KHI) is planning for an import route based on lignite from the region of Victoria in Australia. Already by the winter Olympics in Tokyo in 2020, the first LH_2 tanker ships with a capacity of 2.500 m^3 are scheduled to import the first large hydrogen quantities from Australia. However, there is a high risk involved in the way the LH_2 import project is set up for the time being as it will only become carbon neutral with the CO_2 from coal gasification being taken care of by CCS. Other potential renewable hydrogen imports to Japan include activities with Norway and Argentina for the medium- to long-term. Moreover, parallel strategies are earmarking other large-scale energy import vectors for renewable energy carrying hydrogen to Japan; both ammonia and methylcyclohexane are being studied in detail. Japan is also studying hydrogen infrastructures within Japan to tap Japan's own renewable energy resources such as wind energy on the Northern Island of Hokkaido. One ongoing consideration is a pipeline to be built across Hokkaido from the wind-energy rich North to possible user centres (e.g. Sapporo) in the South.

Japan is undergoing a dramatic re-structuring of its energy markets. With electricity shortages and a high dependency on fossil energy imports today, it has identified hydrogen as a new import fuel with a long-term sustainable perspective. It is foreseen to import fossil-based hydrogen in the short to mid-term, and renewable hydrogen at a growing pace until 2050 from various world regions (Australia, South America, North America and Northern Europe). Japan has deployed a national strategy for a hydrogen economy, currently developing the core technologies for its infrastructure and for hydrogen use. Even though the motivation to use hydrogen at large scale is different from European motivations (energy imports to Japan versus gas-based power plants to balance fluctuating renewable electricity in Europe), similar concepts and technologies will be employed and can help to drive costs down globally. Even though Japan lacks an internal gas transport or distribution infrastructure, this strategy is bringing forward the same type of end-user technologies as those which have been proposed by some European Member States: stationary residential fuel cells for combined heat and power production as well as fuel cells for various applications in transport and industrial electricity production at large scale. Concerning distribution infrastructure, developing individual but locally delimited pipelines is now being scrutinised. The final goal is to develop a hydrogen society.

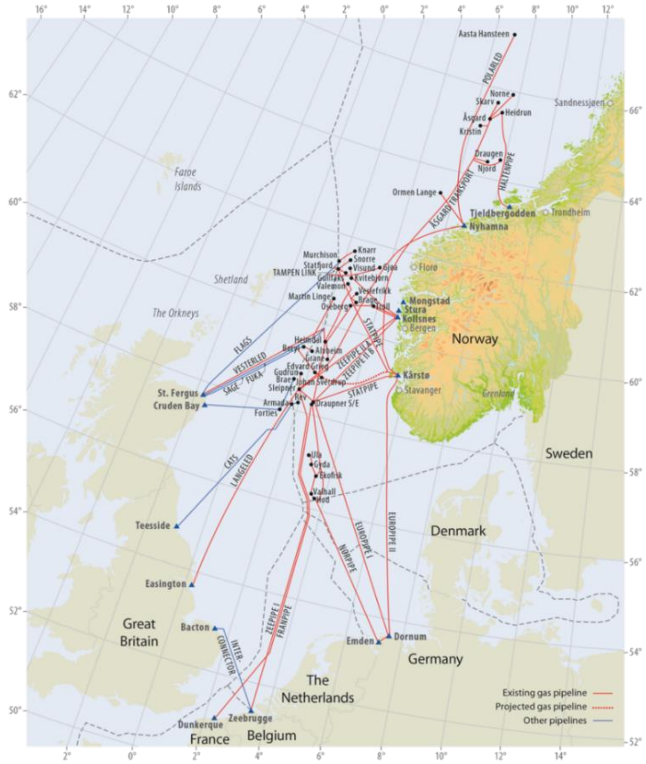
Japan in some cases already is (stationary fuel cells for combined heat and power production) and in other cases could be an ideal partner for Europe to cooperate on the development and commercialization of hydrogen energy technologies. To date, it seems however that it has spurred the industrial activities in Europe (e.g. fuel cell electric vehicle development) and could even be seen as a major world level competitor.

2.4.4 Norway

Since the early 1970s, Norway's economic strength has been increasingly based on the exploitation of its resources of fossil energies, which has helped Norway to develop from a country of fishermen and farmers to the status of a globally leading fossil energy exporter. In 2013, Norway was the world's third-largest natural gas exporter, after Russia and Qatar, having provided 21% of the total European natural gas needs [EIA 2014a] climbing to an all-time high of 25% in 2015 [Elliot 2016]. The value of gas exports in 2017 represented about 22% of exports. Most of the gas was transported via the pipeline system under the North Sea (see

Figure 2-14) while about 50% of the LNG production from Melkøya in Finnmark were exported via LNG tankers [Norskpetroleum 2017]. The largest recipients of Norway's natural gas exports in 2013 were the UK, Germany, France, the Netherlands, and Belgium. However, doubts have increased in recent years whether Norway will or can continue to remain a major natural gas provider for Europe due to the rising operating costs of existing gas production and difficulties to access new gas reserves in more remote regions, e.g. in the Arctic [Elliot 2016].

Figure 2-14: Norway's extended North Sea gas pipeline system



Although the use of natural gas has been intensively debated over the years, Norway is using only small amounts of its gas production domestically (central CHP, e.g. refinery Mongstad and decentral plants based on waste and biomethane). About 96% of all gas is exported. There is only one national stretch of natural gas pipelines in the southwest of Norway around Haugesund. In fact, the Norwegian energy system is dominated by electricity based on vast amounts of hydro power capacity. This has had a strong impact on the use of electricity in all end use sectors[37] and has given rise to an electricity dominated industry. Moreover, hydroelectric power could be exported to the EU in larger quantities if new grid connections were established. Using these electricity connectors to e.g. Denmark and Germany, Norway can replace some of its income losses from fossil fuels in providing new flexibility for other European energy markets by offering its vast hydropower potentials for load balancing.

For its own energy demand Norway has set ambitious targets to mitigate GHG emissions by 2030 and 2050. In particular, Norway's domestic energy market is characterized by a massive roll-out of e-mobility for passenger cars being a blueprint for all of Europe in developing the necessary charging infrastructure. Also, a hydrogen refuelling infrastructure is now being developed for fuel cell electric cars. In fact, Norway has been among the first countries to assess the potential of hydrogen as a means specifically for the transport sector to substitute fossil fuels by electricity [Bünger, U. et al. 1992], [Stiller, C. et al. 2008]. In combination with a strong maritime sector, Norwegian industry and politics have announced the commercialization of hydrogen fuelled fuel cell propulsion systems as a sustainable future technology for shipping. In addition, Norway has developed a number of electricity related technologies which make its industry stand out internationally. Among these technologies are water

[37] At a specific electricity consumption of ca. 23,000 kWh per capita, Norway is the world's second electricity intensive country, only dwarfed by Iceland at 54,000 kWh per capita (Electric power consumption (kWh per capita), based on [World Bank 2014]).

electrolysis to produce hydrogen and the production of aluminium and magnesium from cheap hydropower.

In combining its natural gas resources and the interest in the increased use of sustainable electricity via hydrogen, Norway has started a cooperation with the Netherlands to assess the use of carbon capture and storage concepts to provide clean hydrogen from natural gas, transport it to the Netherlands via pipelines to be used in combined-cycle power plants. Although rejected by other countries as having limited potential and connected with the threat of CO_2 escaping at a later point in time, Carbon Capture and Storage (CCS) has been identified by Norway very early for GHG mitigation[38]. Norway has also offered the UK support in putting their Leeds City Gate project into operation [IEA 2017b].

In general, Norway is caught in a situation of competing challenges. With its ambitious sustainability targets, the country is now confronted with a situation of how to best use the high incomes from the oil and gas industry in the last 40 years to bridge the gap of becoming not only a fossil energy independent energy nation, but furthermore to take profit from exporting a share of its yet untapped renewable energy resources. Norway's options are to either decarbonise its ample natural gas potential by the use of CCS (which is limited by the decreasing availability of natural gas and the limited CO_2 storage potential) or to use its electricity storage potentials (pumped hydro plants) in the south to offer flexibility of renewable electricity supply to its European neighbours[39]. A third option will be to tap into its vast on- and offshore wind energy potentials in the remote and widely unpopulated north by the use of hydrogen transport by e.g. tanker ships. As this is however limited to the application of liquid hydrogen (LH_2) which cannot be blended with methane gas a fully new supply chain comprising, electrolysis, liquefaction, sending terminal, tanker and receiving terminal would have to be established which could however synergetically be needed to supply the maritime sector. The latter options would be Norway's chance to continue its status as influential exporter of energy and connected services, building on its natural resources and competence as renewable electricity dominated nation. In that respect, Norway will remain to be a reliable partner to exchange energy to the benefit of reducing electricity fluctuations from renewable energies or export renewable energy via electricity or hydrogen from natural gas with CCS, wind or hydro power.

2.4.5 China

Starting in about 2009, China's natural gas consumption, production and imports have grown at a two-digit annual percentage level to reach 8% of China's energy mix in 2015, having become the 3rd largest natural gas consumer in the world. Natural gas is mostly used for heating and cooking in private homes as well as for the generation of electricity in power plants. Natural gas accounts for only 4% of the Chinese power generation capacity. Even though the Chinese demand growth is expected to be rather dramatic over the next two decades outpacing the U.S. as the biggest natural gas consumer sometimes between 2040 and 2050, the natural gas capacity in power generation is only expected to contribute 7% to the generation mix by 2040.

China's domestic natural gas resources are limited and do not match its consumption, which is why the country imports about a third of its natural gas from e.g. Central Asia, Australia, Indonesia, Malaysia and Qatar. Gas is being imported either by pipeline (e.g. from Myanmar) or as LNG (e.g. from the

[38] A major reason for Norway applying CCS technologies at larger scale is the win-win situation by increasing the productivity of its oil wells when injecting the CO_2 in the subsea operations.
[39] By means of high voltage direct current transmission cables, now already being built.

Middle East and Africa). Currently, Chinese natural gas is by a factor of four more expensive than American natural gas which is a consequence of the shale gas boom in the U.S. on one side, and the uncertainties of the Chinese gas market development which have fostered the use of expensive LNG on the other side. Since 2012 the country has also started to successfully look into shale gas exploration expecting shale gas to reduce natural gas prices and improve its energy security. However, China is also facing several challenges in developing efficient shale gas extraction, e.g. the geology being more complex than e.g. in the U.S., a lack of sufficient water resources and missing expertise in exploration.

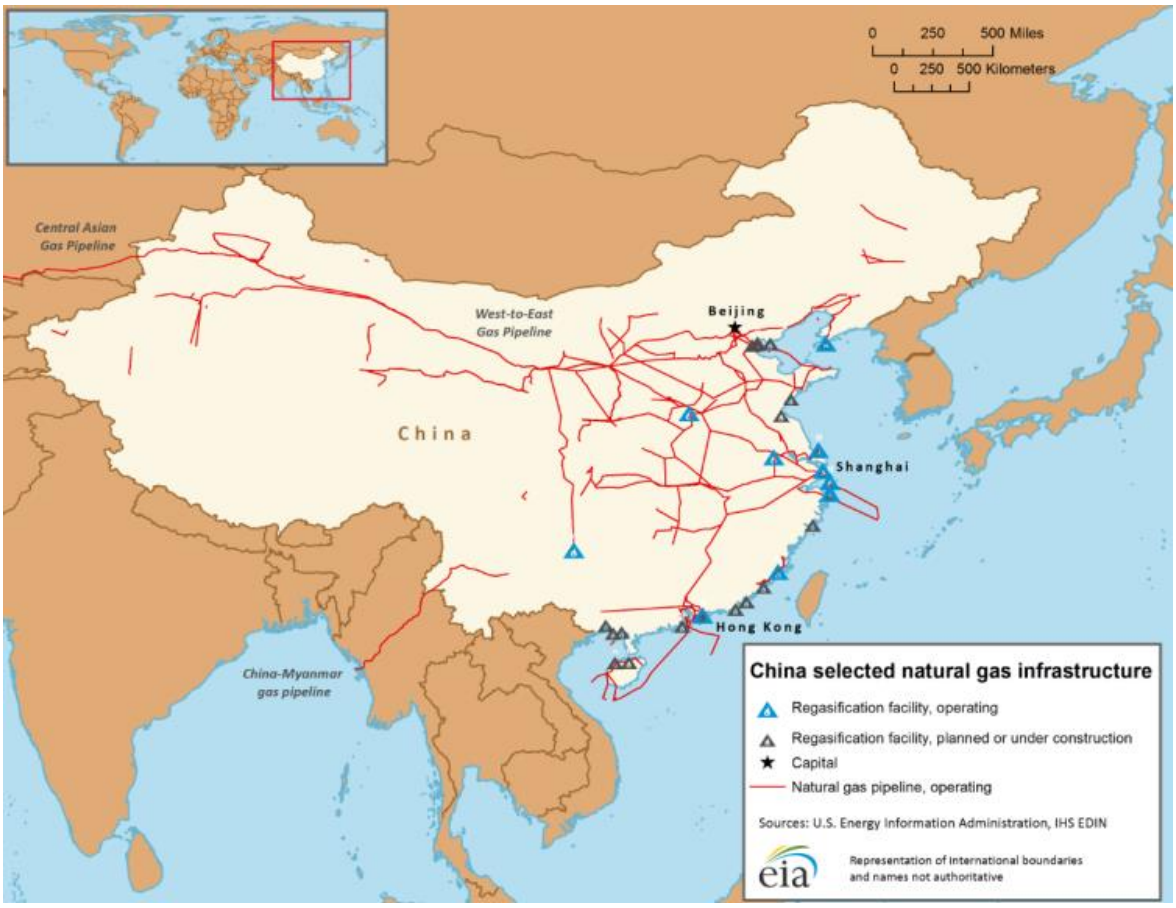
The recent debate in China's shifting energy supply plans has specifically addressed the challenges of heavy inner-city pollution. In order to mitigate damage to human health, China has defined an Action Plan for the Prevention and Control of Air Pollution and a series of ambitious goals for the electricity, industrial and transport sectors. As part of an economic reform, being a central element of the last 5-year plan in November 2016 the Chinese government has also set new targets in the energy sector. Market-based pricing schemes, energy efficiency, pollution-control measures and competition among energy firms shall be introduced. In addition, greater investments in more technically challenging upstream hydrocarbon areas and renewable energy projects shall be made. Chinese government has furthermore set a target to increase non-fossil energy consumption to 15% of the energy mix by 2020 and to 20% by 2030 in order to reduce China's dependency on coal. As part of that strategy, China foresees the use of natural gas as a cleaner burning fuel, i.e. up to 10% of its energy consumption by 2020 [EIA 2018] and 15% by 2030 [Paraskova, T. 2017].

As another consequence of the megacity pollution challenge, electric mobility is now being pushed at an unprecedented speed, enforced by strict governmental regulations [Yan 2017] and supported by city-specific strategy plans (for the example of Shanghai: [FCW 2017]. More than 300,000 battery busses are on Chinese roads and in parallel a strong fuel cell bus development has been kick-started – often with international experts involved.

Even though the dominance of fossil energies is overwhelming today, rapid progress has been made in the development of renewable energies. In this context, curtailment of renewable generation is a huge challenge in China as renewable energy is not yet well integrated into the energy system. This is a strong sign, that China will arrive at a point where either the electricity grid has to become a "copper plate" or sufficient small and large scale storage capacity will have to be added to the system, which e.g. can contributed to a gas based system. In this respect it is important to know that China is now developing its gas grid (see

Figure 2-15). In order to substitute coal, the country will further invest in natural gas pipeline infrastructure to link production areas in the Western and Northern regions of the country with demand centres along the coast as well as to accommodate greater imports from Central Asia and Southeast Asia. Moreover, China and Russia have agreed on natural gas supply from Eastern Russia by pipeline. Even though it is being laid out for natural gas now it can later be adapted to transport, distribute and store (linepack) green gases such as synthetic methane or hydrogen and hence support the electricity system, much like it is being discussed in Europe now.

Figure 2-15: Selected natural gas infrastructure in China [EIA 2014b].



Little evidence can be found in literature on strategies to harvest biomass for producing biomethane for injection into the gas grid. In the past, biomethane has been used widely (7 million biomethane plants were constructed nationwide between 1973 and 1978), mostly at local level [Gregory 2010]. Due to societal changes, many of these plants were rapidly decommissioned thereafter. Currently, the number of small single household biogas digesters is on the rise. Also, and only recently new initiatives, among others from Germany [Mingyu, Q. 2017] have been kicked off to develop a new surge for biogas, potentially creating new but short-term markets for European industry. The biogas potential has been estimated to be about 150 bcm/a.

In general, China's development as a nation is unprecedented in its gradient of growth, both in economic and in energetic terms. In late 2015, China suffered from a shortage of gas infrastructure, which had not grown sufficiently with gas demand. From a European perspective, China could become the blueprint for a fast development into a fully decarbonised energy system dominated by renewable energies including all necessary ingredients to handle their fluctuating character. At a sufficiently large share of renewable energy in the grid, rapid commercialization of new technologies in the gas sector, including Power-to-Gas at large scale, may be necessary also in China. China is world leader in photovoltaics and battery technology, including battery mass production, the key technology of future battery based e-mobility. In addition, China has also started an offensive fuel cell development strategy for mobility applications, is catching up on fuel cell component and system level development [Lehner, F. 2017], and is already building plants to commercially mass manufacture fuel cell technology and complete vehicles and for stationary CHP use. In addition to serve as a sound cooperation partner, China may become Europe's toughest competitor with a view to new sustainable gas technologies from production to end-use.

2.4.6 *Middle East and North Africa (MENA)*

The MENA region controls about 57% of the world's proven oil reserves and 41% of proven natural gas reserves, which are, however, unevenly distributed across this region. At the same time, MENA is one of world's regions with the highest average annual solar irradiation and lends itself to further develop this potential at very large scale [WB 2010]. Specifically in the oil and gas producing countries of the Middle East, i.e. Saudi Arabia and the United Arab Emirates (UAE), plans are under development to reduce their reliance on fossil energy and to develop competencies in the fields of energy savings and use of renewable energies. Also the North African countries have developed strategies to develop their renewable energy potentials.

Three factors make the MENA region vulnerable to the consequences of climate change:

- water scarcity (in a hot and dry climate);
- concentration of economic activities in coastal areas (susceptible to flooding); and
- reliance on climate-sensitive agriculture.

MENA representing a wide group of countries, also its energy technology preferences vary widely. With a focus on renewable energy feedstock, wind, solar as well as hydro or biomass energy e.g. in Morocco based energy has all been targeted at regionally varying energy mixes.

An important activity to advance cooperation between Europe and the MENA region on energy matters was the establishment of project Desertec Industrial Initiative (Dii). It was launched in July 2009 by 12 companies that agreed to establish financing plans to develop solar projects in the Sahara desert. Designed as a B€400-project, Dii had planned to provide as much as 15% of Europe's renewable electricity needs with solar power imported via high-voltage direct current transmission cables by 2050. However, in November 2012 Bosch and Siemens announced to leave the project, which put Dii's electricity import activities on hold. For the time being, the North African countries as initial focus of Dii's activities have decided to concentrate their activities on the use of renewable energies to cover their domestic electricity demand, which is rather low but growing rapidly.

The decision to leave the Dii has been mostly based on the electricity industry's opinion without involving other infrastructure industries. Eurelectric's view then was that (a) Europe is lacking the required transmission capacities (e.g. in and through Spain as well as across the Pyrenees) and (b) can furthermore cover its own renewable electricity needs domestically. However, this statement had been made when sectoral integration and the growing pressure on renewable electricity to also supply virtually all energy end-use in one way or the other had not been on the electricity industry's agenda. Only recently, the issue of cheap hydrogen production in MENA has been revitalised by [NCI 2017]. It is claimed that based on 100 MW_{el} scale PEM water electrolysis plants, green hydrogen could be produced at costs of 2 €/kg[40] at large scale, 50% down from earlier assessments (see Figure 2-16).

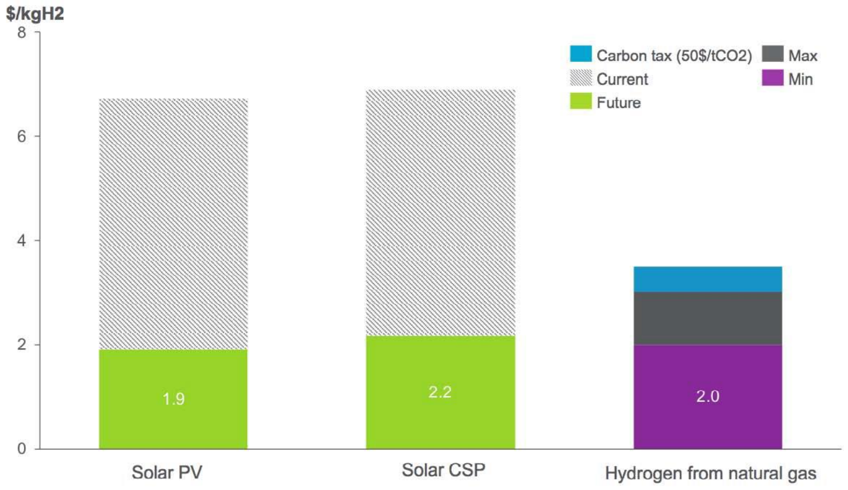
As an alternative hydrogen production pathway, being specifically well-suited for the application in solar-rich North Africa and bearing an export of hydrogen to Europe in mind, the concept of

[40] Which is about the same price as for hydrogen produced by a new conventional large scale steam methane reforming plant today.

thermochemical water splitting has been developed in the EC-funded study Green Hydrogen Pathways. In Europe, the technology is being developed by the Paul Scherrer Institute/CH, Deutsches Zentrum für Luft und Raumfahrt (DLR)/DE, CNRS/FR and CIEMAT/ES [LBST; Hinicio 2015]. The technology's maturity has been assessed as TRL 5, which could possibly reach TRL 7-9 by 2030 based on financial, public support.

Biomethane is being understood as a potential energy source that is easy to be produced decentrally and stored onsite. Yet, it would require (a) an extensive pipeline infrastructure if the catchment area was large and dispersed as well as (b) national development plans. The literature survey has not revealed any relevant hints that strategies to resolve any of these issues are being prepared.

Figure 2-16: Green hydrogen cost comparison with steam methane reforming (€/kg_{H2})



As an example of several other relevant activities, a Supreme Council of Energy was installed by the UAE government as early as 2009 to develop an integrated energy strategy until 2030, and an action plan. With this ambition, the Council has expressed its intention to improve the energy system's sustainability profile by the rational use of energy and water, promotion of air quality, encouragement of the conversion of waste to energy, clean and renewable energy, water security, sustainable transport and rationalisation of fuel use [Reuters 2014]. In a sequence of solar energy projects like the Mohammed bin Rashid Al Maktoum Solar Park, the scale has been ramped up from 13 MW in 2013 to 100 MW in 2017, with the ambition to attract international investors. Likewise, the World Bank has been funding a number of projects on energy market structures and renewable energies across the MENA region, such as in Egypt, Iraq, Jordan, Lebanon, Morocco, Syria, Tunisia, West Bank and Gaza, and Yemen [WB 2010].

A final aspect concerns the MENA regions which are currently focusing on the transport of energy in the form of electricity, for large scale transport using direct current transmission. In future energy systems with a shrinking quantity of fossil fuels for power production and hence decreased flexibility, other forms of large scale energy transport will be required which allow to storing electricity also in large quantities and for periods of weeks. Then, the use of gas, methane or hydrogen, could become a vital option, which however needs to be prepared for already today [E3G 2017]. We suggest that at EU level discussions on the use of gas next to electricity are stimulated with the MENA countries, e.g. through the energy cooperation in the various regions of the European Neighbourhood Policy.

Concluding on the potential renewable energy export potentials from the MENA region, further analysis will be need to better understand which share of the total regional renewable energy/electricity potential will realistically become available for export, given that other renewable electricity intensive applications such as desalination of sea water for freshwater production need to be taken into consideration.

2.4.7 Conclusions

In brief, the specific implications from the assessment of non-EU storylines for Europe have been summarized in Table 7.

Table 7: Potential implications from an assessment of non-EU storylines for the future European gas infrastructure

Country or region	Reasoning
Russia/Ukraine/Belarus (Eastern countries)	Strong focus on fossil methane gas will endure. Potential to export biomethane, synthetic methane (PtCH_4) or hydrogen (PtH_2) from renewable electricity by using (partially under-utilised) existing gas transport infrastructure.
Japan (JP)	Largely dependent on fossil energy imports; forced to move away from LNG, coal and oil imports for climate protection; major interest in FCs & H_2, LH_2 imports as innovative energy import vector; 2050 strategy to convert to 100% green H_2. Potentially sound cooperation partner for technology development or strong competitor.
Norway (NO)	Large export potential for synthetic methane (by existing pipelines or as LNG) and hydrogen (by converted or new pipelines or as liquid hydrogen) from remote areas based on on- and offshore stranded wind energy (due to limited connection to the electric grid). Sound collaboration on hydrogen and fuel cell technologies, e.g. in the power maritime sector.
China (CN)	As major potential competitor on (renewable) gas exports from Eastern Europe, possibly steep technical learning in gas technologies and applications (e.g. FCs for transport at large scale) and sheer future market size. Possible cooperation partner on advanced gas technologies are strong competitor.
Middle East and North Africa (MENA)	Potential for medium-distance import and diversification of renewable gas imports with very large renewable power generation potential: synthetic methane and hydrogen as pragmatic approach (PV, wind, solar thermal) and with perspective of socio-economically positive impacts for the region.

For the above mentioned export possibilities in some cases the methane leakage issue needs to be fully assessed and addressed as well as the potential under consideration of the regions' own energy or electricity needs.

3 Development of well-reasoned qualitative 2050-storylines

3.1 Introduction

Chapter 3 comprises the creative part of the storyline exercise. Based on the extensive findings and interpretations of the existing storylines, chapter 3.2 groups EU's 28 member states into five distinctive regions, chapter 3.33.3 describes three generic storylines developed for the purpose of this project and reflecting possible bandwidth of future developments of the gas infrastructure and chapter 3.4 outlines the interface of the gas demand data and other qualitative information to future modelling exercises by the PRIMES and METIS models.

According to the definition of the term 'storyline' mutually agreed with the European Commission a storyline is a qualitative description of a possible evolution of the energy landscape in contrast to a "scenario", which would be of quantitative nature and would have to be modelled.

3.2 Definition of European gas regions

The gas sector shows major structural differences in the individual EU Member States: Some are producers, some are strong consumers, some are minor consumers, some are gas transit countries, some are heavily dependent on imports from Russia, others have rather diversified import sources, etc. Therefore, the assessments in this chapter build on a grouping of Member States with similar gas structures into five European regions. Consequently, a well-underpinned European regions' definition is paramount for a comprehensive assessment of the future role of gas in the European energy system.

This chapter starts with providing the definition of five European regions for further analysis. The differentiation between the regions is based on (1) regional proximity covering North, West, South, East (2) common interests related to security of supply policies and gas import diversification and (3) expected or announced pathways to reaching the GHG emission reduction targets of the EU.

As depicted in Figure 3-1 the following five European regions have been defined:

- **Northwest (BE, DE, DK, FR, IE, IT, LU, NL, SE, UK):** The countries in this region are developing a variety of technical or structural approaches for replacing (fossil) natural gas by synthetic methane or hydrogen, through concepts such as $PtCH_4$ or PtH_2, and technologies such as electrolysis and methanation. Also, diversifying the use of fossil methane by admixing biomethane to the gas grid has become common practice in most Member States. They are partially characterised by gas transport via pipelines from the Netherlands, Russia and Norway as well as LNG import infrastructure. Through the Trans-Mediterranean Pipeline from Algeria via Tunisia to Italy, the Northwest also has potential access to renewable gas imports from the MENA countries. The Northwest is seen as the region with the highest level of conceptual and technological innovation in the gas sector in Europe with regard to GHG emission reductions. This region might export its know-how to less advanced regions. Security of supply and gas import diversification are less prominent in the strategic considerations related to the future role of gas. The region consists of 10 Member States, namely Belgium, Germany, Denmark, France, Ireland, Italy, Luxembourg, the Netherlands, Sweden and the United Kingdom;

- **Southwest (ES, PT):** Decarbonisation of gas is one of the major objectives for the energy system in this region. With a view to a green gas future, both countries benefit from their proximity to the MENA countries. Both the Maghreb-Europe Gas Pipeline from Algeria via Morocco to Spain and LNG import infrastructure (eight existing import terminals) play an important role for the gas sector. Also both Member States are rather detached from the rest of the European gas system today with only very limited connection to the French gas grid. The region includes Spain and Portugal;

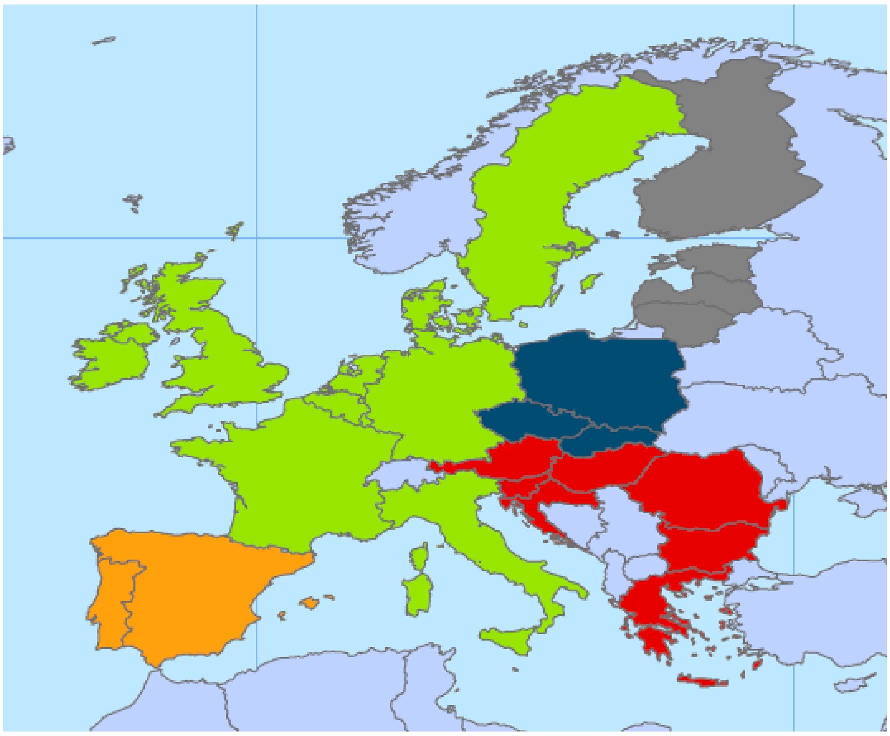
- **Southeast (AT, BG, GR, HR, HU, RO, SL):** Growing gas import independence from Russian sources is a strong common interest unifying the south-Eastern Member States, such that most are seeking to diversify gas sources by either developing LNG import capabilities or new gas pipeline projects including import infrastructure to ensure access to new gas supply sources (TAP pipeline) as well as bi-directional pipelines between EU Member States. These countries are affected by the abandoned South Stream pipeline project – where the Southern Gas corridor might now be developed as alternative - and possibly to be supplied by green gases from the MENA area by imports through the Algeria-Italy pipeline. This region includes Austria, Bulgaria, Greece, Croatia, Hungary, Romania and Slovenia;

- **East (CZ, PL, SK):** This region is an important gas transit region with the objective of keeping the specific energy transport costs as low as possible as a basis for maximum national value creation. Reverse flow infrastructure is a separate relevant issue in the context of security of supply as well as the concern about gas import dependence from Russia. The recently opened LNG regasification terminal in Poland and reverse flow capabilities of pipelines have already improved the security of supply situation in the East. The contribution of CO_2-lean or CO_2–free gas could be through imports of green gas from Eastern countries outside the EU using existing gas transport infrastructure (which is now partly under-utilised), although the GHG emission reduction targets in the gas sector do not have the highest priority on the political agendas. The region includes Czech Republic, Poland and Slovakia. As for the Northeast the East can profit from the exploitation of the Baltic off-shore wind and, possibly aquatic biomass, potential;

- **Northeast (EE, FI, LT, LV):** The strong import dependence from Russia is a major issue for the countries in this region which has already somewhat alleviated by the LNG import terminal in Lithuania. In this context, security of gas supply is one of the major objectives of strategies for the future of the gas sector. However, this region could become a producer of green gas (biomethane, synthetic methane, hydrogen). The region is very similar to the region East and it includes Estonia, Finland, Latvia and Lithuania. As for the East the Northeast can profit from the exploitation of the Baltic off-shore wind and, possibly aquatic biomass, potential.

In this context, Malta (MT) and Cyprus (CY) are not included in the abovementioned regions because of their very specific situations as small islands. At this point it is also important to mention that the grouping is suffering from criteria overlapping the regions.

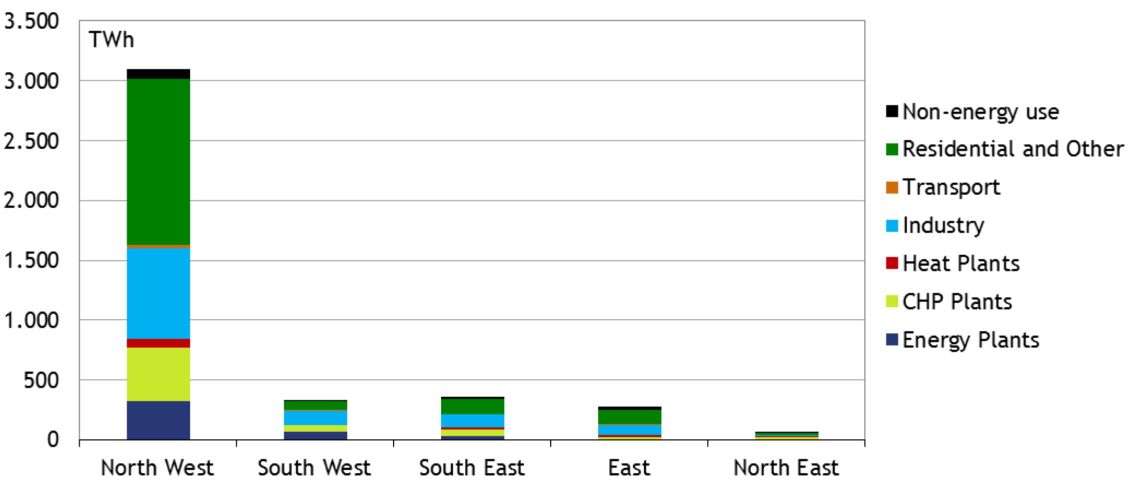
Figure 3-1: Representation of the five European regions for further analysis



Green: Northwest; Orange: Southwest; Red: Southeast; Blue: East; Grey: Northeast.

An analysis of the total gas demand of these regions shows a strong imbalance towards the North Western and Central regions which in 2015 have consumed a factor of 3 more than all other regions taken together. The outstandingly largest gas consumers in Europe have been Germany (24.5 % in total EU gas demand), the UK (23.0 %), Italy (20.8 %), France (13.1 %) and the Netherlands (10.9 %). Both Western and Eastern regions are concerned for the future of their gas infrastructures, Western Europe as it is now relying on its gas transport and distribution infrastructure for domestic applications and Eastern Europe as its gas infrastructure needs to be depreciated based on the gas transit business.

Figure 3-2: Total gas demand of EU28 regions in 2015(energy and non-energy) as defined in chapter 3.2



3.3 Description of three qualitative European storylines

In this chapter, three qualitative storylines on the possible future role of gas in Europe until 2050 are developed and discussed. In each of the storylines, one energy carrier takes a central role in the energy system which is used in the heating, transport and industry sectors to a large extent. Other energy carriers are also used, but to a lesser extent. The three energy carriers are electricity, methane and hydrogen related to the storylines "Strong electrification", "Strong development of methane" and "Strong development of hydrogen" as presented in Figure 2-1, respectively. The clear focus of the work will be on aspects that are relevant for the gas sector. For each storyline, a quantitative structure of future gas demand in each sector is proposed over a timeframe up to 2050. These values should be considered as ballpark figures. They are based on selected literature values and own assumptions. Precise quantification of the gas demand would require energy system modelling.

In this study, issues such as energy conversion efficiencies, European renewable potentials, energy import dependencies etc. are not in the scope. However, those topics are also of great importance and should of course be considered in future scenario based modelling approaches. In addition, the analysis was focused on the four main sectors: industry, transport, heating and power. Energy industries' own consumption, losses, gas works and other transformation[41] were not considered. Therefore, the total gas demand mentioned in figure 3-2 is about 5% below the actual overall European gas demand.

3.3.1 General remarks, methodology and assumptions

The development of the three storylines is based on insights gathered in the literature study documented in the previous chapters. However, the available literature does not cover all EU-28 Member States in all relevant aspects. In fact, detailed studies for a 95% GHG reduction are only available for some EU Member States, notably in the Northwest region. As a consequence, assumptions for the development of the three storylines are general and applied to Europe.

To be able to derive a semi-quantitative estimation on the possible development of gas demand in Europe, a simple and straight-forward approach is used. For each storyline, the gas demand per country/region is estimated based on a few central assumptions. Those assumptions are based on learnings from the literature review or are taken directly from literature. Gas demand is estimated for 2030 and 2050 for the power, the heating, the transport and the industry sector. Values for 2020 and 2040 are linearly interpolated also using today's gas demand in each sector.

In the power sector, 2030 gas demand is estimated based on figures from the latest ENTOS-G's ten year network development plan. For 2050, a factor is used to calculate gas demand for electricity production based on the electricity demand today. This factor is derived from literature. The gas demand in the transport sector is estimated based on an assumption regarding the share of gas powered vehicles (trucks and passenger cars) in combination with a slightly increasing transport demand. In all storylines, directly electric driven vehicles (e.g. BEV, overhead wires) take a relevant share of the transport sector. In the heating sector, a significant reduction of total heat demand is assumed for all countries/regions. In addition, for each storyline the share of heat from gas and the type of gas is assumed. For this, today's share of gas (per country) in the heating sector is the basis. In the industry sector, a reduction of gas demand based on literature values is the fundamental assumption to estimate future gas demand.

41 Gas consumption sectors definition according to IEA statistics

Central assumptions and prerequisites valid for all three storylines are listed in the following bullet points:

- All three storylines successfully achieve a 95% GHG emission reduction by 2050 compared to 1990 levels;
- Emissions from certain industrial processes and from agriculture can be considered “unavoidable”. These emissions are assumed to account for the great majority of the remaining 5% of 1990s GHG emissions. As a consequence, all energy related GHG emissions need to be fully avoided to achieve a 95% emission reduction. This means that by 2050, virtually no fossil energy carriers will be consumed (without CCS) in the energy sector;
- The 95% GHG emission reduction target is assumed to be agreed as of today, i.e. there will be no change in the target ambition over the timeframe until 2050. This is important to avoid any undesirable developments or lock-in effects (e.g. a late introduction of near zero emission technologies) an 80% reduction target might allow or require, and to enable a high level of planning security for all stakeholders;
- A wide societal acceptance of the 2050 emission reduction target in all Member States is assumed. People show high commitment and acceptance towards required measures to achieve this target. As a consequence, infrastructure expansions and adaptions can effectively be pursued; new technologies (e.g. new heating systems, new transport technologies) can successfully be introduced. New technologies such as e.g. hybrid end-user appliances find acceptance and support a cost-efficient transition to a fully decarbonised light transport and domestic heating sector by reducing stress on the electricity grid in times of peak consumption;
- An increasing integration of the energy systems and markets towards a fully integrated, well-functioning EU internal energy market for electricity and gases by 2050 is assumed;
- The international ambitions regarding emission reductions are assumed to be consistent with the ambitions in Europe in accordance with the Paris Agreement. This is a prerequisite for avoiding carbon leakage and economic disadvantages for EU companies (especially the energy intensive and export oriented industry) and Member States as a consequence of a 95% emission reduction target;
- The EU is anticipated to experience a moderate economic growth until 2050. This results in a slightly increased demand in road transport (tkm, Pkm) until 2050. The energy demand of the industrial sector remains constant at about today’s level thanks to increasing energy efficiency on the one hand and economic growth on the other. The residential and commercial heat demand is significantly reduced to about half of today's values by applying efficient heating systems and deep insulation of buildings;
- The energy demand of aviation and maritime transport is assumed to be supplied without having any relevant impact on the European gas pipeline infrastructure. For this sector, energy is provided e.g. via domestic or imported Power-to-Liquids (PtL) or other fuels.

The following table shows the major parameters of the three storylines.

Table 8: Main assumptions per story

			Strong electrification		Strong development of methane		Strong development of hydrogen	
	Storyline:		Strong electrification		Strong development of methane		Strong development of hydrogen	
Category	**Criteria**		**Parameter**					
General aspects	Macroeconomics		Moderate growth					
	International context		Strong international climate ambitions					
	Acceptance		High public acceptance for energy transition					
	Energy market		Well-functioning EU internal energy market					
	Decarbonisation path		Fast		Fast		Slow	
Energy system	Long-term energy storage		Low, hydrogen		High, methane		Medium, hydrogen	
	Utilisation of gas pipeline infrastructure (compared to today; on Energy basis)		Significantly reduced		Constant		Reduced	
	Power grid expansion/investments		High		Medium		Medium	
	Cross border power transfer capacity		High		Medium		Medium	
	Pressure on renewable potentials (in contrast to other storylines)		Low		High		Medium	
	Total efficiency of energy system		High		Low		Medium	
	Flexibilities		Batteries, DR/DSM, electrolysis (minor role)		CH_4 production (and re-electrification); also batteries and DR/DSM		H_2 production (and re-electrification); also batteries and DR/DSM	
			2030	**2050**	**2030**	**2050**	**2030**	**2050**
Power sector	Gas for power production (compared to today)		Increasing		Increasing	Decreasing	Increasing	Decreasing
	Share methane		High	Low	High	High	High	Low
	Share hydrogen		Low	High	Low	Low	Low	High
Transport sector (Road)	Transport demand		Increasing 0.5% p.a. (tkm, Pkm)					
	Public road transport and private cars (Share of vehicles)	Electric	Medium	High	Low	Medium	Low	Medium
		Methane	None	None	Low	High	None	None
		Hydrogen	None	Low	None	None	Low	High
		Other	High	None	High	None	High	None
	Heavy goods transport, commercial vehicles (Share of vehicles)	Electric	Low	High	Low	Medium	Low	Medium
		Methane	Low	Low	Low	High	None	None
		Hydrogen	Low	Low	None	None	Low	High
		Other	High	Low	High	Low	High	Low
Other transport	Rail		No gases, mainly electric					
	Maritime, Air, …		No gases, mainly PtL					
Heating sector (Residential/ Commercial)	Heating demand		Significantly decreasing, -50% by 2050					
	Share in	Electric	Medium	High	Medium	Medium	Low	Medium
		Methane	Medium	Low	Medium	Medium	Medium	Low
		Hydrogen	None	Low	None	None	Low	Medium
		Other (e.g. direct biomass)	Low, about at today's level					
Industry	Gas demand		Significant decrease		Moderate decrease			
Domestic gas production	Natural gas		Medium	Negligible	Medium	Negligible	Medium	Negligible
	Synthetic methane		Low	Low	Medium	High	Low	Low
	Biomethane		Low	Low	Medium	High	Low	Low
	Hydrogen		Low	Medium	Low	Low	Low	High

3.3.2 Storyline 1 – Strong electrification

In this storyline, decarbonisation is achieved by strong and profound electrification of the most important energy consuming sectors in Europe. The direct use of electricity enables a highly efficient distribution and use of energy. The pressure on renewable potentials is, compared to the other storylines, on a reduced level as domestic production of gas from electricity is limited. The 2050 emission reduction target (-95%) is achieved in time, with major emission reductions already materialising around 2030. The importance of gas as energy carriers is significantly reduced.

General drivers

Today, major technologies required for the electrification of the European energy system such as battery electric vehicles, electric heat pumps, PV, hydro and wind power already exist. In this storyline, these technologies see (further) rapid commercial expansion already in the short to medium-term, enabling a rather quick substitution of relevant shares of fossil energies with a related reduction of emissions. This is possible by first focusing on applications that can be considered as rather easy to electrify which are notably the heating sector, passenger cars and delivery vans. Other applications such as long-distance transport or industry processes are decarbonised mainly after 2030. The focus on strong direct electrification without the wide usage of hybridized (e.g. electricity plus gas hybrid) end user appliances results in a rather high stress on the electricity transport and distribution grid. This will require relevant investments in the electricity storage, transport and distribution infrastructure as well as in assured power production capacities. In the short-term, further development of fossil technologies is significantly reduced and then completely stopped. CCS and CCU technologies might be an exemption for a very limited number of member states. Instead, technologies which enable the production, transport, storage and use of renewable electricity are increasingly in the focus of R&D and commercialization. This enables a continuous improvement in terms of e.g. efficiency and costs, and also widens the possible field of applications for these technologies.

Assuming that even in the long-term some applications cannot be supplied directly with electricity (e.g. due to technical, economic and/or practical reasons), hydrogen production, (long-term and strategic) energy storage, (intercontinental) energy transport and end-use technologies are also continuously under development, however, initially with reduced efforts. These technologies become available and are being introduced to the market on a larger scale after 2030. Compared to technologies that directly use electricity, hydrogen plays a lesser but unneglectable role in 2050. For some niche applications, methane (first fossil then renewable) and liquid fuels (PtL) remain an option until 2050 either due to the lack of other viable options or due to the easy availability of renewable methane (from biomass or electricity) in some regions or for some stakeholders. In 2050, other renewable energies (except for PV and wind) such as geothermal or the direct use of biomass for heating[42] are used at about the same level as today.

The power sector is ramping up renewable energy sources rather quickly. The increasing demand for electricity from the heating and the transport sector is satisfied by increasing installations of mainly PV and wind power (on and offshore). To geographically balance fluctuating power production from these sources, the European power grid is continuously expanded. Pumped hydro power potentials e.g. in Norway are well-integrated into the power system to provide short-term electricity storage. In the

[42] Assuming that particle emissions from biomass for heating are not of concern anymore

medium to long-term additional flexibilities are provided e.g. by stationary batteries and demand response / demand side management (incl. charging of electric vehicles and operation of heat pumps). Towards 2050, electrolysis for hydrogen production provides some additional flexibility and seasonal electricity storage. Assured power capacity is provided by hydrogen re-electrification and biomass fired power plants.

In 2050, no fossil energies are used in the European energy system. Electricity is the most commonly used energy carrier in all sectors ensuring high energy efficiency. Applications that are not suitable for direct electrification exist and usually rely on hydrogen as energy carrier. Hydrogen is also used for seasonal and strategic energy storage as well as for intercontinental trade. Further CO_2-neutral energy carriers such as renewable methane and liquid energy carriers are used in small amounts, mainly in aviation and maritime transport. Overall, the use of the existing gas infrastructure is at a low level.

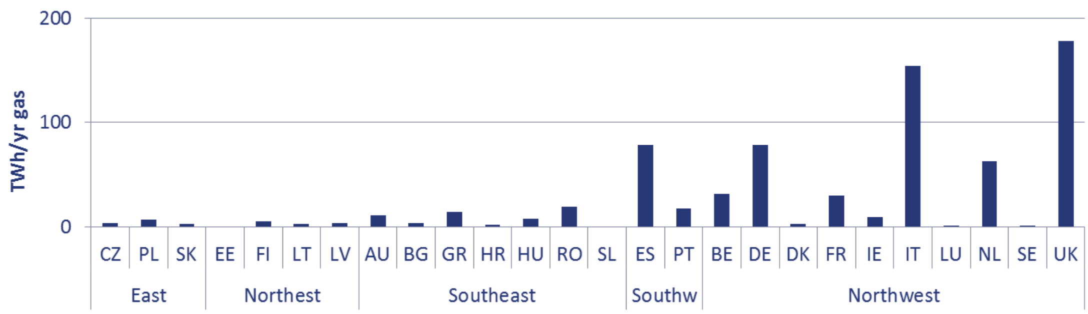
Gas consumption until 2050

In this subchapter, the gas consumption in each sector is discussed. The possible development of the overall gas demand in this storyline is estimated.

Power sector

In 2050, gas for power production is mainly used in periods with insufficient electricity production from renewables such as hydro, PV and wind as well as from other power sources like geothermal or nuclear. Energy demand from the heating, transport and industry sectors significantly increase the power that needs to be provided to the electricity system. After the activation of available flexibilities such as stationary batteries or demand response / demand side management, additional power needs to be generated. For this case, most studies foresee power production from renewable gases. The yearly gas demand in the power sector depends on a number of detailed assumptions (e.g. available flexibilities, degree of electrification of the energy system, installed type and quantity of renewables, regional conditions, interconnection of the European electricity grid, etc.) and can only be determined by thorough system simulations. The reviewed studies show significant differences in gas consumption for power production in 2050.

Figure 3-3: Gas demand in the power sector 2015, based on [IEA 2017a]



For Germany, [Enervis 2017] calculates a gas consumption of 193 TWh_{th} in 2050 for a scenario comparable to this "Strong electrification" storyline. For a similar scenario, [EWI 2017] estimates an annual gas demand of 160 TWh_{th} (84 TWh_{el}). Referred to the 2015 electricity demand of Germany (~ 600

TWh), this translates into specific values[43] of 0.32 and 0.26 $TWh_{gas2050}$ per TWh_{el2015}. For the Netherlands, [Netbeheernederland 2017] discusses a so-called “regional scenario” with a rather strong electrification. From this, a specific value of 0.48 $TWh_{gas2050}$ per TWh_{el2015} can be derived for NL. For the UK, [KPMG 2016] assumes power production from gas in 2050 to be in the same order of magnitude as today. This translates roughly into a factor of 0.49 $TWh_{gas2050}$ per TWh_{el2015}. This short comparison shows that from today’s perspective it is rather uncertain how big the gas demand of the power sector will be in 2050. For this storyline, an average gas demand of 0.32 $TWh_{gas2050}$ per TWh_{el} of electricity consumption in 2015 is assumed in 2050. For 2030, gas demand in the power sector is estimated based on values from the [Entsog 2017] “Green Revolution Scenario” (see Figure 3-4). Generally speaking, the role of gas-fired power plants changes from base and mid-load production today to peak-load plants balancing fluctuating renewable electricity generation.

Figure 3-4: Gas demand in the power sector in 2030 [Entsog 2017] “Green Revolution Scenario”

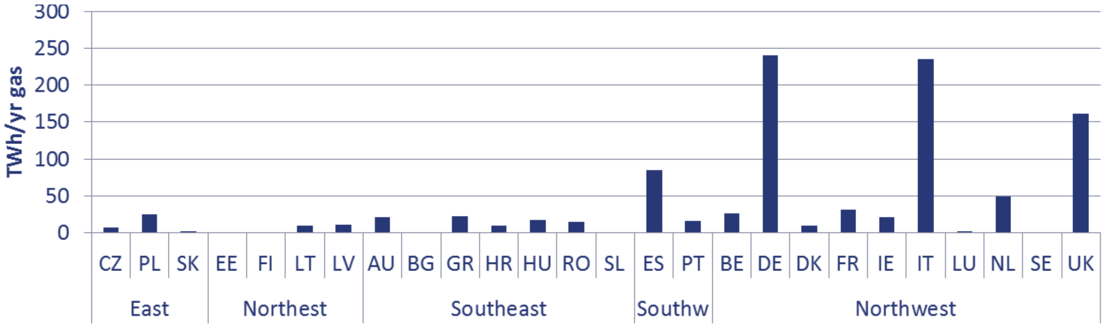
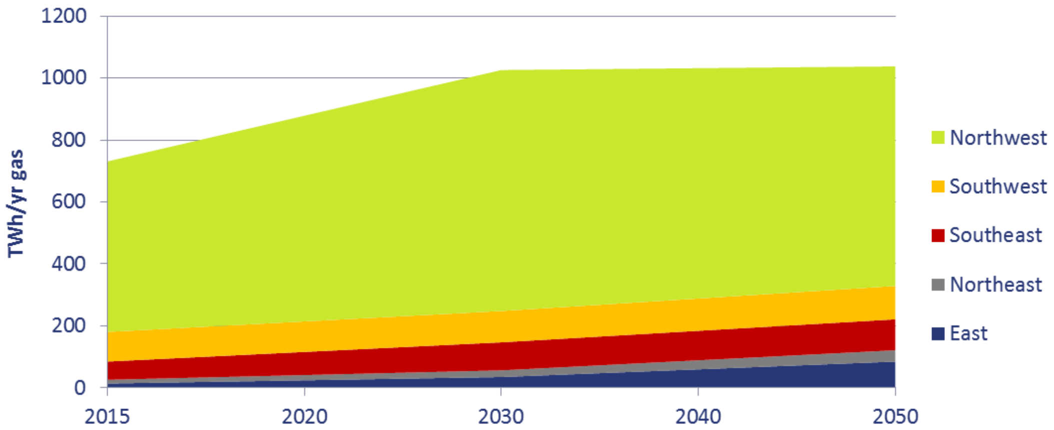


Figure 3-5: Development of gas demand in the power sector (own assumption)



The gas demand for power production in Europe increases from today’s about 700 TWh/a to about 1,000 TWh/a in 2030 and stays at this level until 2050. While gas demand slightly decreases in Western Europe after 2030, the gas demand steadily increases in the other regions from 2015 throughout 2050.

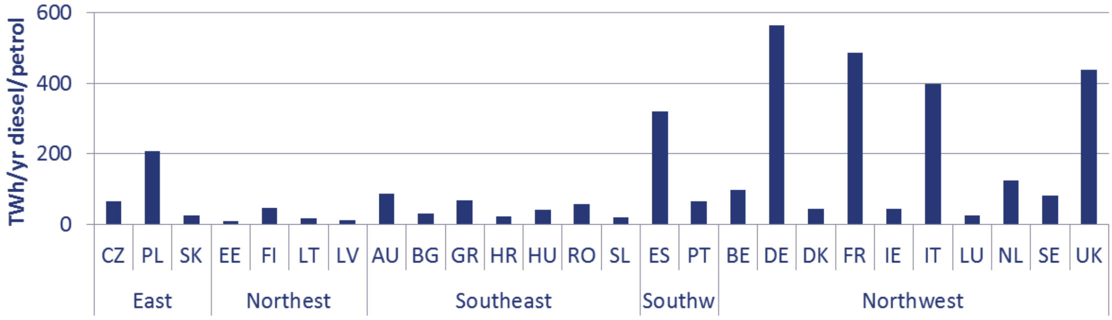
[43] This specific value allows a rough estimation of 2050 gas for power demand based on today’s electricity consumption for all European countries. The value considers a) development of electricity demand until 2050 and b) the amount of gas required to balance renewable electricity production to supply 2050s electricity demand.

Transport sector

So far, the transport sector has not achieved any relevant GHG emission reductions compared to 1990 in Europe. In recent years, the sales of electric vehicles have gained momentum but are still at a low level. In this storyline it is assumed that the penetration of electric vehicles significantly increases in the short-term making battery electric vehicles a mainstream technology by 2030, and the dominant technology by 2050.

According to [EC 2016] energy for road transport (public road transport, passenger cars, motorcycles, heavy goods and light commercial vehicles) amounts to about 3,400 TWh/a today (all energies). Together, Spain, Germany, France, Italy and the UK account for about 65% of this consumption. The amount of gas used in the (road) transport sector is at about 50 TWh/a, today.

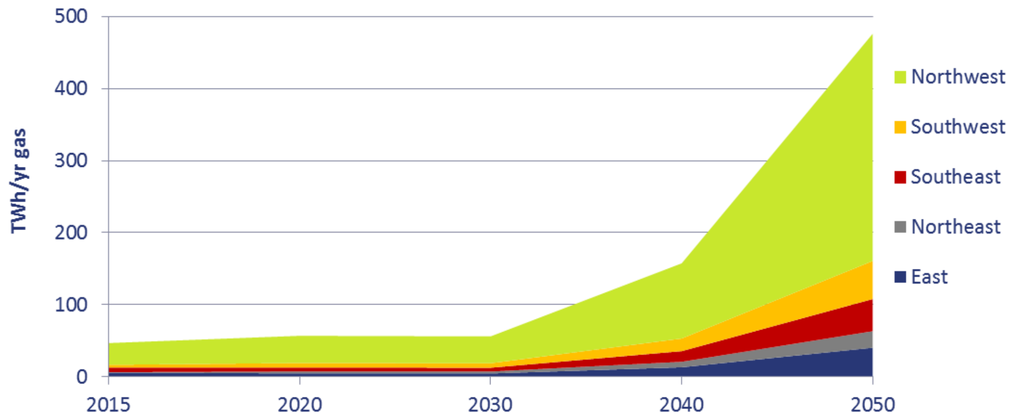
Figure 3-6: Energy for road transport in 2015 [EC 2016]



It is assumed that energy for road transport moderately increases until 2050. Literature shows that even in scenarios with rather strong electrification, not the entire (road) transport sector can be switched to battery electric vehicles. In various studies a relevant share of the sector is using gas as fuel, as the consequences of limited driving ranges between recharging ('range anxiety') and long recharging times of battery electric vehicles (practicality) are assumed not be acceptable for certain user groups ([Netbeheernederland 2017], [EWI 2017], [Enervis 2017]). This result is also adopted in this storyline. Resource availability for battery production is an additional driver for not considering 100% battery vehicles.

In 2030, most passenger cars are still conventional (fossil) ICE vehicles, about 1/3 are battery electric vehicles. Gas is not used for passenger cars and public road transport in relevant quantities. However, heavy goods and light commercial vehicles use some methane and hydrogen. By 2050, the share of heavy goods and light commercial vehicles that use hydrogen increases to about of fifth, methane remains constant at a rather low level. Passenger cars and public road transport mainly use batteries, but also one fifth of the vehicles use hydrogen. In those vehicles hydrogen is used either as single fuel or as range-extender for battery vehicles. It is assumed that gas is not used as energy carrier in rail transport in relevant quantities.

Figure 3-7: Development of gas demand in the road transport sector (own assumption)

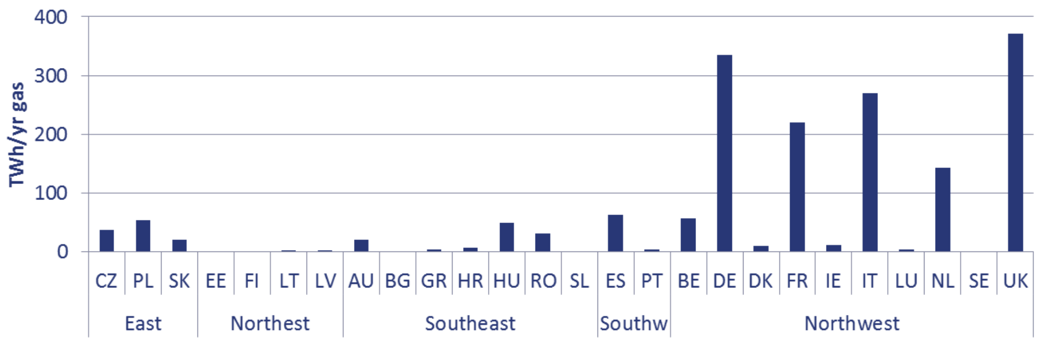


In this storyline, battery electric vehicles rapidly gain relevant shares of the vehicle population based on continuously improving battery technology. As a consequence, the complementary hydrogen technology is required and introduced rather late. This results in low gas demand in transport until 2030, followed by a strongly increasing demand during the following 20 years.

Heating sector

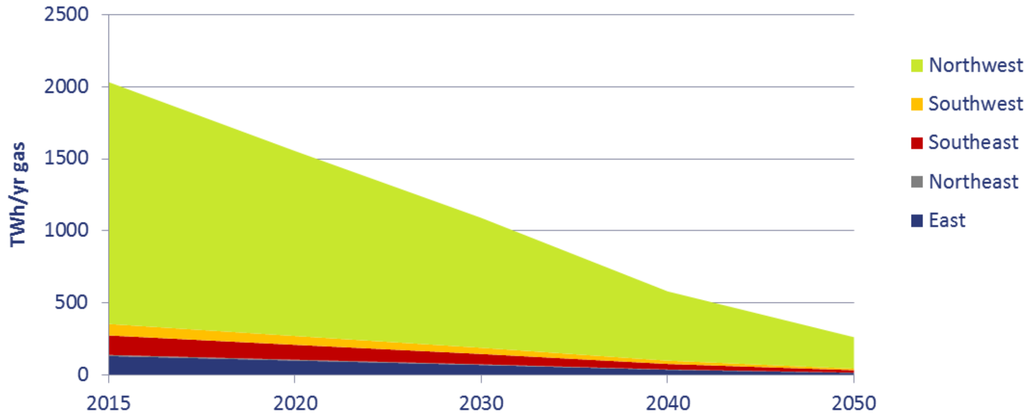
Today, about 50% of the heat demand of residential and commercial buildings is directly produced from natural gas, about 10% from biomass, 10% from electricity and 10% from district heating, and about 20% from other fossil fuels [Halmstad University 2015]. The share of gas in the heating sector strongly varies between European countries. The overall annual gas demand for heating today amounts to about 2,000 TWh/a.

Figure 3-8: Natural gas for residential heating in European countries (2010, [Halmstad University 2015])



In literature, the reduction of heat demand is often a key prerequisite to reaching strong emission reduction targets. However, there is no uniform opinion on how much reduction can be achieved and is economically viable. As a consequence, different heat demand reductions can be found in studies. In [Frontier Economics, et al. 2017] a reduction of 34% in 2050 as compared to 2015 values is assumed for Germany, while [EWI 2017] assumes a reduction of 64% for the same period. [Klavs, G.; Rekis, J. 2015] mention a 50% reduction for Latvia and [Seimas 2012] a reduction of 70% for Lithuania. For the Netherlands [Netbeheernederland 2017] mentions an expected reduction of between 12 and 23%. From [KPMG 2016] a reduction of about 20% to 30% can be derived for the UK, however, only aiming at an overall 80% GHG reduction. From [UBA-AT 2016] a reduction of about 40% can be estimated for Austria. For this storyline it is assumed, based on the aforementioned sources, that the energy demand for heating in all European countries can be halved by 2050. In addition, the efficiency of heat production from gases is expected to increase to about 98% (e.g. through widespread use of condensing boilers). At that time, electricity has become the major energy for residential heating accounting for about 75% of the total heat demand. Gases (mainly hydrogen and some biomethane together supply 15%, other energies such as biomass account for 10% of the heat demand. The relevance of gases for heat production is reduced from about 50% today, to 40% in 2030 and to 15% in 2050 (at a reduced absolute level of total consumption; see above). This reduction is applied to all countries relative to their current relevance of natural gas in this sector.

Figure 3-9: Development of gas demand in the heating sector (own assumption)

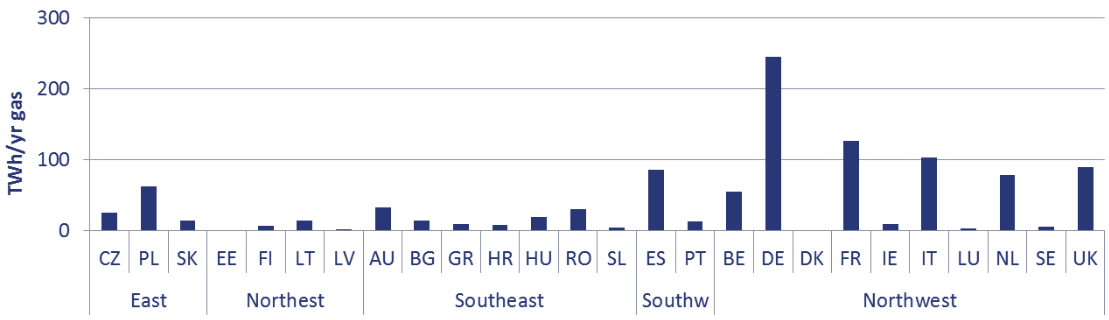


As a consequence, in 2050, the gas demand in the heating sector will be significantly reduced. This is the result of the reduced share of gas for heat production in combination with a profound reduction of overall heat demand. Gas demand decreases from about 2,000 TWh/a today to 250 TWh/a by 2050. This corresponds to a reduction of more than 85%. Such drastic reductions can also be found in literature, e.g. in [EWI 2017] or [UBA-AT 2016].

Industry sector

The decarbonisation of the industry sector is often not in the focus of studies (e.g. [KPMG 2016]). As a consequence, projections of gas demand developments in a 95% GHG emission reduction world are rather sparse. According to [IEA 2017a] industry accounts for roughly ¼ or about 1,000 TWh/a of gas consumption in Europe today.

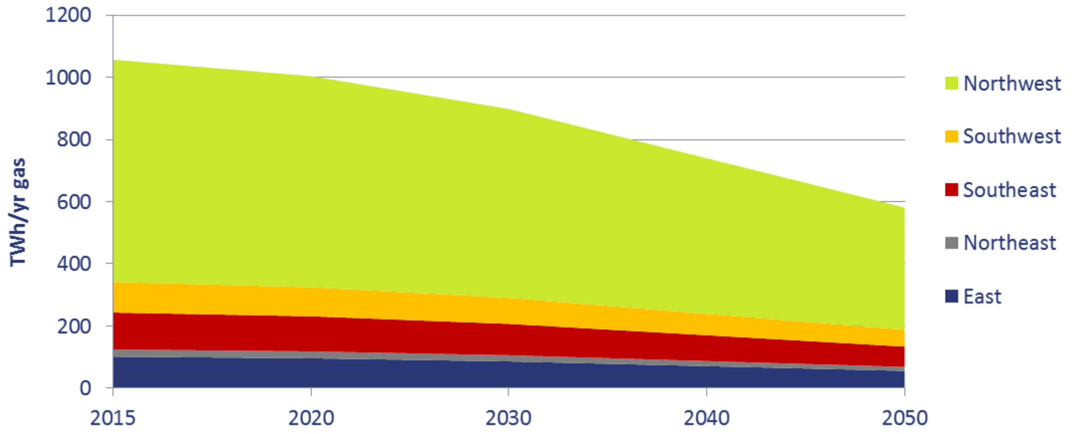
Figure 3-10: Today's gas demand in the industry sector (incl. non energetic use) [IEA 2017a]



For Germany, [EWI 2017] assumes a nearly constant gas demand in the industry sector until 2030 followed by a 28% decline until 2050. They assume that gas used for the production of high temperature heat cannot easily be replaced by electricity. For Austria [UBA-AT 2016] estimates a reduction in industrial gas demand from about 30 TWh/a in 2010 to 25 TWh/a by 2030 (-16%) and to 16 TWh/a by 2050 (-46% compared to 2010). In [UKERC 2016], which assesses pathways towards -80% GHG emission reductions for the UK, the gas demand in the industry sector is reduced by 45% to 70% between 2010 and 2050, depending on the scenario.

For this storyline it is assumed that gas demand is reduced by 15% in 2030 and by 45% in 2050 for all regions.

Figure 3-11: Development of gas demand in the industry sector (own assumption)



Total gas demand

The development of the total gas demand (power, transport, heating and industry sector) per region is shown in Figure 3-12. Gas demand decreases from about 4.000 TWh/a today to about 2.500 TWh/a by 2040. After 2040, gas demand decreases less strongly to 2,400 TWh/a by 2050.

Figure 3-12: Development of total gas demand per region (own assumption)

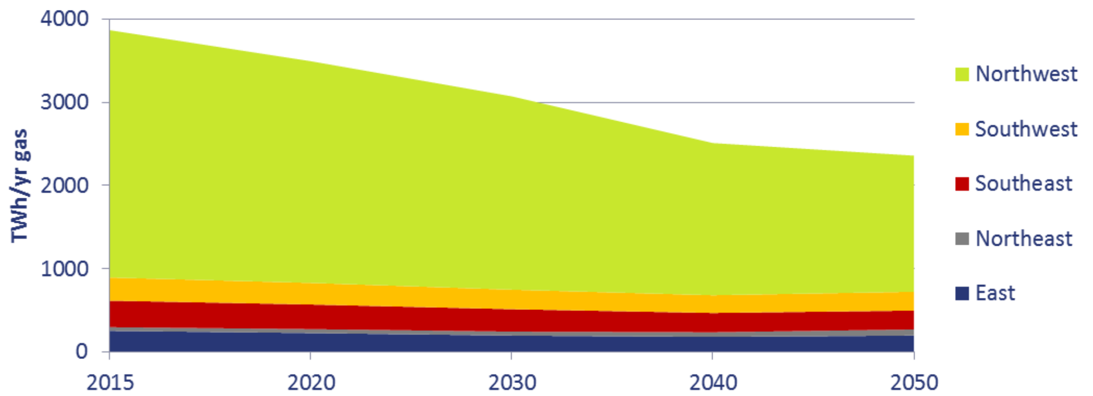
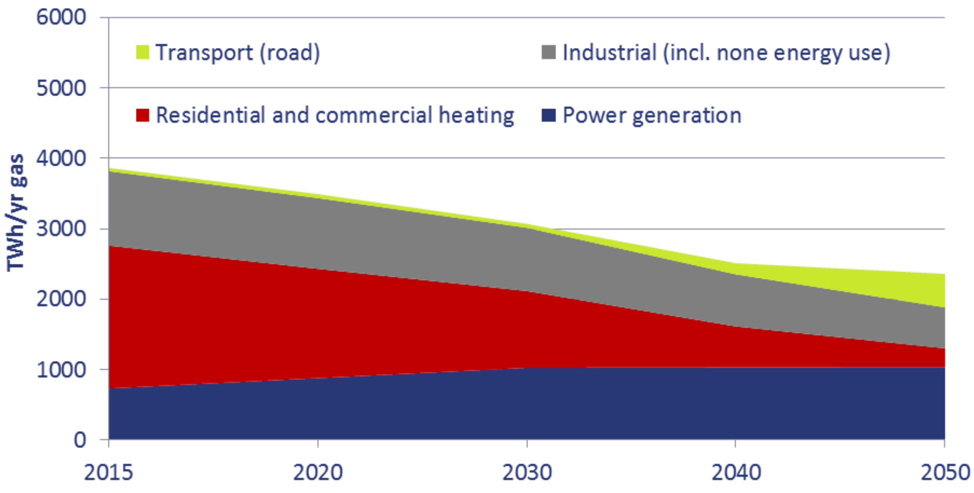


Figure 3-13 details the contribution of each sector to the total gas demand. Demand reductions in the heating and industry sector are partly compensated for by increasing demand from the power sector until 2040. Between 2040 and 2050, further reductions are almost completely compensated by increasing demand from the transport sector.

Figure 3-13: Development of gas demand per sector (own assumption)

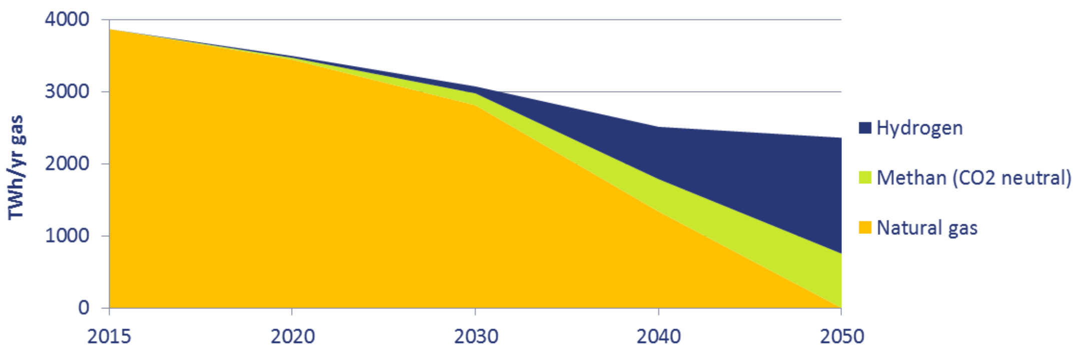


Type of gas and gas sourcing

Today, virtually all gas consumed in Europe is fossil energy based. Renewable gases such as e.g. biomethane or hydrogen from electrolysis are used in marginal quantities.

In this storyline, gas consumption is reduced from 4,000 TWh/yr to about 3,000 TWh by 2030. By 2030, still about 90% of the gas consumed will be natural gas. About 5% of the gas will be from renewable sources, another 5% hydrogen. Between 2030 and 2050, mainly hydrogen but also synthetic and biomethane completely replace natural gas as relevant energy carrier in Europe. Hydrogen, however, is used to a greater extent due to the comparable high efficiency of production and use (e.g. as vehicle fuel, seasonal energy storage).

Figure 3-14: Development of type of gas in the energy system (own assumption)



In 2050, hydrogen will mainly be produced from water electrolysis using renewable electricity. A CO_2-lean[44] production of hydrogen is also possible by using SMR in combination with CCS technology. However, this technology option has so far only been discussed for the UK [Northern Gas Networks, et al. 2016] and the Netherlands [WEC 2018]. In total 1,600 TWh of hydrogen will be used in Europe by 2050.

[44] To make SMR+CCS truly CO_2-neutral, additional measures such as avoiding any natural gas leakage and compensating for incomplete removal of CO_2 from SMR exhaust stream, are required.

The demand for CO_2-neutral methane amounts to about 750 TWh per year by 2050. This amount can be produced from biomass or catalytically from electricity in combination with CO_2. [Ecofys 2018] estimates an EU potential of 1,000 TWh of biomethane from biomass per year in 2050. In addition, up to 400 TWh of methane per year could be produced catalytically using CO_2 from large-scale concentrated renewable sources [LBST; Dena 2017]. Therefore, the estimated methane demand is within the European production potentials.

Gas infrastructure

Gas demand in the heating sector is significantly reduced due to strong insulation of buildings (-50% in average), increased efficiency of heat production (e.g. condensing boilers) and due to a fuel switch from gas to electricity for the majority of today's gas customers. As a consequence, large parts of the gas distribution grid are not in use anymore and are decommissioned. Remaining gas customers will not be spread across the entire distribution grid, they will rather be concentrated in single (island) grids which will be kept operational. Those remaining island grids will crystalize around easily available CO_2-neutral gas sources e.g. in rural areas with a high availability of required feedstock (e.g. biomass for methane or renewable surplus electricity for hydrogen production). In 2050, the grids are fed with pure methane, pure hydrogen or a mixture of both gases (hythane). The switch from natural gas to renewable methane can be slow and the share of renewable methane in gas can vary e.g. based on seasonal availability[45]. In contrast, the switch to hydrogen or hydrogen dominated mixtures needs to develop at a high gradient to be able to adapt all equipment in a grid section in a short time span (as experienced with the conversion from town gas to natural gas e.g. in the UK and Germany in the 50s/60s). The limited spatial reach of individual grids will permit a rather flexible choice of these gases.

Despite the strongly reduced gas demand of individual gas consumers, their absolute cost contribution for the low pressure distribution grid (grid fees) will (at least) remain constant due to more or less constant total costs for the grid section. For those remaining distribution grids it was possible to stop the cost spiral of high (grid) costs causing high energy costs which again will cause additional customers to switch fuels. As a consequence (grid) costs for remaining consumers would increase even further causing again additional consumers to turn their back on gas usage, and so on [EWI 2017].

The operational distribution grids will likely require their own gas storage for short- and long-term storage or alternatively need to be connected to a gas transport pipeline, hence in need of reversing today's typical gas flows backwards from distribution to transport grid. Gas transport pipelines will mainly be kept operational to connect central gas power plants to gas sources, collect biomethane from decentral plants and especially to connect gas storage facilities (e.g. underground storages). Due to the higher gas production efficiency hydrogen will play a major role for long-term energy storage (e.g. in underground salt caverns) and re-electrification in periods with low power production from renewables. Total gas storage capacity will be lowest compared to the two other storylines due to an overall reduced energy demand as a consequence of efficient use of energy (e.g. heat pumps, battery electric vehicles). To store sufficient amounts of hydrogen it might be required to develop new storage sites. Transport pipelines will also be used for inter-European as well as intercontinental energy trade and transport. This might require to upgrade certain pipelines for reverse flow. Also the reclassification from methane (natural gas) pipeline to hydrogen pipeline will be required for a relevant share of

[45] It may then be required to add gases such as nitrogen or propane to stabilize the heating value of the gas.

pipelines. However, not all gas will be hydrogen. Methane will still play a role in the energy and pipeline system mainly due to the advantage of existing infrastructure, especially of assets that cannot be converted to hydrogen use (e.g. some natural gas storages) or of industrial customers that require methane (but not hydrogen) as feedstock.

By 2050, a relevant quantity of hydrogen will be used for the road transport of goods and people. This fuel can be transported to the refuelling stations by a gird of pipelines and hence unburden the electricity distribution grids. However, relevant alternative hydrogen supply technologies exist and are used and discussed for the transport sector, today. Those technologies (e.g. transport of liquefied hydrogen, onsite hydrogen production) do not use the gas grid. Hydrogen transport to the refuelling station by pipeline will likely only be economically attractive for the case that decommissioned natural gas pipelines can easily be converted and used or if new required hydrogen pipelines stretches are rather short.

Considering that not all hydrogen in the transport sector is transported via pipeline, the amount of gas in the European pipeline system is about halved by 2050 compared to today. Thus, the utilization of the system as a whole will drop dramatically. However, this might partly be compensated by the decommissioning of relevant shares of the distribution and transport grid. A certain (increased?) share of the gas might be transported twice through the system, 1) after production from renewable sources to be fed into a seasonal storage and 2) after withdrawal from the seasonal storage to be used for re-electrification, in industry and for the transport or heating sector. Some new investments might be required to make certain parts of the pipeline system compatible to hydrogen or hydrogen-methane mixtures.

In this storyline, no major imports of liquefied gases into the EU have been assumed, neither methane nor hydrogen. As a consequence, LNG import terminals and gasification plants will be decommissioned. Hydrogen liquefaction plants will exist in Europe e.g. to supply high purity gas to the industry and to supply some hydrogen refuelling stations (e.g. stations with low footprint). Existing import pipelines will also see very strong underutilization. The share of imported gases will likely become insignificant. At this point, it has to be emphasized that despite the seemingly small role of gas in this storyline, gas and gas infrastructure (especially gas storage, transport and re-electrification units) are crucial to the stability of the energy system as a whole. Those assets will continue to provide a large share of the required dispatchable peak power production capability, as well as important long-term and strategic energy storage. It is therefore important to ensure that all relevant infrastructures remain available to the energy system throughout the transformation process.

Critical appraisal

In this storyline, total gas demand is significantly reduced. This is the result of a few central assumptions taken. Changing those assumptions has a direct impact on the gas demand. Thus, for the same storyline, also lower or higher gas demand values can be generated. However, the general trends should stay the same in the context of the general drivers.

The used technology (e.g. BEV, heat pumps) allows for an efficient use of energy which promises rather low (absolute) costs for energy production in the long-term. However, relevant investments in electricity balancing, transport and distribution as well as investment in technology development are required. Within the scope of this work it is not possible to draw any conclusion regarding the economic efficiency of this storyline (as in e.g. specific CO_2 abatement costs).

3.3.3 *Storyline 2 – Strong development of methane (CO_2-neutral)*[46]

Methane is key to achieving a 95% reduction of GHG emission by 2050 in this storyline. In sectors such as heating and industry, gas will continue to play a major role until and beyond 2050. In other sectors it will replace large shares of fossil energy carries such as petroleum products (transport sector) or coal (power sector). The remaining fossil energies will mainly be replaced by electricity. Compared to the other storylines, very large renewable potentials need to be developed to supply sufficient methane quantities towards 2050. The 95% emission reduction target is met in time, relevant emission reductions are already achieved around 2030. The role of gas in the energy system remains strong.

General drivers

Methane is one of the most important energy carriers today. Especially in the heating, industry and power generation sectors it represents relevant shares of the total energy consumption. In the transport sector, the CO_2-lean gas (compared to other fossil fuels) is currently used in very low quantities despite the fact that required technologies are available.

In this storyline, methane remains strong in the heating, industry and power sector until and beyond 2050. In the transport sector, methane internal combustion engines quickly gain foothold in the short to medium-term. Rather early, the existing gas infrastructure, including a Europe-wide gas refuelling network, are expended, adapted and optimized to also supply the transport sector. In parallel, electric technologies such as e.g. battery electric vehicles and heat pumps are further developed. Battery electric vehicles are introduced fast in the short to medium-term, but are considered not suitable for a rather large share of users due to technical and economic constraints and missing user acceptance. Here, vehicles with methane ICE continuously replace diesel and gasoline engines. In the heating sector, electricity-based heating technologies are primarily used for buildings in areas without gas grid. The share of methane in the heating sector will remain rather at a 50% level throughout the period until 2050.

The extended use of electricity mainly in the heating and transport sector and the strong switch of the transport sector towards (synthetic) methane are the major drivers for profound reductions of GHG emission until about 2030. The strong reduction of heat demand mainly through building insulation (reducing methane demand in absolute terms in this sector) continues after 2030 until 2050. By 2030, methane from fossil sources still represents the majority of the gas consumed in Europe, only minor shares are biomethane or synthetic methane. Step by step, natural gas will be replaced by CO_2-neutral methane after 2030. Synthetic methane and to a lesser extent biomethane completely replace natural gas by 2050. Natural gas in combination with CCS technology is only an option for large scale power generation but not for the transport and heating sector. It is not assumed that CCS is introduced to a large extent in Europe.

The large-scale production of methane from renewable electricity will require the installation of large renewable electricity generation capacities, especially PV and wind power (on and offshore). These fluctuating power sources will be balanced by inter-European electricity exchange, stationary energy storage in pumped hydro and battery storages as well as by demand response / demand side management. The production of synthetic methane offers significant additional flexibility to the power sector with electrolysis plants following consuming excess load in the system. Gas turbines and CCGT

[46] Methane based on biomass or electricity

plants provide the majority of assured power generation capacity. Underground methane storages provide large-scale seasonal storage capacities.

By 2050, renewable methane and electricity have replaced all fossil energy carriers in Europe. Methane (gaseous and liquefied) is the commonly used energy carrier for seasonal and strategic energy storage as well as for international/intercontinental energy trade and transport. Other CO_2-free energy carriers such as hydrogen or Power-to-Liquids only play a negligible role. The utilisation of the existing gas infrastructure remains at a high level, new investments e.g. in refuelling stations are required in the short to mid-term.

Gas consumption until 2050

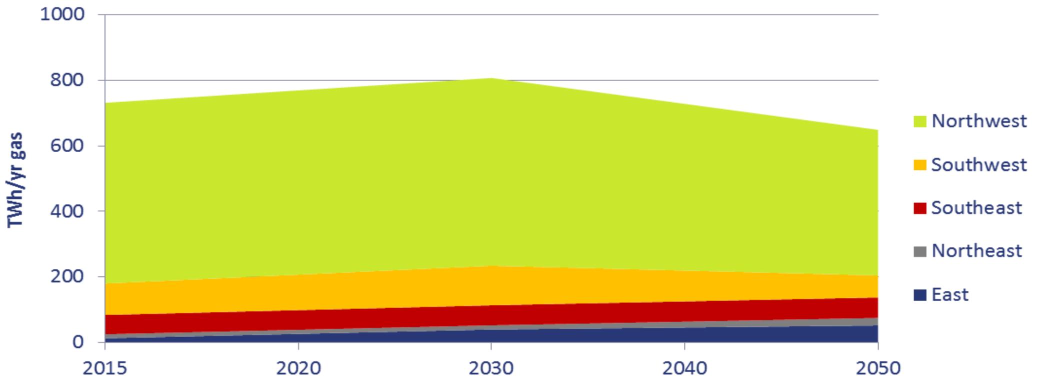
The gas demand until 2050 is estimated based on today's gas consumption and general assumptions regarding possible developments in each sector as described below. Various literature values on gas demand in 2030 and 2005 as well as general assumptions are discussed for each sector in chapter 3.2.2 (Storyline 1: "Strong electrification"). In the following subchapters, relevant assumptions specific to this storyline are described.

Power sector

For Germany, [Enervis 2017] mentions a gas consumption of 119 TWh_{th}/a in 2050 in the power sector for a scenario that relies on a rather large share of gas in the energy system. The same study mentions a gas consumption of 193 TWh_{th}/a for a scenario that focuses on electrification. Thus, the need for gas in the power sector is reduced when changing the focus from strong electrification to less strong electrification. The same effect can be observed when comparing the different scenarios in [EWI 2017]. In the "Revolution" scenario, the focus is on electrification. Here 84 TWh_{el}/a of electricity are produced from gas in 2050. In the "Evolution" scenario, electrification is less pronounced; gas-fired power is reduced to 61 TWh_{el}/a. The comparison of regional versus national scenarios in [Netbeheernederland 2017] also confirms that tendency. The reason for this effect is probably that more assured power (and energy) has to be provided if more sectors heavily rely on direct use (direct coupling of sectors) of electricity. Thus, in those cases more gas has to be provided to the power sector.

The following lesson/conclusion from the literature review can be learnt here: Instead of using a value of 0.32 $TWh_{gas2050}$ per TWh_{el2015} (as done in the "Strong electrification" storyline), a value of 0.2 $TWh_{gas2050}$ per TWh_{el2015} is used to estimate gas demand in the power sector. For 2030, a gas demand as cited by [EC 2016] (Blue Transition) is used.

Figure 3-15: Development of gas demand in the power sector (own assumption)

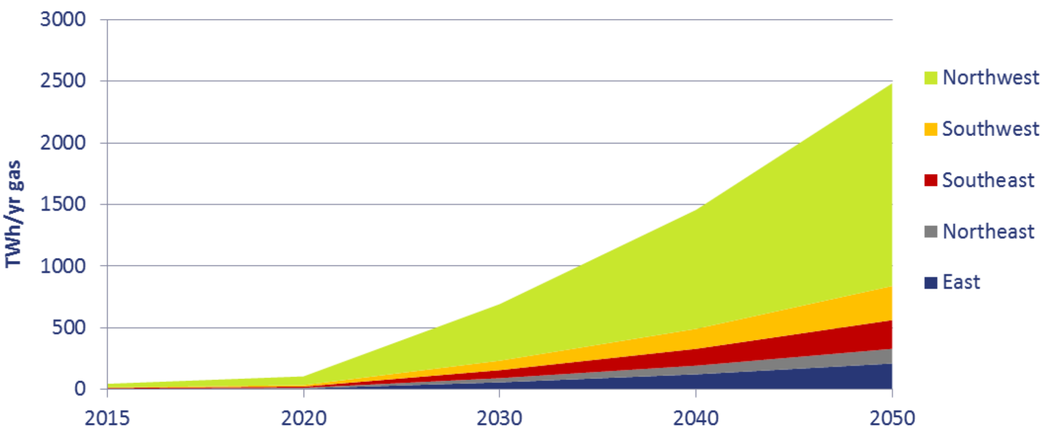


Gas demand for power production peaks in 2030. This is mostly due to a switch in primary energy used for power production (gas before coal). Afterwards, the gas demand decreases to below 700 TWh_{th}/a as a consequence of an increasing share of renewable power production.

Transport sector

As in "Strong electrification", transport demand is also slightly increased in this storyline. Methane powered ICE vehicles are introduced rather quickly. By 2030, about one fifth of all trucks, commercial vehicles and all other vehicles use methane as fuel. By 2050, those shares increase to more than half of the entire vehicle fleet. A relevant share of transport applications will use electrified vehicles mainly due to economic/efficiency advantages.

Figure 3-16: Development of gas demand in the road transport sector (own assumption)

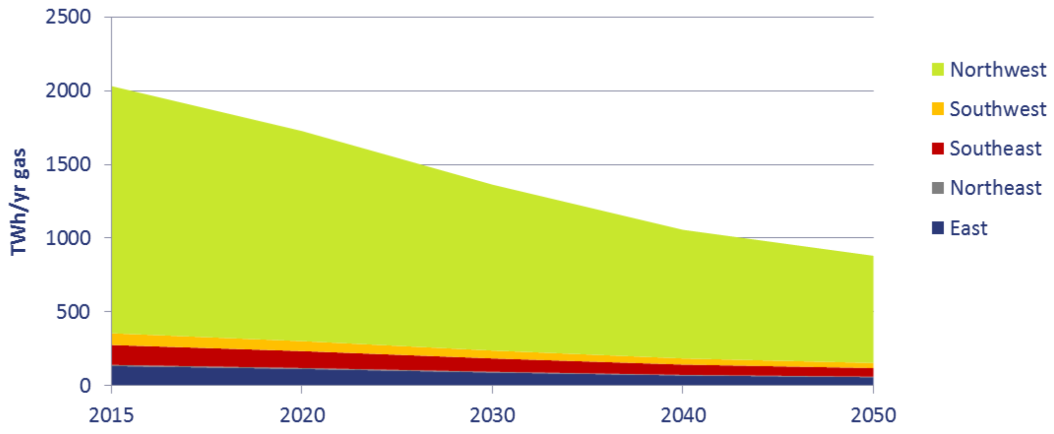


As a consequence, the gas demand for road transport increases 25-fold from below 100 TWh/a in 2020 to almost 2,500 TWh/a by 2050.

Heating sector

The heating demand is assumed to be 50% less by 2050 compared to today's values. In this storyline it is further assumed that virtually all buildings connected to the natural gas grid today will also use gas for heating in the future. Thus, the share of gas in the heating market remains constant at about 50%. The reduction in gas demand is caused by the above mentioned reduction of heating demand through building insulation, increased efficiency of boilers, etc.

Figure 3-17: Development of gas demand in the heating sector (own assumption)

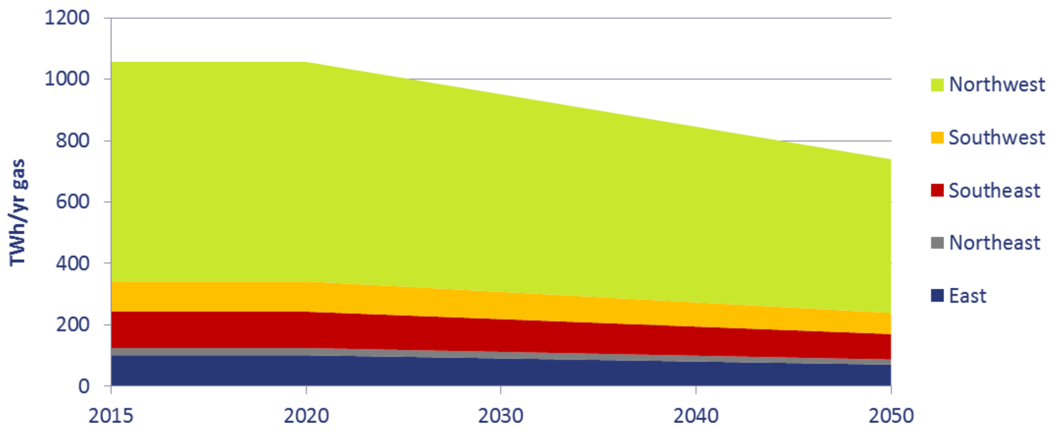


Gas demand in the heating sector will be roughly halved from about 2,000 TWh/a in 2015 to below 1,000 TWh/a by 2050.

Industry sector

The electrification of industry processes is less pronounced than in the "Strong electrification" storyline. It is assumed that gas demand in the industry sector is only reduced by 10% by 2030 and by 30% by 2050.

Figure 3-18: Development of gas demand in the industry sector (own assumption)

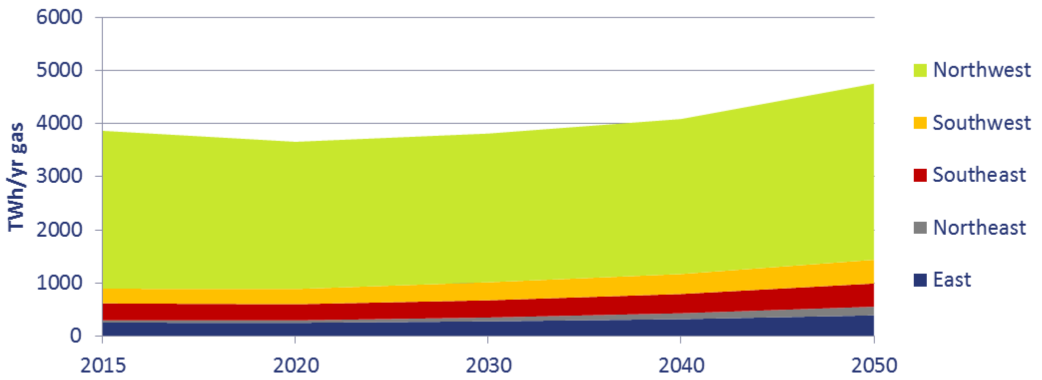


The gas demand for industry will be reduced from above 1,000 TWh/a today to below 800 TWh/a by 2050.

Total gas demand

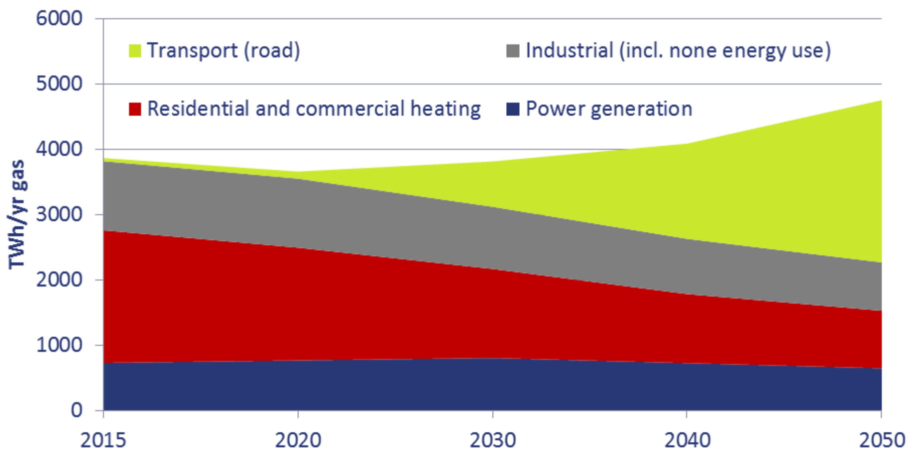
The total gas demand will then be about constant until 2040, with a small dip around 2020. Starting around 2040, the gas demand will increase by about 25% until 2050.

Figure 3-19: Development of total gas demand per region (own assumption)



The increasing gas demand of the transport sector will overcompensate the demand reductions in the heating and industry sectors (see Figure 3-20).

Figure 3-20: Development of gas demand per sector (own assumption)



Type of gas and gas sourcing

Between 2020 and 2050, fossil methane will completely be substituted by methane from renewable sources. In the industry and power sectors, small shares of hydrogen will be used. Most renewable methane will be used in the transport sector in 2050.

Figure 3-21: Development of type of gas in the energy system (own assumption)

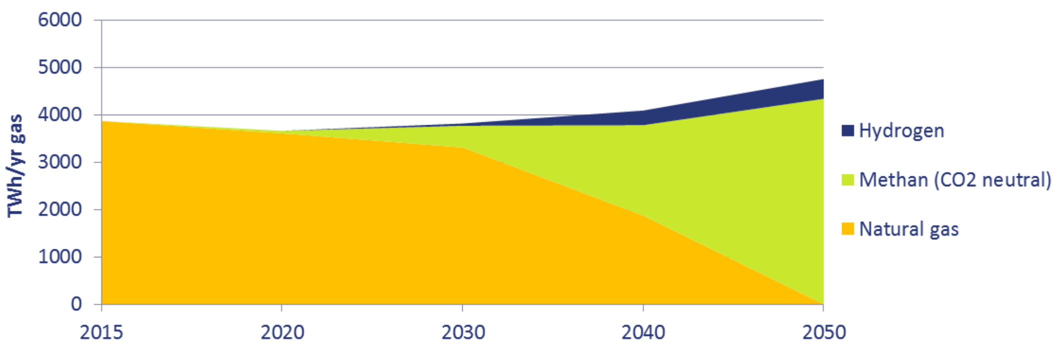
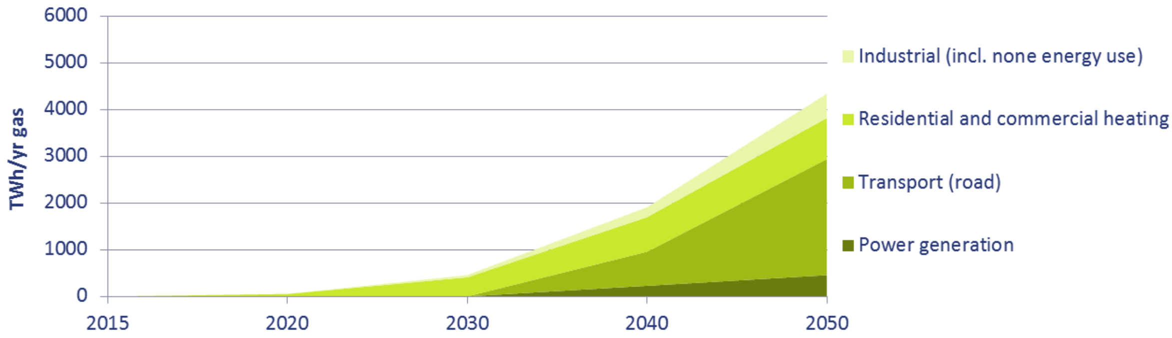


Figure 3-22: Use of methane (CO2 neutral) by sector (own assumption)



By 2050, the total hydrogen demand will amount to roughly 400 TWh/yr; the demand for methane will then be above 4,000 TWh/yr. This value is slightly above today's gas consumption in Europe and significantly above the production potential of biomass based methane which is estimated to be at 1,000 TWh methane per year for the EU [Ecofys 2018]. This means that a large share of the methane has to be produced catalytically from electricity plus CO_2 (methanation), or alternatively needs to be imported from non-EU countries.

For the catalytic production of methane electricity will be used to produce hydrogen which is then combined with CO_2. For the production of CO_2-neutral methane two different CO_2 sources can be used. CO_2 can either be taken from concentrated renewable sources such as e.g. exhaust gas of biomass fired heat or power plants or it can be extracted from air. The advantage of using concentrated renewable CO_2 sources is an increased efficiency compared to extraction from air. However, the availability of concentrated renewable CO_2 sources is limited, especially when considering that only sources of a certain size can reasonably be used. In a ballpark estimate, [LBST; Dena 2017] identifies CO_2 potentials from concentrated renewable sources to be able to support the production of about 400 TWh of methane annually in the EU (for 2015). This potential might increase until 2050, but it is unlikely that it will be sufficient to supply a few thousand of TWh of catalytic methane per year. Thus, the less efficient CO_2 extraction from air or imports will also need to be applied.

Gas infrastructure

By 2050, the demand of gas in the heating sector is halved due to increased insulation of buildings and increased efficiency of heat production (e.g. condensing boilers). The total number of end users in this sector stays relatively constant. While some new consumers (e.g. former oil heaters) can be connected to the existing gas distribution grid (fuel switch), other customers switch to electricity for heat production. The new investments into the distribution grid are limited to rather small adaptions and replacements. New distribution grids for the heating sector (low pressure) are not built due to missing economic feasibility (low gas demand per consumer due to insulation). However, the relevance of gas in the heating sector remains strong, providing about 50% of all heat required. With a constant number of customers connected to the low pressure distribution grid, the costs for this part of the gas grid will more or less remain constant. As a consequence, the absolute cost burden on the customer from this part of the grid will also remain constant. An increased specific (€/kwh) grid tariff has to compensate for the significantly reduced gas demand in the low pressure grid.

The reduction of gas demand in the heating sector frees capacities in the distribution and transport pipelines for the strong establishment of gas in the transport sector. A dense network of methane refuelling stations is established throughout Europe in 2050. To connect those to the gas grid, new pipelines stretches will be required. In regions without adequate gas grid, alternative supply options such as e.g. virtual pipelines, onsite methane production or road transport of liquid methane can be applied.

The supply of gas to the industry and power sector and the related infrastructure will change little in most cases. Total gas demand in both sectors will change only moderately until 2050. However, in the power sector the role of gas will significantly increase for European regions which do not use much gas for electricity production today. This is especially true for Eastern and North-eastern Europe. Here existing gas infrastructure might need to be supplemented.

In cases where infrastructure needs to be adapted to comply with future needs of power generation, it might be worth thinking about using hydrogen instead of methane as energy carrier to exploit the higher efficiency of gas production from renewable sources. However, in most cases methane will remain dominant in this storyline.

The substitution of natural gas by CO_2-neutral methane can be gradual and regionally inhomogeneous. Even seasonal fluctuations in the share of renewable methane in the gas should not pose a major difficulty (in contrast to the strong admixture of hydrogen to natural gas „strong development of hydrogen" storyline). Depending on the source of the natural gas in the grid (Norway, Russia, Netherlands etc.) and the source of the renewable methane (e.g. fermentation of biomass), admixture of additional gases to the renewable methane might be necessary e.g. to adapt the heating value of the gas. The heating value of biomass based methane can be increased by adding (renewable) propane to then being mixed with natural gas from Russia. A reduction of the heating value can be achieved by adding nitrogen. The adjustment of renewable methane is not always subject to technical issues but rather to assure correct billing of delivered energy.

Today, gas for heating stands for more than half of Europe's gas demand. This share will be reduced to less than one fifth by 2050. The relevance of the transport sector increases from virtually zero today to about half of the total gas demand by mid-century. This shift impacts on the seasonal gas demand structure. The elevated gas demand during the winter season compared to summer is significantly reduced. This enables an adapted operation of existing gas storages to consider renewable electricity (and therefore also gas) production surpluses and deficits throughout the year. The requirements regarding a more dynamic operation of gas storages to cope with fluctuating renewable production might require an update or retrofitting of gas storage infrastructure. This might also be true for gas transport pipelines. Reverse flow capabilities might be required in the European gas grid to allow for effective energy trade and balance of available energies (e.g. for gas production and transport: PV in summer in Southern Europe vs. Wind in winter in Northern Europe).

Considering the trend of increasing total gas use, the grids' new task of renewable gas "collection" on one hand and the possibility of decentral gas production and supply as well as the competing alternative transport modes of gas on the other hand, one can argue that gas throughput in the gas grid could possibly stay roughly at today's level.

By 2050, the European gas demand might not completely be supplied from European sources either due to limitations in ascertainable potentials (renewable electricity, CO_2, biomass, acceptance) or due to economical advantageous import opportunities. Methane imports either gaseous via pipeline or liquefied by ocean tanker are relevant options to cover domestic gas production deficits. Thus, existing LNG and pipeline import infrastructures will still be used in the long-term, in this storyline.

Critical appraisal

As a consequence of the strong focus on methane, also in the transport sector, the total gas demand in this storyline increases. This has mainly to do with the rather low efficiency of internal combustion engines used in vehicles. Also in this storyline, a few central assumptions are used to generate the gas demand figures in each sector. Changing some assumptions can further increase or lower the gas demand in each sector. In the context of this storyline, it is also possible to produce a rather constant gas demand until 2050.

The used technologies, especially the ICEs in the transport sector, cause the energy system to be rather inefficient in terms of overall energy demand. This significantly impacts on the amount of renewable primary energy required. As a consequence, (absolute) costs for energy production will be rather high in the long-term. However, the strong use of existing gas infrastructure as well as the flexibility from gas production usable in the electricity system might lead to lower costs for transport, distribution and balancing of electricity and gas. In addition, ICE technology in the transport sector is already available and further costs for development of e.g. fuel cells can be spared. Within the scope of this work it is not possible to draw any conclusion regarding the economic efficiency of this storyline (as in e.g. specific CO2 abatement costs).

3.3.4 Storyline 3 – Strong development of hydrogen

This storyline strongly builds on the use of hydrogen as energy carrier in all sectors to achieve an emission reduction of -95% by 2050. Electricity-based technologies (heat pumps, BEVs) cover a low to medium share of sectoral energy demand by 2050. The use of hydrogen and electricity enables an energy system with a good efficiency: lower than in „Strong electrification", but higher than in „Strong development of methane". The 2050 emission targets are met in time. However, only less emission reduction materializes by 2030 due to the missing fast and strong deployment of direct electric technologies in the short-term. Hydrogen will play a strong role in the energy system in the long-term.

General drivers

Battery electric vehicles, electric heat pumps and other electricity-based technologies are available on the market today. However, so far the market penetration of these technologies is low. In this storyline, the expected rapid growth of electric technologies does not materialize. Instead, these technologies develop rather slowly in the medium-term. In parallel, hydrogen technologies are also being developed with increasing effort. The large-scale roll-out of hydrogen technologies gains momentum in the medium-term and greatly impacts the GHG emission reduction after 2030. In combination with a rather slow deployment of electric technologies, the decarbonisation is rather slow until 2030 compared to the other storylines. However, a reduction of -95% is nonetheless achievable by 2050.

Already in the short-term it becomes common understanding that electric and hydrogen technologies together are capable of efficiently replacing fossil energy carriers in almost all applications. As a consequence, rather early the development of fossil and methane-based technologies is significantly reduced and completely stopped in the mid-term. Despite the availability of some renewable methane e.g. from biomass, methane is not used in the transport sector in 2050. Instead, it is used to a very low extent in the heating sector, for power generation and in industry.

By 2050, electricity in combination with hydrogen will become the dominating energy carriers in Europe and worldwide. Hydrogen will have replaced methane (natural gas) as major energy carrier in the heating sector now accounting for about 50% of energy used for heating. In the transport sector, hydrogen has then become the standard fuel being used to power over half of the road transport. Battery electric vehicles contribute a relevant share as well. Hydrogen for all sectors will be produced (centralized and decentralized) in large quantities by water electrolysis within Europe. This production technology will provide significant flexibility (demand side management) to the power sector. Assured power capacity will be provided by hydrogen re-electrification technologies such as gas turbines, CCGT-plants or stationary fuel cells. Hydrogen (and electricity) will be transported and traded throughout Europe thanks to a well-functioning internal energy market and transport infrastructure of relevant capacity. Seasonal and strategic storage of energy will be provided by large-scale underground hydrogen storages (e.g. in salt caverns).

For international and intercontinental energy trade, hydrogen will be transported in gaseous form via pipelines or as liquid hydrogen in large tankers. PtL fuels are mainly used in aviation and maritime transport.

Gas consumption until 2050

Gas demand until 2050 is estimated based on today’s gas consumption and general assumptions regarding possible developments in each sector. Various literature values on gas demand in 2030 and 2050 as well as general assumptions are discussed for each sector in chapter 3.2.2 (Storyline 1: “Strong electrification”). In the following subchapters, relevant assumptions specific to this storyline are described. In fact, most assumption are similar to or the same as in the “strong development of methane” storyline, now using hydrogen instead of methane as energy carrier.

Power sector

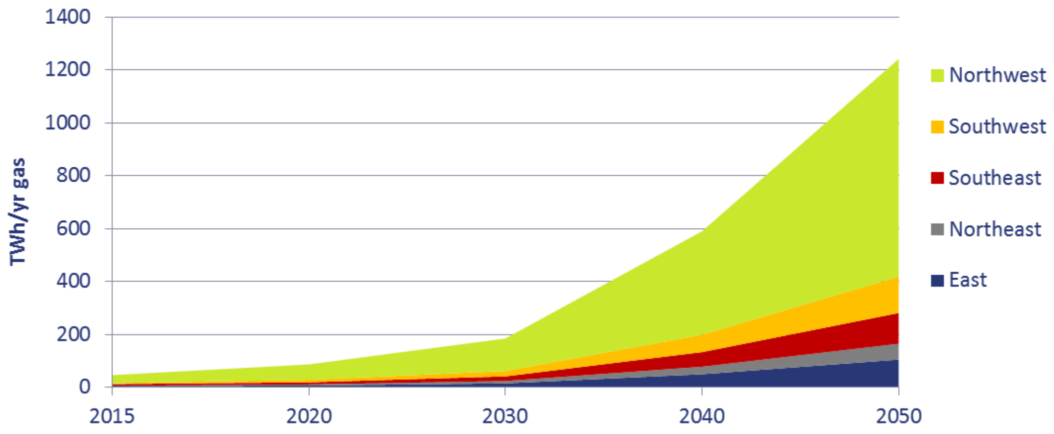
It is assumed that power production from hydrogen and methane has the same efficiency[47]. As a consequence, gas demand in the power sector will remain the same for the “Strong development of methane” and the “Strong development of hydrogen” storylines.

Transport sector

For this storyline, transport demand also increases by 0.5% per year. Compared to the “Strong development of methane” storyline, vehicles with FC-powertrain will be introduced with some delay compared to methane ICE vehicles. This is due to technology and infrastructure developments still required for hydrogen. However, the share of vehicles using hydrogen will also be above 50% in 2050. Gas demand in the transport sector will be significantly lower in this storyline relative to the “strong development of methane” storyline due to the superior efficiency of fuel cell electric vehicles compared to methane ICE vehicles.

[47] Hydrogen fuel cell plants have slightly higher efficiencies compared to H_2 or CH_4 CCGT plants.

Figure 3-23: Development of gas demand in the road transport sector (own assumption)



Gas demand in the road transport sector will increase 12-fold from below 100 TWh/a in 2020 to about 1.200 TWh/a by 2050.

Heating sector

It is assumed that heat production from hydrogen and methane will have the same efficiency in average. As a consequence, gas demand in the heating sector will be the same for the “Strong development of methane” and the “Strong development of hydrogen” storylines.

Industry sector

It is assumed that gas demand in the industry sector will be the same for the “Strong development of methane” and the “Strong development of hydrogen” storylines.

Total gas demand

Gas demand will be slightly reduced between today and 2050. This development will be mainly driven by significant demand reductions in the heating sector, but also in the industry sector. Starting in 2030, a large share of the demand reduction in the above-mentioned sectors will be compensated by an increasing demand in the transport sector. However, due to the rather high efficiency of hydrogen-powered fuel cell electric vehicles, the impact will not be as pronounced as in the “Strong development of methane” storyline.

Figure 3-24: Development of total gas demand per region (own assumption)

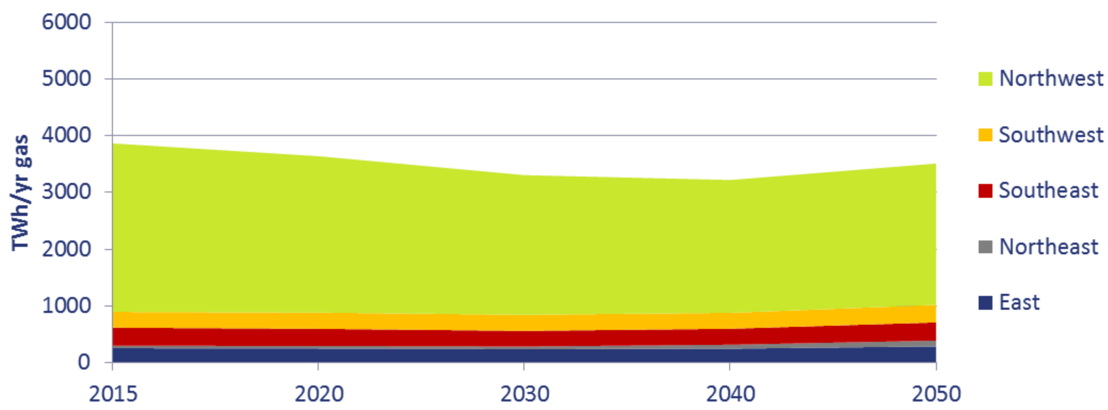
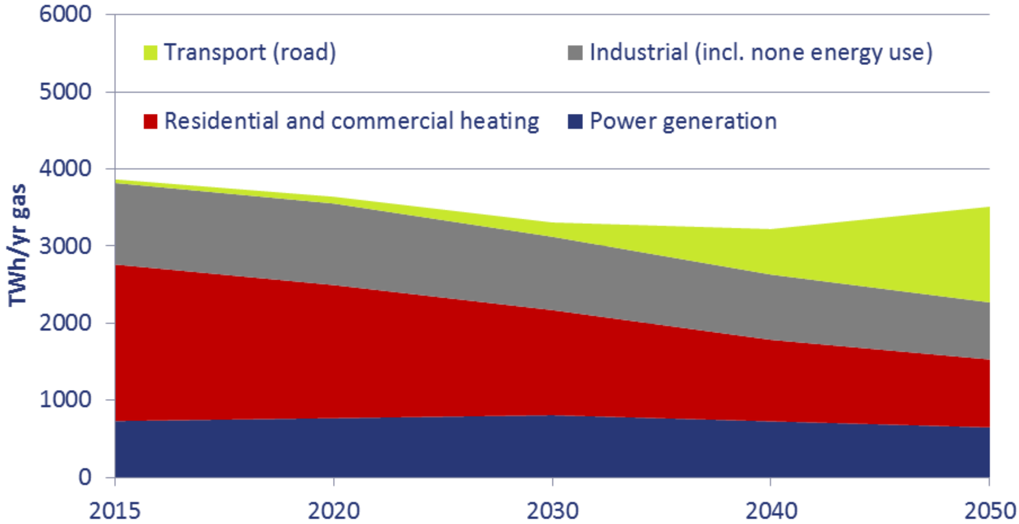


Figure 3-25: Development of gas per sector (own assumption)



Type of gas and gas sourcing

The use of natural gas will be reduced from about 4,000 TWh per year today to about 3,000 TWh in 2030. By that year, minor amounts of CO2-neutral methane and hydrogen will also be used. After 2030, hydrogen replaces natural gas rather quickly. In 2050, hydrogen will completely have replaced natural gas in the energy system. Renewable methane will be used to a low extent in the industry, heating and power sectors.

Figure 3-26: Development of type of gas in the energy system (own assumption)

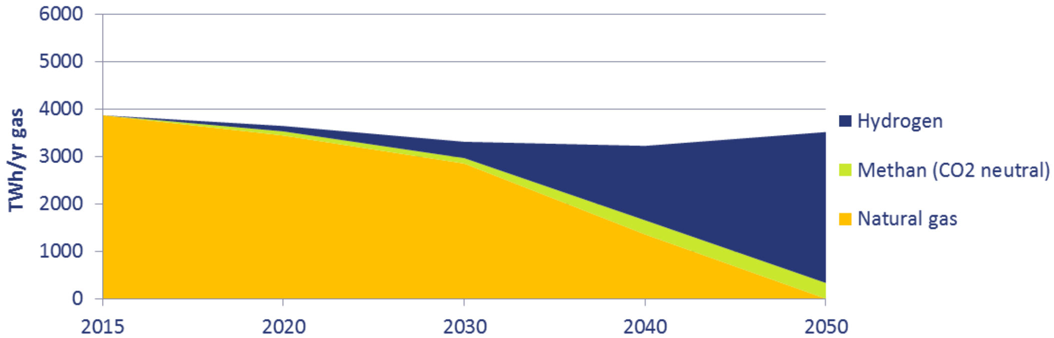
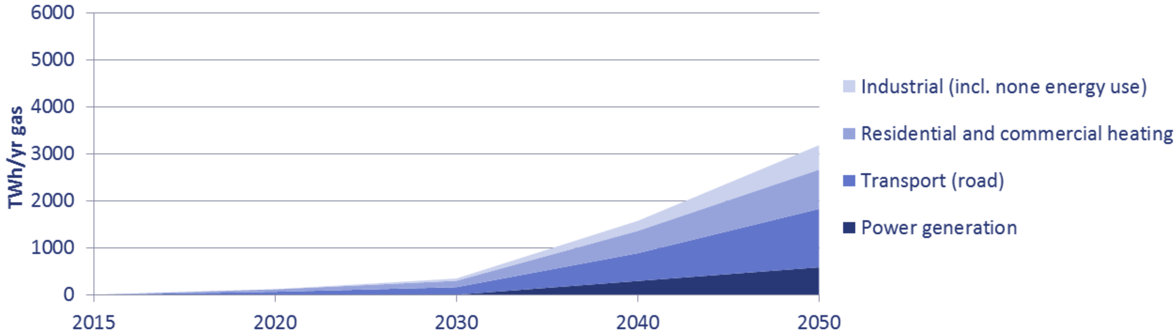


Figure 3-27: Use of hydrogen by sector (own assumption)



Hydrogen from fossil sources (e.g. SMR) might be used to some extent in the medium-term. However, in the long term SMR+CCS will not be considered as acceptable option for large shares of total hydrogen demand. In fact, only the UK and the Netherlands are currently considering CCS. The availability of by-product hydrogen is very limited and will not considered relevant in view of the medium- to long-term demanded quantities. Thus, hydrogen will mainly be produced by electrolysis using renewable (fluctuating) electricity.

Gas infrastructure

In this storyline, the heating sector will experience the same development of gas demand as in the „strong development of methane" storyline. An increased insulation of buildings will significantly reduce the gas demand in the low pressure distribution grids. The main difference in this storyline is that hydrogen instead of methane will be used to substitute natural gas in the grid. This substitution with hydrogen however, is more complex than with methane. Using hydrogen for residential heat production will require the adaption of end user equipment to handle the different burning properties of the gas. Admixture of small amounts of hydrogen (few percent) to natural gas does usually not cause a problem for most burners. However, as in the long-term hydrogen will completely substitute natural gas, it will be required at some point to convert the distribution grids incl. attached users step by step to hydrogen use. This conversion might not only be required within the domain of the end user but also in the distribution gird. For some industrial gas customers even slight changes in the properties of the gas are relevant. Those customers however, are usually not connected to the low pressure distribution grid, but have to be considered when also converting medium and high pressure pipelines to hydrogen or hydrogen-methane mixtures.

Today, very few experience and knowledge for the conversion of gas distribution grids to hydrogen exists. In [Northern Gas Networks, et al. 2016] such a conversion has theoretically been studied in detail for the city of Leeds. Single relevant studies and projects especially for the admixture of hydrogen to natural gas exist. Experience for the conversion of entire grid sections from L-gas to H-gas are available and might be of interest also for the conversion to 100% hydrogen.

Before converting the gas grids to 100% hydrogen, an increasing admixture of the gas to the grid will reduce the specific GHG emissions of the gas in the short-term. However, the admixture of hydrogen to the gas grid will be limited based on the consumer or asset with the lowest tolerance for that gas. This limit can be different for each grid section depending on connected assets (e.g. 2% hydrogen admixture in case a NG refuelling station is supplied). In this storyline, admixture of gas to selected grid sections will continuously increase until 2030. Between 2030 and 2050 entire grid sections will be converted to 100% hydrogen use, e.g. in batches of about 2,500 users as for the example of Leeds. The upcoming L-gas to H-gas conversion of grid sections in Europe due to decreasing natural gas production in the Netherlands will pose a chance for some grid sections to leapfrog H-gas and directly switch from L-gas to hydrogen. By 2050, virtually the entire gas distribution grid will distribute hydrogen. Methane and hydrogen-methane mixtures in single grid sections will play a minor role, but will exist. The distribution grids will be supplied from local hydrogen production assets and/or from the transport grid which is also converted to hydrogen use. Even though first conversion studies exist, the difference in conversion costs and technology options of transport and distribution grid will have to be further assessed in future studies.

Due to technical constraints, a significant reduction of gas (energy) demand in the heating sector will have become a prerequisite of using hydrogen as gas in the pipeline system. Due to different gas characteristics, pipeline transport capacities are significantly reduced when transporting hydrogen instead of methane (at same gas flow speed). This reduction can partly be compensated for in cases where the gas velocity can be increased substantially.

The transport sector will heavily begin using hydrogen as fuel after 2030. In 2050, hydrogen in the transport sector will account for about one third of total gas usage in Europe. In this storyline, the gas demand in the transport sector will be significantly reduced compared to the „strong development of methane" storyline. Although the same share of the transport sector is supplied with gas in both storylines, gas demand in this storyline is about half. This is due to the significantly higher efficiency of a fuel cell (incl. electric motor) over internal combustion engines. Not all of the hydrogen used as vehicle fuel will have to be transported via pipeline. In case of insufficient pipeline capacity or the absence of a gas grid, hydrogen can be produced locally via electrolysis or can be supplied by liquid or gaseous road tanker. Also hybrid supply solutions (e.g. electrolysis + truck) are concepts that are already in use today. Especially for larger hydrogen refuelling stations new pipelines stretches will be installed to close gaps in the gas distribution infrastructure or to increase transport capacities.

In the power sector hydrogen is used to produce power in periods with insufficient renewable electricity production. Those central and decentral power plants are a major source of assured power capacity in the system and will be connected to the gas grid to get access to the large-scale gas storage facilities.

Some industry processes (e.g. production of high temperature heat) can easily be converted to hydrogen while others will require methane (and not hydrogen) as feedstock. This is taken into account by still operating a minimum of gas infrastructure for methane supply to industrial customers. However, this might not be feasible in all cases.

To supply hydrogen from production and gas storage facilities to distribution grids, major parts of the gas transport pipeline system need also be converted to pure hydrogen transport. The pipeline system will also be used for hydrogen trade and transport in Europe and with neighbouring regions. This is enabled by upgrading the system to work (partly) bi-directional (reverse-flow). Central and decentral power plants will also be connected to that infrastructure. Large gas storage facilities will then be connected to the grid to supply energy to the transport, heating, industry and power sector in periods with low renewable electricity and/or gas production. Large-scale underground storage of hydrogen is possible in new or converted salt caverns. The possibility of storage in other geological formations such as e.g. aquifers still has to be evaluated [HyUnder 2014]. Next to central hydrogen sources, also decentral hydrogen production facilities will be developed and connected to the gas grid. In some grid sections this will require the capability of hydrogen flow from lower to higher pressure grid segments.

Hydrogen can be transported over large distances either gaseous by pipeline of liquefied by ocean tanker. This enables an international trade and transport of this gas in large quantities in the future. Hydrogen imports can be used in the future to supplement domestic hydrogen production. This is possible by e.g. converting existing natural gas import pipelines to hydrogen or by installing liquid hydrogen terminals and re-gasification units. As explained in chapter 2.4.4 the liquefied cryogenic gas infrastructures for methane (LNG) and hydrogen (LH_2) are neither compatible nor convertible (both liquefaction processes yields each gas with highest purity). The downstream inland transport (road, train) of liquid hydrogen imports is also an option in this storyline to supply customers that cannot withdrawn their gas demand from the gas grid (e.g. due to missing transport capacities, or due to the absence of a gas grid).

The gas transported in the pipeline grid is likely to be lower (on a TWh/a basis) than today. This is a result of a stable gas demand in combination with alternative gas transport modes and onsite gas production technologies especially for the transport sector.

The significant adaption of the gas infrastructure required in this storyline poses as major challenge, the feasibility has to be considered carefully. However, the required efforts for hydrogen conversion allow for a gas system that is significantly more efficient than when used with CO_2-neutral methane.

Critical appraisal

In this storyline, total gas demand in Europe is slightly reduced. In contrast to the “strong focus on methane” storyline, this reduced use of gas has to do with the increased efficiency of fuel cells over internal combustion engines. The developments in the other sectors are almost identical. However, by adapting central assumptions, a higher or lower gas demand can also be generated in the context of the drivers of this storyline.

In terms of energy efficiency, this storyline is in between the “strong electrification” and “strong focus on methane” scenario. Especially in the transport sector, fuel cells provide a much better efficiency than ICE’s but a lot lesser than battery electric vehicles. This might lead to moderate (absolute) costs of energy production in the long-term. However, additional costs for the development of hydrogen technologies (e.g. fuel cells) are required. Also the conversion of the gas grid to hydrogen transport and distribution might significantly contribute to total economic efficiency of this storyline. However, within the scope of this work it is not possible to draw any conclusion regarding the economic efficiency (as in e.g. specific CO2 abatement costs).

3.4 Ensuring compatibility with PRIMES and METIS energy modelling

3.4.1 Interpretation of numbers and trends from the three qualitative European storylines

For each of the three qualitative European storylines, the gas demand was roughly estimated based on single central assumptions per demand sector (power generation, heating, transport, industry). The assumptions were derived from the literature reviewed in this study. On a regional level, gas demand in the power, heating, transport and industry sector was developed and discussed. In addition to the total gas demand per sector, the type of gas (e.g. share of natural gas, CO2-neutral methane or hydrogen) was assumed. The resulting gas demand in each storyline is directly linked to the assumptions taken. In the context of the general drivers of each storyline, those assumptions could be argued to be somewhat varied e.g. an increase or decrease of the share of hydrogen powered vehicles could reasonably be assumed or a higher or lower share of gas in the heating sector is also plausible. It has to be kept in mind that the numbers generated are not the result of any modelling nor do they claim to reflect a forecast of the future development in detail. The gas demand (numbers) in each storyline should be interpreted as possible trend on the role of gas and should only be used as such.

The graphs shown, and the trends and effects discussed are not meant to be used as input for detailed gas infrastructure or any other modelling. The developed storylines should rather show the spectrum of possible future gas scenarios that could be developed and considered for Europe in the context of deep decarbonisation up to 2050.

Especially in the context of developing scenarios for gas (transport) infrastructure and markets modelling (e.g. PRIMES and METIS), the considered storylines pose new challenges to the modellers. The future (renewable) gas demand in each sector is not necessarily entirely transported via the gas grid. Local gas production (e.g. from biomass or from electricity) and usage might cover a relevant share of gas demand e.g. in the transport and heating sector (e.g. onsite electrolysis and methanation). In addition, alternative transport modes for gases might become more relevant in the future especially for renewable gases. One example is the (road) transport of liquefied hydrogen to refuelling stations for road vehicles. Today, it is unclear to what extent those concepts will be used in the future. Recent studies on this topic are not available. As a consequence, it will be challenging to derive the amount of gas transported in the grid from the storylines developed herein. New methodologies might need to be developed. The structural change from central production and transportation of natural gas to central and decentral production of renewable gases poses an additional challenge. Instead of transporting gas along well known supply chains e.g. from Russia to Europe to Germany to distribution grid and to households, the flow of renewably produced gases in the future is rather uncertain, today. While a certain share of produced gas might be consumed more or less directly and locally, another share might need to be compressed to high pressure to be fed into the transport pipeline. It can then be transported across Europe to be used somewhere else or could be fed into short-, medium or long-term central or semi-central gas storages. The flow of gas might change significantly based on temporary local conditions such as e.g. availability of electricity (and interlinkages between the gas and electricity sectors more in general), local gas demand, SOC (state-of-charge) of gas storages, etc. In addition, strong development of hydrogen would require additional investments in dedicated pipelines, grids and infrastructure, as hydrogen can be blended in the existing natural gas grid up to a certain share (15% on a volume basis) due to technical limitations. As a consequence, the gas system as whole will become more complex compared to today.

3.4.2 High-level description of the PRIMES and METIS models

The objective of this section is to provide the reader with an overview of the PRIMES and METIS models, with an emphasis on the gas sector. These models are extensively used to support the evidence-based policy making process of DG ENER, and of the European Commission more in general. The section concentrates on the description of the models' capabilities and the associated data requirements.

PRIMES

The PRIMES model simulates the EU energy system and markets on a country-by-country basis (E3Modelling, 2017[48]) and provides medium- and long-term projections of detailed energy demand and supply balances, CO2 emissions, energy technology deployment, energy prices and costs. PRIMES simulates a multi-market equilibrium solution for energy supply and demand by explicitly calculating prices which balance demand and supply. Investment is endogenous in all sectors, including for purchasing of equipment in demand sectors and private vehicles, and for energy producing plants in supply sectors. PRIMES combines behavioural modelling following a micro-economic foundation with engineering, technical and system aspects, covering all energy sectors and markets at a high level of

[48] http://e3modelling.gr/images/files/ModelManuals/PRIMES_MODEL_2016-7.pdf

detail. PRIMES can support impact assessment of specific energy and climate policies and measures and can inform policy and decision makers on subjects including:

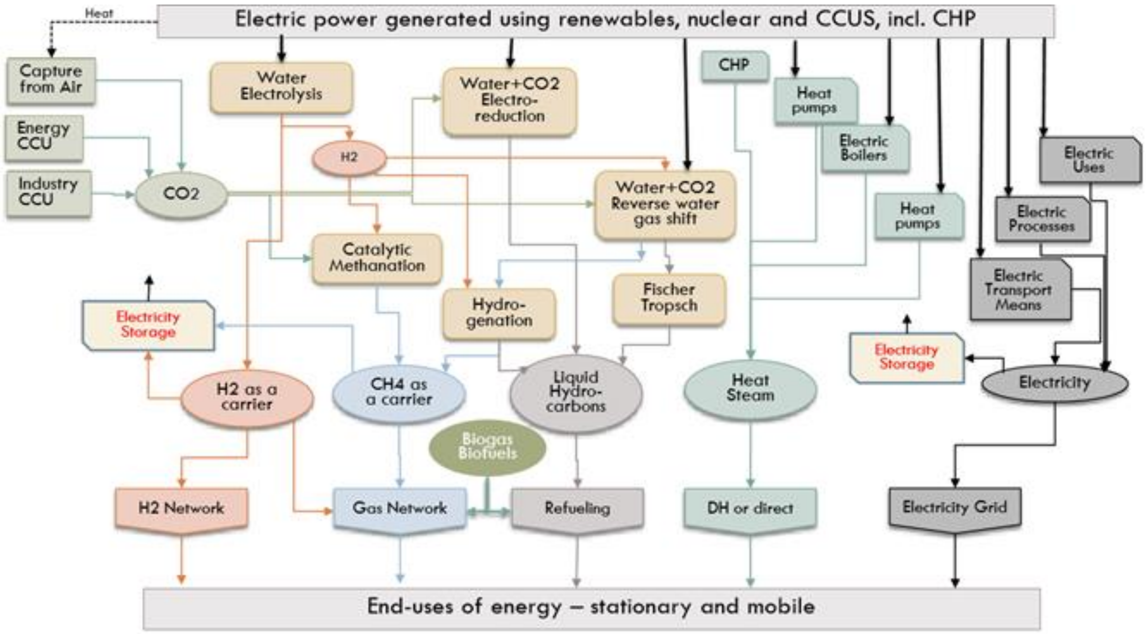
- Climate policy (CO2 emissions reduction and energy efficiency policies by sector);
- Fiscal policy for energy (fuel taxation and/or subsidization, cap-and-trade, ETS pricing);
- Promotion of Renewable Energy Sources (including RES support schemes and Feed-In-Tariffs);
- Regulation and policies to address market and non-market failures for new technologies;
- Impact of market design proposals for internal EU electricity and gas markets;
- Promotion of clean energy forms (including synthetic methane, biomethane and hydrogen).

PRIMES includes a gas supply module (PRIMES-Gas) that provides projections for gas imports by country of origin, by transport mean (LNG, pipeline) and route as well as wholesale gas prices by country. The model covers the entire Eurasian/MENA areas and the global LNG market and presents in detail the gas infrastructure and the different "agents" that participate in the market. The agents compete for access to gas infrastructure and for gas supply to customers, the latter being responsive to gas prices. The model can accommodate different assumptions about the degree of competition and the integration of the EU gas internal market.

PRIMES-Gas uses as input the gas demand projections developed by PRIMES, both in end-use sectors and electricity generators. The model captures seasonal gas demand variation by representing a number of typical days per season, while gas load derives from the aggregation of sector-specific gas use patterns. PRIMES-Gas optimises the use of gas infrastructure (pipelines, LNG, storage, production capacity) to meet gas demand at the lowest cost, while satisfying all technical and engineering constraints of the entire gas production chain and infrastructure. Thus, the flow of gas over the entire network, the economic decisions of the agents and the market prices are endogenous and are computed dynamically. The operation of infrastructure and related gas flows are constrained by a physical system involving pipelines, LNG terminals, gas storage facilities, liquefaction plants and gas producing wells. The interregional flows of gas are derived from a gas transport network consisting of high-pressure gas pipelines and ship routes for LNG. A simplified representation of the physical gas pipeline system is used to establish interregional transfers, allowing gas transfers from the producers to end-users. PRIMES-Gas allows for transit pipelines and reverse gas flows in cases of bidirectional pipelines, while it captures specific elements of the gas sector, including modelling of storage (injection and withdrawals from storage facilities), long-term contracts (both pipelines and LNG) and variability margins of flows over pipelines, reflecting physical and/or contractual limitations.

PRIMES can also analyse the costs and future role of synthetic fuels, hydrogen, electricity, heat, and power storage, as well as the synergies and competition between them in the deep decarbonisation context. PRIMES simulates hourly operation of the interconnected electricity, hydrogen, gas, heat, steam and synthetic fuels systems in a synchronised way. The model includes alternative pathways for the production of hydrogen and synthetic methane. PRIMES also captures the operation of power storage systems (batteries, pumped storage, chemical storage) and the competition for carriers that can serve different purposes for different customers (power generators vs. synthetic fuel factories). PRIMES fully-fledged modelling of the entire energy system ensures consistent integration of hydrogen, synthetic methane, biomethane, synthetic liquid hydrocarbons, biofuels and heat into the overall energy demand and supply system by endogenous fuel choices in the demand sectors, i.e. calculating the share of synthetic methane vs. hydrogen (and petroleum-based fuels) used by cars and trucks. PRIMES solves all EU countries simultaneously in order to capture the trade of carriers and expansion of infrastructure (power grids, gas, hydrogen infrastructure network and distributed heat). By representing the complex interlinkages between the gas, electricity and hydrogen sectors, PRIMES can consistently evaluate the role of sectoral integration in the energy system decarbonisation context.

Figure 3-28: Process flow diagram of the new PRIMES sub-model including hydrogen and power-to-X

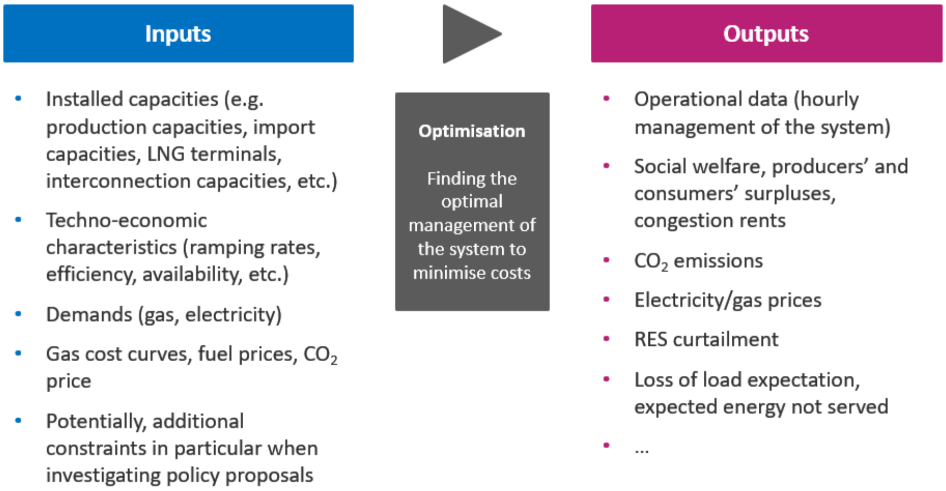


METIS

METIS aims at simulating the operational management of the European energy system by minimising the total cost (investment costs, fuel costs, start-up costs, no-load costs, CO2 costs, etc.), while meeting the demand and respecting all technical constraints (e.g. ramping rates, minimum stable generation, storage injection and withdrawal rates, etc.). The simulations typically use an hourly time resolution and a Member State level spatial granularity, and factor in uncertainties e.g. due to weather variations or outages[49]. The following figure provides an overview of the inputs and outputs of METIS. It should be noted that METIS can run in several configurations (electricity-only, gas-only, joint gas and electricity dispatch, with or without capacity expansion, etc.). The set of inputs and outputs can therefore change depending on the configuration that is chosen (e.g. cost-curves and potentials have to be provided when using the capacity expansion features of METIS).

[49] METIS is also capable of handling finer time resolutions (e.g. 5-minute balancing activation simulations have been carried out in METIS Study S12) and/or finer spatial granularity (e.g. at the NUTS2 level).

Figure 3-29: Overview of the METIS inputs and outputs (without capacity expansion)



METIS has been designed to provide decision-makers with quantitative insights on topics such as:

- Resource adequacy assessment (e.g. ability of the system to meet adequacy standards, evaluation of additional investment needs, impact of assessing adequacy at the national, regional or European level, etc.);
- Impact of market design proposals (e.g. electricity balancing reserves' procurement rules, design of gas tariffs/fees, etc.);
- Cost-benefit analysis of infrastructure projects (e.g. new electricity interconnector, new gas storage, etc.) taking into account the interlinkages between the gas and electricity sectors where relevant;
- Assessment of future flexibility needs and the role of different flexibility solutions;
- Role of power-to-heat and power-to-gas technologies;
- Impacts of new electricity and gas end-uses on production costs and infrastructure needs (e.g. heat pumps, hybrid heat pumps, electric vehicles, gas mobility, etc.).

All the studies that have been carried out using METIS are available on the webpage dedicated to METIS: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

Figure 3-30: Overview of the METIS gas market model

The METIS gas market module, which would be used to analyse the scenarios built from the storylines discussed in this report, takes as inputs the installed capacities and investment options (production, storage, transmission, liquefaction, regasification, power-to-gas, etc.), their associated investment and operational costs (e.g. cost-curves for production), and the gas demand. METIS then optimises the use of and investment in infrastructure to meet the demand at the lowest possible cost, while satisfying all the technical constraints of the different elements along the gas value chain. The precise list of inputs can be found in the annex.

Focus on interlinkages

METIS is able to represent interlinkages between energy carriers. For example, it includes a fully coupled gas-electricity model where the operations and investments on both networks can jointly be optimised. We present in the following paragraphs the required datasets for the interlinkages that are discussed in the different storylines that have been presented in this report:

- Gas-to-power (for each cluster of gas-fired generation plants): installed capacity per zone, technical parameters (efficiency, min load, min time off, ramping rates, reserve procurement constraints, etc.), operational costs (variable costs, start-up costs, no-load costs, etc.);
- Electrolysis /methanation: installed capacity per zone, technical parameters (efficiency, min load, min time off, ramping rates, reserve procurement constraints, etc.), operational costs (variable costs, start-up costs, no-load costs, etc.), maximum hydrogen injection into the gas network, hydrogen demand by zone (in addition to injection into the gas network: industry, mobility, etc.);
- Biomethane: installed capacity per zone, production profile, production cost curve.

Where the investments are to be optimised, one should provide the associated costs (CAPEX, OPEX, etc.) and potentials instead of the installed capacities.

3.4.3 How to translate storylines into PRIMES and METIS modelling inputs?

The objective of the section is to highlight how alternative storylines reflecting different possible directions in which the gas sector could evolve can be translated into inputs to PRIMES and METIS models.

PRIMES

Hydrogen and synthetic fuels if produced with renewable energy are also considered as renewable sources. All decarbonisation storylines have clear positive impacts on EU energy security of supply as they lead to significant reduction of energy import dependence. The extent to which the production of clean synthetic methane, biomethane and hydrogen is located in the EU drives the energy security impacts for EU countries.

Storyline 1 – Strong electrification

This storyline seems initially less complex relative to the other decarbonisation pathways and requires lower increase in electricity production compared to storylines based on clean gas and hydrogen (due to the high efficiency of the electric end-use equipment both in stationary applications and in transport uses). However, it would require the full electrification of all end-use sectors to achieve near-zero emissions and this entails high challenges for industry and transport. In industry, complete electrification is very difficult without considerable changes in production processes. Even though significant advancements in heat pumps are possible, there are specific uses in industry that is technically difficult to supply solely by heat pumps. In transport, extreme solutions such as electric aviation and shipping would need to succeed, or alternatively massive production of advanced fungible biofuels will be necessary. In this storyline, electricity is the single energy carrier for all consumers, which may cause concerns in case of lack of sufficient reliability.

To model this storyline, PRIMES would assume a series of electrification-promoting policies in end-use sectors coupled with accelerated technology progress of electric cars and batteries, heat pumps, and electric arc furnaces. In transport, this includes tighter CO2 standards for LDVs and HDVs, fast electrification of cars, vans and busses, penetration of battery and trolley based truck systems, and a niche market for electric planes. In buildings, the storyline is driven by strong penetration of heat pumps in heating combined with ambitious energy efficiency policies. In industrial sectors, the storyline involves strong electrification of heating purposes, including steam generation as well as of industrial processes (e.g. electric arcs).

Storyline 2 – Strong development of methane (CO_2-neutral)
The storyline assumes highest deployment of electricity-based synthetic methane in transport, heating and industry and for electricity storage. The main advantage of the storyline is that end-use sectors do not require major changes of equipment and infrastructure. However, carbon-free gas requires strong development of technologies which are still far from reaching market maturity (i.e. direct carbon capture from air). In addition, this storyline requires very high amounts of electricity to produce clean synthetic fuels; this implies relatively high investment costs and poor overall energy efficiency.

To model this storyline, PRIMES would assume a series of policies to promote synthetic methane in end-use sectors combined with accelerated progress and deployment of related technologies. Extensive investments in R&D are required to drive down the costs and ensure timely development of technologies related to the CO_2-neutral methane (electrolysis, catalytic methanation, direct carbon capture from air). Priority should be given to finding suitable policy instruments to enable emergence and widespread adoption of clean methane technologies, and facilitate market coordination more effectively. Building the right scale of penetration of synthetic gas in the EU's energy mix is crucial for the timely development of economies of scale. In transport, development of synthetic methane can be driven by strong technical progress coupled with strong policy signals and specific support schemes. In buildings, strong efficiency policies are combined with increased penetration of electricity-based methane in heating uses. The large-scale use of clean methane in gas distribution grids might be driven by setting specific standards for zero-carbon gas in the gas network. The development of clean methane in industrial applications implies limited changes in industrial processes and infrastructure. In addition, vehicles using clean methane exhibit no range limitations (in contrast to battery electric vehicles) and therefore synthetic fuels could be more easily adopted by transport consumers.

Storyline 3 – Strong development of hydrogen
Hydrogen can be used as a carbon-free energy carrier in all consumption sectors, as a provider of versatile electricity storage and as a feedstock for the production of carbon-free methane. The production of hydrogen should be based on carbon-free electricity through electrolysis or from natural gas steam methane reformed equipped with CCS to be compatible with EU decarbonisation targets. The electrolysis-based production chain can benefit from large economies of scale, especially for alkaline water electrolysis, Proton Exchange Membrane (PEM) and Solid Oxide Electrolyser (SOEC). Several technologies required for the development of a hydrogen economy are not yet market mature, and high

uncertainties surround their future performance regarding costs, efficiency and the timing of readiness. The large-scale development of H2 implies increased electricity requirements, while hydrogen availability allows smoothing of the load variations thank to the chemical storage services and hence allows further exploitation of RES resources without curtailment.

To model the hydrogen storyline, PRIMES would assume accelerated progress and deployment of related technologies, including economies of scale in electrolysis. The penetration of hydrogen in transport can be facilitated by technology neutral standards, the design of appropriate policy frameworks and accelerated progress in fuel cells. Hydrogen use in passenger cars can solve issues related to range limitations that limit the use of batteries for long-distant trips, while H2 can also be applied to heavy-duty vehicles and inland navigation. Hydrogen can be used in industries for energy purposes (high temperature heat) and in non-energy uses (process feedstock). Fuel cells are difficult to be used in high-temperature industrial applications due to costs and technical issues, but instead direct injection of hydrogen in furnaces is a valid option both from a technical and economic perspective in deep decarbonisation.

In the storyline assuming widespread use of hydrogen and fuel cells in buildings, a fully-fledged H2 infrastructure and distribution system would have to develop in the long term. Building the right scale of hydrogen penetration in the fuel mix is crucial for economies of scale, which has to be justified in the light of deep decarbonisation targets. Adaptation of existing gas distribution infrastructure is technically possible. In an intermediate phase, hydrogen can be blended up to 15% on a volume basis in existing gas grids to take advantage of the gas infrastructure. However, in the long-term the grid should eventually be adapted to H2; the end-use equipment has also to be converted for hydrogen burning for mixtures beyond the 15% blending limit. The large-scale development of H2 in gas distribution grids can be driven by standards and mandates for zero-carbon gas in the network. The development of the H2 distribution system has to be accompanied by hydrogen storage at a large-scale. Small-scale storage systems (pressurised tanks and tubes storing liquefied H2) could develop in early stages of the transition to facilitate specific H2 uses in transport and in industry.

There are two possible business models for hydrogen, which are both represented in PRIMES: decentralised production close to end-users or centralised hydrogen production. The latter might be the preferred long-term option due to economies of scale for large-scale electrolysis. The business models imply different infrastructure requirements, as local hydrogen production and usage (onsite electrolysis and methanation) might cover a share of future gas demand, while alternative transport modes might become more relevant (i.e. road transport of liquefied H2 to refuelling stations for road vehicles). The structural change from centralised production and transportation of natural gas to central and decentral H2 production poses an additional challenge to modelling, as the flow of renewable H2 in the gas grid is rather uncertain and the gas system will become more complex compared to today (local production and consumption, transport of compressed high-pressure H2 with pipelines to be fed into gas storage). The successful development of H2 requires effective and timely market coordination in the entire chain of technology and infrastructure providers, end-use consumers, upstream hydrogen producers and policy makers. In this context, long-term anticipation, policy predictability and regulatory certainty are of utmost importance for market coordination.

Integration of storylines into PRIMES energy system model

In order to produce model-based scenarios for EU deep decarbonisation with PRIMES based on the developed storylines, the process is to translate qualitative storyline assumptions into quantitative modelling inputs, with regard to: technology costs and their evolution, development of infrastructure (gas supply capacities and pipelines, storage, LNG, power interconnections, hydrogen production, storage and distribution) and related costs, specific support policies, measures to promote clean synthetic methane and/or hydrogen (i.e. standards for zero-carbon gas in the network), fuel mix in end-uses and technical progress of mitigation options. This input can be generated through a combination of expert judgment and a dedicated modelling exercise.

PRIMES provides a comprehensive analytical framework to capture the interlinkages between energy carriers and can be used to perform a scenario-based analysis to represent the alternative storylines. PRIMES can consistently estimate and quantify the energy system, economic, security of supply, and emission impacts of alternative scenarios, each focusing on a specific decarbonisation carrier (electrification, synthetic methane, hydrogen) and can assess the effects of investment in infrastructure (related to the power, gas and hydrogen network). PRIMES can also perform a comprehensive sensitivity analysis by changing the value of key model parameters (e.g. technical progress in fuel cells, batteries and electrolyses, fuel prices) in order to assess their impacts on deep decarbonisation pathways. The PRIMES modelling can support the European Commission in the impact assessment of energy and climate policies and the quantitative analysis of costs and benefits of gas infrastructure developments including synthetic gas, biomethane and hydrogen.

In addition, the PRIMES modelling can provide a sound basis for validating and benchmarking technology assumptions for future technology options by type of gas and production chain used in large-scale models (focused on synthetic methane and hydrogen). The PRIMES model includes the entire chain of alternative production pathways, transport, conversion, storage, distribution and application of hydrogen, synthetic methane and biomethane, so the technical and economic characteristics of all stages have to be quantified and validated.

The added value of fully-fledged energy system modelling

The developed stylised storylines show the spectrum of possible future gas scenarios to be considered in the context of deep decarbonisation of the European energy system. The trends depicted in these storylines are not meant to be used as an input for detailed gas infrastructure or energy system modelling. The storylines are based on simplified, extreme and highly contrasted assumptions in order to explore a wide spectrum of potential developments of the EU gas sector in the deep decarbonisation context. Analysis with fully-fledged energy system models is required to explore the benefits of alternative strategies towards zero-emissions and quantify the synergies and trade-offs between decarbonisation carriers and alternative pathways to zero emissions. Model-based analysis can produce robust quantifiable results for the impacts of decarbonisation scenarios including sectoral integration of electricity, hydrogen, heat and gas markets.

The integration of energy sectors is crucial for the transition to a decarbonised system. The PRIMES model captures the following integration aspects:

- Hydrogen production through electrolysis (mainly from RES-based electricity);
- Power to Gas, and the use of H2 and clean gas in decarbonising the gas grid;

- The use of carbon-free hydrogen in industry (in high temperature applications and as a feedstock);
- Linking the power and mobility sector, both via electricity and hydrogen;
- Linking the power and heating sector, both in buildings and industrial uses;
- Analysing deep decarbonisation strategies and the contribution of clean gas and hydrogen.

In this context, it is clear that the complexity of the decarbonisation challenges cannot be solved just through single technological solutions. Decarbonisation requires deep changes at the system level with increased deployment of multiple technologies and disruptive systems that fully exploit innovation potential. A system-level approach is thus required to capture the complex interactions and linkages between different sectors and explore the synergies and trade-offs of alternative decarbonisation options. As an example, the storyline assumptions for electricity and gas use in residential and transport are rather artificial; in most model-based decarbonisation pathways, electricity is extensively used both in stationary uses and in transport due to its economic and efficiency advantages, while low-carbon scenarios differ mainly in the mix of gaseous fuels (natural gas, synthetic methane and hydrogen) consumed in stationary uses. The system-wide modelling would also capture the impacts of alternative storylines on biofuels. The wide use of hydrogen in trucks and in high-mileage passenger cars would free biomass amounts, which can be used to produce advanced biofuels for aviation and inland navigation leading to near-zero emissions from the transport sector. On the other hand, the storylines capture adequately the very high amounts of electricity required to produce hydrogen and synthetic methane, which could ultimately cause pressures on RES potentials.

METIS

Modelling of sectoral integration and interlinkages

By design, METIS is a multi-energy model that aims at capturing the impacts of the interlinkages (synergies, competition, interdependencies) between different energy carriers (e.g. gas, electricity, heat, etc.). The model can therefore investigate topics such as:

- Role of gas-to-power in the integration of renewables (and competition with other flexibility solutions such as storage, demand-response, interconnectors, etc.);
- Impacts of different scenarios on the gas peak consumption and the use of infrastructure (e.g. gas storage);
- Role of power-to-gas in the integration of renewables (and of power-to-gas-to-power as an alternative to seasonal storage);
- Potential competition between gas and power infrastructure projects;
- Impacts of different scenarios on end-uses (e.g. heat-pumps, role of hybrid heat-pumps, electric mobility vs gas mobility, etc.).

Particularly relevant here is the ability of METIS to provide insights into the role of technologies such as P2X (power to hydrogen, power to gas, power to heat), for example by investigating their economic profitability in different settings (e.g. depending on the CO2 price, on the share of renewables, etc.) through sensitivity analyses. By capturing the interlinkages between the gas and electricity sectors, METIS can help determine where synergies between the gas and electricity infrastructures can help decarbonise the energy system cost-efficiently.

The added value of fully-fledged energy system modelling

As mentioned previously in the case of the PRIMES model, the storylines developed during these studies do not have an immediate translation in terms of modelling inputs, but rather provide insights into different contrasted futures of the gas sector. Since the objective of this study was not to produce detailed scenarios of the evolution of the infrastructure, of national production capacities, of the LNG market, etc., the following process should be undertaken in order to assess the economic impacts of each of the scenarios:

1. Translating the storylines into scenarios: in the case of METIS, this means that all the inputs listed in the annex should be produced. In particular, the development of infrastructure can either be provided as an input into METIS and therefore has to be generated either through expert judgment or via a dedicated modelling exercise, or can be determined through METIS capacity expansion features;
2. Running METIS based on the scenarios representing the storylines: once the scenarios are available[50], METIS can be run in order to:
    a. Compare the economic and environmental impacts (incl. social welfare, gas prices, CO_2 emissions, RES integration, security of supply, supply source dependence, etc.) of each of the scenarios against each other, or against a common counterfactual;
    b. Assess the economic profitability of infrastructure elements: by comparing the revenues of some of the infrastructure elements with their annual costs (annualised investment costs and variable costs), METIS can assess the underlying value of these infrastructure projects, and provide insights into the potential need for a form of financial support to ensure that a credible business case exist for such projects.

In summary, METIS provides a sound analytical framework that can capture the interlinkages between the different energy carriers (gas, electricity, heat, etc.). METIS can be used to perform a number of analyses starting from the scenarios representing the storylines:

- Security of supply: what is the supply source dependence? How does it compare between scenarios? Are there any impacts in terms of electricity security of supply?
- Technology choices: how do the assumed infrastructure perform (economic profitability)? Could other technologies emerge (e.g. competition between gas heating and heat pumps)? Could Power-to-X become a competitor to steam methane reforming for the production of hydrogen? How do different mobility options compare (e.g. electric mobility versus natural gas vehicles)? What is the impact of Power-to-X on RES curtailment?
- etc.

Importantly, METIS users can easily change any of the model parameter (directly in the user interface) so as to independently perform sensitivity analyses (e.g. CO_2 price, RES deployment, fuel costs, presence/absence of a given infrastructure project, etc.). Modelling, in particular with METIS, can therefore help support the European Commission in its evidence-based policy making process by assessing and benchmarking the role of the various infrastructure elements of the scenarios, and the dependence of these roles on exogenous parameters through sensitivity analyses.

[50] A first calibration step will consist in ensuring that the scenarios are well-dimensioned (i.e. that the demand can be met at all times). This may not automatically be true since the scenarios might have been produced using tools that do not include the same representation of weather patterns as in METIS (50 climatic years at the hourly level).

Translation of storylines into inputs for METIS

The METIS model has been designed so as to work in conjunction with the other modelling tools that are used by the European Commission (PRIMES and POTEnCIA). METIS is primarily focusing on the analysis of the operational management of the energy systems and markets. The infrastructure needs can either be provided exogenously or calculated within METIS. The METIS inputs (installed capacities/investment options, techno-economic characteristics, demand, etc.) are listed in the annex.

A number of different approaches can be combined to translate the storylines into scenarios:

- **Dedicated third-party exercises**: should E3M, the JRC or another entity produce the required inputs into METIS based on their respective tools (e.g. demand produced via PRIMES or POTEnCIA, infrastructure deployment by JRC, etc.), these inputs would be easily integrated into METIS to produce a new scenario[51]. As the outputs of these tools might not match the spatial/temporal granularity used in METIS, some elements might have to be based on other approaches such as capacity expansion and/or expert judgment (e.g. hourly time-series would be chosen from the existing METIS database).

- **Expert judgment**: a second approach is to base ourselves on third-party scenarios that already exist (e.g. ENTSOG TYNDP scenarios). The degree of resemblance between the storylines and the third-party scenarios would have to be assessed, for example based on spider graphs representing the role of the various technologies discussed herein (hydrogen, mobility, biomethane, power-to-X technologies, etc.), the magnitude of the gas demand, the centralised/decentralised nature of gas production, etc.

- **Capacity expansion**[52]: METIS can be used in a capacity expansion mode (investment planning). The model can thereby assess the need for infrastructure in a multi-energy setting taking into account the synergies and complementarities between the gas and electricity sectors. Prior to being able to use that option in the case at hand, expert judgment and/or a dedicated third-party exercise would have to be used to disaggregate the demand per country, to determine the set of investment options per country and their associated costs and potentials, and to evaluate what the level of residual capacities is.

In the current METIS project, a combination of the three approaches is used when generating new METIS scenarios and carrying out METIS Studies.

Once the storylines developed herein are translated into quantitative assumptions, METIS enables analysts and decision-makers to carry-out a number of analyses, such as:

Storyline 1 – Strong electrification

- What are the impacts of a full electrification of the heat sector? How does the choice between conventional heat pumps and hybrid heat pumps influence the dimensioning of the electricity generation installed capacities?

[51] As mentioned previously, a careful calibration phase is necessary to ensure the scenarios that are provided allow to meet the demand at all times, including during stress periods.

[52] The “Mainstreaming RES – Flexibility portfolios” study where the investments in flexibility solutions have been calculated so as to integrate RES cost-efficiently is an example of how capacity expansion can help define new scenarios.

- What is the role of vehicle-to-grid to help balance supply and demand? How do real-time pricing and time-of-use pricing compare?
- What set of technologies provide seasonal flexibility? How does this compare to a case where power-to-gas is being deployed? How does the CO_2 price impact the analysis?

Storyline 2 – Strong development of methane (CO2-neutral)

- What is the sensitivity of such a scenario to the cost of electrolysis equipment and methanation technologies?
- What is the business case for hydrogen production (instead of steam methane reforming), where is it located and how does it depend on the generation mix?
- How do hydrogen- and methane-powered mobility compare?

Storyline 3 – Strong development of hydrogen

- What is the optimal balance between using electrolysis and steam methane reforming (coupled with carbon capture and storage) to produce hydrogen?
- Could a nuclear power play a role in supplying cheap electricity for electrolysis?
- Is there a business model for local methanation projects?

4 Interim conclusions

The major objective of this part of the study was to examine the role of the gas infrastructure in a future European energy system in line with the European GHG emission reduction targets until 2050. In this context, Task 1 provides an overview of different storylines developed by various stakeholders from industry, policy makers, research and NGOs derived from an extensive literature research. Based on the main insights from the literature review, Task 2 develops well-reasoned storylines for the expected development of the gas sector in Europe until 2050 in an ambitious decarbonisation context[53].

Categorization of existing storylines according to expected gas demand and decarbonisation level

In general, the existing storylines can be classified according to three major criteria: (1) decarbonisation level of the energy system, (2) role of gas in the energy system (energy demand and supply) and of gas infrastructure and (3) type of gas (namely natural gas with CCS – which does present a 10% CO_2 leakage in practical applications - , synthetic methane from $PtCH_4$, biomethane and hydrogen from PtH_2). In this context, the literature research reveals four different storyline categories with different characteristics. In the first storyline category (referred to as “Green gases expansion”) the gas demand remains high until 2050, but the GHG emission targets will be achieved through a switch of gas type from fossil natural gas to synthetic methane, biomethane or renewable hydrogen. The storylines in the second category (referred to as “Green energy efficiency”) typically achieve the same level of decarbonisation and utilise the same types of gas. The overall gas demand, however, decreases as electricity becomes the major energy carrier mainly due to the better overall efficiency of direct power use in all demand sectors. In the third storyline category (referred to as “Fossil energy efficiency”), the overall gas demand also decreases, but the GHG emission reduction targets are less ambitious, typically less than 80%, whereas this study takes the 95% reduction as starting point for the storylines.

Therefore, in such storylines fossil natural gas is used in selected niches to stabilize the renewable energy system (e.g. through the use of fossil natural gas fuelled gas turbines). The threat of devalued or stranded assets of the gas infrastructure is high in the second and third storyline categories as the existing infrastructure designed for current gas demand will be not needed anymore if gas demand decreases significantly as proposed by such storylines.

Finally, in the fourth storyline category (referred to as “Business as usual”), fossil natural gas is used in the same way as today or even more extensively mainly in order to substitute other more CO_2-intensive fuels such as coal and petroleum products. Obviously, this leads to the highest GHG emissions often failing to achieve ambitious environmental goals. However in order to avoid the GHG emissions, some storylines in this category also advocate the use of CCS technology in combination with steam methane reforming (for hydrogen production) and coal gasification (for hydrogen or synthetic methane production).

Level of detail and ambition of the existing storylines

The analysed literature varies significantly in terms of methodology and level of detail of publications although no studies have been identified which take into account full coverage of the European Union at country level granularity, an hourly time resolution, a timeline until 2050 and a climate ambition of

[53] In this context it is noted that some players prefer the term defossilization as it denotes that fossil based carbon energy carriers should be phased out, allowing renewable carbon based fuels such as biomethane to be used beyond 2050, paying tribute to a sustainable and circular use of carbon.

95% GHG reduction by 2050. The statistical analysis of more than 100 individual storylines, which have been identified as relevant in the context of this study, reveals a correlation between CO_2 emission reduction and both gas demand (the more ambitious the environmental target the lower the gas demand) and type of gas (the more ambitious the target the less likely the use of fossil natural gas and more likely the use of synthetic methane, biomethane and hydrogen). Most of the reviewed storylines predict a moderate to strong decrease of gas demand in the future energy system and CO_2 emission reduction levels of at least 80%. Interestingly, the level of ambition of protecting the global climate in different studies increases with the year of publication coinciding with concrete events such as the nuclear disaster in Fukushima or the signing of the Paris Agreement. –A number of stakeholders developing storylines seem to have become more and more aware in recent years of the urgency for action in view of ambitious climate targets for 2050, a timeframe of only 32 years into the future.

Major results of the existing storylines

In general, the majority of storylines assessed agreed in a holistic future key role of the gas infrastructure, its value and ability to store energy at large scale and across seasons, to efficiently transport energy at large scale and to supply industry with an energy carrier and chemical base material simultaneously. As such the gas infrastructure's role is believed to change to not only providing flexibility to the electricity system but also as an infrastructure in its own rights to provide energy services and material supply for other large energy users such as transport and industry. Outstanding examples are the use of gas in chemical and other industry such as steel making as well as fertilizer, methanol and polymer production. In order to become fully effective, sectoral integration of the end-use sectors (households, mobility, industry, agriculture) and energy infrastructures (electricity, gas) has been identified as mandatory by some of the storylines, to be pursued and supported politically by an adapted regulatory framework in the short-term.

The analysis of the relevant storylines reveals that the majority of the studies predict a decreasing gas demand for heating uses due to significantly improved building insulation and due to the substitution of significant shares of today's gas-based heating appliances by more efficient electric heat pumps. However, this development does not necessarily result in a decreasing overall gas demand as the reduction in the heating sector can be compensated by an increase in other sectors such as transport or industry (e.g. steel industry). Hence, the future utilization level of the gas infrastructure depends on the respective strengths and magnitude of the opposing trends from above. Although the assumptions, approaches and results in most of the analysed storylines are reasonable, some studies leave open questions with respect to the use of fossil natural gas in an almost fully renewable energy system. Biomass potential[54] transparent comparison of all technological options, limits for the electrification in specific energy demand sectors (e.g. heavy duty vehicles) and consistent energy price assumptions are the most important.

From a technological perspective, almost all the alternative and advanced gas technologies have reached a high technological readiness level of at least 7 and have either already been introduced to the market commercially, or are close to this stage. In addition, biomass potentials in Europe are limited. Moreover, synthetic methane is exposed to potentially high CO_2 supply costs as biogenic CO_2 resources are strongly decentralized and limited in availability, and CO_2 extraction from air is costly. Hydrogen and fuel cell technologies have only recently started commercialization and need to be

[54] None of the studies on biomass potential consider the aquatic biomass potential.

integrated into the energy system in order to achieve the necessary ramp-up in the energy market. Also, hydrogen used in the gas grid would require an adaptation of the existing gas infrastructure and possibly larger transport and storage capacities taking into account the lower energy content of hydrogen per volume compared to methane. However, as hydrogen and fuel cells enable the gas infrastructure to better harmonise with the electricity grid for efficiency reasons and because they represent customer-friendly end-use technologies hydrogen and fuel cells have been pointed out as energy technologies of possibly 'disruptive' nature. Countries like China entering this market seriously could have a big impact on any current cost-projections and feasibility assumptions.

The literature review also shows that the different CO_2 emission reduction targets of -80% and -95% lead to significantly different designs of the future energy system. Although in the -80% case fossil natural gas still is a good source for balancing fluctuating power generation, in the -95% case the power, heating and transport sectors must become fully zero carbon by 2050 squeezing out all fossil fuels from the market. In this case, the required flexibility in the energy system will have to be provided by renewable gases such as synthetic methane, biomethane or hydrogen and other measures such as demand response / demand side management, trans-European power exchange, etc. Moreover, the role of large-scale energy storage and renewable energy imports will become increasingly important. In addition, recent studies explicitly warn of methane leakages from natural gas extraction and transport with a GHG impact of about a factor 34 or 86 higher than from CO_2, in particular for shale gas, with a severe impact on global climate change. Such increased methane emissions have been identified as potential roadblock for alternative natural gas production by some studies. The same might go for the future of piped imports from suppliers with a jurisdiction in which methane leakage at source and in transport to the EU border are not addressed.

A number of storylines stress that strong decarbonisation of the future energy system will necessitate behavioural changes of the end user such as different mobility habits and more resource-saving lifestyle. Moreover, the societal acceptance of new energy infrastructure projects such as new overhead high voltage power lines, the costs of DC undergrounding, CSS, or the use of appliances compatible with the new renewable gases will become crucial for an important future role of gas in the energy system. In this context, missing public acceptance with respect to the above-mentioned issues could become a major roadblock.

The assessment of the existing storylines also reveals that Eastern Europe and Western Europe have different approaches and policy priorities with regards to the supply of gas. Whereas Eastern Europe at this moment seems to focus mostly on security of supply for natural gas and pursues a substitution of coal by fossil natural gas to reduce CO_2 emissions, Western Europe seems more concerned about the decarbonisation of the gas grid by 2050. The number of major stakeholders promoting a consequent decarbonisation of the gas grid through full substitution of fossil natural gas by other renewable gases such as hydrogen, synthetic methane or biomethane is growing. Some isolated storylines including CCS technology have been identified, e.g. for the UK or the Netherlands proposing hydrogen production form natural gas and for Poland considering coal gasification hydrogen or synthetic methane generation.

On a sideline, and as an interpretation from the storyline assessment, the authors of this study understand that today's role of the gas infrastructure in balancing seasonal demand fluctuations will probably have to be adapted to also balance more short- and medium-term supply fluctuations in the

future, having a possible impact on how to consider both the annual gas transport and storage volumes and the short-term peak requirements. This role will have to be assessed in more detail by dynamic modelling.
As the use of biogas and biomethane as well as the use of any other form of renewable energy or electricity will strongly depend on the regional as well as total resources and specifically the technical and economic potentials, it is suggested to take up this discussion in great detail in future analyses of individual members states' own assessments as well as at European level.

Five non-EU storylines affecting the future role of gas in Europe

In addition to the European storylines, this study also analyses the major developments in the gas sector of five non-EU regions, namely Russia/Ukraine/Belarus, Japan, Norway, China and MENA countries. These provide relevant insights into market perspectives, strategies and technology developments.

Based on Russia's role as the world's largest exporter of natural gas today and the dominance of Ukraine's and Belarus's role as gas transit countries, little evidence was found in literature on any activities to reduce the carbon burden of natural gas in this region. However, even though not being widely discussed, the existing natural gas pipeline infrastructure could be used to import renewable gases from east to west in the future.

With an electricity shortage and a high dependency on fossil energy imports today, Japan has identified hydrogen as a clean fuel to import fossil energy in the short to mid-term, and renewable energy at a growing pace until 2050 from other world regions such as Australia or South America. Even though the energy strategies of Europe and Japan have different foci with Japan creating a secure electricity resource base, the proposed technologies along the value chains are similar, which opens opportunities to Europe for cooperation or as competitor.

Although Norway is a major exporter of natural gas, the country has succeeded in becoming the blueprint country for the application of relevant clean energy technologies such as battery electric vehicles, and has started introducing hydrogen, e.g. for clean propulsion in maritime applications. In this context, a strong development of renewable electricity in Norway, based on its vast wind energy potentials and pumped hydropower plants, could enhance the existing gas and electrical link to Europe in view of balancing power services for European grids, or concerning large green energy quantities imported to Europe both as electricity and as clean gas.

China may leapfrog the gas infrastructure technology development in many aspects as both methane and hydrogen grids will be developed to transport increasing quantities of green gas. Also, hydrogen and fuel cell technologies are now being commercialized at a yet unnoticed speed, offering Europe the role of co-operator or competitor.

The huge renewable energy potential of North Africa and the Middle East as one possible source for energy imports at large scale have so far focused on electricity imports to Europe. For the import of large renewable energy quantities the gas infrastructure has great potential. In all cases of export to the EU, indigenous use, for instance in the case of MENA for desalination, will need further consideration This, however, would have to be put into focus by the major stakeholders on both sides.

Development of three well-reasoned storylines

In Task 2 of this study, three generic storylines have been developed in order to analyse potential future roles of gas and the gas infrastructure until 2050 together with their potential impacts. The storylines address fundamentally different energy system configurations based on (1) electricity becoming the major energy carrier, (2) a coordinated role of the gas and energy infrastructures with a focus on methane gas either as synthetic methane ($PtCH_4$) or biomethane and (3) a coordinated role of the gas and energy infrastructures with a focus on hydrogen gas. All three storylines have in common the achievement of the -95% GHG emission reduction target by 2050 compared to 1990 levels as an illustration of deep decarbonisation effort. Moreover, in all three storylines Europe is subdivided into five different regions comprising Member States in geographical proximity and with similar interests in energy and environmental policy: “Northwest” (BE, DE, DK, FR, IE, IT, LU, NL, SE, UK), “Southwest” (Spain and Portugal), “Southeast” (mainly Balkan countries), “East” (Czech Republic, Poland and Slovakia) and “Northeast” (Baltic countries and Finland). Based on current consumption levels, gas demand in the Northwest region is a factor of three higher than in the other four regions together, underlining the outstanding role of these Member States for the future development of the gas sector in Europe.

A focus on a future energy system dominated by electricity in the first generic storyline would significantly reduce the role of the gas and gas infrastructures and hence create devalued or stranded assets in the existing gas infrastructure (import pipelines, gas storages, LNG regasification terminals, bi-directional pipelines). In the second generic storyline, the decrease of gas demand mainly in the heating sector can be (over)compensated by the dedicated use of gas in transport as well as in industry. This could lead to a significant utilisation of the existing gas infrastructure for the case of methane and hydrogen, to be validated in further more detailed modelling exercises. Due to the lower energy efficiency along the energy chain of methane compared to hydrogen technologies the pressure on domestic European energy resources for gas production would be higher in the second storyline (methane case) than in the third storyline (hydrogen case). This may necessitate larger energy imports in the methane case.

Comparing the three generic storylines, the hydrogen-based storyline No. 3 requires the strongest level of infrastructure development and technical conversion or adaptation and will require the longest timespan for its realization. However, it might present a robust perspective concerning overall energy and economic efficiency and level of integration, as well as a high level of end-user friendliness.

In Tasks 3 and 4 of this study, selected Transmission System Operators and National Regulatory Authorities will be asked for the challenges and opportunities they see under the three identified storylines. This will give a picture of where they see devalued or stranded assets in the network, where refurbishment would be needed, where expansion might come into play, and where the storage facilities would be needed, and what form these could take. It will also give an indication on how the current regulatory framework would be suited under the three storylines, and could give ideas on a possible adaptation of the framework.

5 Literature

[ADEME 2018] Agence de l'Environment et de la Maîtrise de l'Energie: Un mix de gaz 100% renouvable en 2050. Angers, January 2018.

[Altfeld, K.; Pinchbeck, D. 2013]: Admissible hydrogen concentrations in natural gas systems. In: *gas for energy* (03/2013).

[APRC 2000] Asian Pipeline Research Center: Overview of the transportation of wind-generated hydrogen using natural gas pipeline network in Northeast Asia. Tokyo, August 2000.

[Becker, W. et al. 2012]: Production of Fischer Tropsch liquid fuels from high temperature solid oxide co-electrolysis units. Golden, USA, November 2012.

[Bittmann, M. 2013]: Is Natural Gas 'Clean'? New York, September 2013.

[Blumberga, D. et al. 2014]: Green Energy Strategy 2050 for Latvia. Riga, October 2014.

[BMWi 2017] Bundesministerium für Wirtschaft und Energie: Projekte „Langfrist- und Klimaszenarien": Übergreifende Einordnung. Berlin, 2017.

[BP 2016] BP: BP Statistical Review of World Energy. London, June 2016.

[BP 2017a] BP: BP Energy Outlook, 2017.

[BP 2017b] BP: BP Statistical Review of World Energy. London, June 2017.

[Braaksma, A.; Jensen, N. 2018]: Scenario Study with Primes. DG ENER Meeting. Brussels, February 2018.

[Bünger, U. et al. 1992]: Hydrogen as an energy carrier, production and liquefaction of hydrogen in Norway for transportation to and storage/distribution in Germany. Paris, 1992.

[Bünger, U. et al. 2017]: Wasserstoff – Schlüsselelement von Power-to-X. Ottobrunn, August 2017.

[Buryk 2010] Buryk: Russia's Natural Gas. Bethlehem, USA, May 2010.

[CAT 2017] Climate Action Tracker: Foot of the Gas, June 2017.

[CEF 2017] Connecting Europe Facility: TSO2020. Brussels, September 2017.

[CertifHy 2015] CertifHy: Overview of the market segmentation for hydrogen across potential customer groups, based on key application areas. Brussels, June 2015.

[Christensen, C. M. 1997]: The innovator's dilemma. Boston, 1997.

[CIB 2017] Consorzio Italiano Biogas: The Development of Biomethane. Lodi, Italy, February 2017.

[Consonni, S. et al. 2005]: Co-production of hydrogen, electricity and CO2 from coal with commercially ready technology. Milan & New Jersey, 2005.

[Creutzig, F. et al. 2015]: Bioenergy and climate change mitigation. In: *GCB Bioenergy* 7 (5). DOI: 10.1111/gcbb.12205.

[DBFZ 2009] Deutsches Biomasse-Forschungszentrum: Erdgassubstitute aus Biomasse für die mobile Anwendung im zukünftigen Energiesystem. Leipzig, April 2009.

[Deloitte 2016] Deloitte: A sustainable energy model for Spain in 2050. Madrid, May 2016.

[Dena 2017] Deutsche Energie-Agentur: Roadmap Power to Gas. Berlin, November 2017.

[DLR, et al. 2013] Deutsches Zentrum für Luft- und Raumfahrt; Institut für Energie- und Umweltforschung Heidelberg; Ludwig-Bölkow-Systemtechnik; Deutsches Biomasseforschungszentrum: Biomass potentials and competition for biomass utilisation. Leipzig, 2013.

[DLR, et al. 2014] Deutsches Zentrum für Luft- und Raumfahrt; Institut für Energie- und Umweltforschung Heidelberg; Ludwig-Bölkow-Systemtechnik; Deutsches Biomasseforschungszentrum: Power-to-Gas (PtG) in transport. Leipzig, June 2014.

[DLR, et al. 2015] Deutsches Zentrum für Luft- und Raumfahrt; Ludwig-Bölkow-Systemtechnik; Frauenhofer-Institut für Solare Energiesysteme; KBB Underground Technologies: Studie über die Planung einer Demonstrationsanage zur Wasserstoff-Kraftstoffgewinnung durch Elektrolyse mit Zwischenspeicherung in Salzkavernen unter Druck. Stuttgart, February 2015.

[DNV GL 2017]: The potential role of power-to-gas in the eHighway2050 study. European Power to Gas Platform. Høvik, Norway, September 2017.

[DVGW, et al. 2013] Deutscher Verein des Gas- und Wasserfaches; EON Ruhrgas; DBI Gas und Umwelttechnik; Frauenhofer-Institut für Windenergie und Energiesystemtechnik; Verbundnetz Gas: Entwicklung von modularen Konzepten zur Erzeugung, Speicherung und Einspeisung von Wasserstoff und Methan ins Erdgasnetz. Bonn, February 2013.

[E3G 2017] E3G: Infrastructure for a changing Energy System. Brussels, December 2017.

[E4tech; Element Energy 2014] E4tech; Element Energy: Fuel cells and hydrogen Joint undertaking. Lausanne & Cambridge, February 2014.

[EC 2013] European Commission: Roadmap EU-Russia Energy Cooperation until 2050. Brussels, March 2013.

[EC 2016] European Commission: EU Reference Scenario 2016. Brussels, July 2016.

[Ecofys 2018] Ecofys: Gas for Climate. Utrecht, February 2018.

[EDF 2017] Environmental Defense Fund: Oil and Gas Methane Emissions in New Mexico. New York, 2017.

[EEG; TU Wien 2018] Energy Economics Group; Technische Universität Wien: Wärmezukunft 2050. Wien, Januar 2018.

[EFZN, et al. 2011] Energie-Forschungszentrum Niedersachsen; Leibnitz Universität Hannover; TU Clausthal; Georg-August-Universität Göttingen; OECOS: Ökologische Auswirkungen von 380-kV-Erdleitungen und HGÜ-Erdleitungen. Berlin, 2011.

[Egbue, O.; Long, S. 2015]: Critical Issues in the Supply Chain of Lithium for Electric Vehicle Batteries. In: *Engineering Management Journal* 24 (3). DOI: 10.1080/10429247.2012.11431947.

[EIA 2014a] U.S. Energy Information Administration: Norway supplies more than 20% of Europe’s natural gas needs. Washington D.C., May 2014.

[EIA 2014b] U.S. Energy Information Administration: Natural gas serves a small, but growing, portion of China’s total energy demand. Washington D.C., August 2014.

[EIA 2018] U.S. Energy Information Administration: China. Washington D.C., 2018.

[Elliot 2016] Elliot: Analysis: Doubts stack over Norway's gas export momentum plans. London, March 2016.

[ENAA 2003] Engineering Advancement Association of Japan: Developing Technology for WE-NET. Tokyo, 2003.

[Energi Styrelsen 2013] Energi Styrelsen: Energiscenarier frem mod 2020, 2035 og 2050. Copenhagen, November 2013.

[Energi Styrelsen 2014] Energi Styrelsen: Gasinfrastrukturen. Copenhagen, March 2014.

[Energinet 2015] Energinet: Gassens rolle i omstillingen. Fredericia, Denmark, November 2015.

[Energinet 2017] Energinet: Future Role of the Gas System. Fredericia, Denmark, 2017.

[energinet.dk 2018]: Hybridvarmepumper, Lærkevej – konvertering af naturgasopvarmning til varmepumper og hybridvarmepumper. Fredericia, January 2018.

[EnergyPost 2015] EnergyPost: Russia's Grand Gas Strategy – the power to dominate Europe? Brussels, March 2015.

[Enervis 2017] Enervis Energy Advisors: Erneuerbare Gase - ein Systemupdate der Energiewende. Berlin, December 2017.

[Entsog 2017] European Network of Transmission System Operators for Gas: TYNPD 2017. Brussels, 2017.

[Entsog 2018] European Network of Transmission System Operators for Gas: TYNDP 2018. Brussels, 2018.

[Europacable 2011] Europacable: An Introduction to High Voltage Direct Current (HVDC) Underground Cables. Brussels, October 2011.

[EWI 2017] ewi Energy Research & Scenarios: Energiemarkt 2030 und 2050. Köln, November 2017.

[Fargione, J. et al. 2008]: Land clearing and the biofuel carbon debt. In: *Science* 319 (5867). DOI: 10.1126/science.1152747.

[FCW 2017] FuelCellsWorks: Shanghai Releases its Development Plan for Fuel Cell Vehicles. fuelcellworks.com. Online: https://fuelcellsworks.com/news/shanghai-releases-its-development-plan-for-fuel-cell-vehicles/, last accessed 23.03.2018.

[FfE 2017] Forschungsstelle für Energiewirtschaft: Kurzstudie Power-to-X. Munich, November 2017.

[FhG-ISE 2018] Frauenhofer-Institut für Solare Energiesysteme: Stromgestehungskosten Erneuerbare Energien. Freiburg, March 2018.

[FhG-ISI 2017a] Fraunhofer-Institut für System- und Innovationsforschung: Langfristszenarien für die Transformation des Energiesystems in Deutschland. Karlsruhe, May 2017.

[FhG-ISI 2017b] Fraunhofer-Institut für System- und Innovationsforschung: Brennstoffzellen-Lkw. Karlsruhe, August 2017.

[Florisson, O. 2010]: NaturalHy. GERG Acedemic Network Event. Brussels, June 2010.

[Forum Energii, et al. 2017] Forum Energii; WiseEuropa; Enervis Energy Advisors; Centre for Innovation and Technology Transfer Management of Warsaw University of Technology: Polish energy sector 2050. Warsaw, October 2017.

[Fritz, S. et al. 2013]: Downgrading recent estimates of land available for biofuel production. In: *Environmental science & technology* 47 (3). DOI: 10.1021/es303141h.

[Frontier Economics, et al. 2017] Frontier Economics; IAEW; 4Management; EMCEL: Der Wert der Gasinfrastruktur für die Energiewende in Deutschland. London, September 2017.

[FZJ 2012] Forschungszentrum Jülich: Konzept und Kosten eines Pipelinesystems zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff. Aachen, 2012.

[FZJ 2018] Forschungszentrum Jülich: Comparative Analysis of Infrastructures: Hydrogen Fueling and Electric Charging of Vehicles. Jülich, 2018.

[Gallachóir 2015] Gallachóir: The future of renewable energy in Ireland. Cork, September 2015.

[Gasefuels 2014] Gasefuels: Power to Gas. Green Gas Research Outlook Sweden. Stockholm, March 2014.

[Gazprom 2018] Gazprom: Gas supplies to Europe. St. Petersburg, January 2018.

[GDF SUEZ 2011] GDF SUEZ: The first Hythane Refueling Station in France. Seoul, 2011.

[Greenpeace; GWEC; Solar Power Europe 2015] Greenpeace International; Global Wind Energy Council; Solar Power Europe: Energy [R]evolution. Amsterdam, September 2015.

[Gregory 2010] Gregory: China - Biogas. Honolulu, November 2010.

[Gruber 2017]: Effizienzsteigerung der Power-to-Gas Technologie durch thermische Integration von Hochtemperatur Dampfelektrolyse und CO2-Methanisierung - das HELMETH Projekt. ProcessNet. Frankfurt am Main, March 2017.

[Gutsch, M. et al. 2015]: Uncertainty of biomass contributions from agriculture and forestry to renewable energy resources under climate change. In: *metz* 24 (2). DOI: 10.1127/metz/2015/0532.

[Halmstad University 2015] Halmstad University: Quantifying the Heating and Cooling Demand in Europe. Halmstad, 2015.

[HBS UA 2017] Heinrich Böll Stiftung UA: Transition of Ukraine to the renewable Energy by 2050. Kiev, 2017.

[Hiranuma 2014] Hiranuma: Japan's Energy Policy in a Post-3/11 World. Yokohama, October 2014.

[Hölling 2017] M. Hölling, M. Weng, S. Gellert: Bewertung der Herstellung von Eisenschwamm unter Verwendung von Wasserstoff (Evaluation of Hydrogen-Based Production of DRI). Stahl Eisen, 2017.

[Hybrit 2018] Hybrit - Fossil Free Steel: Summary of findings from HYBRIT Pre-Feasibility Study 2016–2017. Stockholm, January 2018.

[Hychico 2016] Hychico: Patagonia Wind - Hydrogen Project: Underground Storage and Methanation. Zaragoza, June 2016.

[Hydrogen Council 2017] Hydrogen Council: Hydrogen scaling up. Brussels, November 2017.

[Hypos 2018] Hypos: Hydrogen power storage & solutions East Germany. Leipzig, February 2018.

[Hyundai 2014] Hyundai: Hyundai ix35 Fuel Cell. Online: https://www.hyundai.de/Modelle/ix35-Fuel-Cell.html, last accessed 23.03.2018.

[Hyundai 2018] Hyundai: Tucson. Online: https://konfigurator.hyundai.de/configure/tucson/8/V2/43/trims/1/summary, last accessed 23.03.2018.

[HyUnder 2014] HyUnder: Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe. Huesca, June 2014.

[IEA 2016] International Energy Agency: Energy Policies of IEA Countries: Italy. Paris, 2016.

[IEA 2017a] International Energy Agency: World Energy Balances. Paris, 2017.

[IEA 2017b] International Energy Agency: Norway contributes to global energy security, while seeking to decarbonise its energy supply. Paris, May 2017.

[IEA Bioenergy 2016] IEA Bioenergy: Cascading of woody biomass: definitions, policies and effects on international trade, April 2016.

[IIASA 2014] International Institute for Applied System Analysis: Public protests against deployment of electricity transmission infrastructure in Europe. Laxenburg, Austria, 2014.

[Jakobs 2016] St. Jakobs: Wasserstoff in der Stahlindustrie - Erzeugungs- und Einsatzmöglichkeiten in der Zukunft. Umwelt- und Klimaschutz, thyssenkrupp Steel Europe AG,. H_2-Congress Berlin, Juli 5/6, 2016.

[Jauslin Stebler 2013] Jauslin Stebler: Erdgas-Röhrenspeicher Urdorf. Online: https://www.jauslinstebler.ch/VGA/VEM/projekte/erdgas-roehrenspeicher-urdorf.html, last accessed 23.03.2018.

Judd, R.; Pinchbeck, D.: 8 – Hydrogen admixture to the natural gas grid. In: Compendium of Hydrogen Energy - A volume in Woodhead Publishing Series in Energy, Volume IV: Hydrogen Use, Safety and the Hydrogen Economy, S. 165–192.

[Klavs, G.; Rekis, J. 2015]: Modelling of Energy Strategy in Latvia. Conference on Energy Security: Outlook & Perspectives in the Baltic Sea region. Lithuanian Academy of Science. Vilnius, November 2015.

[Klimaretter 2015] Klimaretter: Ukraine: Skandal um die INDCs. Berlin, September 2015.

[KPEKMU 2017] Ministry of Energy and Coal Mining of Ukraine: Energy Strategy of Ukraine until 2035. Kiev, August 2017.

[KPMG 2016] KPMG: 2050 Energy Scenarios. London, July 2016.

[KPMG 2017] KPMG: Situation of the Ukrainian natural gas market and transit system. Budapest, April 2017.

[KTBL 2012] Kuratorium für Technik und Bauwesen in der Landwirtschaft: Biomethaneinspeisung in der Landwirtschaft. Darmstadt, 2012.

[Länder Analysen 2018a] Länder Analysen: Russland-Analysen Nr. 348. Brussels, February 2018.

[Länder Analysen 2018b] Länder Analysen: Ukraine Analysen Nr. 195. Brussels, February 2018.

[Langås, H. G. 2015]: Large Scale Hydrogen Production. Renewable Energy and Hydrogen Export. Trondheim, March 2015.

[LBST 2014] Ludwig-Bölkow-Systemtechnik: Hydrogen production potential in Norway. Ottobrunn, February 2014.

[LBST 2016] Ludwig-Bölkow-Systemtechnik: Vergleich von CNG und LNG zum Einsatz in LKW im Fernverkehr. Ottobrunn, Mai 2016.

[LBST; Dena 2017] Ludwig-Bölkow-Systemtechnik; Deutsche Energie-Agentur: E-Fuels Studie. Ottobrunn & Berlin, 2017.

[LBST; Hinicio 2015] Ludwig-Bölkow-Systemtechnik; Hinicio: Study on hydrogen from renewable resources in the EU. Ottobrunn & Brussels, July 2015.

[Lehner, F. 2017]: Building industrial supply chains for fuel cells -where will the value be created? Stuttgart, October 2017.

[Levinsky, H. B. 2004]: Limitations on H2 addition to natural gas. Proceedings Natural Gas Technologies. II Conference. Des Plaines, USA, 2004.

[LOCSEE 2014] Low Carbon South East Europe: National Energy Plan: Roadmap to 2050. Athens, December 2014.

[Maruta 2016] Maruta: Japan's Energy Policy andH2/FC Market perspectives. Tokyo, March 2016.

[McKinsey 2018] McKinsey: What if the latest wind and solar auction results were the new reality of electricity prices? Online: https://www.mckinseyenergyinsights.com/insights/what-if-the-latest-wind-and-solar-auction-results-were-the-new-reality-of-electricity-prices?, last accessed 17.04.2018.

[MEAC 2016] Ministry of Economic Affairs and Communications: Estonian Energy Development Plan until 2030. Tallinn, October 2016.

[METI 2015] Ministry of Economy, Trade and Industry JAPAN: Long-term Energy Supply and Demand Outlook. Chiyoda, Japan, July 2015.

[METI 2017] Ministry of Economy, Trade and Industry JAPAN: Basic Hydrogen Strategy Determined. Chiyoda, Japan, December 2017.

[Miege et al. 2013]: Integration von Wind-Wasserstoff-Systemen in das Energiesystem. Stralsund, 2013.

[MinEnergo 2017] Ministry of Energy of Russian Federation: Energy Strategy of the Russian Federation for the period up to 2035. Moscow, February 2017.

[MINGO 2009] The Republic of Croatia Ministry of Economy, Labour and Entrepreneurship: Energy Strategy of The Republic of Croatia. Zagreb, June 2009.

[Mingyu, Q. 2017]: Opportunity and challenge of Biogas market in China. Berlin, 2017.

[Ministerstwo Energii 2017a] Ministerstwo Energii: Krajowe ramy polityki rozwoju infrastruktury paliw alternatywnych. Warsaw, March 2017.

[Ministerstwo Energii 2017b] Ministerstwo Energii: Innowacje dla energetyki. Warsaw, May 2017.

[Ministerstwo Gospodarki 2009] Ministerstwo Gospodarki: Polityka energetyczna Polski do 2030 roku. Warsaw, November 2009.

[MND HU 2012] Ministry of National Development Hungary: National Energy Strategy 2030. Budapest, 2012.

[MoE BG 2011] Ministry of Energy Republik of Bulgaria: Energy Strategy of the Republik of Bulgaria till 2020. Sofia, June 2011.

[MoE RO 2016] Ministry of Energy Romania: Romanian Energy Strategy 2016-2030, with an Outlook to 2050. Bucharest, 2016.

[Mougin et al. 2014]: Stack performances in High temperature steam electrolysis and co-electrolysis. Gwangju, South Korea, June 2014.

[National Grid 2017] National Grid: The Future of Gas. London, July 2017.

[Nature Communications 2017] Nature Communications: Reduced biomass burning emissions reconcile conflicting estimates of the post-2006 atmospheric methane budget, December 2017.

[NCI 2017] Navigant Consulting: Making the Mena Region a World leader in green hydrogen. Chicago, 2017.

[Netbeheernederland 2017] Netbeheernederland: Grids for the Future, November 2017.

[Netinform 2018] Netinform: H2Mobility: Hydrogen Vehicles. München, 2018.

[NIB 2017] Noordelijke Innovation Board: The Green Hydrogen Economy in the Northern Netherlands. Groningen, April 2017.

[Norskpetroleum 2017] Norskpetroleum: Exports of oil and gas. Oslo, 2017.

[Northern Gas Networks, et al. 2016] Northern Gas Networks; Wales&West Utilities; KIWA; amec foster wheeler: H21 Leeds City Gate. Leeds, 2016.

[OIES 2014] Oxford Institute for Energy Studies: The Outlook for Natural Gas Demand in Europe. Oxford, June 2014.

[OIES 2017] Oxford Institute for Energy Studies: The Future of Gas in Decarbonising European Energy Markets. Oxford, January 2017.

[Öko-Institut 2017] Öko-Institut: Strategien für die nachhaltige Rohstoffversorgung der Elektromobilität. Berlin, October 2017.

[Ontras 2017] Ontras Gastransport: PtG-Potenziale im ONTRAS-Netzgebiet. Berlin, 2017.

[Paraskova, T. 2017]: China Drives Natural Gas Demand Boom. Washington D.C., October 2017.

[Prognos; BCG 2018] Prognos; The Boston Consulting Group: Klimapfade für Deutschland. Berlin, January 2018.

[RadaKMU 2017] Council of Entrepreneurs under the Cabinet of Ministers of Ukraine: Energy Strategy of the Ukraine. Kiev, June 2017.

[RAG 2014] Rohöl-Aufsuchungs Aktiengesellschaft: Underground Sun Storage: Vienna, September 2014.

[RAWI 2017] Russian Association of Wind Power Industry: Perspectives for the wind energy market in Russa (in Russian). Moscow, March 2017.

[Reuters 2014] Reuters: Dubai Integrated Energy Strategy 2030 with UAE Vision 2021. Dubai, February 2014.

[Riigikogu 2017] Parliament of Estonia: General Principles of Climate Policy until 2050. Tallinn, April 2017.

[Roads2HyCom 2007] Roads2HyCom: European Hydrogen Infrastructure Atlas. Oldenburg, July 2007.

[Roland Berger 2015] Roland Berger: Advancing Europe´s energy systems. Luxemburg, 2015.

[RSE 2011] Ricerca sul Sistema Energetico: REALISEGRID. Milan, June 2011.

[RWE 2016] RWE: Das CO2-freie Kraftwerk - Konzepte und deren Realisierungsschritte in Deutschland. Essen, 2016.

[Schoeber 2012]: Power to Gas: Eine zukunftsweisende Innovation für integrierte Energieversorger? Berlin, June 2012.

[Schoof, R. 2017]: Sektorenkopplung mit Power-to-Gas. DBI-Fachforum Energiespeicher 2017. DBI. Berlin, September 2017.

[Seimas 2012] Seimas of the Republic of Lithuania: National Energy Independence Strategy. Vilnius, June 2012.

[Shanda 2017] Shanda Consult: The Biogas Market of Ukraine. Nicosia, 2017.

[Spiridonovs, J. 2015]: Energy Policy Trends in Latvia. Riga, April 2015.

[Stiller, C. et al. 2008]: Options for CO2-lean hydrogen export from Norway to Germany. Trondheim, 2008.

[Swain, M. R. et al. 1993]: The effects of hydrogen addition on natural gas engine operation. Philadelphia, December 1993.

[Swedegas 2018] Swedegas: Power to Gas. Online: https://www.swedegas.com/smart_energy_systems/Power_to_Gas, last accessed 19.03.2018.

[TEM 2017] Ministry of Economic Affairs of Finland: Government report on the National Energy and Climate Strategy for 2030. Helsinki, January 2017.

[Tollefson, J. 2013]: Methane leaks erode green credentials of natural gas. In: *Nature* 493.

[Tuck Foundation 2016] W. Vanhoudt, F. Barth, J.-Ch. Lanoix, J. Neave, P. Schmidt, W. Weindorf, T. Raksha, J. Zerhusen, J. Michalski: Power-to-gas - Short term and long term opportunities to leverage synergies between the electricity and transport sectors through power-to-hydrogen. A joint expertise to the Fondation Tuck by Hinicio and LBST, Feb 2016.

[UBA-AT 2015a] Umweltbundesamt: Energiewirtschaftliche Szenarien im Hinblick auf die Klimaziele 2030 und 2050. Vienna, 2015.

[UBA-AT 2015b] Umweltbundesamt: Energiewirtschaftliche Szenarien im Hinblick auf die Klimaziele 2030 und 2050. Vienna, 2015.

[UBA-AT 2016] Umweltbundesamt: Szenario erneuerbare Energie 2030 und 2050. Vienna, 2016.

[UKERC 2016] UK Energy Research Center: The future role of natural gas in the UK. London, February 2016.

[WB 2010] World Bank: Energy in MENA. Washington D.C., September 2010.

[WB 2014] World Bank: Electric power consumption (kWh per capita). Washington D.C., 2014.

[WEC 2018] World Energy Council Netherlands: Bringing North Sea Energy ashore efficiently. Tilburg, 2018.

[Wehling, A. 2017]: Strategieroadmap zum Ausbau von Power-to-Gas. DBI-Fachforum Energiespeicher 2017. DBI. Berlin, September 2017.

[WEO 2013] WEO Special Report 2013, IEA, 2013.

[Wheeler 1996] Wheeler: Decarbonisation of fossil fuels. Knutsford, UK, March 1996.

[Withers, M. R.; Malina, R.; Barrett, S. R.H. 2015]: Carbon, climate, and economic breakeven times for biofuel from woody biomass from managed forests. In: *Ecological Economics* 112. DOI: 10.1016/j.ecolecon.2015.02.004.

[WWF Österreich; Global 2000; Greenpeace 2015] WWF Österreich; Global 2000; Greenpeace: Energiezukunft Österreich. Vienna, June 2015.

[Yan 2017] Yan: Subsidies to encourage better battery tech. Beijing, November 2017.

[Zhixiang, L. 2018]: Recent development of fuel cell vehicles an hydrogen refueling station in China. Birmingham, March 2018.

[Zittel 1993] Zittel: Methane Emissions from Russian Gas Supply and Measures to Control Them. in “Non-CO2 Greenhouse Gases: Why and How to Control?”, Proceedings of an International Symposium, Maastricht, The Netherlands, pp 329-334, Eds. J. van Ham. J. H. M. Janssen. J. Swart, December 1993.

Annex with model descriptions

PRIMES

The PRIMES model simulates the European energy system and markets on a country-by-country basis (E3Modelling, 2017[55]). The model provides projections of detailed energy demand and supply balances, CO_2 emissions, investment in energy system, energy technology deployment, energy prices and costs. PRIMES simulates a multi-market equilibrium solution for energy supply and demand by explicitly calculating prices which balance demand and supply. The PRIMES model has served to quantify energy outlook scenarios for DG ENER [56] and to provide model-based analysis for EU energy and climate policies, including Low Carbon Roadmap (EC, 2011[57]), Energy Roadmap 2050[58] and the recent Winter Package for 2030[59].

The distinctive feature of PRIMES is the combination of behavioural modelling following a micro-economic foundation with engineering, technical and system aspects, covering all energy sectors and markets at a high level of detail. PRIMES focuses on prices as a means of balancing demand and supply simultaneously in several markets for energy and emissions. The model determines market equilibrium volumes by finding the prices of each energy form such that the quantity producers find best to supply matches the quantity consumers wish to use. Investment is endogenous in all sectors, including for purchasing of equipment in demand sectors (including buildings) and private vehicles, and for energy producing plants in supply sectors. The model handles dynamics under different anticipation assumptions and projects detailed energy balances over a long-term horizon (to 2050) keeping track of technology vintages in all sectors.

The design of the PRIMES model is suitable for medium- and long-term energy system projections and system restructuring up to 2050, in both demand and supply sides. PRIMES can support impact assessment of specific energy and environment policies and measures, applied at Member State or EU level, including price signals, ETS, RES and efficiency supporting policies, environmental policies and technology standards. PRIMES is sufficiently detailed to represent concrete policy measures in various sectors, including market design options for the EU internal electricity and gas markets. The PRIMES model can inform policy and decision makers on subjects including:

- Climate policy (CO_2 emissions reduction and energy efficiency policies);
- Fiscal policy for energy (fuel taxation and/or subsidization, cap-and-trade, ETS pricing);
- Promotion of Renewable Energy Sources (including RES support schemes and Feed-In-Tariffs);
- Energy efficiency promoting policies in houses, buildings, industry and transport;
- Regulation and policies to address market and non-market failures for new technologies;
- Infrastructure policies and development plans in various sectors (mainly for electricity and gas);
- Impact of market design proposals for internal electricity and gas markets;
- Promotion of alternative clean energy fuels and transport electrification;

[55] http://e3modelling.gr/images/files/ModelManuals/PRIMES_MODEL_2016-7.pdf
[56] https://ec.europa.eu/energy/sites/ener/files/documents/20170125_-_technical_report_on_euco_ scenarios_ primes_ corrected.pdf
[57] https://ec.europa.eu/energy/sites/ener/files/documents/2012_energy_roadmap_2050_en_0.pdf
[58] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52011SC0288&from=EN
[59] https://ec.europa.eu/energy/sites/ener/files/documents/20170125_-_technical_report_on_euco_ scenarios_ primes_ corrected.pdf

- Role of hydrogen and power-to-X technologies taking into account the interactions between the gas, heat, electricity and hydrogen sectors.

The following paragraphs provide an overview of the way the gas sector is represented in PRIMES. A complete documentation of all PRIMES sectoral modules, and of their interlinkages is available on E3Modelling's webpage[60].

PRIMES-Gas Supply module

PRIMES includes a detailed gas supply module (PRIMES-Gas) that provides projections for gas imports by country of origin, by transport mean (LNG, pipeline) and route as well as wholesale gas prices by country and by type of consumer. PRIMES-Gas studies the relationships between gas resources, indigenous production, configuration of gas supply network and infrastructure and the degree of competition in gas markets over the Eurasian area and evaluates their impacts on gas prices paid by consumers in the EU countries. The model covers the entire Eurasian/MENA areas and the global LNG market and presents in detail the gas infrastructure and the different "agents" that participate in the market. The agents compete for access to gas infrastructure and for gas supply to customers, the latter being responsive to gas prices. The model can accommodate different assumptions about the degree of competition and the integration of the EU gas internal market.

The gas supply module uses as input the gas demand projections developed by PRIMES, both in end-use sectors (twelve industrial sectors, transport, residential, services and agriculture) and electricity generators. PRIMES optimises the use of gas infrastructure (pipelines, LNG terminals, storage, production capacity) to meet gas demand at the lowest cost, while satisfying all technical and engineering constraints of the entire gas production chain and infrastructure. Thus, the flow of gas over the entire gas network, the economic decisions of the agents and the market prices are endogenous and are computed dynamically.

PRIMES-Gas represents in detail the gas infrastructure of each EU Member State and of gas producing countries of the Eurasian area, Middle East, Persian Gulf and North African countries. The model also represents the supply possibilities of LNG worldwide. The infrastructure types include: gas production, pipelines gas storage, LNG regasification terminals and gas liquefaction. Operation of infrastructure and related gas flows are constrained by a physical system involving pipelines, LNG terminals, gas storage facilities, liquefaction plants and gas producing wells. The interregional flows of gas are derived from a gas transport network consisting of high-pressure gas pipelines and ship routes for LNG. A simplified representation of the physical gas pipeline system is used to establish interregional transfers, allowing gas transfers from the producers (the supply source) to end-users. The model also allows for transit pipelines and reverse gas flows in cases of bidirectional pipelines. Cost data are associated with each type of gas infrastructure, while gas transportation costs, including LNG ship costs, are a function of distances.

The model captures seasonal gas demand variation by representing a number of typical days per season. At system level, gas load derives from aggregation of sector-specific gas use patterns of seasonal variation that derive from the fully-fledged PRIMES energy system model. PRIMES-Gas explicitly represents gas storage: storage inputs and outputs are connected to country nodes to represent net

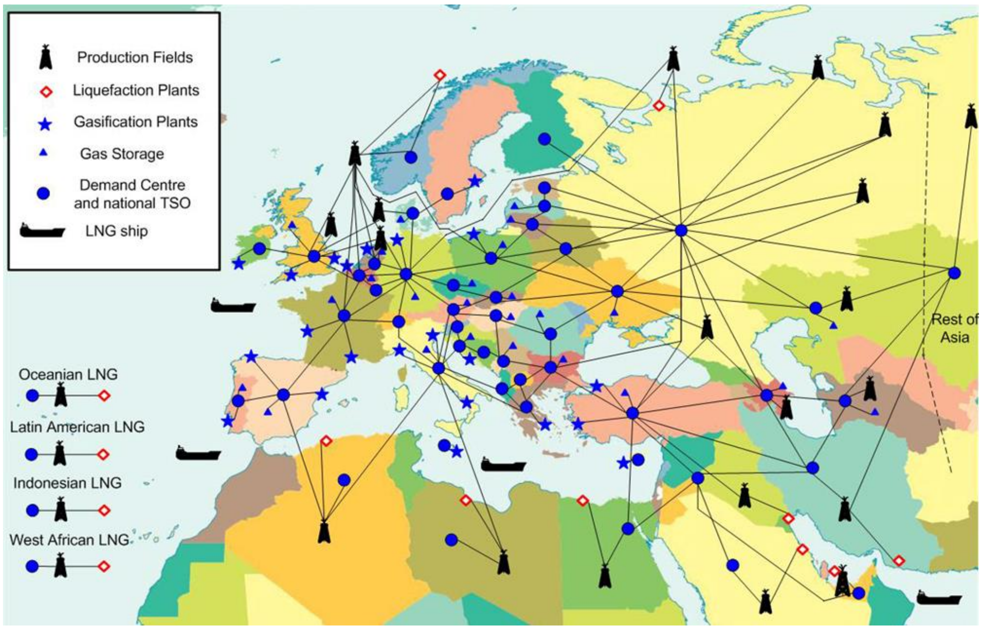
[60] http://e3modelling.gr/images/files/ModelManuals/PRIMES_MODEL_2016-7.pdf

storage withdrawals as needed to manage gas balancing at peak times. During the off-peak period, net storage injections are calculated so as to establish gas storage balance over a year. PRIMES-gas includes long-term contracts (both pipelines and LNG) as constraints between suppliers and customers. The duration and terms of existing long term contracts are exogenous. Upper and lower variability margins of flows over pipelines, reflecting physical and/or contractual limitations, are exogenous in the model and apply on the entire network of physical flows.

	Countries	Capacity	Costs	Constraints	Seasonal pattern
Production	EU28 countries, Norway, Eurasian area (Russia, Ukraine, Belarus, Caspian region), Middle East and North Africa	Exogenous (based on current plans and reserve estimates)	Cost-supply curves for production fields	Gas reserves and resources	Derived from seasonality of gas demand
Pipelines/ Interconnectors	EU28 countries, Norway, Eurasian area (Russia, Ukraine, Belarus, Caspian region), Middle East and North Africa	Current plans & PCI projects	Transmission costs and tariffs based on capacity and characteristics	Physical capacity and flexibility limitations	Derived from gas demand seasonality
Liquefaction terminals	Global	Exogenous(based on plans and resources)	Liquefaction cost	Availability of gas production	
Regasification terminals	Global (focused on EU28 countries, Norway, Eurasian area, MENA)	Injection and storage capacity	Regasification cost	Available capacity	Derived from gas demand seasonality
Storage	EU28 countries, Norway, Eurasian area (Russia, Ukraine, Belarus, Caspian region), Middle East and North Africa	Storage injection/ withdrawal capacity, volume of gas that can be stored	Cost (or tariff) to inject/ withdraw gas from the network	Minimum storage levels, security of gas supply	Derived from gas demand seasonality
Gas demand	EU28 countries, Norway, Eurasian area (Russia, Ukraine, Belarus, Caspian region), Middle East and North Africa		Price penalty to avoid missing gas volumes in case of a supply disruption	Long-term contracts (pipelines and LNG)	Represents a few typical days per season and sector

Pipeline capacities and investments are exogenous. Volume dependent curves are specified for computing tariffs for gas transportation between EU Member States and neighbouring countries. Gas production costs and potential rents are represented by cost-supply curves with increasing slope, constrained by resource potential. Gas field reserves are specified exogenously in the base year and follow a net depletion profile afterwards including further development of reserves. Liquefaction, storage and LNG regasification capacities and investment are exogenous, while the dates of commissioning of new infrastructures are also exogenous. The model also includes specific infrastructure plans for future expansion of all elements of the gas supply network. The figure below illustrates gas infrastructure types as modeled in PRIMES-Gas.

Figure 0-1: Overview of the PRIMES-Gas supply model



Modelling of sectoral integration and interlinkages between clean energy forms

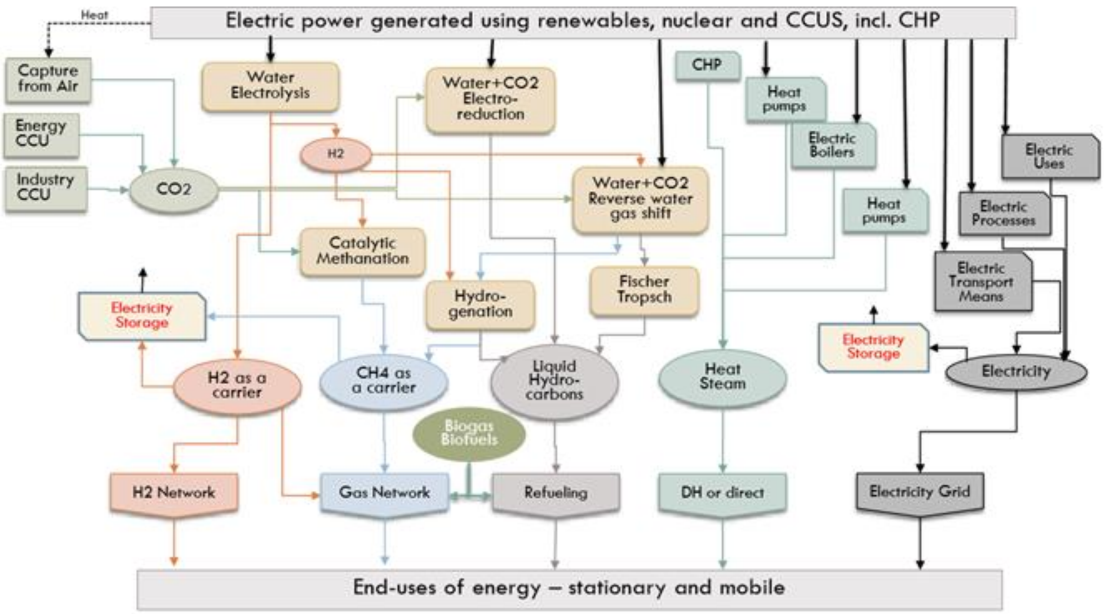
PRIMES has been recently extended to capture the costs, market penetration and future role of synthetic fuels, hydrogen, electricity, heat, and chemical storage, as well as the synergies and competition between them in the context of deep decarbonisation. PRIMES simulates hourly operation of the interconnected electricity, hydrogen, gas, heat, steam and synthetic fuels systems in a synchronised way in order to analyse the transition to near-zero emissions and explore the impacts of sectoral integration. PRIMES includes alternative pathways for the production of low or zero-carbon energy carriers, such as hydrogen, synthetic methane and synthetic liquid hydrocarbons produced via Power to X (PtX) routes. At the same time, conventional energy carriers such as fossil hydrocarbons, biofuels, electricity, steam, are also included. Given the massive penetration of variable renewables in the EU power mix in the deep decarbonisation context, the need for electricity storage will become increasingly prominent. The new PRIMES module can capture effectively the operation of large-scale power storage systems (i.e. to quantify excess RES generation that can be used to produce hydrogen). The model also captures competition for carriers that can serve different purposes for different customers (power generator vs. synthetic fuel factories).

All the aforementioned factors must be considered simultaneously, and along with the operation of the rest of energy system (e.g. availability of biofuels). PRIMES fully-fledged modelling of the entire energy system ensures consistent integration of the new clean energy vectors into the overall energy demand and supply system by endogenous fuel choices in the demand sectors, i.e. calculating the share of synthetic gasoline vs. bio-gasoline (and petroleum-based gasoline) used by cars and trucks. PRIMES solves all EU countries simultaneously in order to capture the trade of carriers and expansion of infrastructure (power grids, gas, H2 network and distributed heat). The PRIMES model covers the following energy forms and their interactions:

- **Electricity**: It can be produced via numerous sources (RES, fossil fuels, nuclear power), and stored either directly in batteries, or via the conversion to intermediate energy forms (pumped storage, chemical storage as hydrogen, synthetic methane etc.);
- **Heat and steam**: Produced via heat pumps, boilers, CHPs units, for distributed or on-site consumption;

- **Carbon dioxide**: Carbon dioxide acts as the main feedstock source for the production of synthetic methane and hydrocarbons. It can be directly captured from air or via applying Carbon Capture and Utilisation (CCU) technologies to energy and industrial applications. The direct capture from air guarantees that the synthetic fuels produced will be carbon neutral;
- **Hydrogen**: Carbon-free hydrogen is assumed to be produced via electrolysis of RES-based electricity. It can serve as an energy carrier (combusted or used in fuel cells in stationary or mobile applications), as feedstock for the production of synthetic fuels, or as a means of storage of electricity produced from variable RES. Hydrogen can be transferred via dedicated pipelines (that require additional investments) or blended in the natural gas grid up to a certain share (15% on a volume basis) due to technical limitations;
- **Biofuels** (liquid and gaseous): They are produced using feedstock of biomass origin. The model distinguishes fungible from non-fungible biofuels. The former can fully substitute petroleum products, while the latter are blended up to certain shares with fossil based gasoline and diesel. Upgraded biogas (bio-methane) can be blended to the natural gas grid;
- **Synthetic methane** is an output of a process such as methanation, which utilises hydrogen and carbon dioxide as inputs. The process is energy-intensive, requiring large amounts of electricity. Synthetic methane can be considered as carbon free (clean gas), if the CO2 is captured from ambient air;
- **Synthetic liquid hydrocarbons** can fully substitute petroleum based products in mobile applications with no radical changes in ICE powertrains and no range limitations. Synthetic liquid hydrocarbons can also develop in other transport modes including aviation and long distances road freight transportation;
- **Fossil fuels** serving as conventional energy carriers, which can be used either in final demand sectors (transport, buildings, industries) or to produce electricity. The deep decarbonisation scenarios however require the phase-out of fossil fuels from all energy-related uses by 2050.

Figure 0-2: Process flow diagram of the new PRIMES sub-model including hydrogen and power-to-X



METIS

METIS is a bottom-up multi-energy model of the European energy systems and markets that represents the electricity, gas and heat sectors. The METIS model is developed by Artelys on behalf of the European Commission (DG ENER) in the context of an ongoing contract, with the assistance of RWTH-IAEW Aachen University, Congas and Frontier Economics. First versions of the METIS model have already been delivered to the European Commission, allowing EC and JRC analysts to conduct quantitative analyses on a wide range of topics (resource adequacy assessment, infrastructure valuation, synergies between energy carriers, gas and electricity market design, etc.) by updating the corresponding assumptions and running the model themselves.

The following paragraphs provide an overview of the way the gas sector is represented within METIS. A complete documentation of both the power and gas market modules, and of their interlinkages is available on DG ENER's METIS webpage[61].

The METIS gas market module takes as inputs the installed capacities or investment options (production, storage, transmission, liquefaction, regasification, power-to-gas, etc.), their associated costs (cost-curves for production), and the gas demand. METIS then optimises the investments in and use of infrastructure to meet the demand at the lowest possible cost, while satisfying all the technical constraints of the different elements along the gas value chain. The inputs are listed below. When capacity expansion is to be used, the investment costs and potentials should be provided for the considered investment options instead of the installed capacities.

Production – *for all Member States and gas producing countries (e.g. Norway, Russia, Algeria, etc.)*

- Production capacity: instantaneous capacity available to produce gas to be used within or exported into Europe;
- Production cost-curves: for each gas producer, the cost curve should represent the cost of producing gas from the different domestic sources, ordered according to their marginal costs;
- Liquefaction capacity: instantaneous capacity available to produce LNG;
- Liquefaction cost.

Storage – *for all Member States and other explicitly represented countries (e.g. Switzerland, etc.)*

- Storage injection/withdrawal capacity: instantaneous capacity to withdraw gas from the network and to inject gas back into the network;
- Storage capacity: volume of gas that can be stored;
- Cost (or tariff) to inject/withdraw gas from the network;
- Constraints related to e.g. minimum storage level for winter periods.

LNG terminals – *for all Member States and other explicitly represented countries (e.g. Norway, etc.)*

- Injection capacity: instantaneous capacity to inject gas into the network;
- Storage capacity: volume of gas that can be stored at the LNG terminal (in liquid and/or gaseous forms);
- Regasification costs;
- Constraints related e.g. to arrival of tankers.

[61] https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

Pipeline/interconnectors – *for all interconnectors between Member States and from third countries (e.g. Russia, Norway, Algeria, etc.)*

- Pipeline capacity: instantaneous capacity to move gas between interconnected countries;
- Costs/tariffs/fees.

Demand

- Annual gas demand, ideally with a daily or finer time resolution;
- If possible, several gas demand patterns for different climatic years will be provided (alternatively the demand's dependence to temperature can be provided);
- The demand should ideally be decomposed by sector/use. In particular the share (and dynamics) of the gas-to-power demand should be provided.

Imports/exports

- Constraints on imports and exports with countries that are not explicitly represented (e.g. time-series, annual targets, profile cone, etc.).

Interlinkages

METIS is able to represent interlinkages between energy carriers. For example, it includes a fully coupled gas-electricity model where the operations on both networks (and potentially investments) are jointly optimised. We present in the following paragraphs the required datasets for the interlinkages that are discussed in the different storylines that have been presented in this report:

- Gas-to-power (for each cluster of gas-fired generation plants): installed capacity per zone, technical parameters (efficiency, min load, min time off, ramping rates, reserve procurement constraints, etc.), operational costs (variable costs, start-up costs, no-load costs, etc.);
- Electrolysis /methanation: installed capacity per zone, technical parameters (efficiency, min load, min time off, ramping rates, reserve procurement constraints, etc.), operational costs (variable costs, start-up costs, no-load costs, etc.), maximum hydrogen injection into the gas network, hydrogen demand by zone (in addition to injection into the gas network: industry, mobility, etc.);
- Biomethane: installed capacity per zone, production profile, production cost curve.

Based on the set of inputs presented in the previous paragraphs, METIS optimises the investments and operations (production, storage, liquefaction/ regasification, and transport of gas) to meet the demand at the lowest possible cost. Besides the optimal investment and operational decisions related to the infrastructure discussed above, METIS also produces marginal costs per country and a set of statistical indicators that can be used when performing cost-benefit analyses of infrastructure projects (for example: socio-economic welfare, supply source dependence, etc.).

Trinomics B.V.
Westersingel 32A
3014 GS Rotterdam
the Netherlands

T +31 (0) 10 3414 592
www.trinomics.eu

KvK n°: 56028016
VAT n°: NL8519.48.662.B01